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Ozone Impacts of Natural Gas Development in the Haynesville Shale

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The Haynesville Shale is a subsurface rock formation located beneath the Northeast Texas/Northwest Louisiana border near Shreveport. This formation is estimated to contain very large recoverable reserves of natural gas, and during the two years since the drilling of the first highly productive wells in 2008, has been the focus of intensive leasing and exploration activity. The development of natural gas resources within the Haynesville Shale is likely to be economically important but may also generate significant emissions of ozone precursors. Using well production data from state regulatory agencies and a review of the available literature, projections of future year Haynesville Shale natural gas production were derived for 2009−2020 for three scenarios corresponding to limited, moderate, and aggressive development. These production estimates were then used to develop an emission inventory for each of the three scenarios. Photochemical modeling of the year 2012 showed increases in 2012 8-h ozone design values of up to 5 ppb within Northeast Texas and Northwest Louisiana resulting from development in the Haynesville Shale. Ozone increases due to Haynesville Shale emissions can affect regions outside Northeast Texas and Northwest Louisiana due to ozone transport. This study evaluates only near-term ozone impacts, but the emission inventory projections indicate that Haynesville emissions may be expected to increase through 2020.

Introduction

The Haynesville Shale is a rock formation that lies at depths of 10,000 to 13,000 feet below the surface and straddles the border between Northeast Texas and Northwest Louisiana near Shreveport (Figure 1). This formation is estimated to contain very large recoverable reserves of natural gas (*1*, *2*), and during the two years since the drilling of the first highly productive wells in 2008, it has been the focus of intensive exploration and leasing activity (*3*). Despite the economic downturn of 2009 and associated fall in price of natural gas, development of the Haynesville Shale has continued (*4*).

The development of natural gas resources within the Haynesville Shale is likely to be economically important but may also generate significant emissions of ozone precursors. Nitrogen oxides (NOx) are emitted during well drilling and subsequent rock fracturing to stimulate natural gas production as well as from compressor engines that are used to produce and transmit the gas. Volatile organic compounds (VOCs) are emitted from many processes including venting and completion of wells, dehydration of produced natural gas and fugitive emissions from well and pipeline components.

To our knowledge, there have been no published studies of regional air quality impacts of shale gas development, although shale gas is projected to play an increasingly important role in meeting U.S. energy needs (*1*). Emissions resulting from developing the Haynesville Shale would be released in a region that is within and/or frequently immediately upwind of potential ozone nonattainment areas (*5*). Several counties within Northwest Louisiana and Northeast Texas as well as nearby Dallas-Fort Worth have been identified by the U.S. Environmental Protection Agency as areas that do not attain the 2008 ozone standard (*6*) of 75 ppb. In 2010, the EPA proposed a more stringent ozone standard (*7*) which heightens the importance of understanding how development in the Haynesville Shale may impact future ozone air quality in the region.

Methods

Haynesville Shale Emission Inventory. In this section, we describe the development of an emission inventory for sources related to projected natural gas exploration and production of the Haynesville Shale. This inventory does not include other regional sources such as power plants, motor vehicles, or biogenic emissions, nor does it include emissions from development of other oil- and gas-producing formations in the region. These non-Haynesville sources are accounted for in the ozone modeling via a separate emission inventory, as discussed in the Supporting Information.

Exploration and production in the Haynesville Shale began only recently in 2008; therefore, peer-reviewed published data that can be used in emission inventory development are extremely limited. Basic information, such as the geographic extent and recoverable reserves of the Haynesville Shale, is not yet known with certainty. Our strategy in developing estimates of future year activity and emissions was therefore to gather the best available information and cross-check among different sources of data where possible. The Texas Commission on Environmental Quality (TCEQ), Texas Railroad Commission (RRC), and the Louisiana Department of Natural Resources (LDNR) were contacted regarding production and activity within the Haynesville Shale. The RRC and LDNR provided drilling and production data, but recommended that the best source of estimates of future year activity and equipment use would be the energy producers active in the area. A survey was sent out to the producers identified on their company web pages, stockholder reports, or in venture capital firm reports as being major leaseholders in the Haynesville Shale as of March, 2009. Because so few wells had been drilled in the Haynesville Shale at that time, several producers felt that they did not yet have enough information to predict future year activity and production, and all of the producers declined to participate in the survey.

Using drilling and well production data from Texas and Louisiana state regulatory agencies and a review of the available literature, the spatial extent of the Haynesville Shale was defined (Figure 1), and projections of future year Haynesville Shale natural gas production for 2009−2020 were derived for three scenarios corresponding to limited,

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FIGURE 1. Spatial extent of the Haynesville Shale in Texas and Louisiana as defined in this study.

moderate, and aggressive development. The projection scenarios were constructed for each future year using two factors: (1) the number of new wells drilled (spuds) in each year and (2) production estimates for each new active well (derived from existing well decline curves). From these two factors, formation-wide spuds, well counts, and gas production were estimated. This analysis does not attempt to predict future economic conditions but attempts to take future economic variability into account by providing a range of potential future production estimates.

The 2001−2008 historical development in a similar nearby formation, the Barnett Shale near Dallas-Fort Worth, was used as a surrogate for modeling growth in drilling activity in the Haynesville Shale. 2001−2008 was a period of favorable natural gas prices that occurred after the development of the horizontal drilling and rock fracturing techniques that made extraction of shale gas economically feasible. The comparison to the Barnett Shale was made to determine a reasonable growth rate in development activity (determined by drilling counts per year) that can be assumed for the Haynesville Shale. For example, historical data from the Barnett Shale were used to constrain how rapidly drill rigs can be diverted from other regions into a more profitable area as well as indicate how quickly new infrastructure can be built to handle the increased gas production from a newly discovered formation. Further description of the Barnett Shale and the rationale for the use of its development as a surrogate for growth in the Haynesville Shale are provided in the Supporting Information.

Development was initialized with the number of drilling rigs operating in the Haynesville Shale during March 2009; this quantity was estimated through inspection of maps (*8*) of active drilling rigs in the area that were drilling development gas wells at depths between 10,000 and 15,000 ft in the counties shown in Figure 1. Three emissions scenarios were then developed. The "Low scenario" held constant the March 2009 drill rig count of 95 through 2012 until 2020. The "High scenario" grew the number of rigs to from the initial count of 95 in 2009 to 200 at the same growth rate as the 2001−2008 barnett Shale rig count. The "Moderate Scenario" grew the rig count to 200 at 50% of high scenario growth rate. The rig count was capped at 200 in the Moderate and High Scenarios to avoid predicting an unreasonably large number of rigs to be operating in the Haynesville Shale in future years. This number is close to the maximum number of drill rigs that have operated simultaneously in the Barnett Shale and is approximately ten percent of the entire U.S. fleet of drilling rigs (approximately 2000 in March 2009). The High Scenario has 170 rigs active in 2012; the 200 rig cap is reached in 2014, and the number of rigs is held fixed thereafter. The Moderate Scenario has 133 active rigs in 2012 and reaches 200 rigs in 2018. A chart showing the number of drilling rigs active in each year from 2009 to 2020 is shown in the Supporting Information.

The drill rig count for each growth scenario was used to determine the number of new wells drilled per year. Drilling records from the LDNR (*9*) were used to determine an average drilling duration of 63 days for spuds occurring in the Haynesville Shale. This duration includes the time needed to move a drilling rig to a new well site, mobilize the rig for drilling, drill the well, and demobilize the rig for transport to the next well site. Therefore, one drill rig was assumed to be able to drill a total of 365/63 = 5.8 wells in one year. The current 2009 baseline drilling success factor was determined from the LDNR wells database (*9*) to be 55% for the Haynesville Shale region; this figure was determined to be the percentage of new active wells added to the region relative to the number of recorded spuds. With assumed technological improvements and better definition of the formation boundaries as exploration proceeds, our analysis assumes that the drilling success factor would improve to 100% by 2018 and would increase linearly between 2009 and 2018. In the High Scenario, there are projected to be 2181 active wells in 2012 and 10,714 wells in 2020; in the Low Scenario, 1568 wells are predicted to be active in 2012 and 5632 wells in 2020.

Using the well development estimates for each of the three scenarios and estimates for the typical gas production of a well over its lifetime, total gas production can be calculated for the three development scenarios. This analysis requires deriving estimates of typical well production over the time period 2009−2020, during which a well's production is expected to decline from an initial production peak. Haynesville Shale wells have been producing gas for a very limited time period (approximately 1 year at the time this analysis was conducted); therefore, long-term yearly production rates were unknown. To estimate long-term production rates, eight wells with the longest production were identified, and the production rates from the LDNR database (*9*) were analyzed to derive a representative decline curve for all Haynesville Shale wells (see the Supporting Information). There is significant uncertainty in this estimate, but development of the Haynesville Shale region is so recent that a more robust well decline data set was not available. The decline curve was extrapolated to the year 2020 by finding the best fit power law function for each well and then averaging over the eight wells to calculate a derived decline curve such that yearly well production could be determined for an "average" Haynesville Shale well. The power law function was chosen as a representative fit based on other historical well decline curves.

A separate literature search was conducted to determine the availability of additional published Haynesville Shale well decline curves. Two venture capital reports from Tristone Venture Capital (*2*) and Southern Star (*10*) contained well decline curves for the Haynesville Shale for a number of individual wells. The reported decline curves from venture capital sources were averaged together to develop a single reported well decline curve. The total cumulative per-well production from the reported curves is 5.2 billion cubic feet (bcf), compared to 1.9 bcf for the derived well decline curves. Both decline curves are shown in the Supporting Information. This analysis assumes that the lower, derived well decline curve is representative of the low and moderate development scenarios, and the reported well decline curve obtained from the venture capital reports is representative of the high development scenario.

Total Haynesville Shale production estimates for the period 2009−2020 were obtained by multiplying the number of active wells by the appropriate annual production rate determined from the decline curve and the year that each well was brought online and summing over all active wells. Cumulative gas production for each scenario is shown in the Supporting Information. These production estimates were then used to develop an inventory of potential emissions from future natural gas exploration and production in the Haynesville Shale for all three scenarios. For exploration and production sources, ozone precursor emission rates were estimated based on data gathered from published reports of emission inventories of natural gas production sources in the region (*11, 12*). "On-the-books" federal or state regulations that would affect the emissions projections (e.g., Federal New Source Performance Standards, off-road engine Tier standards, East Texas Combustion Rule) were applied. A detailed description of the development of the inventory is given elsewhere (*13*).

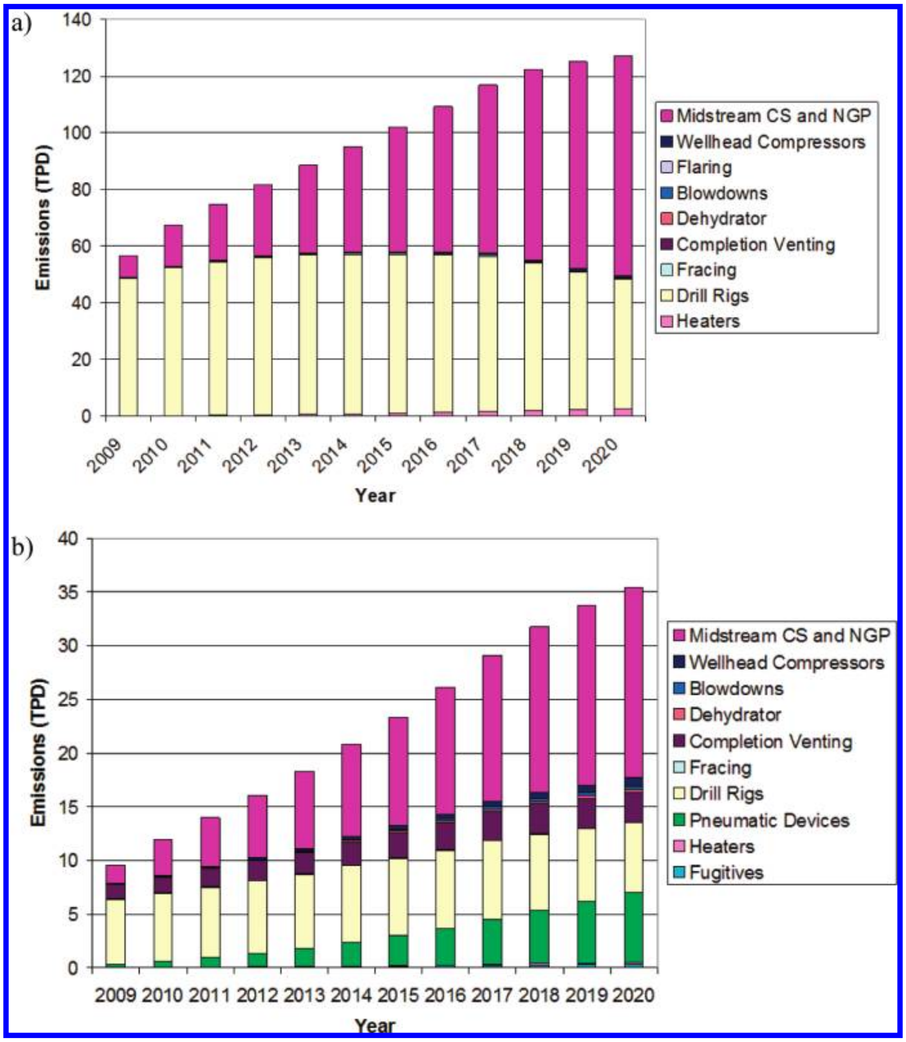

FIGURE 2. a) 2009 to 2020 moderate scenario Haynesville Shale formation-wide NOx emissions by source category and b) 2009 to 2020 moderate scenario Haynesville Shale formation-wide VOC emissions by source category. Midstream CS and NGP refer to central compressor stations (CS) and natural gas processing (NGP) facilities which transmit and process produced gas.

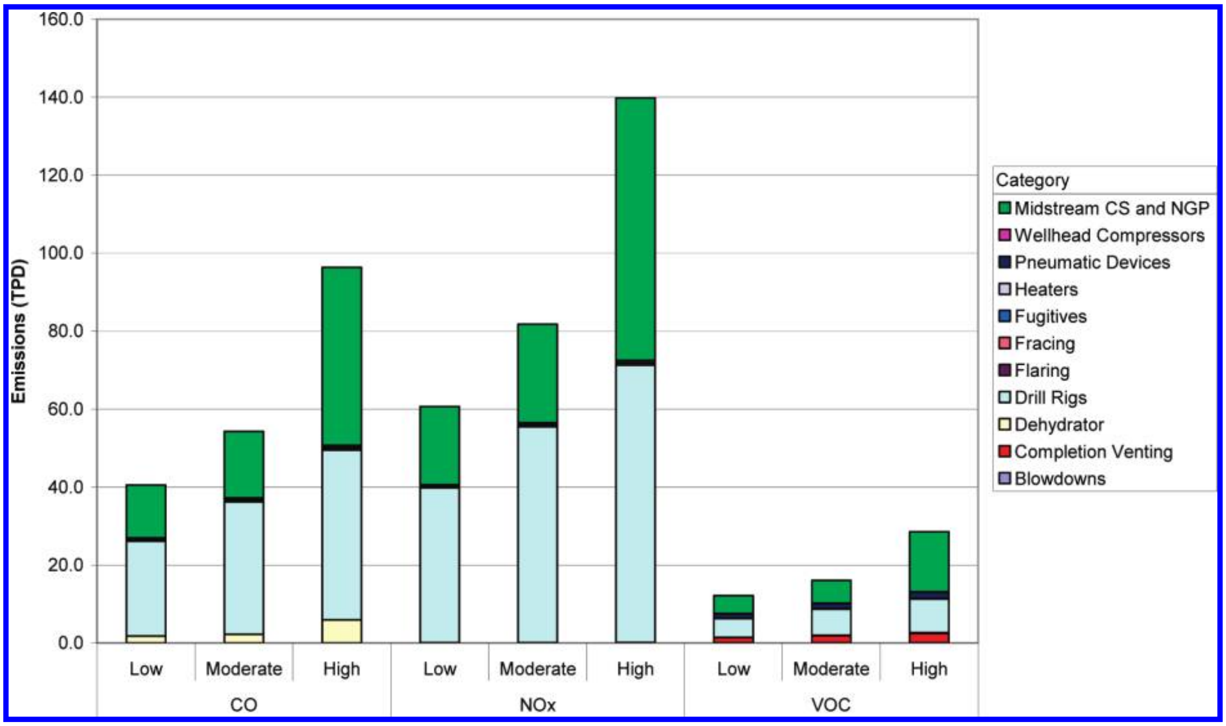

FIGURE 3. 2012 Haynesville Shale formation emissions of NOx, VOC, and CO by scenario and source category. Midstream CS and NGP refer to central compressor stations (CS) and natural gas processing (NGP) facilities which transmit and process produced gas.

Figure 2a shows the formation-wide NOx emissions for 2009−2020 for the moderate scenario. NOx emissions are projected to increase by 124% from 2009 to 2020. By 2020, development in the Haynesville Shale results in more than 120 tons/day of NOx emitted in northeast Texas and northwest Louisiana. Notably, drill rig NOx emissions remain relatively constant, while midstream compressor station and natural gas processing plant NOx emissions account for most of the increase. For the moderate scenario, the number of rigs in the Haynesville Shale region increases from 2009 to 2017, but the drill rig emissions flatten out and eventually decrease because of turnover in the drill rig engine fleet that results in replacement of older engines with higher Tier, cleaner-burning engines. Figure 2b shows that moderate scenario VOC emissions are projected to increase by 271% from 2009 to 2020. VOC emissions increases are primarily due to increases in midstream compressor station and natural gas processing plant VOC emissions, though pneumatic devices, drill rigs, and completion venting among other categories also contribute significantly to VOC emission increases.

Emissions of the ozone precursors NOx, VOC, and carbon monoxide (CO) for the entire Haynesville Shale formation for the 2012 modeling year are shown in Figure 3. Estimates of 2012 NOx emissions ranged from 61 tons/day in the low development scenario to 82 tons/day in the moderate scenario to 140 tons/day in the high scenario. These emissions increases are sufficiently large that it is necessary to evaluate their ozone impacts.

Ozone Modeling. The Comprehensive Air-quality Model with extensions (CAMx) (*14*) was used to model the eastern half of the United States using nested 36, 12, and 4 km resolution grids with the 4 km grid located over the Haynesville Shale region (Figure S1). CAMx is a three-dimensional, chemical-transport grid model used for tropospheric ozone, aerosols, air toxics, and related air-pollutants and is used for air-quality planning in Texas (*15, 16*) and Louisiana (*17*). CAMx was used here to estimate the near-term ozone impacts due to projected Haynesville Shale emissions during 2012.

The model's vertical resolution is finest near the ground (33 m surface layer) and extends to the lower stratosphere in 44 layers. The CAMx modeling databases were originally developed for current regulatory modeling of ozone in Houston and Northeast Texas. Meteorological input data for CAMx were developed using the PSU/NCAR Mesoscale Model version 5 (MM5) (*18*). The MM5 provides CAMx with hourly, gridded data for wind vectors, pressure, temperature, diffusivity, humidity, clouds, and rainfall. Emissions of VOCs, NOx, and CO from the TCEQ's 2005 emission inventory (*15*) were used. Boundary conditions for the outermost (36 km) grid were derived from a continental-scale CAMx run that was itself driven with data from a GEOS-Chem model (*19*) global simulation of 2005. The continental-scale CAMx run included the effects of episode-specific fire emissions derived from satellite observations. Large NOx sources were treated with the CAMx plume-in-grid submodel, and the model was run using a dry deposition algorithm (*20, 21*) developed for Environment Canada's AURAMS air quality forecasting model (*22*) that was newly implemented in CAMx.

The model was first applied for a historical episode during May 20-June 30, 2005 to evaluate its performance in simulating observed ozone and precursors. This analysis is described in (*23*) as well as in the Supporting Information. The model was found to reproduce observed ozone with good accuracy within the Texas-Louisiana-Arkansas-Oklahoma region. Projections of future year emissions for all regional sources unrelated to the Haynesville Shale were made for the year 2012 (*24*). A baseline 2012 model simulation was carried out in which the model was configured exactly as for the May-June 2005 simulation, except that the emission inventory of anthropogenic sources for 2005 was replaced with the 2012 anthropogenic emission inventory excluding emissions from the Haynesville Shale. This simulation is referred to as the 2012 baseline. Then, the 2012 simulation was repeated three times with emissions from the three (low, moderate, and high) Haynesville Shale emissions scenarios added to the 2012 emission inventory. The processing of the Haynesville emissions for use in CAMx, including spatial allocation of emissions, is discussed in the Supporting

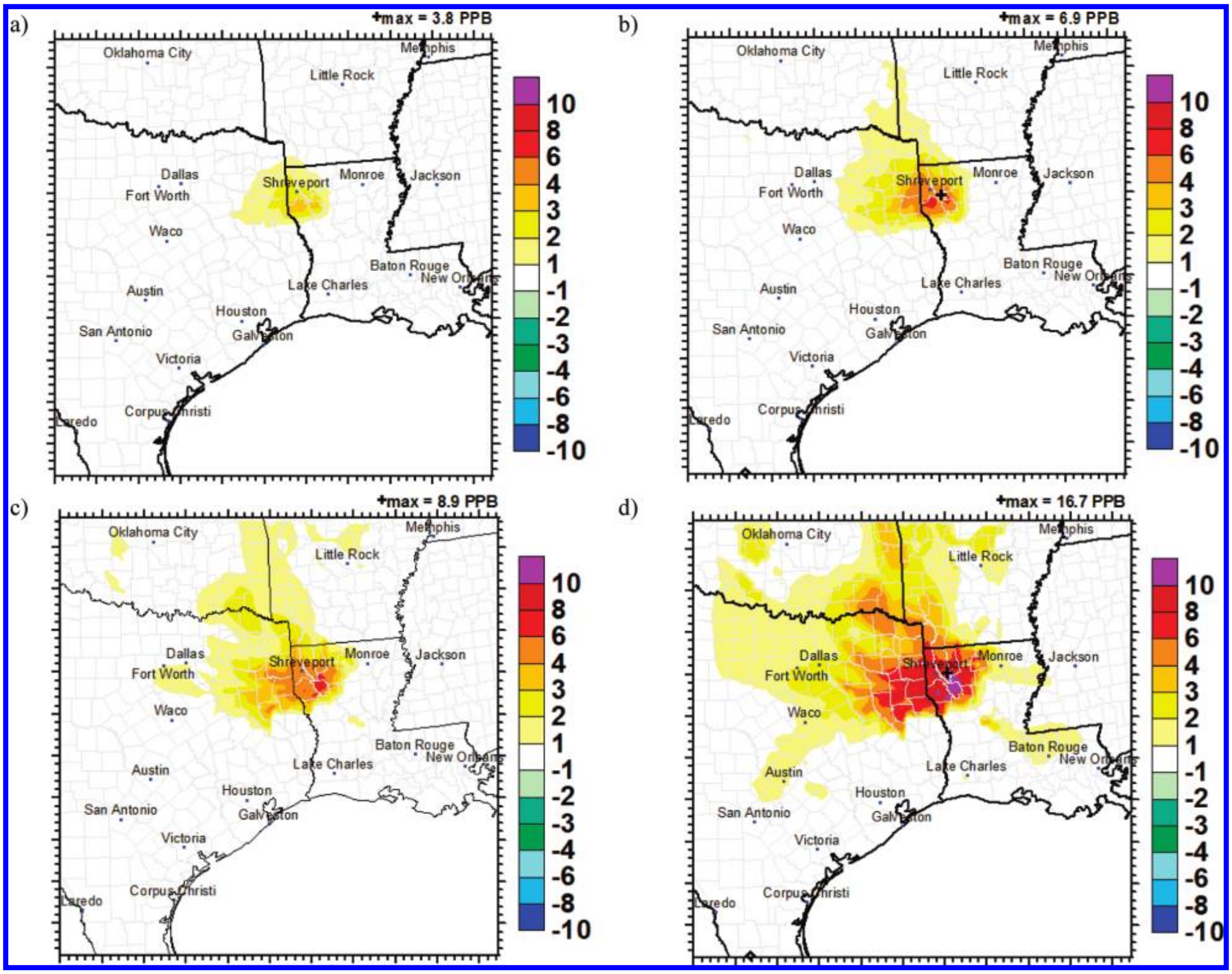

FIGURE 4. Twelve km grid ozone modeling results: a) Episode average difference in daily maximum 8-h ozone (ppb): Haynesville Low Secenario-2012 Baseline and b) Episode average difference in daily maximum 8-h ozone (ppb): Haynesville High Scenario-2012 Baseline and c) Episode maximum difference in daily maximum 8-h ozone (ppb): Haynesville Low Scenario-2012 Baseline and d) Episode maximum difference in daily maximum 8-h ozone (ppb): Haynesville High Scenario-2012 Baseline.

Information. The modeled ozone from each of these three scenarios is compared below to the 2012 baseline simulation ozone to isolate the ozone impacts of the Haynesville Shale for each emissions scenario.

Results and Discussion

Ozone Impacts. In presenting the ozone impacts of the Haynesville Shale, we focus on its effects on regional 8-h average ozone because of the relevance of this quantity to the National Ambient Air Quality Standard (NAAQS) for ozone (1-h ozone impacts are presented in the Supporting Information). We compute the difference in the daily maximum 8-h average ozone between the baseline 2012 run and each of the three Haynesville Shale runs in turn for each day of the May-June episode for all grid cells within the modeling domain. The average difference in the 8-h daily maximum ozone between each pair of runs is calculated for all times when the modeled 8-h ozone was greater than 60 ppb for at least one of the pair of runs. This restricts the analysis to periods of modeled high ozone within the May-June episode (i.e., nighttime and clean periods are removed from consideration). We look at the average difference across the entire May-June episode between the baseline 2012 run and each Haynesville emissions scenario run as well as the maximum difference between the pair of runs during the episode.

Comparisons of the differences in the May-June 2012 episode average daily maximum 8-h ozone are shown for the low and high Haynesville Shale scenarios in Figure 4 for the 12 km grid; we present the results on the 12 km grid to show impacts at the regional rather than local scale but note that the 4 km grid and 12 km grid were consistent in the magnitude of ozone impacts (not shown; see ref *24*). The ozone impacts from the moderate emissions scenario fall between the low and high cases and are not shown here for the sake of brevity.

Figure 4a shows that the episode average ozone impact of the emissions from the Haynesville Shale in the low scenario is largest in northwestern Louisiana, with peak increase of 4 ppb in southern Bossier Parrish. The area in which the episode average increase in daily maximum 8-h average ozone is larger than 1 ppb is mainly confined to northeast Texas and northwest Louisiana. In the high emissions scenario (Figure 4b), the episode average increase in daily maximum 8-h ozone has a similar pattern, but the increases are larger, with a peak of 7 ppb. There are areas of De Soto, Caddo, Bienville, Red River, and Bossier Parishes in Louisiana with episode average increases in the 6−8 ppb range. Texas counties Harrison, Panola, Rusk, Marion, and Shelby all experience average increases in the 4−6 ppb range, and Gregg and Cass Counties have regions where the average increase falls in the 3−4 ppb range. The region with episode average impacts greater than 1 ppb is larger in the high scenario than in the low scenario, extending eastward to the edge of Dallas-Fort Worth and northward into Oklahoma and Arkansas.

Figure 4c and 4d show the maximum differences in the daily maximum 8-h ozone between the Haynesville Shale and 2012 baseline runs for the low and high scenarios, respectively. In the high scenario, the peak increase is 17 ppb in southern Bossier Parish, and the area of increases greater than 6 ppb covers a broad swath of counties in northeast Texas and northwest Louisiana. The region of impacts greater than 4 ppb extends northward into Oklahoma and Arkansas, and the region of impacts between 2−3 ppb extends westward into the Dallas-Fort Worth area. The region of impacts ranging from 1−2 ppb includes McLennan, Travis, Hays, and Bexar Counties in Texas and the Baton Rouge area in Louisiana including Pointe Coupee, East and West Baton Rouge, and Livingston Parishes. The pattern of impacts is similar but less intense in the low scenario. These results show that the impacts of development in the Haynesville Shale may extend well outside the immediate vicinity of the Haynesville Shale into other regions of Texas and Louisiana and affect areas that may not attain the new 2010 ozone standard.

An ozone monitor's compliance with the NAAQS is reckoned using its design value, which is the three-year average of the fourth highest daily maximum 8-h ozone concentration. Changes in the ozone design value due to Hayneville Shale development relative to the baseline 2012 run were calculated for the low and high Haynesville scenarios. The design value analysis was carried out for currently active ozone monitors within the 4 km grid using EPA's Modeled Attainment Test Software (MATS (*25*)). MATS allows the model results to be used in a relative sense, scaling observed base year (2005) ozone design values with a ratio of model results for a base (2005) and a future year (2012) to project future year design values . This method is designed to reduce the uncertainty in future year projections due to any model bias that may be present, and is a standard technique in regulatory ozone modeling (*27*). Additional description of the method is provided in the Supporting Information.

Design values were calculated for three future cases: the baseline 2012 run, the 2012 Haynesville low scenario, and the 2012 Haynesville high scenario; the difference between the Haynesville scenario design values and the 2012 baseline design values was calculated to show the impact on the local design values of the additional emissions from Haynesville Shale development. The MATS results show 2012 design value increases for ozone monitors located within the Haynesville Shale counties of Harrison (TX), Bossier (LA), and Caddo (LA) of 2 ppb in the low scenario and 4−5 ppb in the high scenario. For the Gregg (TX) and Smith (TX) county monitors, which lie west of the Haynesville Shale, design value increases are smaller, ranging from 1 ppb for both monitors in the low scenario to 1−2 ppb in the high scenario.

Implications and Future Work. The magnitude of projected emissions and modeled 8-h ozone impacts described above indicate that development of the Haynesville Shale provides cause for concern about future ozone air quality in Texas and Louisiana. This analysis suggests that if the development of the Haynesville Shale proceeds at even a relatively slow pace, emissions from exploration and production activities will be sufficiently large that their potential impacts on ozone levels in Northeast Texas and Northwest Louisiana may affect the ozone attainment status of these areas. For example, the observed 2007−2009 design value at the Harrison County, TX monitor is 68 ppb, which complies with the 2008 NAAQS. The 4 ppb increase in the design value predicted for the high scenario would cause this monitor to fail to attain the full range of the 2010 NAAQS proposed by the EPA (60−70 ppb). The monitors in Gregg and Smith County have 2007−2009 design values of 75 and 74 ppb, respectively. They attain the 2008 NAAQS but are higher than the 60−70 ppb range of the proposed 2010 standard. The predicted increases in their design values due to Haynesville development would drive them further from attainment. Note that this study only evaluates near-term ozone impacts of development, but the emission inventory indicates that emissions may be expected to increase beyond 2012.

Additional study is required to refine the emission inventories used in this analysis. There is significant uncertainty associated with the emissions estimates since development in the Haynesville Shale is still in its early stages. This study forecasts emissions from development whose pace depends on a wide variety of factors that are subject to change. However, it is important to gain an understanding of the potential effects of this development and their impact on regional air quality; therefore, we account for uncertainty in the ozone model results by developing a range of emissions scenarios and presenting ozone impacts for the high and low scenarios as a method for bounding the uncertainty. The assumptions used in the development of the inventories - particularly the apparent limited need for wellhead compressors - indicate that these inventories could tend toward lower bound estimates. On the other hand, it is also possible that some source categories may be overestimated - for example, improvements in drilling technology could reduce future drilling times and therefore, NOx emissions associated with drilling. New controls or standards could also have a significant effect on future emissions and only on-the-books regulations were applied to the Haynesville inventory. Figure 2 shows that drill rigs and compressor stations and gas plants make the most significant contributions to the NOx emission inventory; additional controls on these sources would therefore be beneficial in reducing future year emissions from the Haynesville Shale. Future work will focus on enhancing the inventory with additional data regarding well site compression, well decline curves, and drill rig use.

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Supporting Information Available

Details describing the emissions estimation methodology, CAMx model, and model performance evaluation. This material is available free of charge via the Internet at http://pubs.acs.org.

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Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas

HYDROGEN SULFIDE REPORT TO CONGRESS -- EXECUTIVE SUMMARY

Under section 112(n)(5) of the Clean Air Act (CAA), as amended, Congress required the Administrator of the United States Environmental Protection Agency (EPA) to carry out a study to assess the hazards to public health and the environment resulting from the emission of hydrogen sulfide (H_2S) associated with the extraction of oil and natural gas. The assessment must include a review of existing State and industry control standards, techniques, and enforcement. This report, developed in fulfillment of section 112 (n)(5), evaluates the hazards to the public and the environment posed by these emissions.

This study was added to the CAA by the Committee on Environment and Public Works, chaired by the late Senator Quentin N. Burdick of North Dakota, because of concern about the health and environmental hazards associated with H_2S emissions from oil and gas wells. Witnesses testified before Congress that these emissions resulted in deterioration of air quality, death and injury to livestock, and evacuation and hospitalization of residents located near the release point of such emissions.

Congress considered listing H_2S as a hazardous air pollutant (HAP) under section 112(b) of the CAA, which regulates industrial sources of routine emissions of HAPs. On the basis of information contained in accident records, it was determined that H_2S is a concern from an accidental release standpoint and it would be listed under the accidental release provisions in section 112(r) of the Act, and not under section 112(b). Substances regulated under 112(r) are known or may be anticipated to cause death, injury, or serious adverse effects to human health or the environment upon accidental release.

Hydrogen sulfide is produced in nature primarily through the decomposition of organic material by bacteria. It develops in stagnant water that is low in oxygen content, such as bogs, swamps, and polluted water. The gas also occurs as a natural constituent of natural gas, petroleum, sulfur deposits, volcanic gases, and sulfur springs. Natural sources constitute approximately 90 percent of the atmospheric burden of H_2S. Ambient air concentrations of H_2S due to natural sources are estimated to be between 0.11 and 0.33 ppb (0.15 and 0.46 $\mu g/m^3$).

H_2S is a colorless gas with an offensive odor characteristic of rotten eggs. H_2S is flammable and highly corrosive to metals. It is toxic and care should be exercised in its presence. There have been several incidences in the United States of deaths of workers exposed to H_2S gases. Other symptoms of exposure include irritation, breathing disorders, nausea, vomiting, diarrhea, giddiness, headaches, dizziness, confusion, rapid heart rate, sweating, weakness, and profuse salivation. Levels above 1.5×10^5 ppb are considered life threatening. Few studies exist measuring effects of natural or accidental exposure of wildlife to H_2S; however, wildlife deaths have been reported in connection with blowouts (a sudden expulsion of gas or oil well fluids with great velocity).

Natural gas and oil formations may be composed of many gases. The largest volume and most beneficial gases in this composition are generally the light hydrocarbons (methane, ethane, propane, and butane). H_2S is the most common impurity in hydrocarbon gases. If an oil and gas formation contains H_2S, it is said to be "sour." Although a sour well's oil and gas can be sweetened by removing the H_2S after extraction, the well is always considered sour once H_2S is present.

Certain areas of the United States are especially prone to contain H_2S in oil and gas reservoirs at varying depths underground. Vulnerability zones have been characterized as 14 major H_2S prone areas found in 20 States. Texas has four discrete H_2S prone areas. Concentrations as high as 42 percent H_2S (by volume) have been found in gas from central Wyoming.

In the oil and gas industry, H_2S may be emitted or released during exploration, development, extraction, crude treatment and storage, transportation (e.g., pipeline), and refining. This report focuses on potential hazards of routine emissions and accidental releases of H_2S from the extraction and storage of crude oil and natural gas at well sites. Potential sources of emissions include flares/vapor incinerators, heater-treaters (an oil/water/gas separation device), storage tanks, equipment (valves, flanges, etc.), and both active and abandoned wells.

When H_2S is released to the air from an oil or gas well, several factors determine its possible effects on surrounding residents and the environment. Accidental releases of sour gas, such as from a well blowout or pipe rupture, are usually at high pressure and will entrain surrounding air. This causes significant, immediate dilution of the H_2S and other components of the gas, thereby reducing the potential magnitude of the consequences of the release. Factors such as chemical composition of the expelled gas, release rate, release orientation, topography and meteorological conditions also determine the effects of such a release.

Human fatalities from H_2S exposure from oil wells in the United States have virtually all been work-related. Significant public impacts are rare although evacuations have been initiated in response to accidental releases and at least one case of loss of consciousness has been reported as a result of exposure.

Eighteen states have developed ambient air quality guidelines for H_2S. Most, however, do not collect continuous data but rather only monitor for H_2S when a complaint is made. These guidelines range from 160 ppb per 24-hr averaging time to 14 ppb per 24-hr averaging time. Little data exist to determine actual levels of H_2S near oil and gas extraction sites. North Dakota was the only State found to have a continuous record of H_2S atmospheric levels at several sites. Exceedences of the North Dakota air quality standard have been minimal in recent years at these monitoring locations. No specific H_2S environmental (i.e., ecological) protection standards were found to exist. Some States require notification of the regulatory authority upon accidental release of H_2S from oil and gas wells but few maintain an inventory of such incidences. Reporting of routine emissions (emissions of small quantities from equipment, pipelines, flares, and storage tanks) was not required by the States reviewed in this report.

H_2S is regulated under a number of United States statutes. It is listed as a hazardous substance under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA). It is listed under the Emergency Planning and Community Right-to-Know Act (EPCRA) for emergency planning and preparedness, community right-to-know reporting, and toxic chemical release reporting. The Occupational Safety and Health Administration (OSHA) has established General Industry Standards that list worker exposure concentration limits, and Respirator Standards. The National Institute for Occupational Safety and Health (NIOSH) has produced a criteria document containing recommendations for safe worker exposure levels and work practices. The United States EPA has the potential for regulation of new oil and gas well sources through the Prevention of Significant Deterioration (PSD) program and, as mentioned previously, H_2S is listed under the CAA section 112(r) accidental release provisions.

Other standards for worker and public protection from H_2S emissions come from the Bureau of Land Management, Minerals Management Service, and the American Conference of Governmental Industrial Hygienists.

The oil and gas production industry has guidelines for safe practices regarding H_2S. The American Petroleum Institute, an industry-wide technical organization, has published six documents regarding H_2S in the industry. They pertain to safety practices for drilling, operation, and equipment.

Findings and Recommendations

As a result of this study, EPA finds that the potential for human and environmental exposures from routine emissions of H_2S from oil and gas wells exists, but insufficient evidence exists to suggest that these exposures present any significant threat. On the other hand, an accidental release of H_2S from an oil or gas well could have severe consequences because of its toxicity and its potential to travel significant distances downwind under certain circumstances. The likelihood (and thus the risk) of an accidental release of H_2S or any other hazardous substance, can be greatly reduced if facility owners/operators exercise the general duty and responsibility to design and operate safe facilities and if they comply with existing industry standards and practices, existing regulations, and future guidance and regulations. Such actions should result in: (1) the safe management of H_2S and other hazardous substances with an emphasis on accident prevention; (2) the preparedness to properly and quickly respond to chemical emergencies and to provide specialized medical treatment if necessary; and (3) community understanding of the risks involved. Industry should ensure that H_2S is safely handled and that accidental releases are prevented; that any releases that do occur are quickly discovered, controlled, and mitigated; and that workers and the community are informed and prepared to properly respond to a H_2S emergency.

From the limited data available, there appears to be no evidence that a significant threat to public health or the environment exists from routine emissions from sour oil and gas wells. States and industry are encouraged to evaluate existing design, construction, and operation principles within the framework of process safety management. EPA recommends no further legislation pertaining to routine H_2S emissions or accidental releases from oil and gas wells at this time. However, the Agency does recommend that the owner/operators of oil and gas extraction conduct drills and exercises with workers, the community, first responders, and others to test mitigation, response, and medical treatment for a simulated H_2S accident. Sour oil and gas extraction facilities should be able to rapidly detect, mitigate, and respond to accidental releases in order to minimize the consequences. The Agency will continue to investigate the need for additional rulemaking under the accidental release prevention provisions of the Clean Air Act.

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CHAPTER I
INTRODUCTION

STATUTORY REQUIREMENTS

Section 112(n)(5) of the Clean Air Act (CAA or Act), as amended in 1990, requires the Environmental Protection Agency (EPA) "to assess the hazards to the public and the environment resulting from the emissions of hydrogen sulfide (H_2S) associated with the extraction of oil and natural gas resources." This assessment must reflect consultation with the States and shall include a review of State and industry control standards, techniques, and enforcement. To avoid duplication of work by other EPA offices, the assessment must build upon a report from the Office of Solid Waste conducted under Section 8002(m) of the Solid Waste Disposal Act. The Section 8002(m) study is a three-volume report to Congress entitled *Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy* (1987).

The EPA Administrator is required by the Act to report to Congress with the findings of the assessment along with any recommendations. Moreover, under Section 112(n)(5) (or 42 U.S.C.7412(n)5), the Administrator "shall, as appropriate, develop and implement a control strategy for emissions of hydrogen sulfide to protect human health and the environment."

This study was added to the Act by the Committee on Environment and Public Works chaired by the late Senator Quentin N. Burdick of North Dakota. The study was included in the Act because of concern about the health and environmental hazards associated with H_2S emissions from oil and gas wells. In 1987, Congress received testimony in which witnesses urged that H_2S should be listed as a hazardous air pollutant under the provisions of Section 112 of the Clean Air Act. The witnesses testified that lack of emission controls resulted in significant deterioration of air quality. There was also testimony that H_2S releases from oil and gas facilities caused death and injury to livestock and required the evacuation and hospitalization of residents from affected areas.

Congress considered listing H_2S as a hazardous air pollutant (HAP) under Section 112(b), which regulates industrial sources for routine emissions of HAPs. On the basis of information contained in accident records, it was determined that H_2S is a concern from an accidental release standpoint and should be listed under the accidental release provisions in Section 112(r) of the Act. The substances regulated under Section 112(r) are known or may be anticipated to cause death, injury, or serious adverse effects to human health or the environment from accidental releases. Under the provisions of Section 112(r) of the Act, the EPA must develop a list of at least 100 substances that pose the greatest risk from accidental releases. The Act listed 16 chemicals, including H_2S, which must be included in the Section 112(r) list.

A clerical error led to the inadvertent addition of H_2S to the Section 112(b) list of HAPs. However, a Joint Resolution to remove H_2S from the Section 112(b) list was passed by the Senate on August 1, 1991, and the House of Representatives on November 25, 1991. The Joint Resolution was approved by the President on December 4, 1991. It should be emphasized that the purpose of this report is not to examine whether or not H_2S should be included in the Section 112(b) list.

SCOPE OF REPORT

The scope of this report is determined by the Congressional directive found in Section 112(n)(5), which is quoted in its entirety in Exhibit 1. For clarity, the Agency has designed the report to respond to specific items in the directive within separate chapters or sections of chapters. It is important to note that although all issues relevant to this study have been weighed in arriving at the conclusions and recommendations of this report, no single issue has a determining influence on the conclusions and recommendations.

The directive in Section 112(n)(5) is expanded upon in the paragraphs below. Detailed methodologies used to analyze and respond to the directive can be found later in this report and in the supporting documentation and appendices. The principal components of the Congressional mandate are:

1. Review existing State and industry control standards, techniques, and enforcement programs.

Currently, there are no Federal ambient air quality standards for H_2S. Most oil- and gas-producing States have their own regulations and enforcement programs. Some States, such as some hosting major producers, have large H_2S programs in place. However, the risk may exist in States that do not have large programs simply because of the lack of State regulatory overview. Although Occupational Safety and Health Administration (OSHA) standards exist that are applicable to oil and gas production, there are no industry-specific standards. However, the industry has developed recommended practices and technologies to reduce the potential for H_2S emissions.

Current State regulations regarding H_2S emissions from the extraction of oil and gas are summarized in this report, with emphasis on four oil-producing States—California, Michigan, Oklahoma, and Texas. Industry safety procedures as well as regulations promulgated and proposed by OSHA and other Federal regulatory programs are reviewed.

2. Assess the hazards to public health and the environment resulting from the emission of H_2S associated with extraction of oil and natural gas resources.

Hydrogen sulfide is a colorless gas almost as toxic as hydrogen cyanide and 5 to 6 times more toxic than carbon monoxide. The principal threat of H_2S gas to human life is poisoning by inhalation (Dosch and Hodgson, 1986). Over the years, there have been

112(n)(5) **Hydrogen Sulfide.**– The Administrator is directed to assess the hazards to public health and the environment resulting from the emission of hydrogen sulfide associated with the extraction of oil and natural gas resources. To the extent practicable, the assessment shall build upon and not duplicate work conducted for an assessment pursuant to section 8002(m) of the Solid Waste Disposal Act and shall reflect consultation with the States. The assessment shall include a review of existing State and industry control standards, techniques, and enforcement. The Administrator shall report to the Congress within 24 months after the date of enactment of the Clean Air Act Amendments of 1990 with the findings of such assessment, together with any recommendations, and shall, as appropriate, develop and implement a control strategy for emissions of hydrogen sulfide to protect human health and the environment, based on the findings of such assessment, using authorities under this Act including sections 111 and this section.

Exhibit 1. 1990 Clean Air Act Amendments: Mandate for a Report to Congress on H_2S Emissions Associated with Oil and Gas Extraction.

incidents involving exposure to H_2S resulting from accidental releases from oil and gas extraction facilities that have caused death or injury to humans or animals (Layton, D.W., et al; Texas Oil and Gas Pipeline Corporation).

Oil and gas extraction, as defined in this study (see Appendix A), includes only the activities involved in removing oil and/or gas from an established (developed) well. This report includes not only a review of oil and gas extraction, but also other associated components of oil and gas extraction such as piping to a separator, separation, and storage. However, in following the Congressional mandate to address extraction, this report does not cover activities primarily associated with exploration or well development, nor does it cover sources such as gas processing plants. It is noteworthy that these plants are potential sources of H_2S releases since one of their functions is to remove impurities such as produced water, H_2S and/or carbon dioxide. Personnel at these plants are trained in H_2S safety. However, this operation falls outside the definition of extraction.

In addition to assessing the sources of H_2S emissions in the extraction industry, this report discusses related control technologies as well as the health and environmental effects associated with exposure to accidental H_2S releases and routine H_2S emissions during extraction and closely associated production activities. When possible, monitored ambient air concentrations of H_2S and cases of death or injury to humans, wildlife, and/or livestock from exposure to H_2S releases and emissions are documented.

The report culminates with a hazard assessment of H_2S routine emissions and accidental releases from oil and gas extraction activities based on information obtained in the efforts described in the previous paragraphs. Past and potential hazards from both routine emissions and accidental releases are identified, the degree of hazard is assessed, and potentially exposed human and ecological populations are identified.

3. **Recommend and, as appropriate, develop and implement a control strategy for H_2S emissions to protect human health and the environment, based on the findings of such assessment, using authorities under this act including sections 111 and 112.**

As stated in a 1987 Senate report on the Clean Air Act Amendments, "Although many State [H_2S regulatory] programs are implemented conscientiously, in some instances concerns have been raised that some oil- and gas-producing States may not be enforcing their regulatory programs sufficiently or may have deficient regulatory programs. The purpose of this subsection is to assess the effectiveness and the level of enforcement of various hydrogen sulfide control programs. The assessment should assure more uniform application of control technology, standards and enforcement. The Administrator should examine in particular means of preventing accidental releases of hydrogen sulfide at remote facilities" (U.S. Senate, 1987). [EPA identifies and reviews current State and Federal regulatory programs and industry-recommended procedures to reduce routine emissions and accidental releases. However, the ability to assess the effectiveness of these programs is limited by the lack of available emissions-monitoring data and the limited information available on accidental release incidents.]

In this report, EPA makes recommendations regarding the release of H_2S from oil and gas extraction activities. The recommendations presented in this report do not constitute a regulatory determination. The Agency is, in several important areas, presenting optional approaches involving further research and consultation with the States and other affected parties.

ORGANIZATION OF REPORT

This report addresses two forms of H_2S losses to the atmosphere: routine emissions and accidental releases. (These terms are defined in the Glossary and examples are provided in Chapter II.)

Chapter II provides an overview of H_2S formation in oil and natural gas deposits and its presence in numerous industries. Potential sources of routine emissions and accidental releases from the oil and natural gas extraction industry are identified along with their causes. Chapter III is a hazard assessment of H_2S losses from oil and gas wells. It contains information on the nature of hydrogen sulfide's hazardous properties; exposure and consequence analyses for routine emissions and accidental releases; protective guidelines, prevention, mitigation, and emergency response procedures; and a characterization of land use around wells and of affected human populations and environmental settings. Chapter IV reviews and evaluates current State, Federal, and industry-recommended procedures related to H_2S in the oil and natural gas extraction industry. At the end of both Chapters III and IV are lists of findings to provide the reader with a condensed summary of key information identified during the development of this report. Chapter V completes the report with EPA recommendations regarding routine emissions and accidental releases of H_2S from oil and gas extraction operations.

This report contains a glossary of terms commonly used, and three appendices providing:

- background information on oil and gas production;
- subjects of State H_2S regulations and guidelines; and
- atmospheric dispersion calculations for accidental H_2S releases.

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CHAPTER II
HYDROGEN SULFIDE FORMATION AND ITS ROLE IN OIL AND GAS PRODUCTION

OVERVIEW

Petroleum oil and natural gas originate in organic-rich sedimentary source rocks composed of decayed marine algae and bacteria and terrestrial plants. In rock formations, temperature increases with depth. The organic matter (kerogen) in sedimentary rock is thermally converted to oil and gas at a specific temperature and migrates from the source rock formation into a reservoir, or trap, formed by less porous cap rock, usually shale. Once the well has been drilled into the reservoir, the oil and gas flow through the interconnected pore spaces to the well.

Natural gas may be composed of many gases. Only a few of these gases are typically found in large concentrations. The largest volume and most beneficial gases in natural gas are the light hydrocarbons (methane, ethane, propane and butane). Other gases that may occur in large concentrations are carbon dioxide, nitrogen, and hydrogen sulfide. H_2S is the most common impurity in hydrocarbon gases.

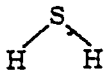
H_2S is generated under reducing conditions from high-sulfur kerogens or oils and is most commonly formed in sedimentary rock formations such as limestone (calcite or calcium carbonate). H_2S can also be generated from hydrocarbon reactions with sulfates in carbonate rock formations containing anhydrites. Oil and gas formations that do not contain H_2S are called "sweet." Oil and gas formations that contain H_2S are described as "sour." Sour gas is defined by the U.S. EPA as natural gas with an H_2S concentration greater than 0.25 grains per 100 cubic feet (GRI, 1990). Others have defined sour gas as having H_2S concentrations greater than 1.0 grain per 100 cubic feet (Amyx, Bass, and Whiting, 1960) or greater than 2 percent (Curtis and Showalter, 1989). The American Petroleum Institute recommends special practices (described in Chapter IV) for sour gas when the natural gas's total pressure is greater than or equal to 65 psia (448 kPa) and the partial pressure of H_2S in the gas is greater than 0.05 psia (0.34 kPa) (API, 1987). It is not known how many sour wells exist in the United States. Sweet oil wells can become sour due to the introduction of sulfur-reducing bacteria during enhanced oil recovery injection. Once an oil or gas field becomes sour, it cannot be made sweet again. However, after extraction from the well, the oil and gas can be sweetened by processing to remove H_2S, and this is a common procedure.

In relatively low concentrations, H_2S has a strong rotten-egg odor (Landes, 1953). However, the sense of smell rapidly becomes fatigued and cannot be relied on to warn of the continuous presence of H_2S. In fact, high concentrations of H_2S may cause a loss of smell. Concentrations of H_2S in crude oil vary greatly. In California alone, the Shiells Canyon oil field measures only 6×10^4 ppb of H_2S, while the Santa Maria Valley oil field has reported H_2S concentrations of 2.7×10^7 ppb (27 percent by weight) (Dosch and Hodgson, 1986).

Table II-1. Physical/Chemical Properties of H_2S

Chemical Formula: H_2S

Molecular Structure:



Molecular Weight: 34.08

Boiling Point: -60.33 °C (-76.59 °F)

Specific Gravity ($H_2O=1$): 0.916 at -60 °C (-76 °F) (Liquid) 1.54 g/L vapor at 0 °C (32 °F)

Vapor Pressure: 20 atmospheres at 25.5 °C (77.9 °F)

Melting Point: -85.49 °C (-121.9 °F)

Vapor Density (AIR=1): 1.19

Solubility in Water: 1 gram dissolves in 242 mL at 20 °C (68 °F)

Flammable Limits: Lower Explosive Limit – (4.3×10^7 ppb)
Upper Explosive Limit – (45.5×10^8 ppb)

Odor Threshold: 20 ppb[a]

Olfactory Fatigue Level: 1×10^5 ppb[a]

Conditions or Materials to Avoid: Avoid physical damage to containers; sources of ignition; and storage near nitric acid, strong oxidizing materials, and corrosive liquids or gases (NFPA, 1978). Hydrogen sulfide is incompatible with many materials, including strong oxidizers, metals (NIOSH/OSHA, 1978, p. 112), strong nitric acid, bromine pentafluoride, chlorine trifluoride, nitrogen triiodide, nitrogen trichloride, oxygen difluoride, and phenyl diazonium chloride (NFPA, 1978).

Hazardous Decomposition or Byproducts: When heated, it emits highly toxic fumes of oxides of sulfur (Sax, 1984, p. 1552)

Source: U.S. EPA, 1993.

[a] NIOSH, 1977.

Hydrogen sulfide is also called hydrosulfuric acid, sulfurated hydrogen, sulfur hydride, rotten-egg gas, swamp gas, and stink damp. Table II-1 lists some of the chemical and physical properties of H_2S. It is colorless, has a very low odor threshold, and being more dense than air, it tends to settle to the ground when released to the atmosphere as a pure gas (NIOSH, 1977). H_2S oxidizes to form sulfur dioxide (SO_2).

Exposure to H_2S is one potential health and environmental concern associated with extraction and related operations. H_2S is found in Paleozoic carbonates in the Rockies, Mid-Continent, Permian Basin, and Michigan and Illinois Basins (GRI, 1990). Figure II-1 shows the areas of naturally occurring H_2S. The Gas Research Institute reported in 1990 that H_2S can often occur in association with carbon dioxide (CO_2) within the deep portions of a basin and can comprise more than 30 percent of the composition.

Among the natural gas deposits in the United States, large deposits in central and north-central Wyoming, in western Texas, in southeastern New Mexico, and in Arkansas were singled out as rich in H_2S. The Health Effects Research Laboratory (HERL) also reported that H_2S concentrations as high as 42 percent may be present in gas from central Wyoming. According to the *Wyoming State Review* (1991), released by the Interstate Oil and Gas Compact Commission (IOGCC), gas reserves in Wyoming were estimated to be approximately 11 trillion cubic feet. The IOGCC also reported that the reserves of liquid hydrocarbons found in western Wyoming are approximately 5 percent H_2S. Fifty percent of the oil produced in Wyoming in 1989 was reported to be sour.

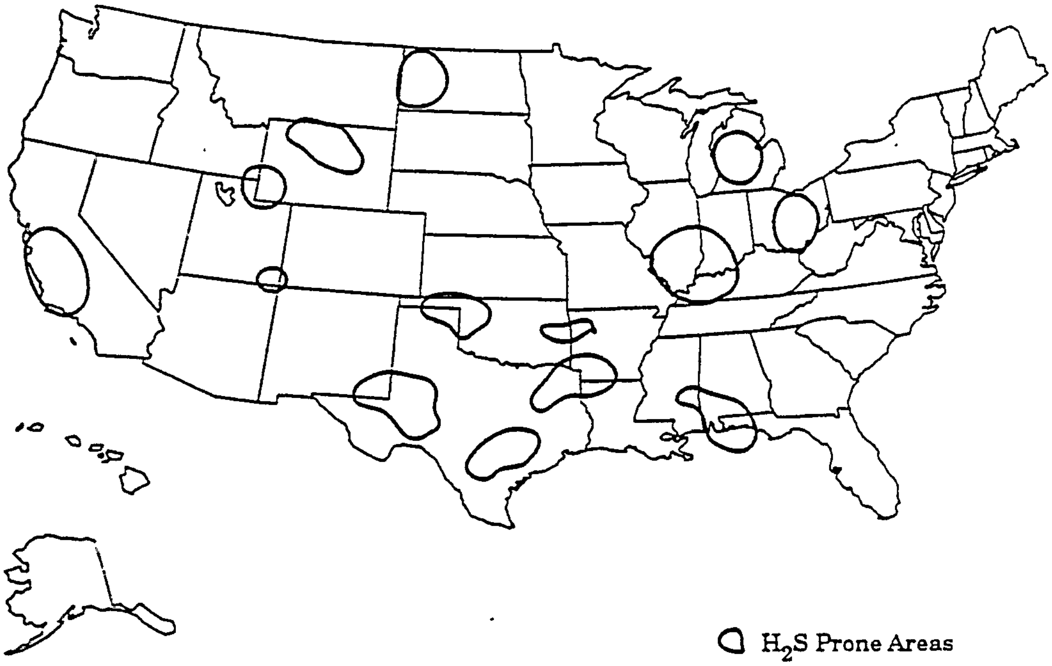
HYDROGEN SULFIDE IN INDUSTRY

Hydrogen sulfide has been cited as a potential hazard for approximately 125,000 employees in 73 industries (U.S. EPA, 1993). Industries with a potential exposure are listed in Table II-2. The health effects of H_2S were recognized in the petroleum industry more than 50 years ago with the discovery of large deposits of high-sulfur oil in the United States (Davenport, 1945). In the oil and gas industry, H_2S may be emitted or released during exploration, development, extraction, crude treatment and storage, transportation (e.g., pipeline transmission), and refining. This report focuses on potential hazards of H_2S routine emissions and accidental releases from the extraction and storage of crude oil and natural gas.

POTENTIAL H_2S EMISSION SOURCES IN THE OIL AND NATURAL GAS EXTRACTION INDUSTRY

Appendix A provides a general overview of the oil and gas extraction industry. Both the exploration/development and extraction sectors of the industry are described along with production data for recent years.

Hydrogen sulfide (H_2S) complicates oil and gas extraction operations because of its toxic effects and its corrosive properties. H_2S exists as a gas at atmospheric pressure, but it



Source: Gas Research Institute. 1990.

Figure II-1. Major H_2S prone areas.

Table II-2. Occupations with Potential H_2S Exposure

Animal fat and oil processors
Animal manure removers
Artificial-flavor makers
Asphalt storage workers
Barium carbonate makers
Barium salt makers
Blast furnace workers
Brewery workers
Bromide-brine workers
Cable splicers
Caisson workers
Carbon disulfide makers
Cellophane makers
Chemical laboratory workers, teachers, students
Cistern cleaners
Citrus root fumigators
Coal gasification workers
Coke oven workers
Copper-ore sulfidizers
Depilatory makers
Dyemakers
Excavators
Felt makers
Fermentation process workers
Fertilizer makers
Fishing and fish-processing workers
Fur dressers
Geothermal-power drilling and production workers
Gluemakers
Gold-ore workers
Heavy-metal precipitators
Heavy-water manufacturers
Hydrochloric acid purifiers
Hydrogen sulfide production and sales workers
Landfill workers
Lead ore sulfidizers
Lead removers
Lithographers
Lithopone makers
Livestock farmers
Manhole and trench workers
Metallurgists
Miners
Natural gas production and processing workers
Painters using polysulfide caulking compounds
Papermakers
Petroleum production and refinery workers
Phosphate purifiers
Photoengravers
Pipeline maintenance workers
Pyrite burners
Rayon makers
Refrigerant makers
Rubber and plastics processors
Septic tank cleaners
Sewage treatment plant workers
Sewer workers
Sheepdippers
Silk makers
Slaughterhouse workers
Smelting workers
Soapmakers
Sugar beet and cane processors
Sulfur spa workers
Sulfur products processors
Synthetic-fiber makers
Tank gagers
Tannery workers
Textiles printers
Thiophene makers
Tunnel workers
Well diggers and cleaners
Wool pullers

Source: NIOSH. 1977.

is soluble in oil and water. As a result of this solubility, H_2S can enter the environment by a variety of pathways. It can enter the atmosphere as a result of releases of gas containing H_2S or as a result of venting tanks or vessels which contain or have contained oil or water with significant concentrations of H_2S. Waters in the general environment can become contaminated with H_2S by contact with either gaseous plumes or waters that contain H_2S.

The potential sources of H_2S emissions associated with oil and gas extraction are summarized in Table II-3.

Routine emission sources may include—

- inefficient air emission control devices
- tank venting due to diurnal temperature changes;
- volatilization;
- generation by sulfur-reducing bacteria in oil deposits; and
- migration through poorly plugged wells.

Potential accidental release sources include —

- equipment failures, e.g., valves, flanges;
- piping ruptures due to corrosion, embrittlement, or stress; and
- venting due to unanticipated pressure changes.

Background information on these potential sources is provided in Appendix A.

The crude oil and natural gas industries use a large number of similar yet distinct industrial processes that together serve a common purpose: to remove hydrocarbons from subterranean deposits of oil and gas and to produce marketable products for industrial, commercial, and residential use. Figure II-2 shows the basic components of a typical oil and gas production operation. From the wellhead, the oil/gas mixture is piped to an oil/gas separator. Oil/water emulsions and mixtures are then transferred to a heater-treater, which separates the oil from the water. The treated crude oil is next piped to storage tanks, and the produced water is piped to a holding tank prior to further treatment and/or disposal. An emergency pit (a wastewater basin) is also provided. Each of these operations, as well as other equipment found at a well site, may be a source of H_2S in sour oil and gas operations.

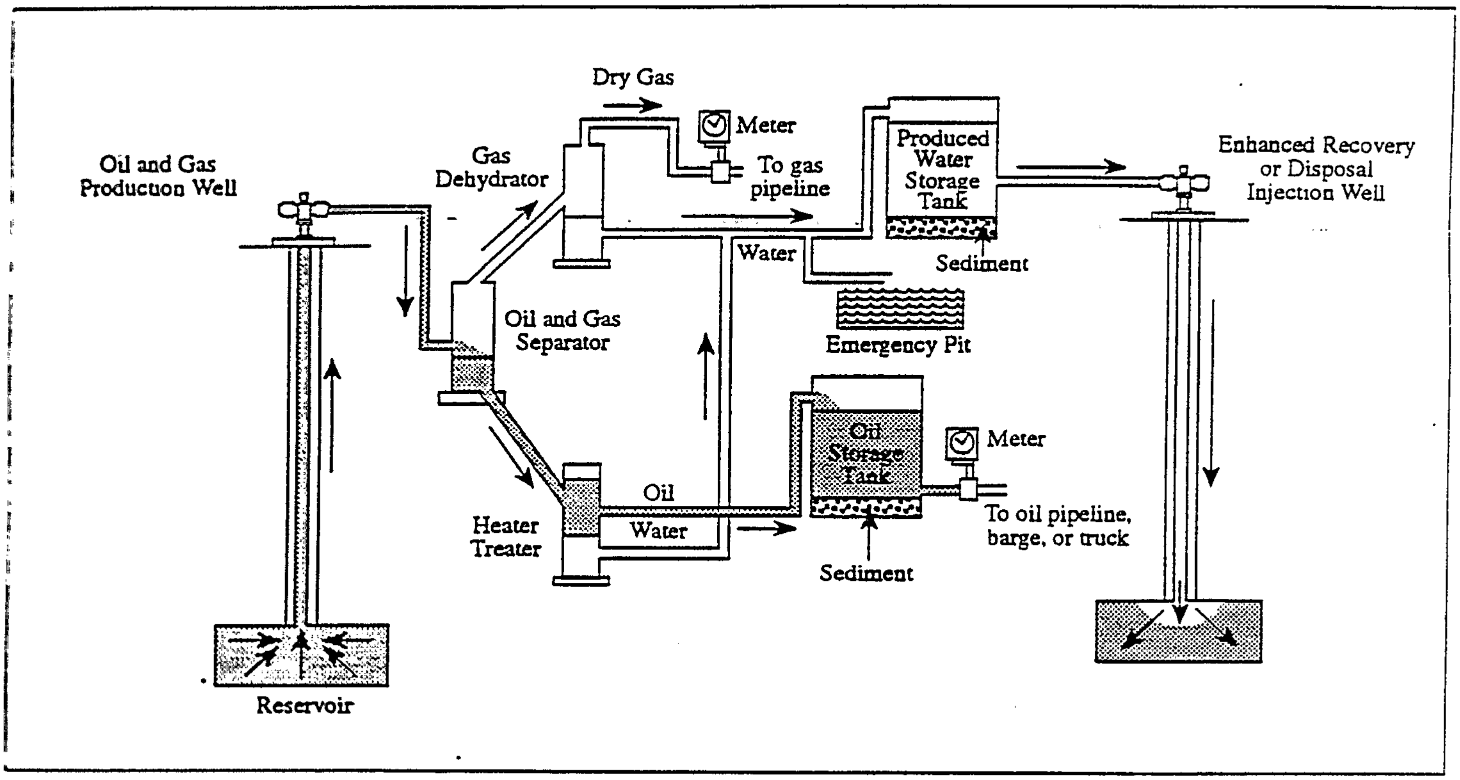
Oil and Gas Production Operations

Crude Oil

In the crude oil production process, releases or emissions of H_2S to the environment may occur from a variety of sources, including wellheads, piping, flares, separation devices, storage vessels, and pumps.

Table II-3. Examples of Potential Routine H_2S Emission Sources and Accidental H_2S Release Sources from Sour Oil and Gas Extraction

Source	Mechanism	Cause
Flares/vapor incinerators	Incomplete combustion	Design; lack of maintenance
Heater-treaters	Pressure change, high pressure	Pressure above design specifications
Crude oil storage tanks	Diurnal temperature change; filling operations; volatilization	Lack of controls; design
Water storage vessels	Volatilization; sulfur-reducing bacteria	Lack of controls; design
Equipment (valves, flanges, etc.) Oil/gas separator	Corrosion and embrittlement	Reaction of water with metal and H_2S; lack of maintenance; poor materials
Well plugging	Migration from well bore to atmosphere	Improper plugging



Source: U.S. EPA, 1987.

Figure II-2. Typical extraction operation showing separation of oil, gas, and water.

Flares are connected to points in the system where gas might be directed in case of an operating problem. Subject to regulatory approval, flares may also burn gases that cannot be sold. The gases are vented up a tall vertical pipe and then ignited at the top of the pipe, releasing heat and combustion products. Flares are connected to production vessel pressure-relief valves, rupture disks, and tank vents, among other places. Few data are available on the efficiency of flares used in a crude oil production setting; however, the operating efficiency of a common flare, regardless of industry application, is about 95 to 99 percent (personal communication, Donelson, Texaco, 12/9/92). The combustion product of H_2S is sulfur dioxide (SO_2). Incomplete combustion from flares is one possible source of H_2S emissions, and actual pollutant emissions vary depending on the combustion efficiency of the flare.

Devices, such as heater-treaters, break down water/oil emulsions or mixtures. These devices operate under pressure and do not normally emit H_2S. However, H_2S may be released in accidental situations when the vessel becomes subjected to pressures above design specifications. The pressure relief valve or a rupture disk will open in a high-pressure situation, and the gas will be sent through these openings via pipeline to a flare (personal communication, Donelson, Texaco, 12/9/92).

H_2S can potentially be emitted by two processes from vessels used to store water produced during extraction:

- Dissolved H_2S may be contained in the produced water and brought up from the reservoir. Pressure reductions from subsurface to surface change the solubility of H_2S in water and can release some H_2S from solution.
- H_2S may be produced by the action of sulfate-reducing bacteria in some aqueous and oil media. Biocides arc used to kill these bacteria and eliminate H_2S formation.

Tanks storing crude oil are another potential source of H_2S emissions. H_2S can be discharged to the atmosphere from a storage tank as a result of diurnal temperature change, filling operations, and volatilization. The process of filling oil-transport vessels is another potential source of H_2S emissions. As the crude oil is loaded, gases containing the pollutant are displaced to the atmosphere. If the gas amounts do not warrant repressuring into the gas sales line, a flare may operate to burn the gas given off (personal communication, Donelson, Texaco, 12/9/92). There have been several accidents involving tanks that have H_2S in them. This is typically a worker safety issue.

Pumps that move the oil during the extraction process can leak oil at the seals between the moving shaft and the stationary casing, causing a possible release of H_2S.

Natural Gas

Two additional items in natural gas extraction can contribute emissions and releases of sulfur compounds into the atmosphere: (1) equipment failure (e.g., leaks and ruptured pipes) due to corrosion or embrittlement, and (2) improperly plugged wells.

Equipment Failure. H_2S can attack the crystalline matrix of the steel, leading to embrittlement and cracking of the steel, which could, in turn, lead to possible leakage of H_2S. This embrittlement is invisible and can occur in a short period of time. Corrosion, which is caused by chemical reactions of metal with water and H_2S, can also cause H_2S leakage. Because of the corrosive nature of H_2S in the presence of water, oil and gas operations take precautions to remove water from gas streams containing H_2S. The National Association of Corrosion Engineers has a "Standard Material Requirement" entitled "MR-0175-92, Sulfide Stress Cracking Resistant Metallic Materials for Oil Field Equipment" which describes corrosion prevention measures. Corrosion resistant materials, coatings, and chemical corrosion inhibitors may be used to prevent equipment failure and gas releases where H_2S and other corrosives are known to be present (personal communication, Donelson, Texaco, 12/9/92). This type of accidental release is discussed in greater detail in Chapter III.

Well Plugging. Improper well plugging may also be a potential source of H_2S emissions. After all of the recoverable natural resources have been removed from a well, it must be properly plugged to avoid degradation of groundwater and surface water. Plugging involves placing cement within a wellbore at specific intervals to permanently block the possible migration of formation fluids containing H_2S. Improper plugging may allow H_2S (if present) to migrate out of the wellbore and into the atmosphere. Well plugging is regulated by the individual states. Plugging bonds are posted and procedures are subject to the regulatory agency's approval and on-site witness (personal communication, Donelson, Texaco, 12/9/92). This type of accidental release is also discussed in Chapter III.

Stripper Wells

Stripper wells are defined in Appendix A as producing at most 10 barrels of oil per day or 100 thousand cubic feet of gas per day. The owners or operators of these wells are typically smaller producing companies. Although stripper wells are often in remote areas, many are not completely isolated from the public. The potential exists for livestock, wildlife, or humans to come into contact with high levels of H_2S from stripper wells due to routine emissions and accidental releases. Although these wells are a potential hazard, no data were available on the number of sour stripper wells in the United States.

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CHAPTER III
HAZARD ASSESSMENT OF OIL AND GAS WELLS

INTRODUCTION

Objective

The objective of this chapter is to evaluate the potential hazards to public health and the environment resulting from routine emissions and accidental releases of hydrogen sulfide (H_2S) from oil and gas production, i.e., extraction; piping to a separator; oil, gas, and water separation; and associated storage.

Focus of Assessment

This hazard assessment was performed in two parts. First, existing H_2S ambient air monitoring data were compared to studies of human health and environmental effects to determine whether the H_2S concentrations measured from routine emissions have potentially harmful effects. Second, the threat of accidental releases was assessed by identifying past accidents and their impacts, reviewing atmospheric dispersion analyses (i.e., modeling) of accidental release scenarios in the literature, and conducting additional analyses. The result is an assessment of whether routine emissions and accidental releases are at levels that would require a national control strategy. In addition, this assessment identifies the hazards of H_2S, recommended protective levels, and the areas of the United States potentially vulnerable to routine emissions and accidental releases of H_2S.

Scope and Limitations

This hazard assessment addresses hydrogen sulfide emissions and releases that may potentially originate from a range of sources beginning with oil and gas wells (after well development) up through their associated treatment processes, storage units, and piping. However, it does not include gas processing or oil refining plants. For the potential H_2S emission sources described in Chapter II, non-occupational health impacts are considered along with environmental impacts (i.e., wildlife, livestock, and vegetation). For wildlife and livestock, the assessment includes animals that may be exposed to H_2S when they wander onto the well site.

For routine H_2S emissions, this hazard assessment is limited by the lack of data available on ambient air quality around well sites. Only a small amount of ambient monitoring data collected by States was identified. In addition, no national statistics on the health and environmental effects of chronic H_2S exposure exist. Nor are national statistics on the frequency and severity of accidental H_2S emissions or releases available. Only case records were located for the assessment of accidental releases. Therefore, the conclusions drawn from this assessment are based primarily on predictive modeling of accidental releases and on a semi-quantitative comparison of ambient monitoring data and non-specific health effects data.

Hazard Assessment Steps

This hazard assessment was divided into three major parts:

- Hazard Identification
- Exposure Analysis
- Consequence Analysis

Figure III-1 displays the various components of this assessment.

The first step in this assessment was hazard identification. It entailed collecting information on the physical and chemical properties of H_2S and its location in the United States as it occurs (1) naturally in petroleum deposits, and (2) where it has been generated by sulfur-reducing bacteria that are introduced by enhanced oil recovery processes. The primary component of hazard identification is determining hydrogen sulfide's hazardous properties: ignitability, corrosivity, explosivity, and toxicity to human health and the environment.

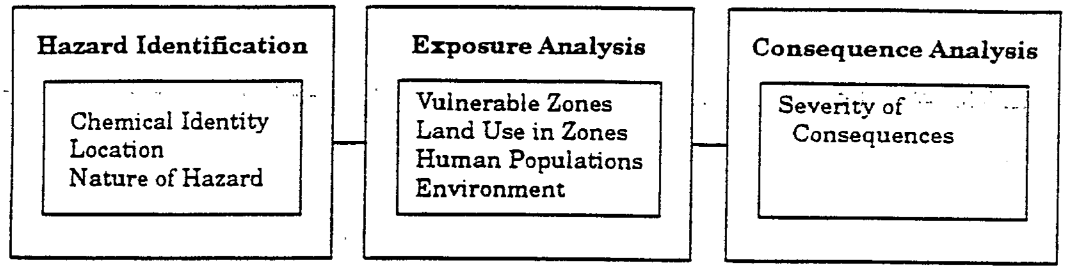
The second step, exposure analysis, included identification of the H_2S prone areas for H_2S exposure in the United States and the human and ecological populations expected to be in these zones. The final part of the assessment, consequence analysis, was an examination of H_2S routine emissions and accidental releases occurring at oil and gas wells and the severity of the consequences.

Since this report examines routine emissions and accidental releases separately, this chapter first presents hazard identification, which is the same for both routine and accidental releases. Next, routine exposure and its consequences are discussed. Finally, exposure to accidental releases and its consequences are presented.

HAZARD IDENTIFICATION

Chemical Identity

Hydrogen sulfide is a colorless, flammable gas which, in low concentrations, has a characteristic odor of rotten eggs. It is a frequent component of crude oil and natural gas. Hydrogen sulfide gas has the Chemical Abstracts Services (CAS) registry number 7783-06-4; its physical and chemical properties are summarized in Table II-1.



Adapted from: U.S. EPA, 1987.

Figure III-1. Components of the hazard assessment exercise.

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Location

H_2S is found at varying depths in the earth's geological formations. Underground sources of the gas are often referred to as pockets of H_2S. Other natural sources of H_2S include volcanic gases, sulfur deposits, sulfur springs, and swamp gas from anaerobic decay. Approximately 90 percent of the air emissions of H_2S are produced by natural sources (U.S. EPA, 1993). A portion of this 90 percent results from the routine emissions and accidental releases resulting from the extraction of oil and gas containing H_2S. Figure II-1 shows major H_2S-prone areas of the United States.

Nature of Hazard

Exposure Routes, Absorption, Metabolism, and Elimination

As described in previous chapters, the most rapid route of exposure to H_2S is through the air. Although eye irritation is the basis for the OSHA Permissible Exposure Limit (PEL), inhalation is the quickest lethal exposure to humans and wildlife. The solubility of H_2S in water decreases as temperature increases; however, drinking groundwater has been found with noticeable H_2S concentrations.

Sullivan and Krieger's *Hazardous Materials Toxicology* (1992) summarizes the effects of H_2S exposure as follows:

> In environmental and occupational exposures, the lung rather than the skin is the primary route of absorption (Burgess, 1979; Yant, 1930). The dermal absorption of H_2S is minimal (Laug and Draize, 1942). Results from animal inhalation studies indicate that H_2S is distributed in the body to the brain, liver, kidneys, pancreas, and small intestine (Voigt and Muller, 1955). Within the body, H_2S is metabolized by oxidation, methylation, and reaction with metallo-or disulfide-containing proteins. Orally, intraperitoneally, and intravenously administered H_2S is primarily oxidized and directly excreted as either free sulfate or conjugated sulfate in the urine (Curtis et al., 1972). The importance of methylation in the detoxification processes of H_2S, however, is unknown (Weisiger and Jakoby, 1980). The reaction of H_2S with vital metalloenzymes such as cytochrome oxidase is the likely toxic mechanism of H_2S (NRC, 1979; Smith and Gosselin, 1979). Reaction with nonessential proteins may also serve as a detoxification pathway (Smith, Kroszyna, and Kruszyna, 1976; Smith and Gosselin, 1964). Systemic poisoning occurs when the amount of H_2S absorbed exceeds that which can be detoxified and eliminated (Yant, 1930; Milby, 1962). Because of its rapid oxidation in the blood, H_2S is not considered a cumulative poison (Yant, 1930; Ahlborg, 1951; Haggard, 1925)....

There are no animal data available regarding the exhalation of H_2S after inhalation exposure. In animals, the excretion of H_2S by the lungs is minimal after peritoneal administration of H_2S (Evans, 1967; Gunina, 1957; Susman et al., 1978). However, because rescue personnel have developed H_2S poisoning shortly after starting mouth-to-mouth resuscitation on victims who had been poisoned, it is likely that significant H_2S is excreted from the lungs (Kleinfeld, Giel, and Rosso, 1964).

Acute Human Toxicity

The odor perception threshold for H_2S is very low. At concentrations between 3 and 20 ppb, the characteristic rotten egg odor is detectable. However, higher concentrations of H_2S in the 1.5×10^5 to 2.5×10^5 ppb range can cause olfactory paralysis. At these concentrations, the olfactory sense may be lost and exposed persons may be unaware of the presence of the toxic gas. Thus, odor cannot be relied upon as a warning sign of possible exposure to H_2S. Pulmonary edema, resulting from inhalation of levels between 3×10^5 and 5×10^5 ppb, can be fatal. (See Table III-1.) Inhaling levels between 5×10^5 and 1×10^6 ppb can cause a stimulation of the respiratory system, and rapid breathing (hyperpnea) will occur followed by cessation of breathing (apnea). The effect of inhaling levels above 1×10^6 ppb is immediate respiratory paralysis followed by death.

Inhalation of levels above 2.5×10^5 ppb can damage organs and the nervous system. Much of this damage is a result of a lack of oxygen (anoxia) caused by the depression of cellular metabolism which can occur at 2.5×10^5 ppb. Instances of permanent neurological damage in humans resulting from acute exposure have been described. Furthermore, animal data have revealed that changes in the tissues of the brain, lungs and heart can occur from exposure to the gas.

Irritation of the respiratory tract and eyes is another major effect of H_2S exposure. The gas is readily absorbed through the nasal and lung mucosa. It is very irritating to the respiratory tract and eyes and can cause serious eye injury above 5×10^4 ppb. The gas can affect the epithelium of the eye causing inflammation and lacrimation. The Integrated Risk Information System (IRIS) (U.S. EPA, 1992) lists several signs and symptoms of H_2S exposure including painful conjunctivitis, sensitivity to light, tearing, and clouding of vision. In addition, permanent scarring of the cornea can occur. At high, and potentially lethal concentrations, the mucous membranes can be anesthetized so that irritation effects cannot be relied upon to warn individuals of H_2S exposure.

In addition to irritation, IRIS lists other signs and symptoms of H_2S exposure including labored breathing and shortness of breath, profuse salivation, nausea, vomiting, diarrhea, giddiness, headache, dizziness, confusion, rapid breathing, rapid heart rate, sweating, and weakness.

Table III-1. Effects of Exposure in Humans at Various Concentrations in Air

Clinical Effect	Level of Hydrogen Sulfide ppb	mg/m^3	Reference
Odor perception threshold	3-20	0.004 - 0.028	Indiana Air Pollution Control Board (1964)
Offensive odor (rotten eggs)	$<3x10^4$	<42	Ahlborg (1951)
Offensive odor (sickening sweet)	$>3x10^4$	>42	National Research Council (1977)
Occupational Exposure Limit (OEL)	$1x10^4$	14	National Research Council (1977)
Serious eye injury	$5x10^4$ - $1x10^5$	70 - 140	National Research Council (1977)
Olfactory paralysis	$1.5x10^5$ - $2x10^5$	210 - 350	National Research Council (1977)
Pulmonary edema, threat to life	$3x10^5$ - $5x10^5$	420 - 700	National Research Council (1977)
Strong stimulation of respiration	$5x10^5$ - $1x10^6$	700 - 1400	National Research Council (1977)
Respiratory paralysis, collapse and death	$1x10^6$ - $2x10^6$	1400 - 2800	National Research Council (1977)

Source: U.S. EPA, 1993.

Hydrogen sulfide may also decrease the body's ability to withstand infection. A toxicological study exposed rats to 4.5 x 10^4 ppb of hydrogen sulfide for 2, 4, or 6 hours, followed by a challenge with an aerosol of *staphylococcus epidermis* (Rogers and Ferin, 1981). A significant dose-response effect was seen in the number of colonies formed, when the exsanguinated lungs were harvested from the rats at 30 minutes, 3 hours and 6 hours post-challenge, and homogenized and grown in a selective growth medium for staphylococci. Rats exposed to hydrogen sulfide for 4 hours had a 6.5-fold greater percent of colony-forming units than controls, while those exposed to hydrogen sulfide for 6 hours had a 52-fold greater percent of colony-forming units. The conclusion reached was that hydrogen sulfide significantly affected the antibacterial system of the rats by impairing alveolar macrophages.

However, Higashi et al. (1983), in a cross-sectional study of viscose rayon textile workers exposed to hydrogen sulfide (average concentration, 3 x 10^3 ppb) and carbon disulfide, found no difference between exposed employees and controls in respiratory and spirometric variables. Similarly, Kangas et al. (1984) found no increased prevalence of subjective symptoms among cellulose mill workers exposed to hydrogen sulfide concentrations of up to 2 x 10^4 ppb and methyl mercaptan levels as high as 1.5 x 10^4 ppb, and much smaller amounts of dimethyl disulfide.

Chronic Human Toxicity

The toxicological data based was reviewed and an inhalation reference concentration (RfC) was verified by the U.S. EPA Reference Dose (RfD)/RfC Work Group on June 21, 1990. The documentation is available via the Integrated Risk Information System (IRIS) (U.S. EPA, 1991). The Integrated Risk Information System is an on-line data base containing EPA risk assessment results and regulatory information. An RfC is defined as an estimate, with uncertainty spanning perhaps an order of magnitude, of a daily exposure to the human population (including sensitive subgroups) which is likely to be without adverse effects during a lifetime (U.S. EPA, 1990). The derivation of the RfC is based on a complete review of the toxicological literature and encompasses adjustments for exposure duration and dosimetry. It utilizes uncertainty factors to account for specific extrapolations between the population in which the effect was observed and the human population. The critical, usually the most sensitive, effect is the focus of the RfC derivation; for this effect the no-observed-adverse-effect level (NOAEL), or lowest-observed-adverse-effect level (LOAEL) if a NAOEL is not available, is identified. Detailed discussion concerning these issues can be found in U.S. Environmental Protection Agency, 1990.

The RfC for H_2S is 9 x 10^{-4} mg/m^3 (6.7 x 10^{-1} ppb) and was derived from the NOAEL for inflammation of the nasal mucosa in mice (Toxigenics, 1983). The subchronic study revealed a lowest-observed-adverse-effect level (LOAEL) of 110 mg/m^3 (8 x 10^4 ppb) and a no-observed-adverse-effect level (NOAEL) of 42.5 mg/m^3 (3.05 x 10^4 ppb). Since the RfC may change due to evaluation of additional data, the reader is referred to IRIS for the most current information regarding the RfC for H_2S.

The extrapolation of the NOAEL to the RfC follows several steps. First, the NOAEL is adjusted to account for the daily length of exposure in the study; and second, it is extrapolated to humans, and a human equivalent concentration (HEC) is calculated. Finally an uncertainty factor is applied. The RfC for hydrogen sulfide is derived using an uncertainty factor of 1000. The 1000 reflects a factor of 10 to protect sensitive individuals, 10 to adjust from subchronic studies to a chronic study (a subchronic study is carried out over a shorter period of time and may not accurately reflect cumulative effects), and 10 to adjust for interspecies conversions and database deficiencies.

Very little data exist on whether H_2S can cause carcinogenic, mutagenic, reproductive or developmental effects in humans or animals. Because of a lack of adequate test data, H_2S is currently placed in Group D, based on the weight-of-evidence criteria in the EPA's Carcinogen Risk Assessment Guidelines issued in August 1986. A Group D ranking means that the available data are inadequate to assess a chemical's human carcinogenic potential. Furthermore, data are inadequate to state that H_2S is mutagenic or that it causes reproductive effects. Limited animal data do suggest that H_2S appears to have potential to alter normal developmental processes. No data on human developmental effects of inhaled H_2S have been located (U.S. EPA, 1993).

Ecological Effects

Data on the ecological effects of H_2S are limited (Table III-2). McCallan, Hartzell, and Wilcoxon (1936) and Benedict and Breem (1955) conducted high-exposure fumigation studies, which noted that young, growing plants were the most susceptible to injury from exposure to H_2S. However, they noted that temperature, soil moisture, and species differences were important factors affecting the results. Heck, Daines, and Hindawi (1970) noted that mature leaves were unaffected while damage to the young shoots and leaves consisted of scorching. Among the plants determined to be sensitive to H_2S are clover, soybean, tomatoes, tobacco, and buckwheat.

According to the EPA *Health Assessment Document for H_2S* (U.S. EPA, 1993), few studies exist that evaluate natural or accidental exposure of wildlife and/or domestic animals to H_2S. However, H_2S has been determined to be highly toxic to some fish species. Animal surveys conducted after a gas well blowout in Lodgepole, Alberta, Canada (Lodgepole Blowout Inquiry Panel, 1984; Harris, 1986) revealed that large animals were exhibiting signs of mucous membrane irritation and were avoiding the geographic area. Most cattle in the exposed area were unaffected. Concentrations of H_2S as high as 1.5×10^4 ppb (sampling time unknown) were measured in the blowout area.

Flammability, Explosivity, and Corrosivity

"Hydrogen sulfide is generally stable when properly stored in cylinders at room temperature. However, in the air, it is flammable and explosive and may be ignited by static discharge. It may react with metals, oxidizing agents, and acids such as nitric acid, bromine

Table III-2. Effects of Ecological Exposure to H_2S

Studies	Species	Level			Source
Aquatic	Bluegill	LC_{50}	0.009 - 0.0478 mg/L		AQUIRE
	Rainbow Trout	LC_{50}	0.013 - 0.047 mg/L		AQUIRE
	Fathead Minnow	LC_{50}	0.007 - 0.776 mg/L		AQUIRE
Mammalian	Mouse	NOAEL	42.5 mg/m^3	(3.05x10^4 ppb)	IRIS
		LOAEL	100 mg/m^3	(8x10^4 ppb)	IRIS
	Rat	NOAEL	42.5 mg/m^3	(3.05x10^4 ppb)	IRIS
		LOAEL	100 mg/m^3	(8x10^4 ppb)	IRIS

AQUIRE	Aquatic Toxicity Information Retrieval
IRIS	Integrated Risk Information Service
LC_{50}	Lethal Concentration 50
NOAEL	No-observed-adverse-effect-level
LOAEL	Lowest-observed-adverse-effect-level

pentafluoride, chlorine trifluoride, nitrogen triiodide, nitrogen trichloride, oxygen difluoride, and phenyldiazonium chloride. When heated to decomposition, it emits highly toxic sulfur oxide fumes" (Sullivan and Krieger, 1992). In pure form, its lower and upper explosive limits are 4.3 percent (4.3 x 10^7 ppb) and 45.5 percent (45.5 x 10^7 ppb), and its auto-ignition temperature is 260 °C (500 °F) (NIOSH, 1977). The National Fire Protection Association (NFPA) has classified hydrogen sulfide in the highest flammability class (NFPA, 1974).

In the presence of water, hydrogen sulfide gas is highly corrosive to metals, including high-tensile steel, which hydrogen sulfide can embrittle. These properties can lead to loss of containment and accidental releases from ruptures if not controlled. Special precautions must be taken to prevent spontaneous ignition fires when vessels that previously contained concentrated hydrogen sulfide are opened. Ignition is caused by reaction of iron sulfide with air to form iron oxide. The conversion of sulfide to oxide produces enough heat to ignite flammable vapors (Dosch and Hodgson, 1986).

ACGIH Threshold Limits

The American Conference of Governmental Industrial Hygienists (ACGIH) publishes a book of threshold limit values for chemical substances in the work environment (ACGIH, 1992). The limits are intended for use in the practice of industrial hygiene as guidelines or recommendations in the control of potential health hazards. When OSHA began setting standards for employee exposure in the 1970s, they adopted the ACGIH threshold limit values (TLV's) as their permissible exposure limits. The ACGIH standards are recommendations rather than regulations; they are updated annually and respond to current research more quickly than OSHA's regulations.

The current limits for H_2S were adopted by ACGIH in 1976. The Threshold Limit Value-Time Weighted Average (TLV-TWA) is 1 x 10^4 ppb or 14 mg/m^3, and the TLV short-term exposure limit (TLV-STEL) is 1.5 x 10^4 ppb or 21 mg/m^3. The TLV-TWA is defined as the time-weighted average concentration for a normal 8-hour workday and 40-hour workweek, to which nearly all workers may be repeatedly exposed, day after day, without adverse effect. The TLV-STEL is defined as the concentration to which workers can be exposed continuously for a short period of time without suffering from 1) irritation, 2) chronic or irreversible tissue damage, or 3) narcosis of sufficient degree to increase the likelihood of accidental injury, impair self-rescue or reduce work efficiency, also provided that the daily TLV-TWA is not exceeded. A STEL is further defined as a 15-minute TWA exposure which should not be exceeded at any time during a workday even if the TWA is within the TLV-TWA. Exposures above the TLV-TWA up to the TLV-STEL should not be longer than 15-minutes and should not occur more than 4 times a day, and should be separated by 60 minutes each.

$\underline{LC_{01}}$

One measure of the airborne concentrations of toxic materials that might cause fatality is the LC_{01}, which is the concentration that could prove fatal to one percent of those exposed to it. The LC_{01} is related to the exposure time, t, by a relationship of the form $LC_{01} = (k/t)^{1/n}$, where k and n are constants that depend on the material in question. This relationship is a manifestation of the probit equation, which is a well-established way of presenting the relationship between concentration, exposure time, and probability of fatality.

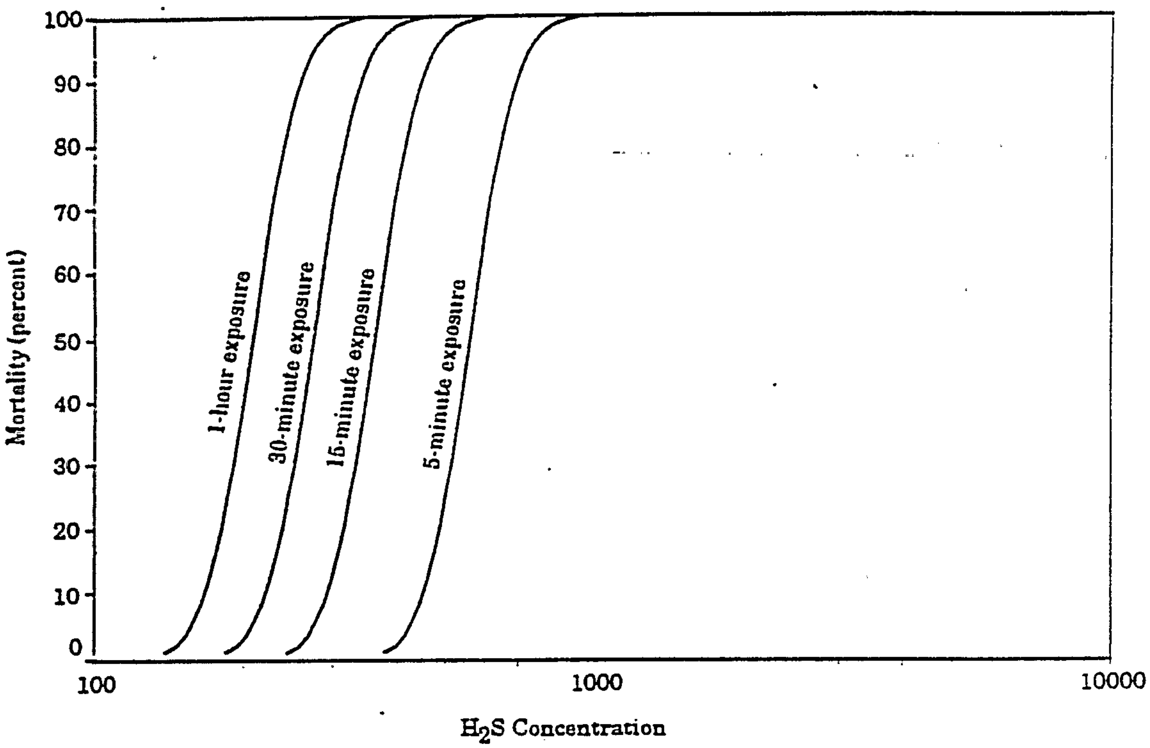
For H_2S, the Center for Chemical Process Safety of the American Institute of Chemical Engineers (AIChE) has a probit equation which gives k = 83,500 and n = 1.43, with C in ppb and t in minutes (AIChE, 1989). Thus, for a five minute exposure, $LC_{01} = 8.95 \times 10^5$ ppb and, for a one hour exposure, $LC_{01} = 1.6 \times 10^5$ ppb.

The Energy Resources Conservation Board (ERCB) of Alberta, Canada (Alp et al., 1990) has developed an alternative probit equation (shown in Figure III-2) which, for the LC_{01}, gives $k = 1.364 \times 10^8$ and n = 2.5. For a five minute exposure, this gives $LC_{01} = 3.75 \times 10^5$ ppb and for a one hour exposure gives $LC_{01} = 1.4 \times 10^5$ ppb. The ERCB values are thus more conservative.

AIHA Guidelines

The American Industrial Hygiene Association (AIHA) sets Emergency Response Planning Guidelines (ERPGs) to protect the general public in the event of an emergency release. The three ERPGs for H_2S, which are time-dependent levels for varying degrees of potential harm, are defined as follows:

ERPG-3	$\underline{1 \times 10^5\ \text{ppb}}$, the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing life-threatening health effects;
ERPG-2	$\underline{3 \times 10^4\ \text{ppb}}$, the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms which could impair an individual's ability to take protective action.
ERPG-1	100 ppb, the maximum airborne concentrations below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing other than mild, transient adverse health effects or without perceiving a clearly defined objectionable odor.



Note: Concentrations intentionally left in ppm.
Source: Alp et al., 1990.

Figure III-2. ERCB H_2S probit relations.

For hydrogen sulfide, the ERPG-3 is based on human experience, while the ERPG-2 is based on animal studies and the ERPG-1 is based on the fact that the objectionable odor of hydrogen sulfide is distinct at 300 ppb (AIHA, 1991). For the purposes of accidental release dispersion analysis, the ERPG-2 was considered conservative and used as a threshold for emergency countermeasures.

As stated above, these ERPG values are for an exposure time of one hour. At the time of writing, there is no definitive guidance on how to extrapolate to shorter durations of exposure. However, Gephart and Moses (1989) suggest that a constant dosage extrapolation might be reasonable; that is, (ERPG in ppb)x(exposure time, t, in minutes). = constant, k. Discussions with one of the AIHA authors have suggested that, for $t < 15$ min, k should be divided by two. Thus, for H_2S, the ERPG-2 is as follows:

- 3×10^4 ppb for an exposure time of one hour
- 1.8×10^5 ppb for an exposure time of five minutes.

The reader should recognize that these extrapolations are tentative and included for purposes of illustration. They represent one of the greater sources of uncertainty in the calculations.

NAS/NRC Guidelines

For the last forty years, the NRC's Committee on Toxicology has submitted emergency exposure guidelines for chemicals of concern to the Department of Defense (DOD) (NRC, 1986). These guidelines are used in planning for sudden contamination of air during military and space operations; specifically, they are used to choose protective equipment and reponse plans after non-routine but predictable occurrences such as line breaks, spills, and fires. These guidelines are for peak levels of exposure considered acceptable for rare situations, but are not to be applied in instances of repeated exposure.

An Emergency Exposure Guidance Level (EEGL) is defined as a concentration of a substance in air (gas, vapor, or aerosol) judged by DOD to be acceptable for the performance of specific tasks by military personnel during emergency conditions lasting 1 to 24 hours. Exposure to an EEGL is not considered safe, but acceptable during tasks which are necessary to prevent greater risks, such as fire or explosion. Exposures at the EEGLs may produce transient central nervous system effects and eye or respiratory irritation, but nothing serious enough to prevent proper responses to emergency conditions.

Since the 1940's, the NRC has developed EEGLs for 41 chemicals, 15 of which are listed in Section 302 of the Emergency Planning and Community Right-to-Know Act of 1986 (EPCRA) as extremely hazardous substances (EHSs). Although acute toxicity is the primary basis for selecting EEGLs, long-term effects from a single acute exposure are also evaluated for developmental, reproductive (in both sexes), carcinogenic, neurotoxic, respiratory and other organ-related effects. The effect determined to be the most seriously debilitating, work-limiting, or sensitive is selected as the basis for deriving the EEGL. This concentration is intended to be sufficiently low to protect against other toxic effects that may occur at higher concentrations. Factors such as age of the exposed population, length of exposure, and susceptibility or sensitivity of the exposed population are also considered in determining EEGLs.

Safety factors are used in developing EEGLs to reflect the nature and quality of the data. Safety factors for single exposures may differ from those used in chronic studies. In the absence of better information, a safety factor of 10 is suggested for EEGLs (i.e., the reported toxicity value should be divided by 10) if only animal data are available and extrapolation from animals to humans is necessary for acute, short-term effects (NRC, 1986). The safety factor of 10 takes into account the possibility that some individuals might be more sensitive than the animal species tested. A factor of 10 is also suggested if the likely route of human exposure differs from the route reported experimentally (NRC, 1986), for example, if oral data are reported and inhalation is the most likely exposure route for humans.

As noted by NRC (1986, p. 7), development of an EEGL for different durations of exposure usually begins with the shortest exposure anticipated (i.e., 10-15 minutes) and works up to the longest, such as 24 hours. For H_2S, 10-minute emergency exposure guideline level (EEGL) is 5×10^4 ppb; 1×10^4 ppb is the 24-hour EEGL. The 24-hour/day, 90-day continuous exposure guide level (CEGL) for H_2S has been recommended at 1×10^3 ppb (NCCT, 1985). Under the simplest framework, Haber's law is assumed to operate, with the product of concentration (C) and time (t) as a constant (k) for all the short periods used (Ct=k) (Casarett and Doull, 1986). If Ct is 30 and t is 10, then C is 3; if Ct is 30 and t is 30, then C is 1. If detoxification or recovery occurs and data are available on 24-hour exposures, this is taken into account in modifying Ct. In some instances, the Ct concept will be inappropriate, as for materials such as ammonia that can be more toxic with high concentrations over short periods. Each material is considered in relation to the applicability of Haber's law.

Generally, EEGLs have been developed for exposure to single substances, although emergency exposures often involve complex mixtures of substances and, thus, present the possibility of toxic effects resulting from several substances. In the absence of other information, guidance levels for complex mixtures can be developed from EEGLs by assuming as a first approximation that the toxic effects are additive. When the chemical under evaluation for development of an EEGL is an animal or human carcinogen, a separate qualitative risk assessment is undertaken in recognition of the fact that even limited exposure to such an agent can theoretically increase the risk of cancer. The risk assessment is performed with the aim of providing an estimate of the acute exposure that would not lead to an excess risk of cancer greater than 1 in 10,000 exposed persons. The following mathematical approach, taken directly from NRC (1986, pp. 26-27), is applicable for EEGL computations for carcinogens:

1. If there has been computed an exposure level d (usually in ppm in air), which after a lifetime of exposure is estimated to produce some "acceptable" level of excess risk of cancer — say, 1×10^{-6} — this has been called a "virtually safe dose" (VSD). Computation of the dose d, if not already done by a regulatory agency, will be computed by the Committee on Toxicology in accordance with generally accepted procedures used by the major regulatory agencies, i.e., using the multistage no-threshold model for carcinogenesis and the appropriate body weight/surface area adjustments when extrapolating from an animal species to humans.

2. If carcinogenic effect is assumed to be a linear function of the total (cumulative) dose, then for a single 1-day human exposure an acceptable dose (to yield the same total lifetime exposure) would be d times 25,600 (there being approximately 25,600 days in an average lifetime); the allowable 1-day (24-h) dose rate would be

$$d \times 25{,}600$$

3. Because of uncertainties about which of several stages in the carcinogenic process a material may operate in, and because of the likely low age of military persons, it can be shown from data of Crump and Howe (1984) that the maximal additional risk that these considerations contribute is a factor of 2.8. As a conservative approach, the acceptable dose is divided by 2.8, i.e.,

$$\frac{d \times 25{,}600}{2.8}$$

   If a lifetime excess risk, R, is established by DOD (for example, at 1×10^{-4}, as has been suggested by the International Council on Radiation Protection for nuclear power plant workers), then the appropriate extent of risk at the EEGL would be

$$\frac{d \times 25{,}600}{2.8} \times \frac{R}{\text{level of risk at d}}$$

   (In the example given here, the level of risk at d was no more than 1×10^{-6}.) If R is 1×10^{-4}, then R/risk at d = $10^{-4}/10^{-6} = 100$ (NRC, 1986).

4. If a further element of conservatism is required (for example, where animal data need to be extrapolated to estimate human risk), an additional safety factor can be used as divisor.

The NRC's Committee on Toxicology has also developed special public exposure guidelines upon request from Department of Defense. The Short-term Public Exposure Guidance Level (SPEGL) is defined as an acceptable ceiling concentration for a single, unpredicted short-term exposure to the public. The exposure period is usually calculated to be one hour or less and never more than 24 hours. SPEGLs are generally set at 0.1 to 0.5 times the EEGL. A safety factor of 2 is often used to take into account effects on sensitive subpopulations, such as children, the aged, and people with debilitating diseases. A safety factor of 10 may be used to take into account the effects of an exposure on fetuses and newborns. Effects on the reproductive capacity of both men and women are also considered. Five SPEGLs (for hydrazine, dimethylhydrazine, monomethyl hydrazine, nitrogen dioxide, and hydrogen chloride) have been developed by the NRC; all five chemicals are on the list of EHSs. (U.S. EPA, 1987).

EXPOSURE AND CONSEQUENCE ANALYSES

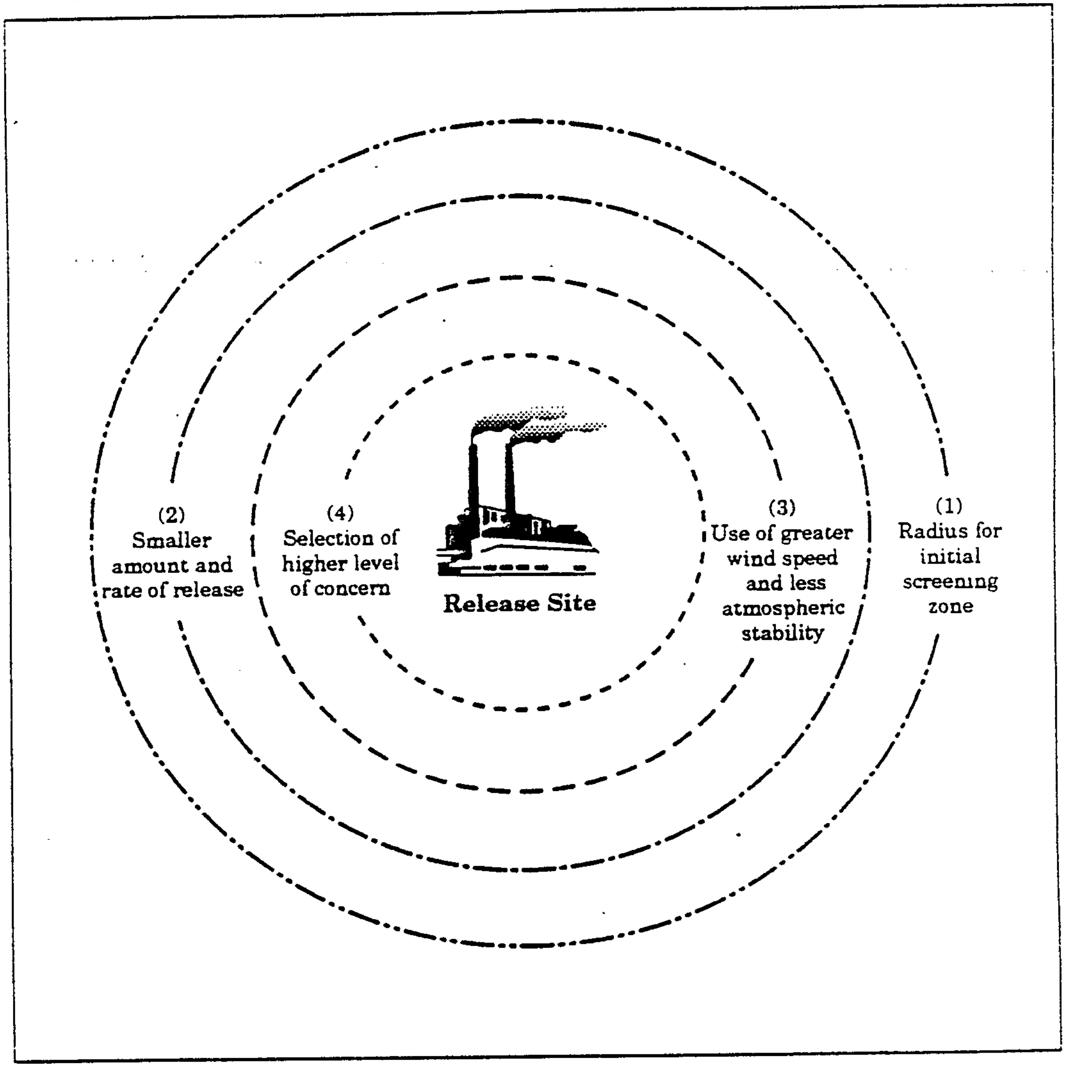
In this section, potential exposures to and consequences of exposure to H_2S from oil and gas wells are analyzed. The zones of the United States most likely to contain H_2S are identified and the potentially exposed human and ecological populations are discussed. Routine emissions and accidental releases of H_2S are characterized using monitoring records and dispersion modeling and the consequences are discussed. For accidental releases, prevention, mitigation and emergency response policies and procedures are also identified.

Vulnerability Zones

Vulnerability zones are estimated geographical areas that may be subject to concentrations of H_2S at levels that could cause irreversible acute health effects or death to human populations within the area following an accidental release. For detailed hazard analyses recommended under the Emergency Planning and Community Right-to-Know Act of 1986 (EPCRA), see Chapter IV; vulnerability zones are based on estimates of the quantity of hazardous substances released to air, the rate of release to air, airborne dispersion, and the airborne concentration that could cause irreversible health effects or death. This concept of vulnerability is used to assess regions most likely to encounter routine emissions or accidental H_2S releases from oil and gas production. This report does not use the EPCRA methodology. Rather, the basic tools of a hazard analysis are used to alert the reader to areas with potential H_2S hazards.

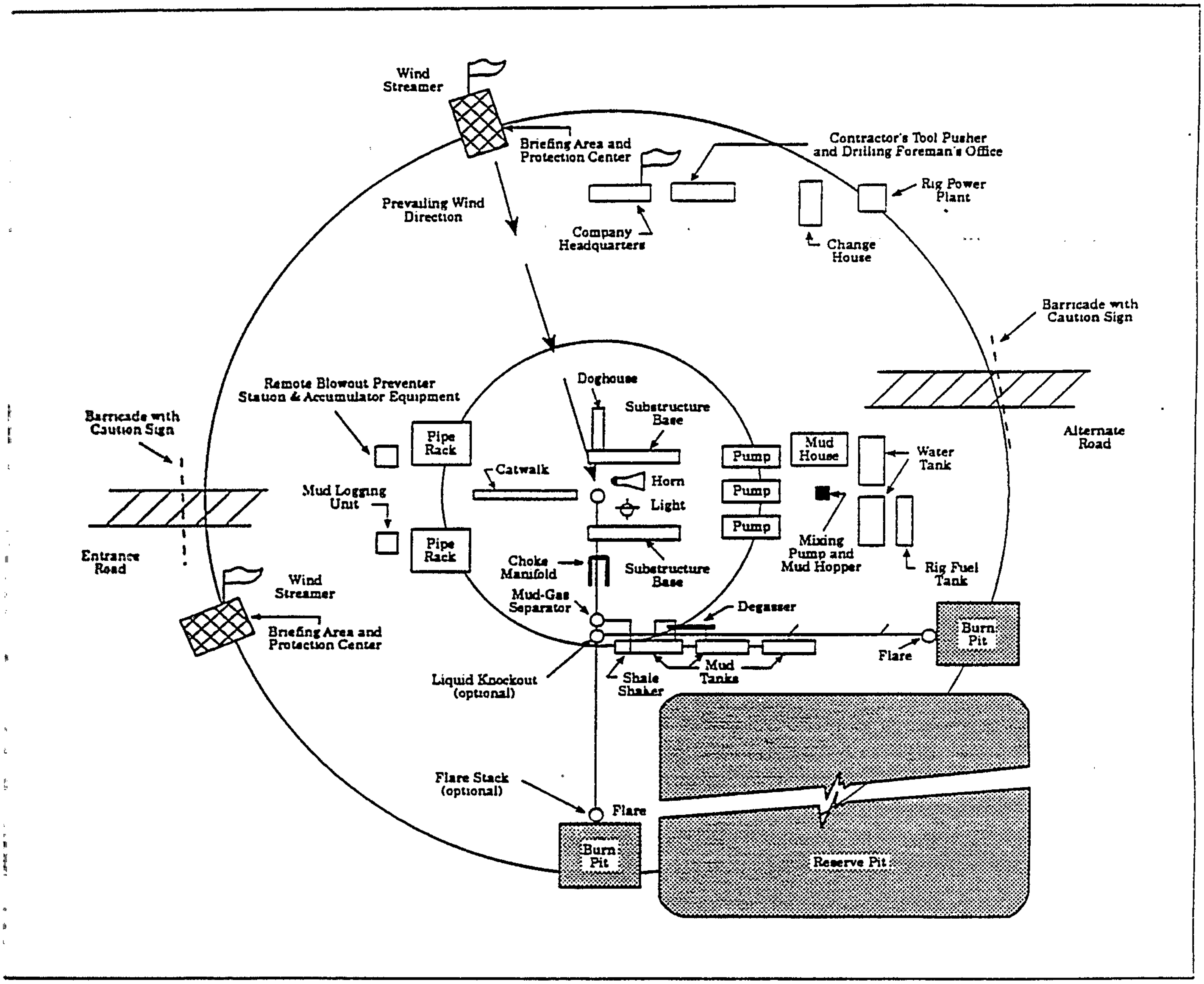
Estimated vulnerability zones are shown in Figure III-3 as circles with different radii to illustrate how changing conditions or assumptions can influence the vulnerablity zone estimate. With most atmospheric releases, the actual concentration of the airborne chemical tends to decrease as it moves further downwind from the release site because of continual mixing and dilution (i.e., dispersion).

The American Petroleum Institute (API), an industry-wide technical organization, has published several recommended practices (RP) pertaining to hydrogen sulfide in the oil and gas production industry. Figure III-4 shows API's RP 49 recommended equipment layout to minimize vulnerability zones for an unconfined area, taking the potential for H_2S releases into consideration. Confinement refers to offshore sites and some land locations confined by



Source: U.S. EPA. 1987.

Figure III-3. The effect of different assumptions on the calculation of the radius of estimated vulnerable zones.



Source: API, 1987.

Figure III-4. Example of drilling equipment layout – unconfined location.

the restriction of area, method of access, terrain, surrounding population distribution, etc. In an H_2S environment, well plot areas should be larger than usual, (i.e., larger reserve pits, turnaround room, etc.). The extra space allows for a greater margin of safety in well site activities and, in turn, a smaller vulnerability zone.

The California Division of Oil and Gas provides guidance on H_2S exposure prevention. In their report, *Drilling and Operating Oil, Gas, and Geothermal Wells in an H_2S Environment*, the State recommends calculating the well area's potential toxicity from H_2S emissions, if the volume of oil or gas produced and the concentration of the H_2S in the oil or gas are known (Dosch and Hodgson, 1986). From these data, the radius from the source to the 3×10^5 ppb and 1×10^5 ppb H_2S concentration area can be determined on dispersion-based scales. Potential sources of toxic gas emissions considered in calculating the toxicity of the well area include wells and associated production, treatment, processing, and storage facilities.

Calculating vulnerability zones for H_2S on a nationwide basis, as in EPCRA hazard analyses, is difficult because vulnerability zones are designed for site-specific studies. Therefore, this assessment will take a broader approach to identifying vulnerability zones, which will be referred to as H_2S prone areas. These areas are considered the major areas of the United States prone to natural occurrences of hydrogen sulfide. Figure II-1 identified 14 major H_2S prone areas in the United States. The 20 states having H_2S prone areas are Alabama, Arizona, Arkansas, California, Colorado, Florida, Idaho, Indiana, Illinois, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Nebraska, North Dakota, Oklahoma, Texas, Utah, and Wyoming. Texas has four discrete areas prone to H_2S. However, some States, such as Louisiana, do not drill to depths of known H_2S deposits; in Louisiana, oil and gas wells appear to be located in more shallow depths.

Exposure Analysis — Routine Emissions

Monitoring Records

Ambient air monitoring programs measure the concentration of pollutants after they have dispersed from one or more sources. These levels are recorded and tracked continuously so that the level of exposure and air quality can be assessed over the long term and under varying meteorological and emission scenarios. Ambient air monitoring is also used to determine compliance with air quality standards by measuring pollutant concentrations. With a dispersed, relatively unreactive primary pollutant such as hydrogen sulfide, often the emissions can be traced back to the specific source.

Many States require ambient air monitoring for hydrogen sulfide at gas plants and refineries; however, monitoring is not frequently required at oil and gas extraction facilities. In the preparation of this report, six States (California, Michigan, North Dakota, Oklahoma, Texas, and Wyoming) were contacted and questioned about the availability of monitoring data. California, Michigan, Oklahoma, Texas and Wyoming had not conducted pertinent ambient air monitoring.

The North Dakota State Department of Health and Consolidated Laboratories (NDSDH&CL) performs ambient monitoring for routine emissions of H_2S and has collected the data since 1980. The following discussion summarizes North Dakota's program to provide an indication of historical, routine emissions of H_2S from wells. Since no other States have such monitoring data available, this report relies on North Dakota's data to assess hazards and draw conclusions.

The North Dakota database contains site name, year/month/day monitored, and H_2S value measured. The database reflects three background and six special purpose monitors (i.e., monitors set up as a result of a complaint). Monitoring periods vary in length from months to over a decade for a total of 393 months (32.75 years) of data (personal communication, D. Harman, NDSDH&CL, 8/11/92). Table III-3 shows the North Dakota data. The data were in half-hour average concentrations up to January 1, 1988, when the averages recorded were changed to hourly, to correspond with the change in the North Dakota Ambient Air Quality Standards (NDAAQS). Some monitoring lasted less than a year; however, monitoring in the Theodore Roosevelt National Park-north unit was begun in 1980 and continues today.

North Dakota's Hydrogen Sulfide Standards - An Historical Review. At the time of the early monitoring activities, there were two NDAAQS for hydrogen sulfide, both based on half-hour averages and on odor thresholds but over different time spans. Adopted in 1970, they were based upon guidelines established in the Interstate Air Pollution Study conducted in St. Louis in the late 1960s. Those standards were 54 ppb (75 $\mu g/m^3$), 1/2-hour maximum concentration not to be exceeded more than twice per year; and 32 ppb (45 $\mu g/m^3$), 1/2-hour maximum concentration not to be exceeded more than twice in any five consecutive days. The 1/2-hour hydrogen sulfide standards were inconvenient because all of the other pollutants were being tracked on an hourly basis. To correct the situation, North Dakota developed a 1-hour standard that would afford the same degree of protection as the old 1/2-hour standards did, while still based on an odor threshold value. Statistically, they narrowed the proposed standard down to a range of concentrations between 48 ppb and 52 ppb. Montana had an existing hydrogen sulfide standard of 50 ppb for a 1-hour period, not to be exceeded more than once per year, and North Dakota decided to adopt the same standard to provide consistency on both sides of the North Dakota-Montana State border. The 50 ppb (70 $\mu g/m^3$) 1-hour hydrogen sulfide standard became effective October 1, 1987.

At the same time that the new standard became effective, a new chapter (Chapter 20) was added to North Dakota's Air Pollution Control Rules entitled "Control of Emissions from Oil and Gas Well Production Facilities." The oil companies expressed concern that the hydrogen sulfide standard was included in North Dakota's table of ambient air quality standards (NDAAQS) and, by law, exceptions could not be granted. Their position was that they could not guarantee compliance with the standard at all times, and that the standard was

Table III-3. North Dakota H_2S Monitoring Studies

Study	Location	Dates	Year	Ambient Std. (ppb)	Violation* (hours)	Maximum (ppb)
Roffler	Farmyard within 1/2 mile of well and tank battery	5/11/80 - 9/29/80	1980	32	0	13
Theodore Roosevelt National Memorial Park – North Unit	Little Missouri River Valley, near the north unit park headquarters	4/24/80 - 8/2/92 (1990 missing)	1980	32	0	4
			1981	32	1	220
			1982	32	34	500
			1983	32	31	158
			1984	32	27	415
			1985	32	35	137
			1986	32	12	87
			1987	32/50	0	73**
			1988	50	0	39
			1989	50	0	10
			1990	50/200	0	10
			1991	200	0	32
			1992	200	0	6
orgenson	Valley with several oil wells within 1 mile	10/2/80 - 5/13/82	1980	32	8	160
			1981	32	19	230
			1982	32	13	250
adrmas	Farmyard within 1 mile of several wells	6/30/82 - 10/31/83	1982	32	9	541
			1983	32	7	353
heodore Roosevelt ational Memorial ark – South Unit	Painted Canyon Rest Area	10/17/85 - 6/30/90	1985	32	0	12
			1986	32	0	16
			1987	32/50	0	18
			1988	50	0	9
			1989	50	0	10
			1990	50/200	0	0*
one Butte	Little Missouri River Valley near an oil tank battery in Little Knife Oil Field	1/17/84 - 7/11/89	1984	32	1808	1630
			1985	32	1859	2734
			1986	32	1653	2182
			1987	32/50	1130	2420
			1988	50	320	1515
			1989	50	25	122
ostwood	Lostwood National Wildlife Refuge Headquarters	12/26/85 - 1/14/91	1985	32	0	0
			1986	32	0	18
			1987	32/50	0	45
			1988	50	0	46
			1989	50	0	47
			1990	50/200	0	88
			1991	200	0	0
son	Farmyard within 1.5 miles of several wells	7/20/89 - 9/18/90	1989	50	2	88
			1990	50/200	0	73
aza	Town of Plaza, within 2 miles of several wells and tank batteries	9/4/90 - 8/3/92	1990	50/200	0	152
			1991	200	0	358
			1992	200	1	269

urce: Personal correspondence, D. Harman, NDSDH & CL, 8/11/92.

alysis of data prior to 10/1/87 based upon 32 ppb, 1/2-hour average standard, not to be exceeded more than twice in any onsecutive days.

alysis of data between 10/1/87 and 6/1/90 based upon 50 ppb 1-hour average standard, not to be exceeded more than once r year.

alysis of data after 6/1/90 based upon 200 ppb 1-hour average standard, not to be exceeded more than 1 time per month.

violation occurs the second time the standard is exceeded.

Monitor out of service much of the time period.

Exceedance defined as 2 times the standard.

not based on health-related concerns but on odor recognition levels. As a result, a joint Health Department/Industry task force was established and four new health-based standards were developed (effective June 1, 1990). These included raising the 50 ppb, 1-hr standard to a 200 ppb, 1-hr standard - a decrease in H_2S protection by a factor of four. These standards, which remain in effect today, are as follows:

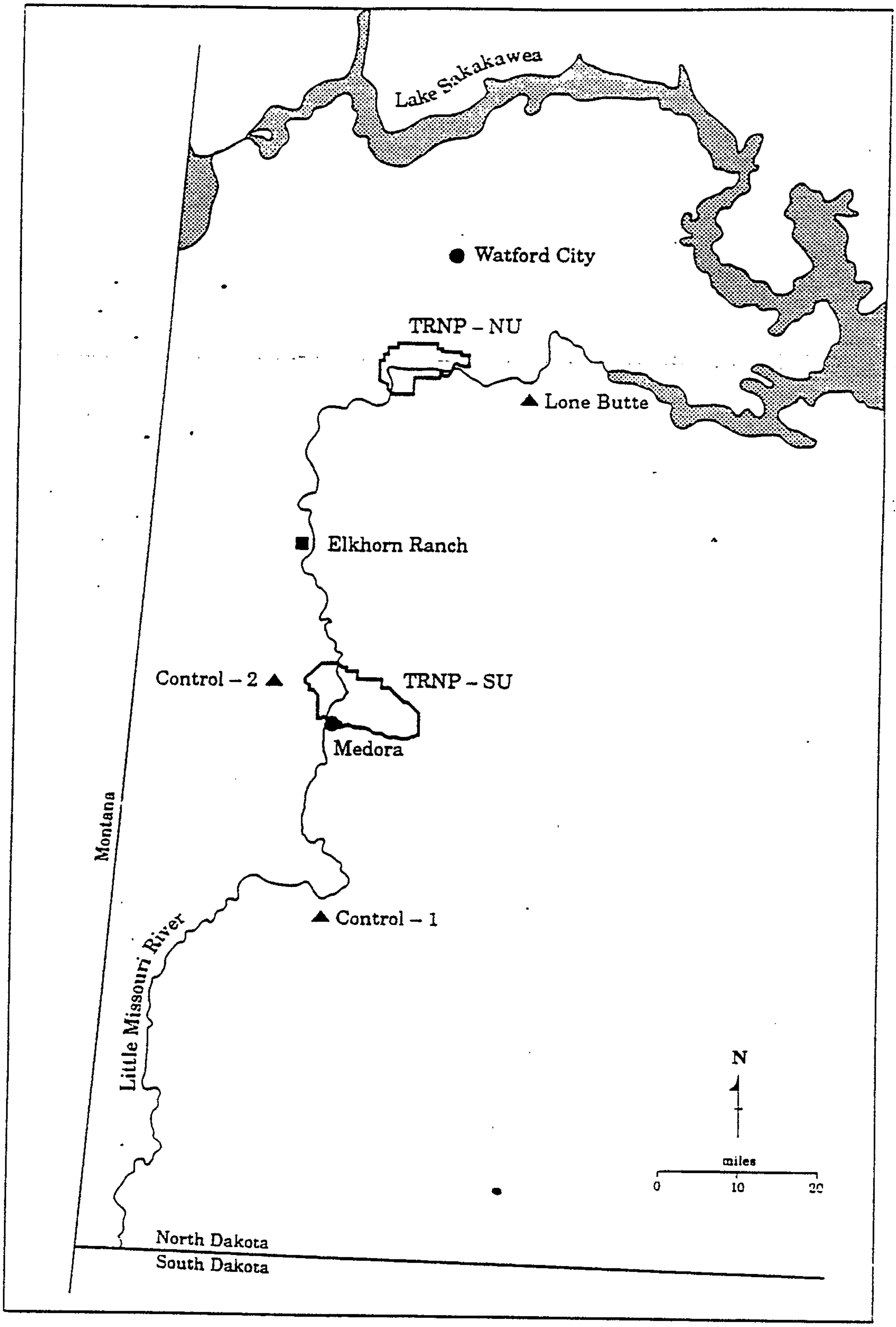
- 1 x 10^4 ppb or 14 mg/m^3) maximum instantaneous concentration not to be exceeded;
- 200 ppb or 280 μg/m^3) maximum 1-hour average concentration not to be exceeded more than once per month;
- 100 ppb or 140 μg/m^3) maximum 24-hour average concentration not to be exceeded more than once per year;
- 20 ppb or 28 μg/m^3) maximum arithmetic mean concentration averaged over three consecutive months (personal communication, D. Harman, NDSDH&CL, 8/11/92).

Methodology for Analysis of Monitoring Data. For the analysis of the monitoring data, only one of the standards was evaluated for each time period. Prior to October 1, 1987, the data were compared to the 32 ppb 1/2-hour average standard, not to be exceeded more than twice in any five consecutive days. After October 1, 1987, and prior to June 1, 1990, 50 ppb was the only standard in effect, not to be exceeded more than once per year. The data collected after June 1, 1990, were compared to the 200 ppb standard which was not to be exceeded more than once per month. The results of the analysis are tabulated in Table III-3.

PSD Class I Areas. Several of the North Dakota monitoring programs were conducted to monitor air quality changes resulting from the oil and gas production industry at national parks and wildlife refuges. The Federal government established the Prevention of Significant Deterioration permit program (PSD) to protect areas with good air quality. In North Dakota, the most important, or Class I, areas include the Lostwood National Wildlife Refuge and the northern, southern and Elkhorn Ranch portions of the Theodore Roosevelt National Park (see Figure III-5). Monitoring sites for hydrogen sulfide were set up at all of these locations except the Elkhorn Ranch locations.

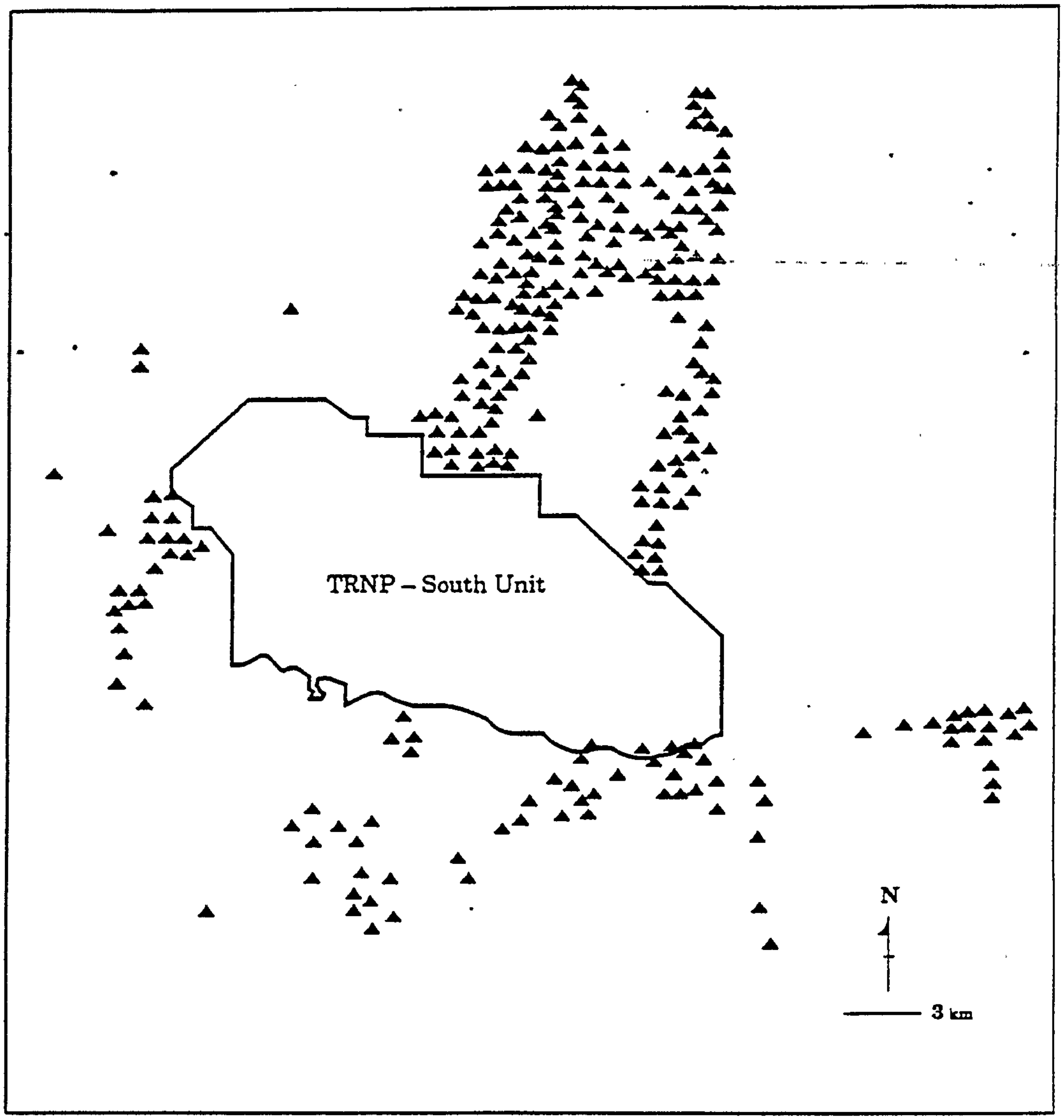
At the Lostwood Wildlife Refuge, data were obtained for the period from December 26, 1985, until January 14, 1991. Throughout the time period the maximum average concentration was 88 ppb, recorded as a 1-hour average in 1990. Overall, this was a site with acceptable air quality with respect to hydrogen sulfide because there were no NDAAQS violations.

In the Theodore Roosevelt National Park system (see Figures III-6 and III-7 for well distribution around the park), data were received by NDSDH&CL for the south unit (obtained at the Painted Canyon Rest Area) from October 17, 1985, to June 30, 1990. The air quality was very good, with no NDAAQS violations, and a maximum half-hour average



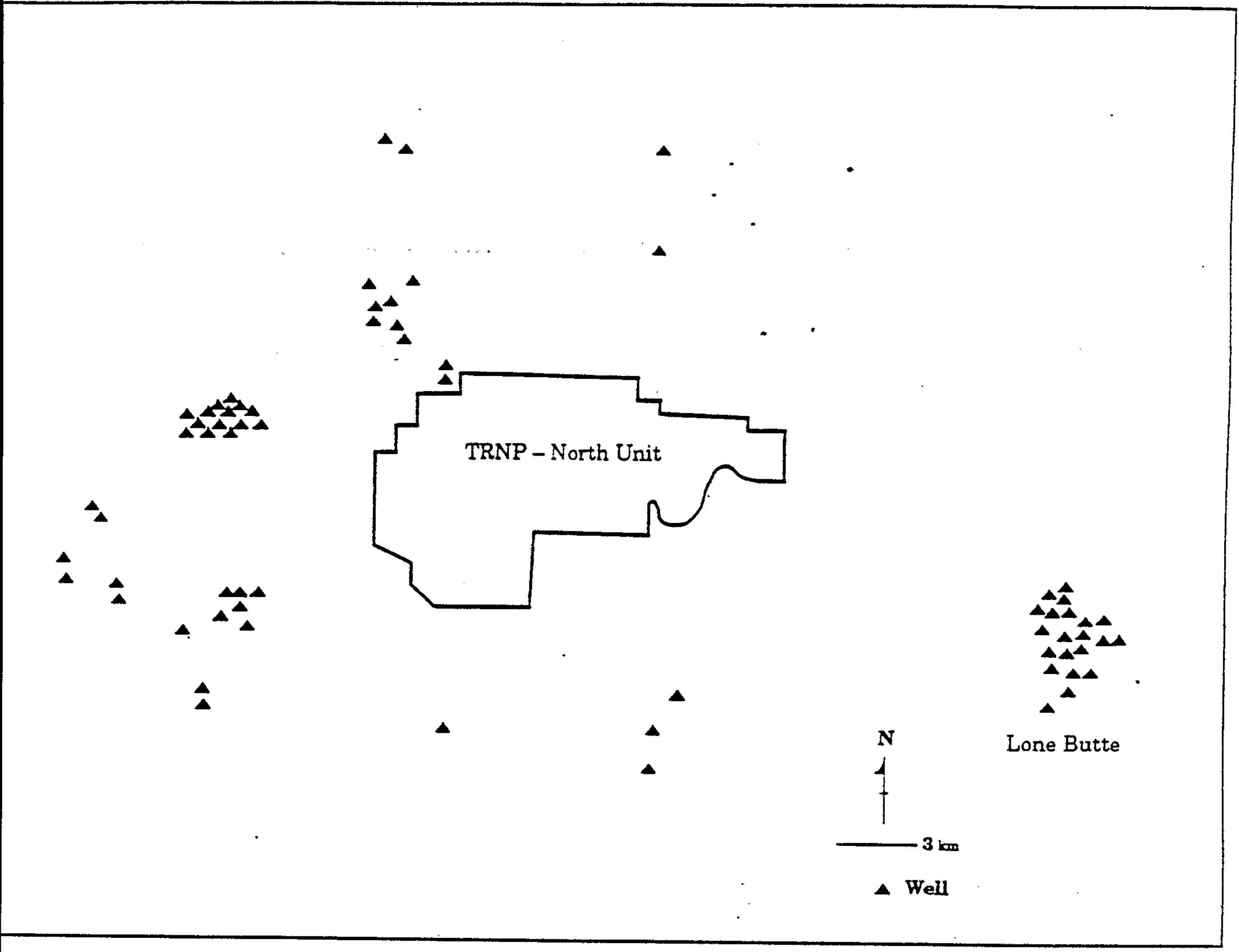
Source: Bilderbeck, 1988.

Figure III-5. Class I and II areas of North Dakota including Lone Butte and Theodore Roosevelt National Park (TRNP). Bold outlined areas are Class I; remaining area is Class II.



Source: Bilderbeck, 1988.

Figure III-6. Well distribution around Theodore Roosevelt National Park, South Unit.



urce: Bilderbeck, 1988.

gure III-7. **Well distribution around Theodore Roosevelt National Park, North Unit.**

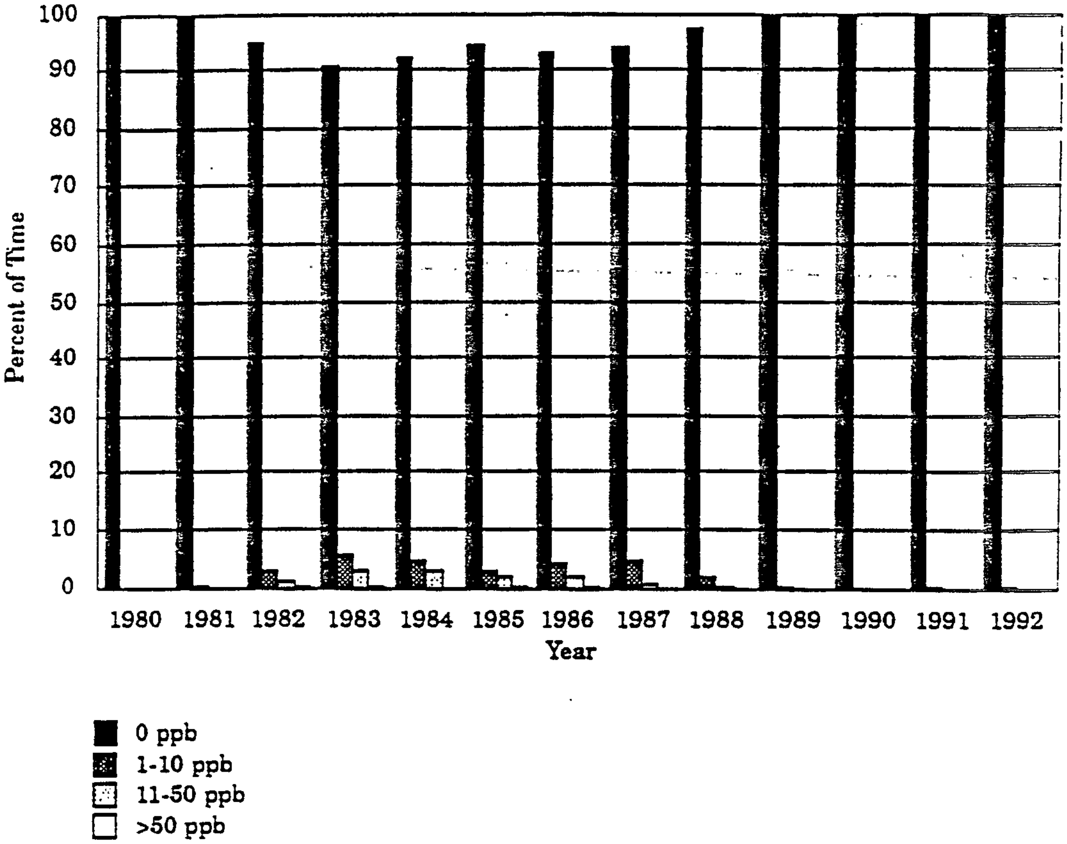
concentration of 18 ppb. The longest period of monitoring data received was from the north unit (recorded in the Little Missouri River Valley), covering the period from April 24, 1980, to August 2, 1992 (1990 data were not received by NDSDH&CL). In the early years, numerous violations of the 1/2-hour, 32 ppb NDAAQS occurred (e.g., 68 in 1982, 62 in 1983, and 70 in 1985). The maximum 1/2 hr time-weighted average concentration recorded during this period was 500 ppb in 1982. Air quality did improve during the second half of the study period, with several years of no NDAAQS violations. This was a result of NDSDH&CL mandated implementation of rigorous operations and maintenance programs by well operators involved in the field and tank vapor collection. Also, expansion of a gas-gathering pipeline network contributed to the decrease in H_2S concentrations because gases were previously released to the atmosphere.

From 1988 to 1990, the Williston Basin Regional Air Quality Study (BLM, 1990) was undertaken as a joint project between North Dakota and the Bureau of Land Management (BLM) to forecast compliance with Federal standards for sulfur dioxide, the resulting product of hydrogen sulfide combustion. Figure III-8 shows the range of concentrations measured at the site. Although over the entire period, 0 ppb was the concentration most frequently recorded, a decrease in air quality is charted, from 1982 through 1987.

Lone Butte. Lone Butte, is located approximately 11 km from the north unit of Theodore Roosevelt National Memorial Park (see Figure III-5). Lone Butte had concentrations of hydrogen sulfide an order of magnitude higher than the other sites. The monitor at Lone Butte (see Figure III-9), in the Little Missouri River Valley near an oil tank battery in the Lone Butte Oil Field, recorded more than 3000 violations of the 1/2-hour average 32 ppb NDAAQS per year from 1984 to 1986. Air quality did improve at the end of the monitoring period, although not to levels continuously below the NDAAQS of 50 ppb which was the standard at that time.

Figures III-10 depicts the range of concentrations measured at the Lone Butte site. Zero ppb is recorded more than 50 percent of the time through the early years, with an improvement towards 80 percent of the time by 1989. (The detection limit of the monitoring equipment was 1 ppb.) The improving trend toward the hydrogen sulfide standard occurred when the NDSDH&CL correlated the sources of the hydrogen sulfide with the ambient monitor levels through the use of the prevailing wind direction. The possibility of NDSDH&CL requiring individual monitoring at each well site convinced the producers to reduce their emissions (personal communication, D. Harman, NDSDH&CL, 8/11/92).

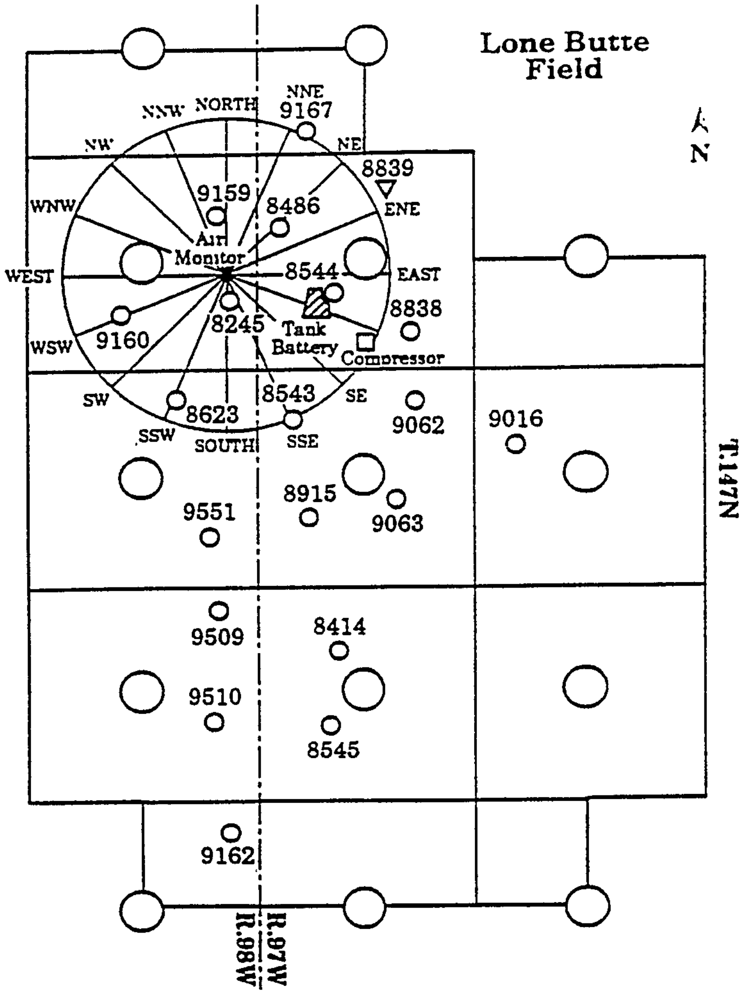
Other Monitoring Sites. Data from thirteen months of monitoring during 1989-1990 were recorded at the Olson farmyard, 1.5 miles from several wells in North Dakota. A maximum 1-hour average concentration of 88 ppb was recorded. Data were also obtained from September 4, 1990, to August 3, 1992, from a monitor in the town of Plaza, North Dakota, within 2 miles of several wells and tank batteries. The maximum concentration recorded on this monitor was 358 ppb, in 1991, with one violation of the NDAAQS recorded.



H_2S monitor detection limit = 1ppb

Source: Personal correspondence, D. Harman, NDSDH & CL, 8/11/92.

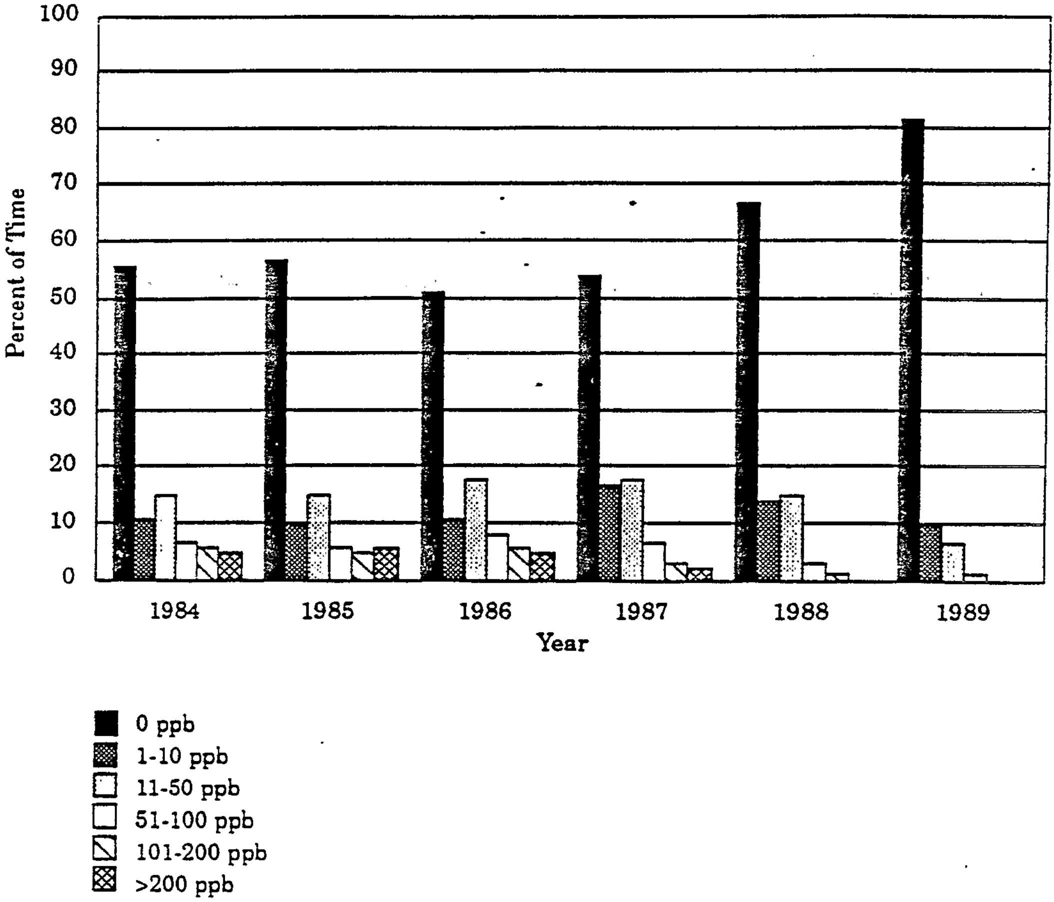
Figure III-8. Percentage of times designated H_2S concentrations were measured at the Theodore Roosevelt National Park - North Unit monitoring site.



File No.	Operator	Well Name	Well No.
8245	Chevron USA, Inc.	Bob Creek Federal Unit	1-13-3B
8414	Chevron USA, Inc.	Carus Federal	1-30-1C
8486	Apache Corp.	Federal 18	1
8543	Chevron USA, Inc.	Bob Creek Federal Unit	4-19-1D
8544	Chevron USA, Inc.	Bob Creek Federal (Comm)	2-18-48
8545	Chevron USA, Inc.	Carus Federal	2-30-4B
8623	Chevron USA, Inc.	Bob Creek Federal	3-24-2A
8838	Apache Corp.	Carus Amoco Unit "A"	1
8839	Apache Corp.	Carus Amoco Unit "C" (SWD)	1
8915	Apache Corp.	Lone Butte Federal Amoco "A"	1
9016	Apache Corp.	Carus Amoco "B"	1
9062	Apache Corp.	Lone Butte Federal Amoco "B"	1
9063	Apache Corp.	Federal	19-1-
9159	Texaco, Inc.	Bob Creek	13-8
9160	Texaco, Inc.	Bob Creek	13-11
9162	Texaco, Inc.	Bob Creek	36-1
9167	Texaco, Inc.	Bob Creek	7-13
9509	Chevron USA, Inc.	Mormon Butte	5-25-2B
9510	Chevron USA, Inc.	Mormon Butte Federal	3-25-3B
9551	Chevron USA, Inc.	Foley-Stewart Federal	4-25-3C
N/A	North Dakota State Dept. of Health	Air Monitor	
N/A	Koch Hydrocarbon	Compressor Station	
N/A	Chevron USA, Inc.	Tank Battery	

Source: Personal correspondence, D. Harman, NDSDH & CL, 8/11/92.

Figure III-9. Wells producing between July 1986 and December 1987 surrounding Lone Butte H_2S ambient air monitoring site.



H_2S monitor detection limit = 1ppb

Source: Personal correspondence, D. Harman, NDSDH & CL, 8/11/92.

Figure III-10. Percentage of times designated H_2S concentrations were measured at the Lone Butte monitoring site.

Only four months of monitoring data from the Roffler site were received by NDSDH&CL. dating from April 11, 1980, to September 29, 1980. Located in a farmyard within 1/2 mile of a well and tank battery, the monitor measured very low concentrations (usually 0 ppb) with a maximum, time-weighted average of 13 ppb recorded. In contrast, at the Jorgenson monitor, the recorded concentration was as high as 250 ppb. The Jorgenson monitor was located in a valley within one mile of several wells, and the data received dated from October 2, 1980, to May 13, 1982. Data from sixteen months of monitoring, from June 30, 1982, to October 31, 1983, were received for the Kadrmas site. Located in a farmyard within a mile of several wells, the maximum half-hour averages recorded were 541 ppb, in 1982, and 353 ppb, in 1983. From these three studies, an analysis was performed on the monitoring data in comparison to the 32 ppb half-hour standard. The results showed that the concentration of hydrogen sulfide never exceeded the NDAAQS during the four months of the Roffler study. Conversely, at the Jorgenson site, the 32 ppb standard was violated 16 times in 1980, 38 times in 1981, and 26 times in 1982. At the Kadrmas site, the violation count was 18 times in 1982 and 14 times in 1983.

Williston Basin Study. The Williston Basin Regional Air Quality Study was undertaken in the late 1980s to assess the air quality impact of oil and gas production in western North Dakota (BLM, 1990). Emissions inventories were prepared and air quality models were applied to project the impact of sulfur dioxide and hydrogen sulfide emissions in these 12 selected oil fields with respect to applicable ambient air quality standards and PSD increments. Study results suggested that exceedances of both sulfur dioxide and hydrogen sulfide ambient air quality standards could be expected for some fields. Exceedances of Class I PSD increments for sulfur dioxide were expected for three of the four Class I areas studied. Further development of the oil and gas fields, where the emissions of sulfur dioxide and hydrogen sulfide would be possible, would not be permitted unless these exceedances were addressed.

To arrive at estimated hydrogen sulfide concentrations for the study, two types of hydrogen sulfide emissions were considered. First a hydrogen sulfide concentration was obtained through back calculation of the output sulfur dioxide concentrations from the Industrial Source Complex Model. The predicted sulfur dioxide concentrations were the result of modeled dispersion of the point source emissions from heater-treaters firing on H_2S contaminated wellhead gas and from flares which burn H_2S contaminated wellhead gas when a gas gathering pipeline is not available. To provide conservative results, combustion efficiency of 75 percent was used in these calculations, meaning that 25 percent of the hydrogen sulfide remained unchanged. [Note: As stated in Chapter II, flares, in most applications, operate at 95 to 99 percent efficiency.] The second emission source used represented fugitive emissions from leaky valves, tank hatches or pipe connections. These fugitive sources were estimated as contributing a background concentration of 7 $\mu g/m^3$ (50 ppb), derived from the 99th percentile of the 1-hr average monitored ambient air concentrations at three remote monitor locations (the Theodore Roosevelt National Park's two sites and the Lostwood site) during portions of 1987 and 1988.

At the time of the study, the NDAAQS for H_2S was 50 ppb 1-hour average concentration not to be exceeded more than once a year. NDAAQS exceedances were predicted for 6 of the 12 fields studied using current emissions estimates, with exceedances predicted for 7 of the 12 fields using future emissions estimates. Of the sites where modeling suggested NDAAQS exceedances, the yearly second highest (the first occurrence of ambient hydrogen sulfide concentrations above 50 ppb would be allowed by the law) expected concentrations exceeded 700 ppb for the Lost Bridge Field and 900 ppb for the Rough Rider Field.

Modeling results are only an estimate and are often considered accurate when they are within a factor of two of the actual ambient concentrations. Except for the Lone Butte Field, ambient monitoring data were not available for the other fields to verify or contradict the modeled estimates.

Conclusions. At several locations, for example, Lostwood and the Theodore Roosevelt-south unit, the monitoring program served as a verification that the air quality was within the levels allowed by the law. In two cases, the monitoring programs were of too short of a duration to support any conclusions. When an area is monitored for a short period of time, as at the Roffler and Olson sites, the full range of meteorological conditions and emissions scenarios are not represented in the ambient air measurements. Monitoring was discontinued at Jorgenson and Kadrmas (both monitored in the early 1980s) and at Lone Butte (the site with the worst air quality) even though numerous NDAAQS violations were experienced during their last monitored year. This occurred because rigorous inspection and maintenance scheduling was established and/or the data indicated no air quality problems existed (personal communication, D. Harman, NDSDH&CL, 11/9/92).

Ambient concentrations of hydrogen sulfide varied for the sites, with maximum yearly concentrations ranging from half-hour averages, below the 1 ppb detection limit, to 2734 ppb (2.734×10^3 ppb). Two common factors were the median and mode values. For all of the monitoring data received from North Dakota, the median and mode values were 0 ppb. In other words, for each site more than half of all observations recorded below the 1 ppb monitor detection limit.

Severity of Consequences. No epidemiological studies have been carried out to assess the effects of hydrogen sulfide exposure resulting from the production of oil and gas. Many States have enacted ambient air quality standards based upon odor for hydrogen sulfide, since its odor recognition threshold is so low (i.e., 3 to 20 ppb).

Annual average H_2S concentrations, which can more appropriately be compared to a long-term concentration benchmark such as the RfC, were also calculated from the Lone Butte site. These values exceeded the RfC by about an order of magnitude from 1984-1987, dropping to about the RfC level in 1988 and 1989. Since these values indicate the combined impacts of 9 separate wells, it is reasonable to conclude that: 1) the long-term impact of routine releases from any individual well is probably not significantly greater than the RfC;

and 2) the use of a gas-collection system with manifolded flares and rigorous operation and maintenance programs can significantly reduce long-term H_2S impacts.

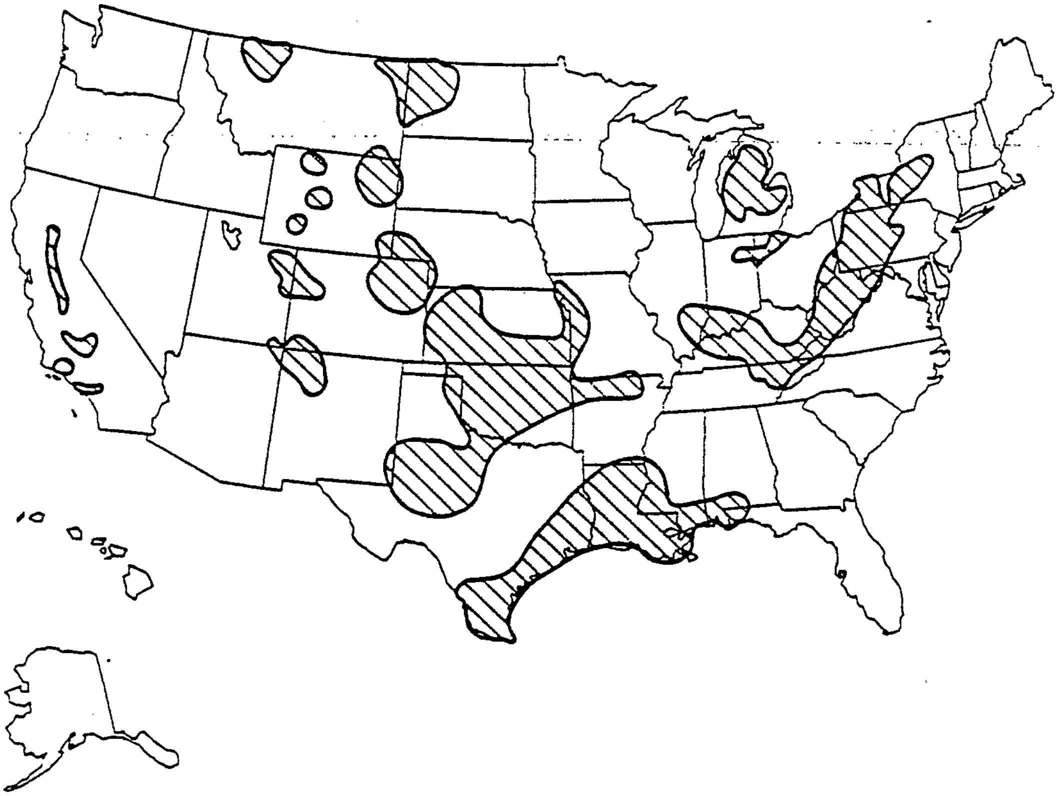
At low concentrations, odor nuisance and eye and respiratory tract irritation are the consequences of exposure rather than the toxic properties of the gas. An explanation for an increased perception of ill health could be related to low level exposure to hydrogen sulfide and pulmonary infections. A study by Rogers and Ferin (1981) concluded that hydrogen sulfide significantly affected the antibacterial system of rats by impairing pulmonary macrophage. However, additional research would be required before any definitive judgements could be made in human exposure scenarios.

Elevated ambient concentrations in two episodes (one in the Great Kanawha River Valley, WV, in 1950, and one in Terre Haute, IN, in 1964) were reported as 0.41 mg/m^3 (293 ppb) and 0.46 mg/m^3 (329 ppb), respectively (West Virginia Department of Health, 1952; U.S. Public Health Service, 1964). These incidents did not result from oil and gas production; however, the ambient concentrations recorded were comparable to some measurements in North Dakota. General symptoms of malaise, irritability, headache, insomnia, and nausea were reported by exposed populations. In the Terre Haute incident, levels measured at a nearby lagoon ranged from 2×10^3 to 8×10^3 ppb). The most common symptoms reported were offensive odor, foul-tasting water, nausea, vomiting, diarrhea, throat irritation, shortness of breath, burning eyes and asthma. Milder symptoms included cough, headache, anorexia, acute asthma attacks, nervousness, weight loss, fever, gagging and heaviness of chest. The symptoms ceased when the odor disappeared. In an episode in Alton, IL in 1973 similar symptoms were reported (Illinois Institute for Environmental Quality, 1974; NRC, 1979). Ambient hydrogen sulfide levels ranged from 25 ppb to higher than 1×10^3 ppb. Other contaminants, such as ozone and nitrogen oxides were also detected during this episode (Hoyle, 1973).

A study of the levels of sulfur compounds in vegetation near the Lone Butte oilfield and Theodore Roosevelt National Park, was conducted during the summer of 1987 (Bilderback, 1988). The study's conclusions confirmed what ambient monitoring had suggested: the South Unit of the national park may have been impacted by moderately high levels of atmospheric sulfur pollution, and the Lone Butte oil field was impacted by high levels of reactive atmospheric sulfur. Visible signs of vegetation damage were also detected at the Lone Butte oilfield. Furthermore, Bilderback attributes the elevated levels of hydrogen sulfide at the North Unit of the Park to the Lone Butte oilfield.

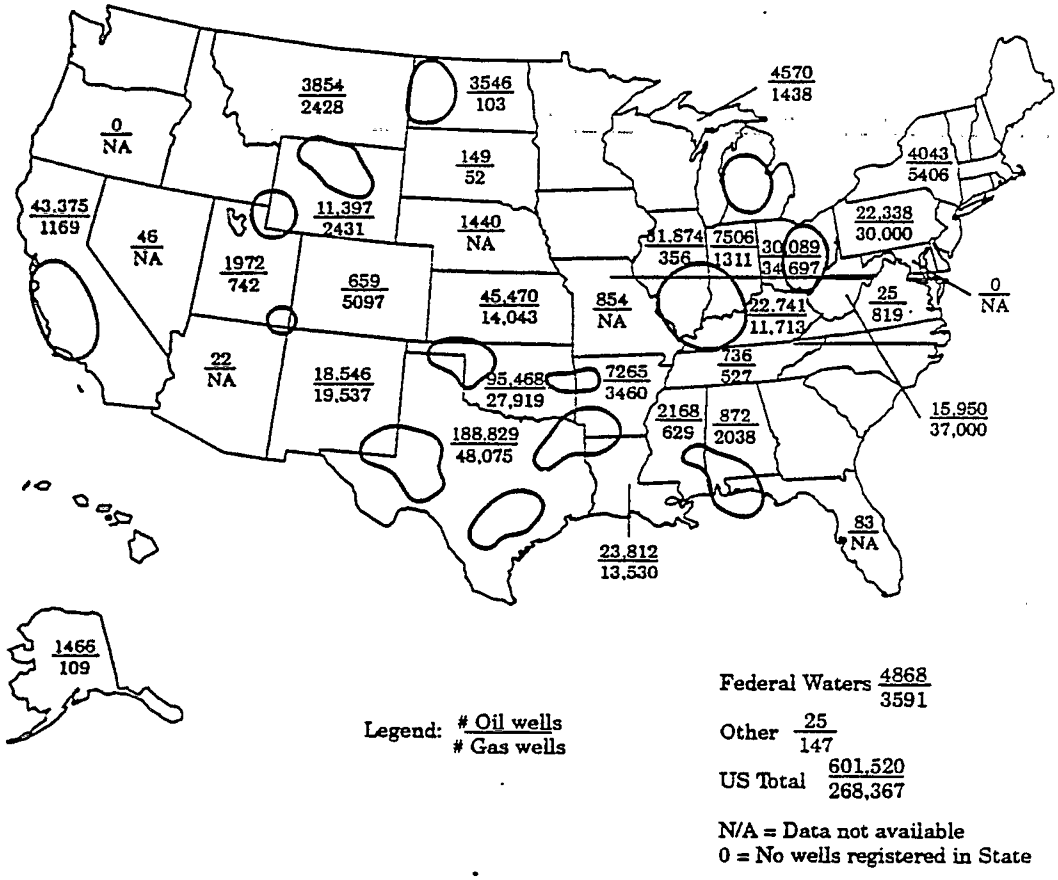
Consequence Analysis — Routine Emissions

As described in Chapter II, several potential sources of routine H_2S emissions can be found at oil and gas production facilities. Figures III-11 and III-12 indicate that 8 States have a significant overlaps of well fields and H_2S prone areas. Using the estimated number of producing wells in these States (Figure III-12) as a conservative measure, it appears that as many as 280.000 oil wells and 54,000 gas wells have the potential for location in an H_2S



Source: IOGCC, 1990.

Figure III-11. Oil and gas fields.



Source: Gas Research Institute, 1990.

Figure III-12. Major H_2S prone areas shown in relation to number of producing oil and gas wells in 1990.

prone area. Although only a fraction of these wells would actually be sour, these figures imply that the potential for routine H_2S emissions is significant. However, no national statistics are available to predict the probability of such emissions. The only record of routine emissions identified is ambient air quality monitoring data from the State of North Dakota. Nine monitoring studies in 12 years resulted in more than 3,300 violations of the NDAAQS. The majority of these violations occurred when the standard was developed based on the more conservative odor threshold rather than on health considerations. Only one violation was recorded after the health-based (higher concentration limits) standards were implemented.

A routine emission scenario would be the incomplete combustion of the wellhead gases, allowing some percentage of the hydrogen sulfide to be emitted. In the oilfields of North Dakota, the concentration of hydrogen sulfide in waste gas stream to flares can reach 30 percent, with the conversion efficiencies of the flaring operations varying from 30 to 100 percent (NDSDH&CL, 1983). (Note, however, that in Chapter II, the common efficiency of a flare, regardless of industrial application is 95-99 percent.) This scenerio would result in releases of 0 to 70 percent of the hydrogen sulfide contained in the wellhead gas. In western North Dakota, the amount of natural gas flared exceeded 1 million cubic feet per month in mid-1982, dropping to less than half of that amount by mid-1985, as more wells were tied into a central gas collection system (Liebsch, 1985). As a worst case scenario, if the gas content were 30 percent hydrogen sulfide, and the combustion efficiency were 30 percent (70 percent of the hydrogen sulfide was emitted unconverted), 210,000 cubic feet of hydrogen sulfide per month could have been routinely emitted in the mid-1982 time period.

No H_2S health or ecological effects studies have been conducted which specifically target oil and gas production. The most common consequences of exposure to routine emissions of H_2S are the odor nuisance and eye and respiratory tract irritation.

Exposure Analysis—Accidental Releases

The discussion of accidental releases begins with a description of examples of accidental releases of sour oil and gas in the United States that have impacted the public and wildlife. These examples are then supplemented by calculations of the consequences of a series of hypothetical accident scenarios using atmospheric dispersion models. The risk to the public from an accidental release of H_2S is a function of both the potential consequences and the likelihood of occurrence of an accidental release. Risks from a major accidental H_2S release will vary from facility to facility depending on site-specific factors such as the population density and distribution of nearby populations and the quality of process safety management and risk management practiced at the facility. Since risk is a product of both consequences and likelihood, risk reduction must take both into account. The accidental release discussion concludes with an assessment of accident prevention, mitigation, and emergency procedure measures that, if systematically implemented, could help to prevent or reduce the likelihood of accidental releases of H_2S from sour oil and gas, and mitigate the consequences in the event that a release occurs. Supporting details for the atmospheric dispersion calculations may be found in Appendix C.

Accidental Release Records

A variety of sources were investigated to locate documentation of accidental sour gas releases. These sources include: Congressional testimony; literature searches; database searches; state regulatory authorities; emergency response organizations; and industry officials. No national statistics regarding sour oil or gas releases were identified. Data base sources were the Accidental Release Information Program (ARIP) database which is maintained by the EPA, the Acute Hazardous Events (AHE) database which was developed by EPA, and the Emergency Response Notification System (ERNS) database. ARIP has records of chemical accidental releases that have occurred since October 1986 with some detailed information on accident cause. AHE has incident records covering the time period 1982 to 1986 and was developed from various sources including press reports, spill reports to the National Response Center, and some state and EPA regional office records. ERNS contains records of releases reported to the National Response Center.

A review of available sources revealed several documented examples of incidents in oil and gas extraction operations in the United States where accidental releases of H_2S have impacted the public and/or the environment since 1974. There was also a very large sour gas release that caused some environmental damage in Alberta, Canada during this time period. Examples of some of these accidents are summarized in Table III-4. It should be noted that these incidents include two accidents related to carbon dioxide injection to improve recovery rather than from the accidental releases of sour natural gas. One of these accidents resulted in eight fatalities, and another accident resulted in two injuries. The other incident resulting in fatalities was the result of fire associated with a natural gas release. However, effects on the public that are directly related to oil and gas extraction activities have most often been limited to evacuation. Isolated incidents resulting in hospital treatment have also occurred. Evacuation may occur as a conservative measure whether or not a life-threatening situation exists. There have been several documented incidents involving livestock and wildlife fatalities. In addition to toxicity, the flammability of accidental releases of sour oil and gas may also present a significant hazard.

Information from the State of Texas shows that there were 145 incidents of sour oil and gas release during the years 1985 through 1992 (Hall, 1992). These accidents were generally related to sour oil and gas rather than specifically from extraction activities. In these incidents, there were 10 deaths (all occupational), and 109 injuries (100 occupational and 9 public). The Texas incidents may be illustrative of the relative hazard to operating personnel, the general public, and the environment. These statistics indicate that the major hazard from oil and gas operations involving H_2S would be to workers rather than the public or wildlife. Workers are more often in close proximity to the wells and associated equipment.

Table III-4. Examples of Accidental Releases of H_2S from Oil and Gas Extraction Operations with Impact on the Public or Environment

Date and Location	Effects on Public	Effects on Environment	Comments	Source
5/21/74 Meridian, MS	5 deaths due to associated fire	40 acres burned	Sour gas gathering pipeline rupture and subsequent fire	Texas Oil and Gas Pipeline Corporation, 1976
2/2/75 Denver City, TX	8 occupants of house 200 ft from well were overcome by the gas and died.	None identified	Gas escaped from gas injection well. Gas was 93 v/o CO_2 and 5 v/o H_2S.	Layton et al., 1983
/21/81 Big Piney, WY	No impact on public	Deaths of some jackrabbits and blackbirds	Well blowout lasting 8 days. Nearest residence was 2 miles away	Layton et al., 1983
0/7/82 Calgary, Canada	No impact on public	A number of moose and other large animals died	Release of 10 million ft^3 H_2S per day of accident	Oil Daily, 1982
/88 Lea County, NM	1 person physically incapacitated	1 horse died	An individual changing a tire was overcome with H_2S	Correspondence NM Oil Conservation Division, 1992
/20/89 curry County, X	Evacuation of nearby residents, 2 treated at hospital	None identified	CO_2 injection line rupture	Texas Railroad Commision Hall, 93
/20/90 aplata County, O	2 mile radius evacuated	None identified	Well leak	ERNS, National Response Center Report #01425
/29/90 eidelberg, MS	No deaths but 2,000 local residents were evacuated	None identified	Well blowout and consequent fire	Platt's Oilgram News, 1990
16/91 ambert, MT	12 people were evacuated	None identified	Incident was caused by corrosion of gathering line. Evacuation due to smell.	National Response Center
19/91 oakum County, X	None identified	7 cows, 1 coyote, and rabbits died	Sour gas gathering line rupture, 1.2% H_2S	Texas Railroad Commision Hall, 93
/17/91 aines County, X	None identified	Unspecified number of wildlife died	Sour gas gathering line rupture, approximately 6% H_2S	Texas Railroad Commision Hall, 93

Atmospheric Dispersion Analysis

Atmospheric dispersion analyses of sour oil and gas releases by computer model were both reviewed in the literature and conducted. The following issues are discussed prior to analyses of the consequences of sour gas release scenarios:

- Choice of scenarios;
- Sour gas composition and density;
- Behavior of sour gas upon release; and
- Choice of atmospheric dispersion models.

Choice of Scenarios. The objective in choosing scenarios was to investigate a representative range of potential accidental release situations including hypothetical worst case scenarios. Scenarios for atmospheric dispersion analysis were chosen from documented accidental releases, expressions of public concern, and literature analyses in which dispersion models were applied to sour gas release scenarios.

The accidental sour gas releases documented in the previous section show some common causes. Well blowouts and line releases are examples of accidents that have occurred and resulted in offsite impact. Therefore, these accident scenarios were included in the atmospheric dispersion analyses. Investigation of some public complaints resulted in concerns regarding sour gas releases from extinguished flares, collection of sour gas in low-lying areas, leakage from temporarily abandoned or idle wells, and line leakage (NDSDH&CL, 1989; U.S. EPA, 1992). These concerns were also investigated as accidental release scenarios.

Several literature sources provided descriptions of hazards associated with the operation of sour oil and gas wells in addition to sour gas dispersion analysis to support scenario development. Hazard/risk analyses and data on the composition of sour gas of wells in Alberta, Canada (Alp et al., 1990), southwest Wyoming and northern Utah (Quest, 1992), and western Wyoming and adjoining areas of Utah and Idaho (Layton et al., 1983) were considered in the choice of scenarios. Assessments of levels of concern (LOC), concentrations at which H_2S is of concern, for acute exposure to H_2S were also provided in these sources. Although H_2S alone is more dense than air, in general, the literature pertains to sour gas mixtures that are typically less dense than air and concludes that sour gas releases from well blowouts and line ruptures are of most concern as potential causes for levels of concern to extend significant distances from the point of release.

Sour Gas Composition and Density. The density of sour gas mixtures is of importance because it is one determinant of whether an accidental release will result in a plume that travels downwind at ground level or will result in a buoyant plume that rises and disperses. A dense plume may have a greater impact on humans and wildlife because it remains at ground level for a period of time. The density of sour gas mixtures at atmospheric pressure (to which accidental releases of sour gas are discharged) is dependent on the temperature and composition of the mixture. The density of a given gas mixture increases as temperature decreases. Expansion of natural gas released from a pressurized system results in cooling of the gas. The colder a gas, the higher its density.

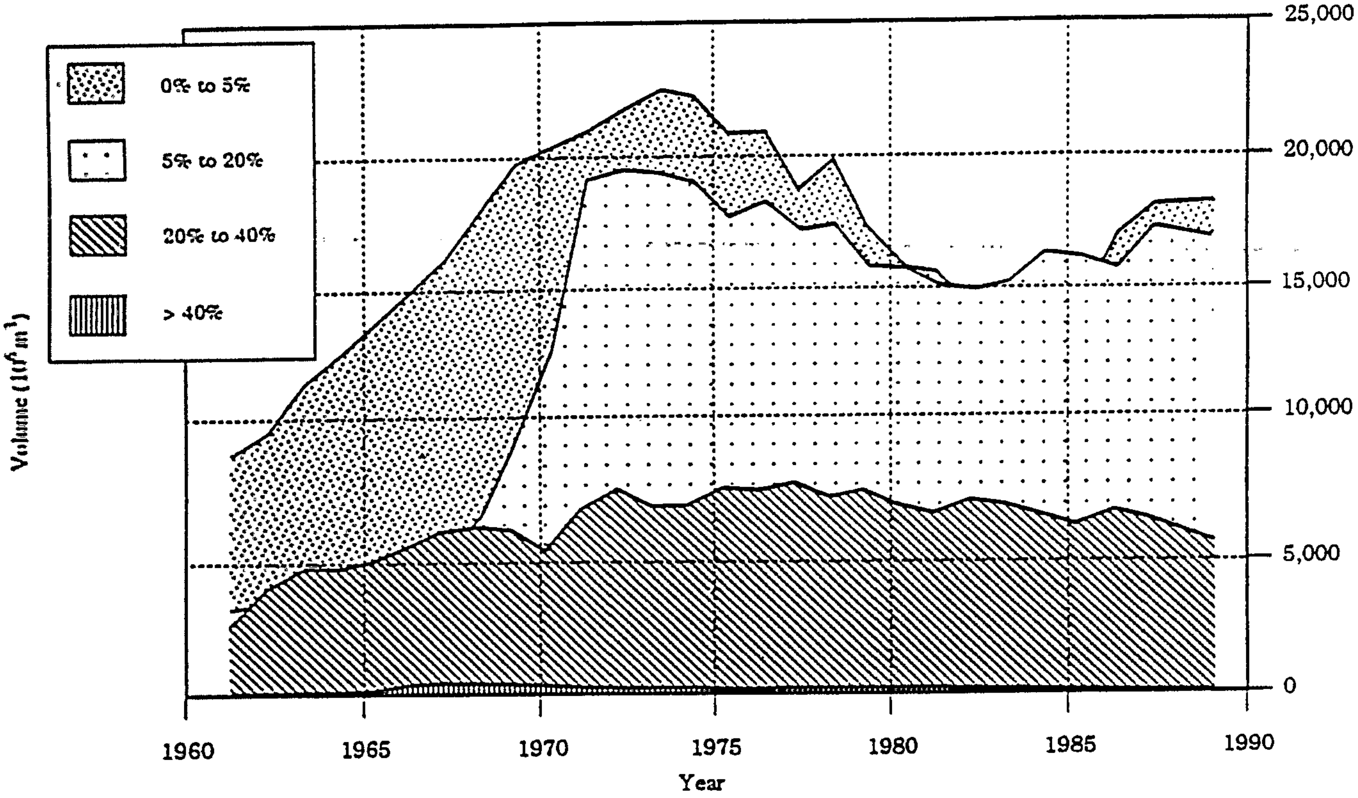
There is a wide variety of potential compositions of sour gas mixtures, depending on the reservoir. The density of these mixtures depends on their composition. In addition to hydrogen sulfide, natural gas can also contain some or all of the following: hydrogen, helium, carbon dioxide, nitrogen, methane, ethane, propane, isobutane, n-butane, isopentane, n-pentane, hexanes, heptanes, and higher molecular weight hydrocarbons. The largest component is typically methane, with hydrogen sulfide, ethane and possibly carbon dioxide (CO_2) likely to be present in significant proportions. Natural gas must contain some proportion of hydrogen sulfide in order to be considered sour.

Figure III-13 illustrates the variability of sour gas composition by showing the distribution of H_2S composition by number of sour gas wells in Alberta, Canada (Alp et al., 1990). Figure III-14 presents the same information as a function of the total number of tons of sulfur from natural gas produced each year. The H_2S composition can range from a small fraction of a percent to over 40 percent. A statistical analysis was performed of the sulfur composition of wells in the Overthrust Belt in western Wyoming and adjoining areas of Idaho and Utah (Layton et al., 1983). Volume percentages of sulfur were found similar to those in the Alberta wells. The sulfur composition ranged from less than 1 percent through 35 percent, with a mean of about 10 percent. Data on H_2S in California oil and gas fields shows fields with H_2S concentrations varying from less than 1×10^5 ppb (0.01 percent) to 20 - 30 percent (Dosch and Hodgson, 1986).

In addition to increasing the density of a sour gas mixture, carbon dioxide in sufficiently large concentrations can extinguish sour gas flares, resulting in uncombusted H_2S being released. CO_2 concentrations in various parts of the Overthrust Belt were found to vary from less than 5 percent by volume to more than 50 percent (Layton et al., 1983).

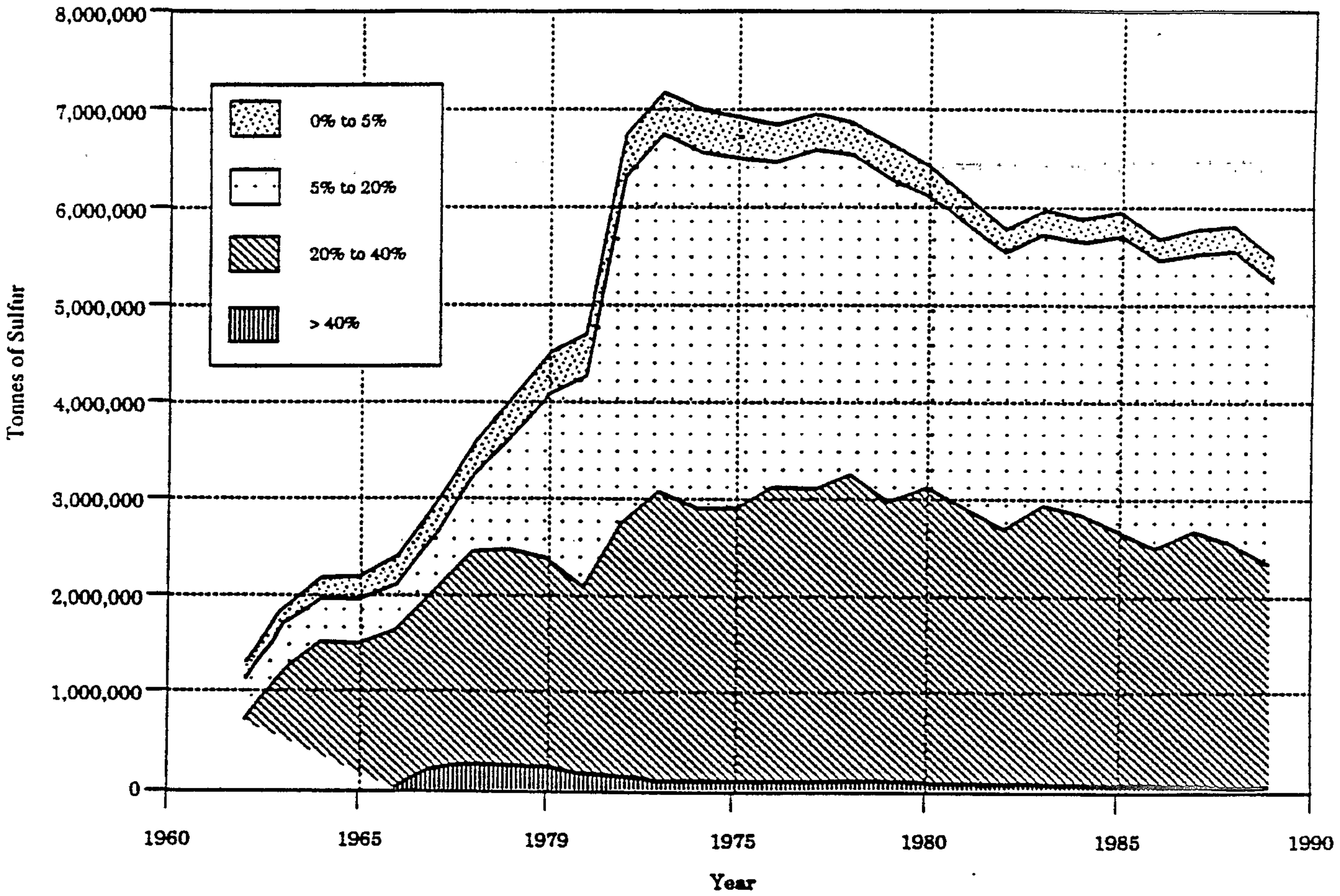
Some example sour gas compositions are presented in Table III-5.. Composition D is the single composition considered representative of all the data on producing gas wells in Alberta, Canada. Composition C is a representative gas composition produced by wells in a southwestern Wyoming sour gas field (Quest, 1992). Data were collected for a producing well in western North Dakota (U.S. EPA correspondence, 26 October 1992), and the compositions of streams after processing to recover hydrocarbon condensate at that well are given by compositions A and B of Table III-5. Composition A shows the gas composition after high pressure separation, and Composition B shows the composition after low pressure separation. The low pressure stream has a significantly higher H_2S concentration than the high pressure stream although its flowrate is lower.

H_2S alone is more dense than air, while methane alone is less dense than air. Natural gas mixtures of H_2S and light hydrocarbons are typically less dense than air to the extent that methane predominates in the mixture. The approximate molecular weight of air is 29. The



Source: Alp et al., 1990.

Figure III-13. Distribution of producing sour gas wells in Alberta by H_2S content.



Source: Alp et al., 1990.

Figure III-14. Total sulfur generated from producing gas wells in Alberta by H_2S composition of well.

ble III-5. **Example Gas Stream Compositions**

Component	Molecular Weight	Mole Fraction			
		Sample Well			
		High Pressure (A) (well flow)	Low Pressure (B) (vapor recovery systems)	Composition Used in Cave Creek Risk Assessment (C)	Composition Used by ECRB (D)
drogen Sulfide (H_2S)	34	0.075	0.277	0.146	0.30
rbon Dioxide (CO_2)	44	0.01	0.013	0.027	0.123
trogen (N_2)	28	0.003	-	0.017	0.02
thane (CH_4)	16	0.83	0.45	0.699	0.55
hane (C_2H_6)	30	0.047	0.10	0.058	0.005
opane (C_3H_8)	44	0.012	0.064	0.018	0.001
utane (C_4H_{10})	58	0.0032	0.024	0.0042	0.001
Butane (C_4H_{10})	58	0.0038	0.026	0.0050	—
entane (C_5H_{12})	72	0.0016	0.011	0.0022	—
Pentane (C_5H_{12})	72	0.0020	0.0086	0.0018	—
xanes (C_6H_{14})	86 }	0.0034	0.019	0.0031	
ptanes+ (C_7H_{16})	100+ }			0.0176	
erage Molecular Weight		19.25	28.9	23.2	25.2

two composite compositions and the high pressure stream shown in Table III-5 have molecular weights less than 29. Thus, these streams are less dense than air at the same temperature and pressure. CO_2 is also more dense than air at similar conditions and may cause the density of a gas mixture to be higher than that of air if present in large concentrations. The low pressure stream has a molecular weight very close to that of air and with some modification in composition, such as more H_2S or CO_2 and less methane, could be more dense than air.

Gas mixtures which are denser than air due to high concentrations of CO_2 have caused fatalities as described in the discussion of release histories. A well blowout near Big Piney, Wyoming, on June 21, 1981, killed small animals up to about 0.8 km from the well (Alp et al., 1990) The gaseous emissions from the well were composed of 70 percent CO_2, 20 percent methane and 3 to 4 percent H_2S. It is not clear that H_2S caused the animal fatalities in this case. However, these emissions were clearly denser than air. The literature generally describes mixtures that are less dense than air; the studies of hazards/risks associated with sour gas (Alp et al., 1990; Quest, 1992) referred to in this report used gas compositions that are buoyant.

In conclusion, sour gas as produced is typically buoyant. There can be atypical cases where natural gas contains high concentrations of H_2S and/or CO_2 which results in a denser-than-air mixture. Also, gas processing such as separation for condensate (liquid hydrocarbon) recovery at the well site may affect the density of a gas stream.

Behavior of Sour Gas Upon Release. High pressure sour gas releases from well blowouts and line ruptures are initially high momentum jets which can vary directionally between the extremes of vertical and horizontal. The jet (high velocity) nature of such releases is caused by the differential pressure between the contained gas and the atmosphere and results in entrainment of the surrounding air into the released gas. Entrainment of air results in dilution of the released gas and causes its density to approach that of air. Thus, as air is entrained, both positively and negatively buoyant gas mixtures with air will tend to have densities approaching that of air. A high velocity jet (such as from a high pressure source) will entrain air more rapidly and to a greater extent than a low velocity jet from a low pressure source. Depending on the release conditions, it is possible for a gas mixture to retain its initial positive or negative buoyancy. Negative buoyancy releases are of greatest concern because of dense gas behavior and their tendency to travel to ground level where exposure is likely to occur.

As previously discussed, the effective molecular weight (and thus, the density) of sour gas mixtures as produced is generally less than that of air with isolated exceptions. Therefore, models for these cases should consider the various mechanisms that describe the near-field (near the point of release) and far-field (downwind) behavior of the plume of released gas and its interaction with the surrounding air. In particular, the models should contain mechanisms for simulation of the following sequence of effects occurring along a plume of released gas from the point of release: a) near-field momentum jet modeling; b) subsequent positively-buoyant rise or negatively-buoyant sinking; c) potential for a nominally buoyant plume that is initially on the ground to rise or, if negatively-buoyant, to stay at ground level; and d) far-field transition to a subsequent Gaussian (passive modeling) phase. The Gaussian or passive phase assumes random mixing in the far-field due to the action of atmospheric turbulence; whereas, close to the source, entrainment of air is affected or sometimes dominated by the released material itself.

Choice of Atmospheric Dispersion Models. The models reviewed in the literature for analysis of the dispersion characteristics of sour gas were GASCON2, FOCUS, and a Gaussian dispersion model. Confirmatory, independent atmospheric dispersion analyses were conducted for most of the scenarios with the SAPLUME, SLAB, and DEGADIS models.

The computer model GASCON2 was specifically developed in Canada to model sour gas releases from well blowouts and line ruptures (Alp et al., 1990). The model incorporates high pressure gas jet releases, plume rise or sinking (depending on density) and subsequent passive atmospheric dispersion. GASCON2 was validated by comparison with experiment. The associated literature also contains extensive discussions on uncertainties and the work was reviewed by a science advisory board.

The proprietary model, FOCUS, contains a treatment of momentum and buoyancy effects and transition to subsequent passive atmospheric dispersion (Quest, 1992). The model has been available for several years and has been used in a number of risk assessments of toxic and flammable vapors.

The Gaussian dispersion model is suitable for passive releases (Layton et al., 1983). Therefore, jet momentum effects are neglected and the results are not expected to be reliable close to the emission source. However, at large distances where low concentrations of H_2S would result (e.g., in the low part per million range), all three of the above models should converge to similar results.

A well-established model developed by Ooms (1974, 1983) for jet releases of vapors can model the dispersion of both buoyant and heavier-than-air momentum jets. The EPA has sponsored the incorporation of the Ooms model into the well-known DEGADIS model (Spicer, 1988), which can only simulate vertical, but not horizontal releases. Another proprietary model, SAPLUME, is also based on the Ooms model and can simulate jets at any orientation (SAIC, 1990).

SLAB was developed by Lawrence Livermore National Laboratory (Ermak, 1989). This computer model also accepts jets of vertical or horizontal orientation. However, it was specifically developed for heavy vapors and has not been carefully validated for use with buoyant plumes, so results must be interpreted with care.

Consequence Analysis — Accidental Releases

In the following sections, the consequences of accidental releases for a variety of scenarios are presented.

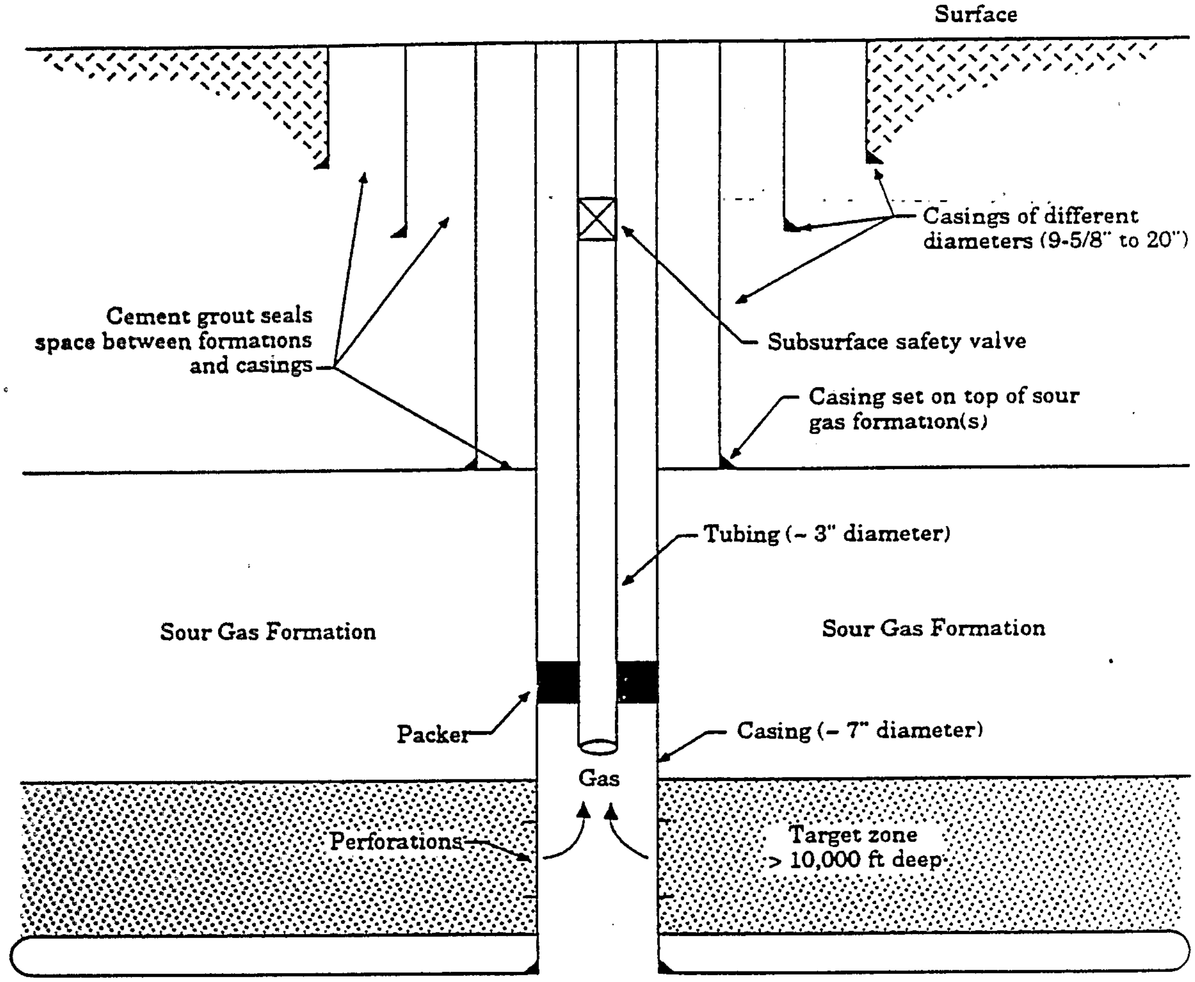
It should be noted that the calculated consequences of some of the modeled scenarios are based on very conservative assumptions in order to examine the worst case. The worst-case scenario is designed to generate the maximum impact off-site. It is considered to be extremely unlikely and does not take into account a variety of factors that can significantly reduce downwind impacts. However, the worst-case scenario is useful to facilities and communities surrounding facilities in gaining an understanding of the potential magnitude of severe situations. The potential for severe consequences should be taken into account along with more probable scenarios when setting priorities for community emergency planning.

Consequence Analysis of Jets from Well Blowouts

Figure III-15 shows the layout of a typical completed sour gas well. A well blowout is an uncontrolled release from a well during drilling, servicing, or production operations. Such an accident could occur if a blowout preventer failed during drilling or a subsurface safety valve fails to operate during production. The possible types of flow from a ruptured well are shown in Figure III-16. A useful simplification is that an accidental release into the casing is possible during drilling or servicing, while flow would likely be restricted to the production tube if there were a blowout during normal production operations. Potential flow orientations are shown on Figure III-17. Examples evaluated for the purposes of this study included the extremes of a vertical jet and a horizontal downwind jet.

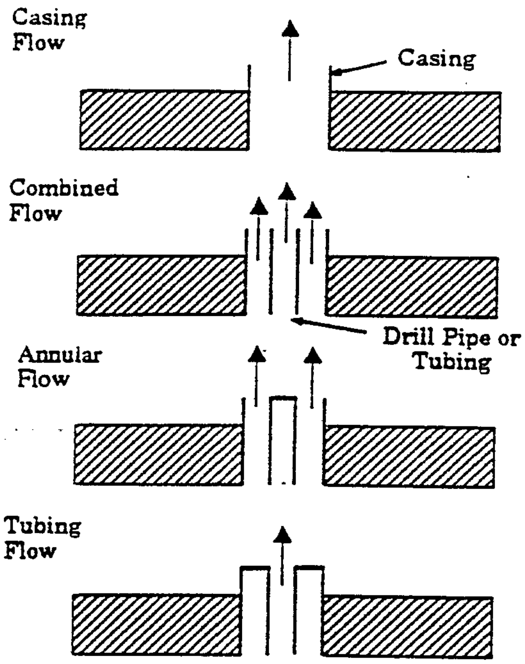
Flow rates for the scenarios identified in Figure III-16 are functions of such items as rock permeabilities, gas properties, depth, and tubing and casing diameters. Overall, there are large variabilities in these parameters. One measure of the potential rate of flow from a well is the Calculated Absolute Open Flow Rate (CAOF), which is the rate of flow of gas into the well bore when the pressure is atmospheric. This measure represents a maximum possible flow rate. The actual flow rates out of a ruptured well will be less than the CAOF because of frictional effects in the pipework. Thus, the use of CAOF for a release rate is conservative. Table III-6 gives some representative examples of how the CAOF is reduced for a specific set of well parameters. A flow rate of 2×10^7 standard cubic feet per day (scf/d) was chosen for representative calculations, with a flow rate of 10^8 scf/d being taken as an example of a very high flow rate. The bases for these assumptions are presented in Appendix C.

For the scenarios analyzed for this report, it was assumed that the gas emerges as a vapor. Since typical pressures are very high (e.g., in excess of 1,000 pounds per square inch gauge (psig)), the flow is choked (limited) at sonic velocity.



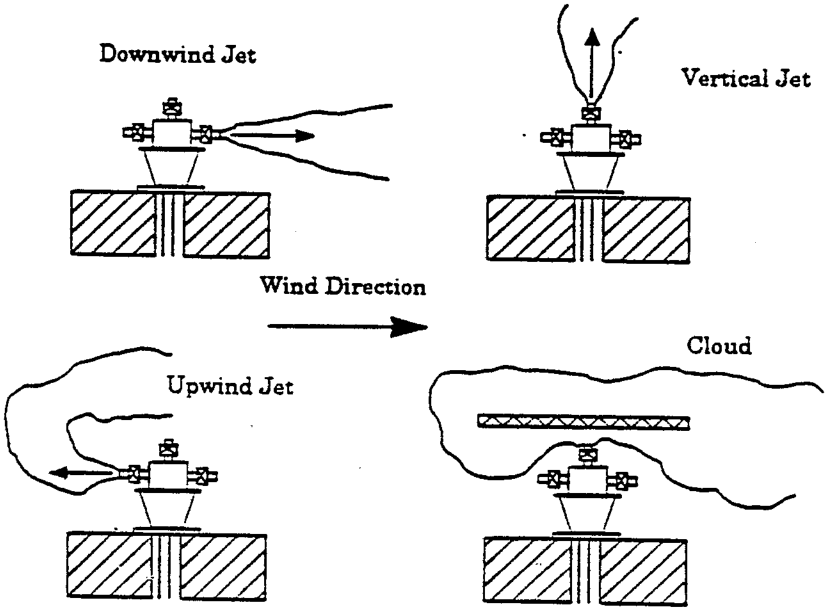
Source: Layton et al., 1983.

Figure III-15. Simplified representation of a completed sour-gas well.



Source: Alp et al., 1990.

Figure III-16. Possible well flow scenarios.



Source: Alp et al., 1990.

Figure III-17. Possible well accidental release geometries.

Table III-6. Surface Deliverability as a Function of Well CAOF

CAOF (10^3 m^3/d)*	Casing Flow	Annulus and Tubing Flow	Annulus Flow	Tubing Flow
5000	57.4 %	52.2%	39.3%	8.5%
1000	95.0	82.5	76.0	26.0
500	98.0	96.0	92.0	46.0
100	99.0	98.0	97.0	90.0
50	99.2	99.2	99.2	98.6

Source: Alp et al., 1990.

* At 15°C and 101.3kPa.

The values in Table III-7 were based on the following well conditions:

• Well depth (m)	2660
• Casing inside diameter (mm)	156.3
• Tubing outside diameter (mm)	73.0
• Tubing inside diameter (mm)	62.0
• Reservoir pressure (kPa)	15,900
• Reservoir temperature (°C)	75

The temperature of the gas in the well prior to expansion to atmospheric pressure through the rupture depends on the depth of the gas reservoir. The amount of cooling depends on the initial pressure and the composition. For the purposes of this analysis, an expanded gas temperature of 0°C (32°F) was assumed. This assumption is further discussed in Appendix C.

For a well blowout, the release could continue indefinitely. For illustrative purposes, it was assumed that any nearby individuals could be evacuated within one hour. The calculations of distances of concern discussed below assume that the duration of release and possible duration of exposure is one hour.

For vertical releases of sour gas from well blowouts, the independent dispersion modeling (SLAB, DEGADIS, SAPLUME, and the Gaussian model) and results reported in the literature (Alp et al., 1990; Quest, 1992) indicate that there will be no concentrations above levels of concern at ground level, either at the emergency countermeasure (ERPG-2) or potential fatality (LC_{01}) level. The jet is oriented upwards and, for either buoyant or negatively buoyant sour gas, dilutes rapidly due to its high momentum.

For horizontal releases from well blowouts, results calculated using the SLAB and SAPLUME models are given in Table III-7 for low wind speed and stable conditions. Releases in the direction of the wind were assumed. Depending on composition, release rate, and the model used, distances to the LC_{01} range from 700 meters (approximately 0.4 miles) to greater than 10 kilometers (approximately 6 miles). Distances to the ERPG-2 range from 2.8 kilometers (approximately 1.7 miles) to greater than 10 kilometers (approximately 6 miles). The atmospheric conditions input into the models represent conditions of high stability and little atmospheric mixing. Thus, these conditions represent the "worst-case" because levels of concern will be exceeded for predicted distances from the point of release that will exceed those for other weather conditions. The results were calculated neglecting the possibility of slight buoyancy of the plume even after dilution. DEGADIS results are not quoted because the jet module of that computer model can only handle vertical releases. For all the models, results in the range greater than 10 km (6 miles) should be regarded as beyond the limit of validity and probably conservative (see below).

For comparison, the GASCON2 model calculates an estimated distance of 1.6 km (1 mile) to the LC_{01} for a composition D flow rate of 2.4×10^5 m^3/d (cubic meters per day), or 8.5×10^6 scf/d, and an estimated distance of approximately 5 km (3 miles) for a composition D flow rate of 9.5×10^5 m^3/d (3.4×10^7 scf/d)(Alp et al., 1990). From Table III-7, for composition D with a flowrate of 6×10^5 m^3/d (2.1×10^7 scf/d), SLAB and SAPLUME predict a distance of 2.9 km and 3 km (both approximately 1.8 miles) to the LC_{01}, respectively. These distances and release rates are intermediate to those values in the GASCON2 model. Therefore, the results calculated with GASCON2 are consistent with the results generated by SLAB and SAPLUME (to within the uncertainties expected in such models).

Table III-7. SLAB and SAPLUME Results – Horizontal Releases from a Well Blowout

Composition (from Table III-6) and Flow Rates (m^3/d)	Predicted Distance 1 h Exposure (SLAB)		Predicted Distance 1 h Exposure (SAPLUME)	
	LC_{01}	ERPG-2	LC_{01}	ERPG-2
A, 6×10^5 m^3/d (7.5% H_2S)	700 m	2.8 km	1 km	3.1 km
B, 6×10^5 m^3/d (27% H_2S)	2.8 km	7 km	2.7 km	10 km
C, 6×10^5 m^3/d (15% H_2S)	1.5 km	4.7 km	1.5 km	5.7 km
D, 6×10^5 m^3/d (30% H_2S)	2.9 km	7 km	3 km	10 km
D, 3×10^6 m^3/d (30% H_2S) (extreme case)	7 km	>10 km	>10 km	>10 km

By contrast, the FOCUS model calculates an estimated distance of 0.7 km to the LC_{01} for composition C with a flow rate of $6x10^5$ m^3/d ($2.1x10^7$ scf/d)(Quest, 1992). This prediction is about half that given by the SLAB and SAPLUME calculations, which predict a distance of 1.5 km (0.9 miles) to the LC_{01} for composition C with a flowrate of $6x10^5$ m^3/d (by implication, GASCON2 would predict similar distances). This difference in predictions may lie within the range of uncertainty of vapor dispersion models; the precise reason for the difference cannot be determined from the information available about the proprietary model FOCUS.

Figure III-18 shows the results of the comparison of observations from actual well blowouts in Alberta, Canada, with GASCON2 predictions. The actual blowouts were at Lodgepole (October 17 through December 23, 1982), Clovesholm (September 24-28, 1984) and Rainbow Lake (December 9-14, 1985). The air quality data associated with each blowout were collected with public safety interests in mind and not model verification or validation. As a consequence, most of the observations were poorly documented with respect to magnitude, location, averaging time and meteorological conditions. Screening of the data to select only measurements in which there could be reasonable confidence produced a data set of 50 (45 of which were from the Lodgepole blowout). For the Lodgepole case, seven stationary and five mobile units collected data within 50 km of the site.

As can be seen, GASCON2 significantly overpredicts, especially when its predicted concentrations are in the greater than 3 x 10^4 ppb range, where overpredictions are by as much as a factor of 10. This concentration is the range of interest for ERPG-2 and LC_{01}. These overpredictions tentatively (because of the poor quality of the data) suggest that the GASCON2 results are conservative and, by implication, that the results from the SLAB and SAPLUME calculations are also conservative.

Possible reasons for conservatism include underestimating the effect of the plume lifting off the ground. For distances in the several km to the greater than 10 km (6 mile) range, neglect of dry deposition (fallout, transfer from the air to other surfaces) of the highly reactive H_2S may also lead to overestimation of airborne concentrations. However, it is more likely that the poor quality of the observations is reponsible for the apparent disagreements.

Standard text-book calculations indicate that flammable mixtures will not propagate more than 100 m from the point of release (Quest, 1992). If ignition occurs, potentially fatal thermal radiation loads could be received up to approximately 100 meters from the source. Although not pertinent to a discussion of hazards from H_2S releases, it should be noted that SO_2 will be emitted as a result of igniting a sour gas stream and may present a toxicity hazard.

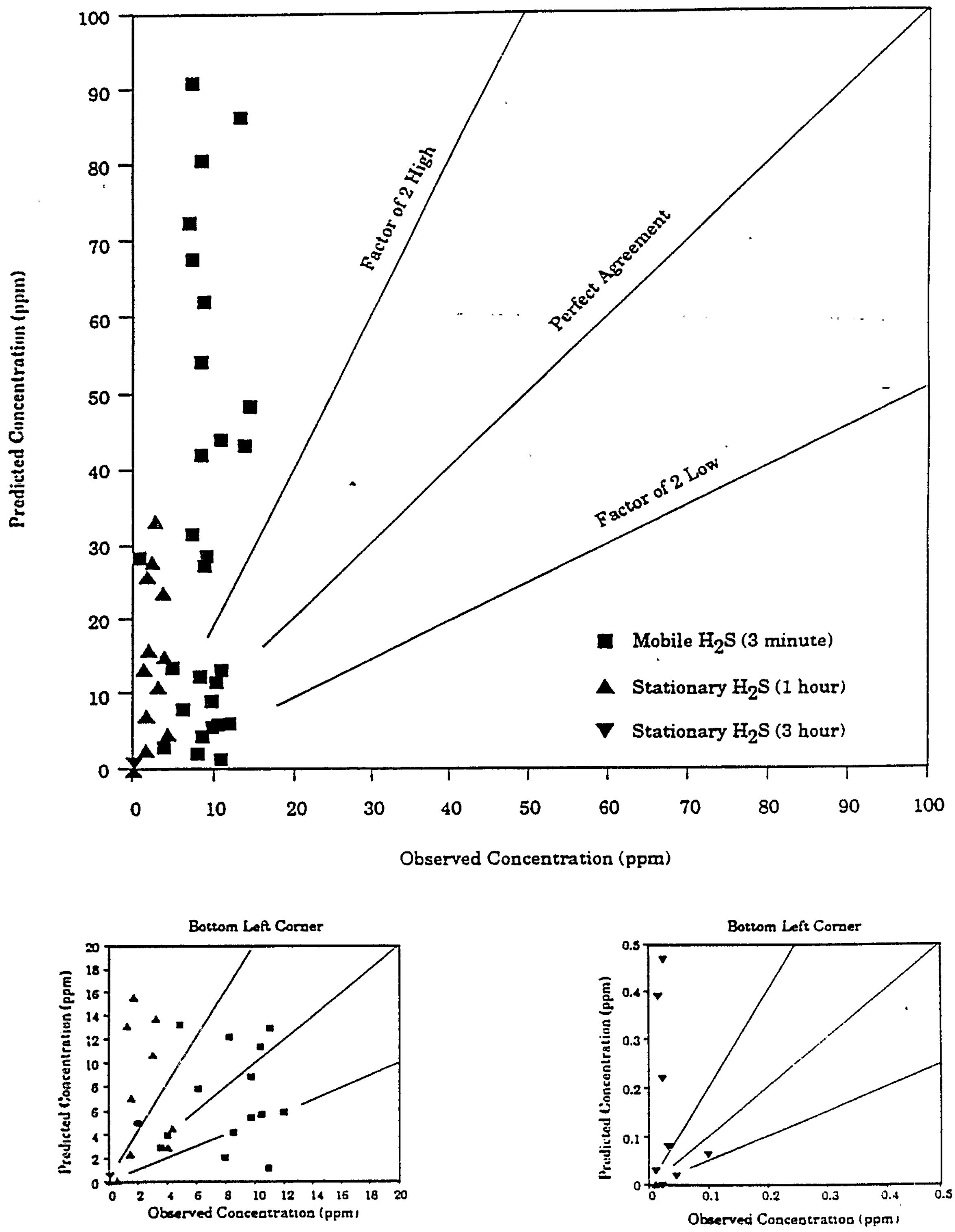


Figure III-18. Predicted H_2S and SO_2 concentrations for selected well blowout observations.

Consequence Analysis of Line Ruptures

Releases from line ruptures will behave much like well blowouts unless there is a means to isolate the rupture. Most gathering systems are not equipped with isolation systems, and aging pipework presents integrity concerns (particularly when not properly maintained). Advanced gathering line systems may have emergency shutdown valves (ESDs) that are remotely or locally operated. ESDs may be manually or automatically operated (e.g., by a signal from an H_2S detector). Figures III-19 and III-20 show some typical configurations for ruptures of lines that are equipped with ESDs. For such releases, the total mass released is limited by the quantity of gas between ESDs. The valves may be 1 km to 3 km apart (0.6 mile to 1.8 mile) (Alp et al., 1990).

Figure III-21 shows typical mass release rates for the rupture cases identified in Figure III-20, assuming a 6" diameter pipe at a pressure of approximately 5,000 kPa (725 psi). Rupture Scenario 4 (no ESD) follows Scenario 1 until a steady state of 2.4×10^5 m^3/d (8.5×10^6 scf/d) is reached after about a minute.

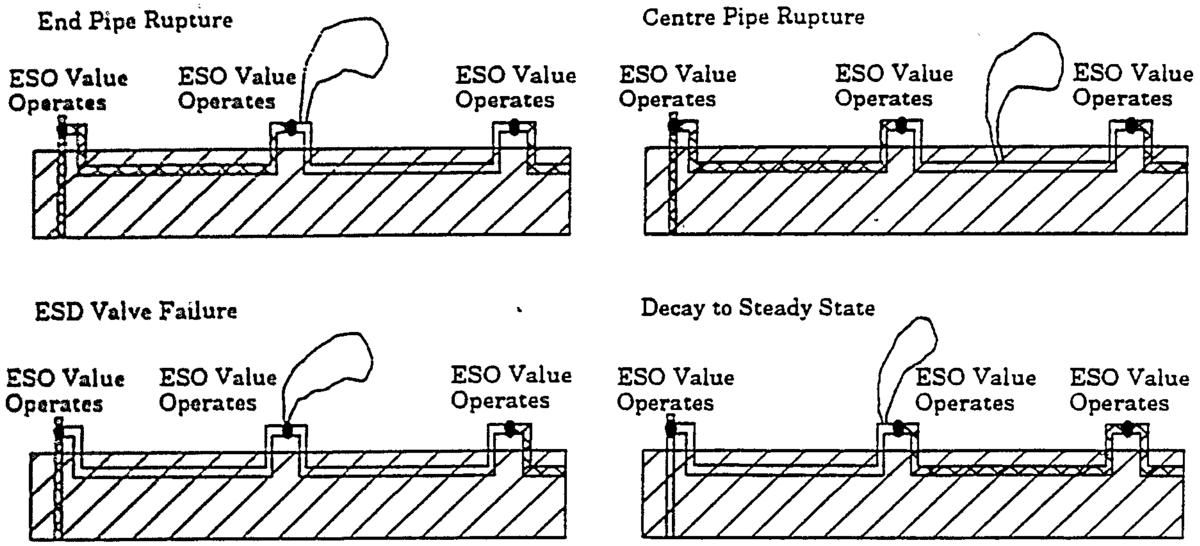
Figure III-22 shows mass release rates as a function of time for various pipe diameters and various ESD separations with an assumed line pressure of approximately 50 atmospheres (735 psi). The variable, t_d, listed on Figure III-22 is the time in seconds taken for 99 percent of the line contents to be depleted after closure of the ESD valves. M_d is the total mass released in kg. As can be seen, for many of the cases, a puff release (rather than a continuous release) is a reasonable approximation because of the short duration.

The predicted distances of concern for lines with ESD valves that close promptly are smaller than those for wellhead blowouts because the duration of release is shorter, the total mass released is smaller, and because shorter exposure times allow higher tolerable levels of concern.

Calculations from SADENZ, a companion model to SAPLUME for puff releases, predict that distances to the LC_{01} for compositions A-D in Table III-5 and released masses specified in Figure III-22 range from 600 m (0.4 miles) to 4.3 km (2.6 miles). Predicted distances to the ERPG-2 adjusted for shorter exposure time (method described by Gephart and Moses, 1989) range from 750 m (0.45 miles) to approximately 5.6 km (3.4 miles). This is consistent with the calculated results from the GASCON2 model (Alp et al., 1990) and, as before, somewhat higher than those calculated from the FOCUS model (Quest, 1992).

Consequence Analysis of Line Release Seepage

A survey of several gas pipeline incidents that were investigated by the National Transportation Safety Board (NTSB) indicated that, for buried gas pipelines operating above 600 psig, a 1" diameter hole will blow away the soil above the line (Quest, 1992). This will result in the formation of a crater from which the gas will escape as an unobstructed jet. For smaller holes (e.g., a 1/4" diameter hole caused by corrosion), the soil remains in place



End Pipe Rupture

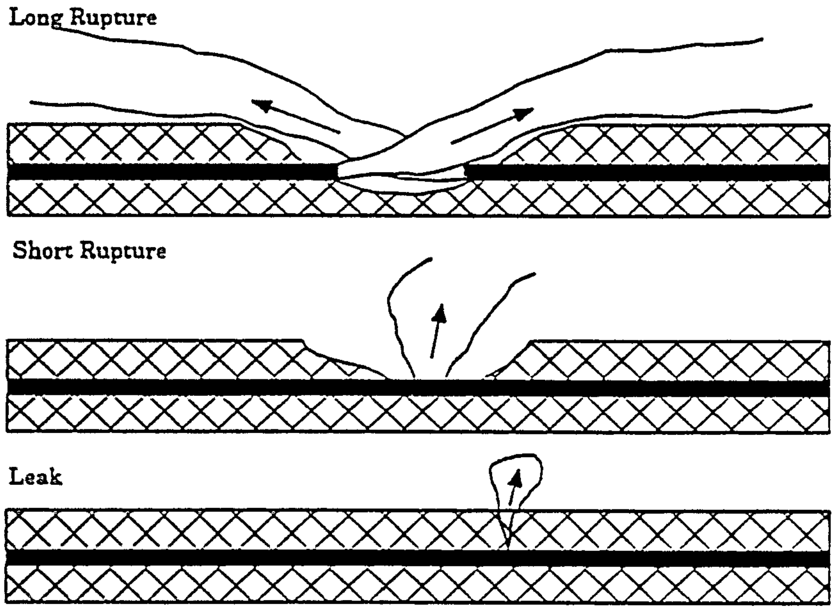
Centre Pipe Rupture

ESD Valve Failure

Decay to Steady State

Source: Alp et al., 1990.

Figure III-19. Possible pipeline rupture scenarios.



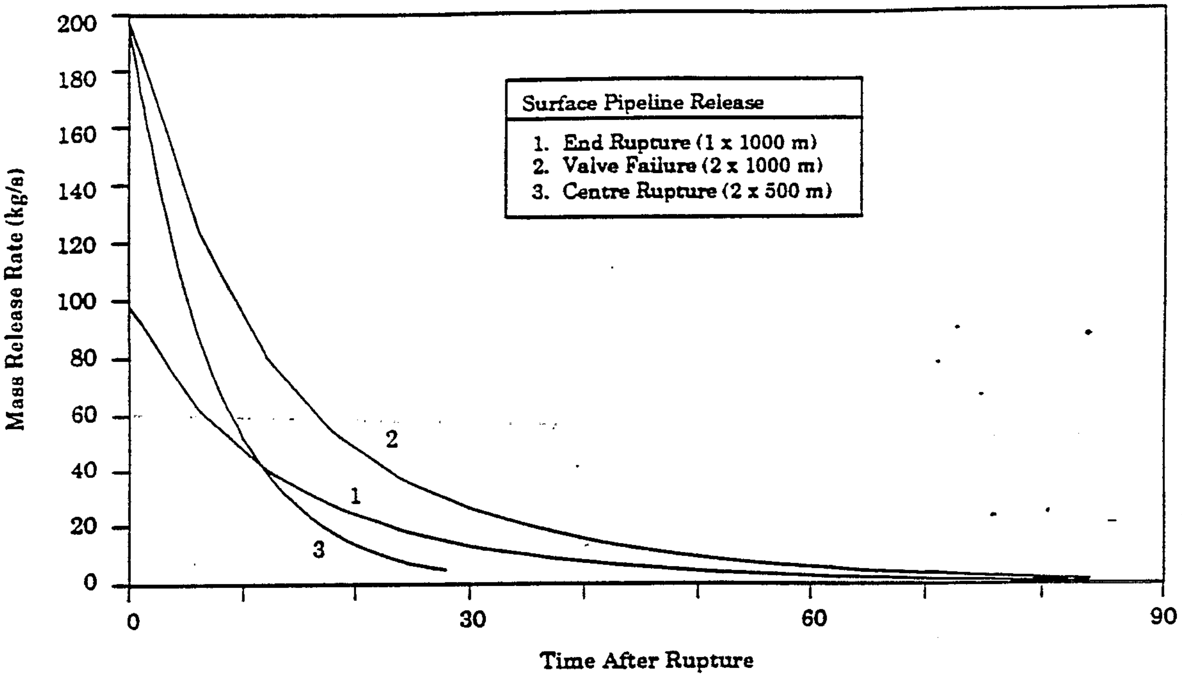
Long Rupture

Short Rupture

Leak

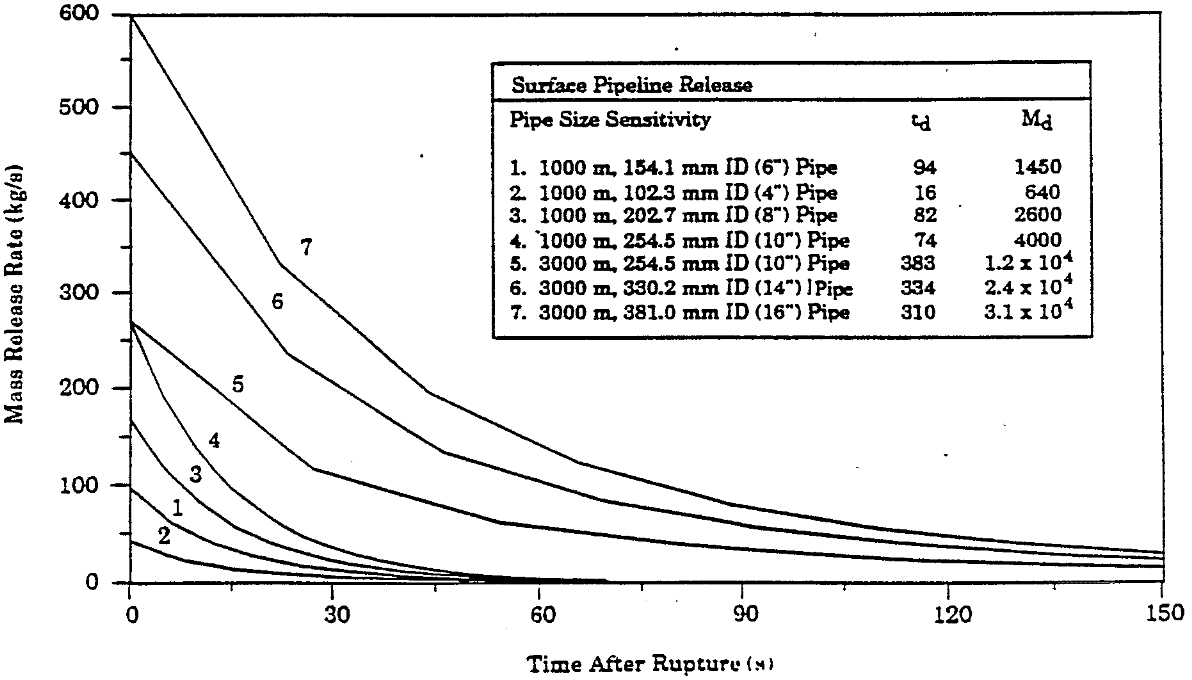
Source: Alp et al., 1990.

Figure III-20. Possible pipeline release geometries.



Source: Alp et al., 1990.

Figure III-21. Predicted mass release rates - rupture of 6" pipe.



Source: Alp et al., 1990.

Figure III-22. Predicted mass release rates - rupture of pipes of differing diameters.

and the vapors migrate to the surface where they are released without any momentum (although the resulting vapor cloud may still be buoyant enough to lift off).

For a 1/4" diameter hole in a line containing gas at a pressure of 1,000 psig, the calculated release rate (using standard text book formulae for choked flow) is about 1 lb/sec, assuming that the surrounding soil does not reduce the emission rate by physically impeding the flow. If this gas seeps to the surface, the predicted distance to which the ERPG-2 would be exceeded for a person who inadvertently enters the plume for five minutes is about 400 m (0.2 miles) and the predicted distance to the LC_{01} is about 250 m (0.15 miles) when the atmospheric stability category is F and the windspeed is 1.5 m/sec (4.9 feet per second), utilizing composition C from Table III-5. These results neglect the possibility that the plume might lift off the ground or exhibit dense gas behavior.

Consequence Analysis of Flare Stack Releases

Results calculated using the GASCON2 (Alp et al., 1990) and FOCUS (Quest, 1992) models and those carried out independently with the SAPLUME model show that, with or without sour gas ignition, the plume emitted from a flare stack is a momentum jet with dilution of the discharge and will rise sufficiently high to avoid concentrations above the ERPG-2 at ground level.

It is possible that a release of very dense gas from an unignited flare could exhibit dense gas behavior. For example, in 1950 in the town of Poza Rica, Mexico, 22 people died from exposure to hydrogen sulfide emitted from a malfunctioning flare at a gas purification plant (McCabe and Clayton, 1952). However, in this case, the gas from the well contained 3 percent by volume of H_2S and 15 percent by volume of CO_2. During the startup period for the desulfurization units to which the gas was sent, partially processed gas containing 81 percent CO_2 and 16 percent H_2S was sent to a flare. It was this processed, heavy vapor and not the produced gas that, upon failure of the flare, descended to ground level. However, despite the limitations in applicability and the unlikelihood of occurrence, this incident is illustrative of the potential for severe consequences when managing a dense gas stream.

Consequence Analysis of Releases Collecting at Ground Level

The specific cases listed in Table III-5 are all less dense than air. This has been the case for all the gas streams investigated for this report for which detailed compositions were documented. Also, note that the most dense composition on Table III-5, stream B which has a density close to that of air, was obtained after some separation and processing for vapor recovery. It appears that the concern about heavy vapors containing H_2S settling or collecting in low-lying areas may be justified for only a fraction of wells such as the previously described Big Piney, Wyoming well blowout and Poza Rica, Mexico flare incident. It is pertinent to address other situations where this concern is justified.

Nine people were killed in an incident in Denver City, Texas, when they were exposed to gas escaping from a well injecting gas into an oil reservoir as part of an enhanced oil recovery project (Layton et al., 1983). The injected gas was composed of 93 percent by volume CO_2 and 5 percent by volume H_2S - clearly denser than air, but as before, gas that was previously processed and not of as-produced composition.

In general, it is possible that releases directly from wells with unusually dense sour gas compositions or associated lines could settle in low-lying areas at ground level. These releases would not be of typical composition. It is also possible that people entering areas of seepage such as those previously described for line releases could confuse these with settling on the ground. It is therefore reasonable to speculate that, in some cases, such concerns could possibly have arisen from seepage events.

The modeling described in the foregoing applies to plumes over flat terrain. In complex terrain, it is unlikely that released gas of typical composition will flow into lower elevations such as valleys because, as previously noted, it is generally not denser-than-air. However, it is very likely that a small or chronic release will follow the flow of the wind. Thus, for example, on cold, still nights there could be flows of air with relatively little turbulence from higher elevations into valleys (katabatic flows). This could carry slowly diluting H_2S with it and potentially cause odors within houses in valleys some distance from the well. This situation would likely not occur during the day when such air flows are uncommon. However, as previously discussed, it is possible for sour gas of unusually dense composition to remain at ground level. Therefore, for such releases, it is conceivable that flow could "channel" through terrain of low elevations such as valleys. This possibility is highly uncertain. The study of the behavior of dense gas flow around obstacles and through rough terrain is controversial and is an area where further research is needed.

Accidental Releases—Prevention, Mitigation, and Emergency Response

The design and operation of sour gas systems require special consideration as a result of the potential hazards presented by a release of H_2S. The hazards of exposure to H_2S can be significantly reduced by the implementation of process safety management principles. A primary emphasis on containment together with design features for the detection and mitigation of losses in containment are necessary for safe operations. The degree of sophistication of individual sour gas system designs will vary depending on site-specific circumstances and age. Older systems may incorporate relatively simple safety designs when compared with current state of the art. The presence of sour oil and gas operations in remote locations or near populated areas may both be justification for the use of advanced designs. Remote areas may be subject to extended releases if accessibility is limited. Process safety management and major safety considerations are discussed below.

Process Safety Management

Facilities that handle hazardous materials have a responsibility to understand the hazards present at their sites and to take steps to ensure that chemical accidents due to these hazards are prevented. Many organizations, including the American Institute of Chemical Engineers - Center for Chemical Process Safety (AIChE-CCPS) and the EPA, have found that major chemical accidents cannot be prevented by hardware or by technology alone. Prevention requires comprehensive management systems designed to identify and control hazards (AIChE, 1989; U.S. EPA, 1988). These management systems are known as Process Safety Management (PSM) and consist of "comprehensive sets of policies, procedures, and practices designed to ensure that barriers to major incidents are in place, in use, and effective. The management systems serve to integrate process safety concepts into the ongoing activities of everyone involved in the process - from the chemical process operator to the chief executive officer" (AIChE, 1989). The Occupational Safety and Health Administration (OSHA) has set standards for process safety management, which are discussed in Chapter IV.

PSM consists of several essential elements that work together to allow safe operation of a facility;

- Management Commitment: Management must adopt a philosophy that makes safety an integral part of operation from the top down; an attitude that all accidents can be prevented and that business must always be conducted safely.

- Process Hazards Analysis or Hazard Evaluation: The purpose of the process hazards analysis is to systematically examine the equipment, systems, and procedures for handling a hazardous substance; to identify the mishaps that could occur, analyze the likelihood that mishaps will occur, and evaluate the consequences of these mishaps; and to analyze the likelihood that safety systems, mitigation systems, and emergency alarms will function properly to eliminate or reduce the consequences of the incident. Thorough process hazards analysis is the foundation for the remaining elements of the PSM system.

- Process Knowledge and Documentation: Facilities document the details of the technology and design of the process, its standard conditions and consequences of deviation from these standards, the known hazards of the chemicals and processes involved and protective systems for protection of workers, the public, and the environment.

- Standard Operating Procedures (SOPs): These are procedures that describe the tasks to be performed by the operator or maintenance worker to ensure safety during operation and maintenance.

- Training: A program to teach those responsible for designing, operating, and maintaining the unit or plant. Elements in a management training system include development of training programs, training of instructors, measuring performance and determining the effectiveness of training. Training is typically carried out by facility managers and training staff.

- Maintenance (Process and Equipment Integrity): A formal program to ensure that equipment is constructed according to design, installed properly, and adequately maintained.

- Prestartup Review: The purpose of this review is to ensure that all elements of process safety, including hardware, procedures, and control software, are in place prior to startup, and that all prior issues of concern have been resolved.

- Management of Change: Management must instruct personnel to recognize change and to evaluate change with regard to process safety.

- Safety Audits: The purpose of safety audits is to measure facility performance, to verify compliance with a sound process safety program, and to determine that risks are being appropriately managed.

- Accident Investigation: Accident investigation is a management process by which the underlying causes of an incident are identified and steps are taken to prevent similar incidents.

- Emergency Planning and Response: Emergencies involving highly hazardous substances can have catastrophic results if not handled properly. Employees need to know and be trained in proper emergency procedures, evacuation requirements, and notification steps.

Major Safety Considerations

Siting. The magnitude of the potential consequences from human exposure to an H_2S release decreases with distance from the sour oil or gas source. Therefore, operations involving H_2S should be situated as far as possible from residential and commercial structures to minimize potential hazards to the public. Prevailing weather patterns (e.g., wind direction), terrain features, transportation routes, population centers, the potential for evacuation, and the potential for access control are some additional factors to be considered in siting decisions. These are site-specific factors that must be determined for each location.

At a minimum, well sites should be fenced to maintain some obstacle to approaching the wellhead.

Materials Selection and Corrosion Prevention. Materials must be chosen that are suitable for the service into which they are placed. Sour oil and gas operations are often conducted under high pressure and corrosive conditions. Therefore, in addition to temperature and pressure considerations, system designs for the wellhead, downhole equipment, and pipelines must incorporate features to minimize the effects of corrosion in order to prevent a breach of containment and accidental release of H_2S. Several national engineering standards governing the choice of materials are applicable. Standards include those by the American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), and the National Association of Corrosion Engineers (NACE). One such standard is NACE Standard MR0175, "Material Requirements for Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment." Also applicable are the API 6A specifications for equipment in high H_2S concentrations in close proximity to occupied structures.

In addition to proper selection of materials, corrosion inhibiting fluids can be used to prevent internal corrosion and cathodic protection can be used to prevent external corrosion. Inhibitor applications include the filling of wells with inhibitor during extended periods of shut-in and injection into pipelines.

Corrosion monitoring programs should be a normal part of the operations and maintenance for sour oil and gas systems so that corrosion problems can be anticipated and repairs made before an accidental release occurs. The need for a corrosion control program and program monitoring was discussed in the first edition of API RP 55, "API Recommended Practices for Conducting Oil and Gas Production Operations Involving Hydrogen Sulfide" (API, 1983). This document has been withdrawn pending publication of an updated, second edition. Additional discussion of RP 55 can be found in Chapter IV. Corrosion monitoring systems can take a variety of forms including external monitoring (ultrasonic or X-ray inspection), corrosion coupons and spool pieces (test pieces), instrumented "pigs", or in-place instrumentation. Pigs are instruments that can be transmitted through lengths of larger diameter piping to take measurements of internal surfaces.

Leak Detection and Mitigation. While systems should be designed to meet the appropriate standards, there is still the potential for releases to occur as a result of human error or equipment failure (e.g., corrosion, impact, etc.). A possible design feature for oil and gas operations is the use of detection systems which monitor for evidence of system leaks and then isolation systems that can be used to shut off leaks. For H_2S-containing systems, detection systems can focus directly on measurement of H_2S, on measurement of pressure changes which could be indicative of a leak, or temperature indicators that can be indicative of a loss of containment and subsequent fire. Signals from such detection systems can be used in modern, sophisticated systems to automatically initiate additional containment measures such as well shut-in or isolation of sections of pipeline. There are national standards for performance and use of H_2S monitoring equipment such as these set by the Instrument Society of America, ISA-S12.15 "Part I: Performance Requirements of Hydrogen Sulfide Detection Instrumentation" and "Part II: Installation, Operation, Maintenance of Hydrogen Sulfide Detection Instruments." Not all systems have leak detection or signalling devices associated with them. Such systems may present a greater hazard potential than those that have devices because detection would have to be by visual means or by smell. Any release would continue until detected.

Flares may malfunction resulting in extinguishment of the flame. This may occur due to several causes including flow of noncombustible compounds (e.g., nitrogen or carbon dioxide) and high winds. Flares can be equipped with automatic ignition devices to reignite extinguished flames and supplemental fuel systems to maintain ignition of the flare gas in the presence of inert gas. Flares should also be constructed at a height that provides for sufficient dispersion of the discharge.

The equipment used to mitigate releases depends on the operations. For well drilling and workover operations, a blowout preventer is used. This piece of equipment consists of high-pressure valves that allow the operator to shut in the well. For operating wells, there can be subsurface shutoff valves which are located in the well as well as above grade valves located at the wellhead and in the lines around surface equipment such as separators. Shut-in may be accomplished automatically via a signal (H_2S concentration, pressure change, temperature) that is received indicating a potential leak. For pipelines, there may also be isolation or shutdown valves located along the pipeline and these may be automatically activated if there is an indication of a leak in the pipeline or at the well. Not all systems will have automatic mitigation capability and isolation would have to be manual in these cases.

Inspection and Monitoring Practices. API RP 55 made recommendations for actions that were intended to monitor performance of the containment system for the sour oil and gas. API RP 55 specifically called for inspection of equipment and system performance to look for indications of corrosion that are indicators of degradation of the sour oil and gas containment equipment. Inspections were specifically recommended for changes in lift performance; changes in pressures associated with packed off annuli; and for the condition of valves, flanges, and connections. The document also recommended that any equipment failures be evaluated to determine the cause of the failure. Particular attention should be paid to the effectiveness of the corrosion control program at a site and corrective action should be considered if there is any indication that the program is inadequate.

API RP 55 also called for the monitoring, maintenance and recalibration of monitoring equipment (temperature, pressure, composition, etc) to make sure it is functioning as intended.

Emergency Procedures. In the event of loss of containment of the sour oil and gas, emergency procedures must be implemented to both restore containment and to protect the public. API RP 55 called for the preparation of a contingency plan for operations involving sour oil and gas. The plans are to contain information that would be needed by personnel responding to the accident at the site. Among the information that should be in the plan according to the API recommended practices are:

1. Location of wells and details on the equipment including flow lines, isolation valves, processing facilities, and tank batteries;
2. Location of safety and life support equipment;
3. Location of telephones and other communication equipment;
4. Potential location of roadblocks for excluding unauthorized personnel for the areas associated with the accidental release;
5. Location of residences, businesses, parks, schools, roads, medical facilities;
6. Areas that could experience elevated H_2S concentrations (e.g. levels greater than 1×10^5 ppb);
7. Potential evacuation routes; and
8. Designated safe areas for operations personnel.

In addition to this information, the plan should have a list of emergency telephone numbers including company supervisors; residences, schools and businesses; nearby operators and service companies; local law enforcement agencies; officials responsible for public facilities that could be impacted; medical assistance personnel, facilities and equipment; and concerned local, state, and Federal agencies.

Beyond the information listed above, the contingency plan should have an immediate plan of action. Among the elements in an immediate action plan are the determination of the potential hazard to the public from the discharge and then an identification of actions to respond to the hazard (e.g. immediate measures to eliminate the discharge, notification of responsible supervisors, establishment of a restricted access zone, evacuation of personnel). API RP 55 also recommended consideration of advanced briefing of public and public officials so they understand the nature of the hazard, the necessity for emergency response plans, and the general steps that would be taken in the event of an emergency. Finally, API RP 55 called for the updating of the plan as necessary to keep the information in the plan current and conducting periodic drills so that personnel are familiar with the type of situations to which they may have to respond.

The Department of the Interior has promulgated regulations that are applicable to sour oil and gas operations on Bureau of Land Management (BLM) property (BLM, 43 CFR 3160). These regulations call for the preparation of public protection plans for drilling and production operations where (1) the 1×10^5 ppb H_2S radius is greater than 50 feet <u>and</u> the area includes locations where the public could reasonably be expected to be (e.g. occupied residences, schools, churches, parks); (2) the 5×10^5 ppb H_2S radius is greater than 50 feet and includes any part of Federal, State, or county or municipal road or highway; or (3) the 1×10^5 ppb H_2S radius is greater than 3,000 ft. where facilities and roads are principally maintained for public use. The requirements for the content of these public protection plans are very similar to those called for in API RP 55.

Abandonment Practices

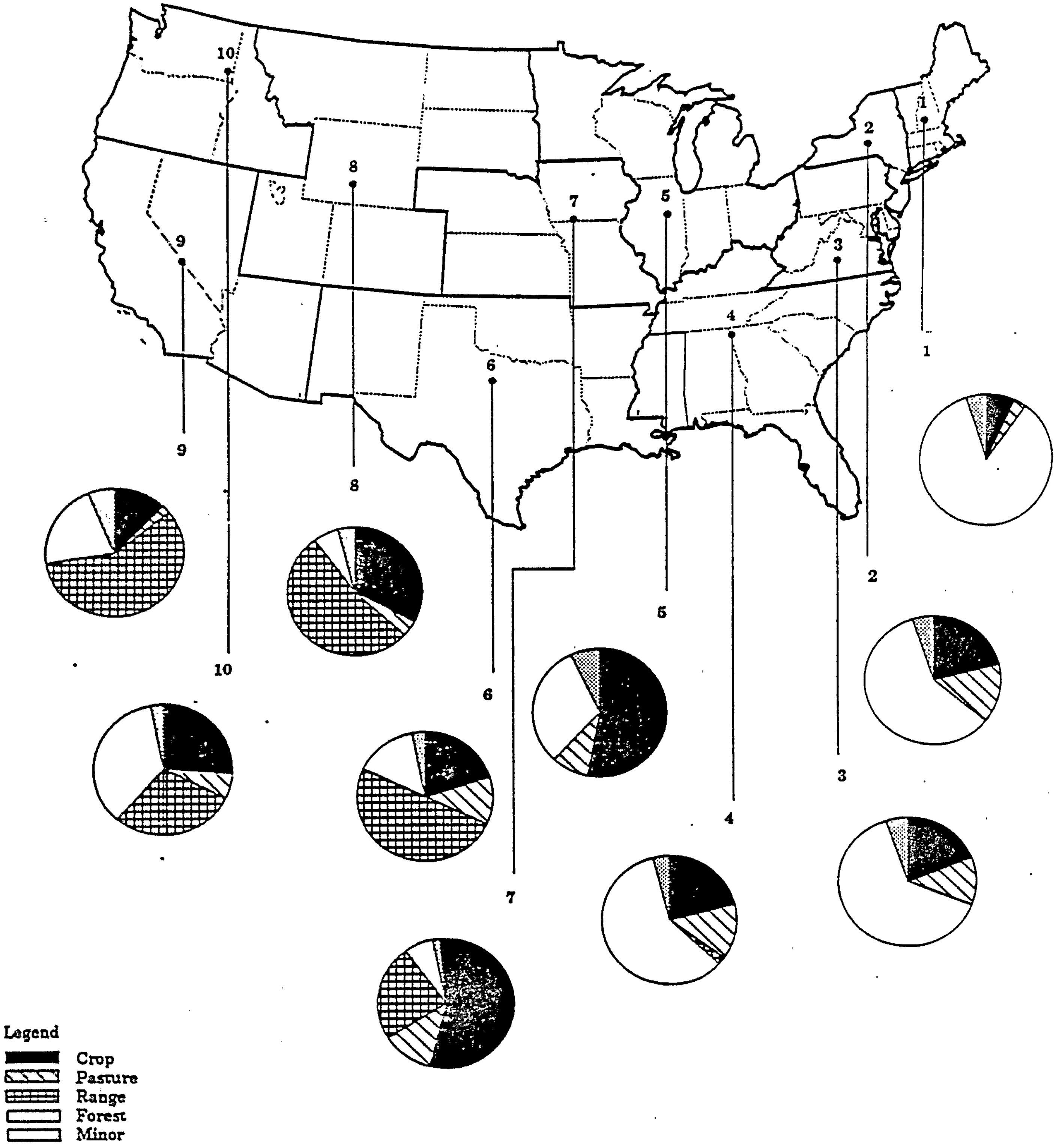
The termination of sour oil and gas production operations normally results in the plugging of the well with cement prior to abandonment by the operator. As a result, a potential exists for H_2S to be released from sour oil and gas from the well and associated equipment if proper precautions are not taken. API RP 55 identified actions that should be taken at the end of operations. The document specifically called for precautions to ensure that H_2S does not present a hazard to the public and the environment. The document called for either air purging or water flushing of equipment followed by opening to the atmosphere. Pipelines then were to be purged and capped. API RP 55 also called for the setting of cement across formations that could produce H_2S.

In some cases, wells may be temporarily abandoned. These wells may also be called "idle" or "inactive." In temporary abandonments, the well will not be plugged with cement but perforations may require isolation. Typically, application must be made and approval given by a state authority to temporarily abandon a well. Conditions justifying temporary abandonment to a State most often include economic conditions and future utility (IOGCC, 1992). Approval is temporary and of limited duration although extensions may be granted at the discretion of the state authority. Depending on the state, initial approval periods range from 6 months up to 10 years. Extensions may be granted for up to an unlimited number of time periods. In many states, but not all, periodic testing is required on idle wells. For example, mechanical integrity and pressure tests may be required. These practices are intended to prevent releases of oil and gas.

Of 215,000 oil and gas wells estimated to have been idle in 1992, approximately 68,000 were thought to have been idled without State approval (IOGCC, 1992). 50,000 of these wells, known as orphan wells, were believed to have been idled by operators who were unknown or insolvent. Although the fact that a temporarily abandoned well has not been reported to the State does not mean the well will be the source of an accidental release, the lack of control and supervision does represent an unsafe situation and may present a greater risk to the public and the environment. The majority of States have developed some funding mechanism and implemented programs to plug and abandon orphan and preregulatory wells although these activities vary widely from state to state (IOGCC, 1992).

Land Use Around Well Sites

Land use can vary enormously around oil and gas wells. The wells may be found in urban areas or open rangelands. Figure III-23 shows current land-use patterns by EPA region (Southerland, 1992). In Regions 6, 8, and 9, which contain the majority of wells in naturally occurring H_2S areas, between 50 and 60 percent of the land is used as range. The three regions represent about 60 percent of the oil and gas producing wells. In the Midwest's Region 5, which contains 12 percent of the nation's producing oil and gas wells, over 50 percent of the land is farmed (U.S. EIA, 1990; U.S. EIA, 1991).



Source: Southerland, 1992.

Figure III-23. Current land-use pattern by EPA region

Regarding urban areas, in California, for example, the Division of Oil and Gas reports that "one-third of California's 1.7 billion barrels of oil reserves are in urban areas or in areas where residential development is increasing. (The H_2S content of these reserves was not available.) The Los Angeles Basin both typifies the situation and is the most complex example. Here, a large metropolitan area lies over one of California's major petroleum-producing provinces. Because oil and gas are so fundamental to the U.S. economy, any recoverable amounts cannot be ignored. Ways have been developed to produce oil and gas safely in urban areas, with minimum negative effects. Urban planners, administrators, and California Division of Oil and Gas engineers work together to ensure a safe partnership between urban life and oil and gas development" (CDC, 1988).

Affected Human Populations

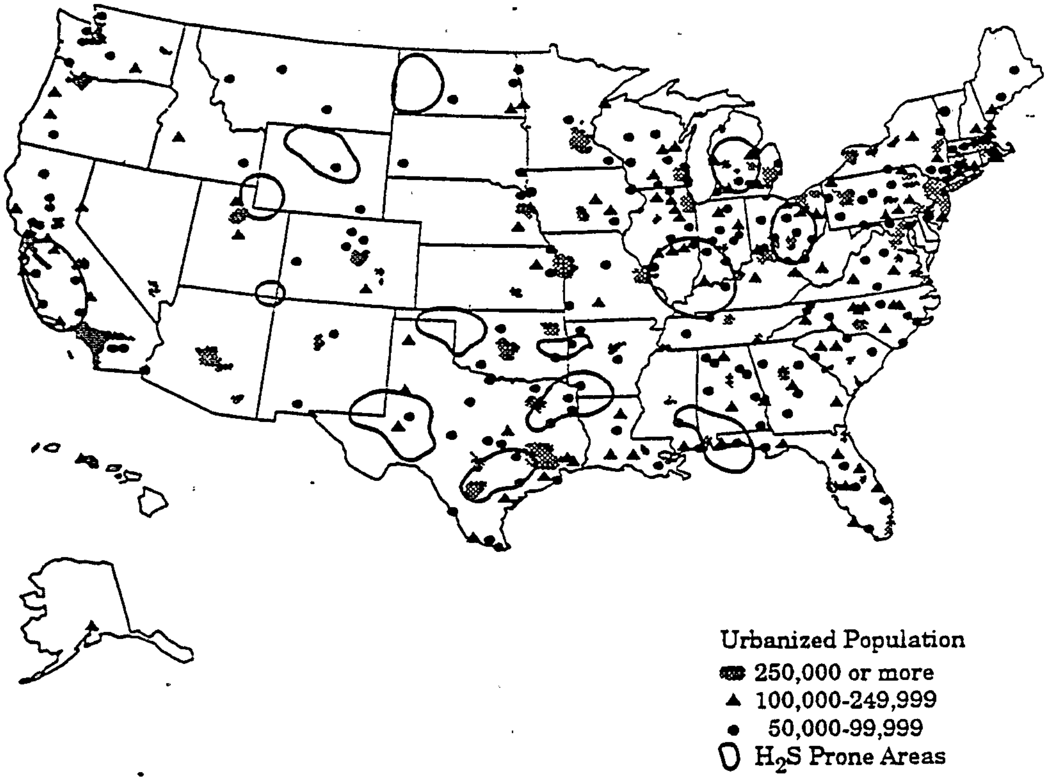
Figure III-24 overlays 1980 census data on the H_2S prone areas to show the proximity of major populations to H_2S deposits. The figure shows that a wide range in population density can be found in H_2S deposit areas. However, a look at the locations of well fields in the United States (Figure III-11) and the number of wells per State (Figure III-12) clarifies the potential exposure of large human populations to H_2S from oil and gas wells.

Data were not available to arrive at statistics on individuals exposed to H_2S emissions. Because the number of wells in the U.S. is so great and the diversity of population density around wells so large, it was not possible to arrive at an estimated affected population. The photographs in this report show that wells may be found in urban, suburban, and rural areas. Populations that could be exposed include adults in work settings (e.g., fire stations), children in schools, shoppers in downtown areas, and people in residential areas.

Affected Environmental Settings

A 1991 study in Wyoming found that, in two years, 237 animals had been killed by H_2S gas. In many oil fields this gas was vented through flare stacks. The researcher stated that when flare stacks are used, it is possible to install devices which would prevent raptors and other birds from using flares as perch sites. Also, wildlife mortality caused by H_2S would be reduced by ensuring that igniters were operating efficiently so that the gas would be properly flared and not accidentally vented directly into the environment (Esmoil, 1991). Based on other accident history, one impact on environmental settings has been the loss of livestock attributed to exposure to H_2S. Sixty percent of the U.S. wells are located in EPA Regions that contain more than 50 percent rangeland. However, many other species of animals and plants are potentially exposed to H_2S concentrations that could cause adverse effects. Testimony for the Clean Air Act Amendments included statements about episodes in the Great Plains that resulted in livestock dying and humans being hospitalized (Audubon Society, 1987).

Twelve percent of all wells are located in EPA Region 5, which is more than 50 percent cropland. As noted in a previous section of this report, soybeans have been



Source: Gas Research Institute, 1990, and Bureau of the Census, 1983.

Figure III-24. Major H_2S prone areas shown in relation to 1980 census data.

determined to be sensitive to H_2S along with other crops. There has been evidence of scorching to young leaves and shoots but no effect on mature leaves (Heck et al., 1970).

Waterfowl habitats of major concern are located in some areas of oil deposits with H_2S, as shown in Figure III-25. Concern has also been expressed about the deterioration of air quality in Theodore Roosevelt National Park (Sierra Club, 1987). Figure III-26 shows the location of national parks and national forests in relation to H_2S deposits.

FINDINGS

1. Human exposure to H_2S may cause death, as well as symptoms including irritation, breathing disorders, nausea, vomiting, diarrhea, giddiness, headaches, dizziness, confusion, rapid heart rate, sweating, weakness, and profuse salivation. Levels greater than 1.5×10^5 ppb are life threatening.

2. No epidemiological studies were found on the effects of H_2S emissions from oil and gas extraction/production.

3. Human acute and chronic health effects data and ecological effects data are limited.

4. H_2S is classified as a Group D carcinogen, meaning not classifiable as a human carcinogen. The inhalation RfC is 9×10^{-4} mg/m^3 (0.67 ppb) in chronic exposures scenarios. This RfC is not appropriate, however, for assessing concentration-response relationships in short-term or accidental exposure scenarios.

5. Few studies exist measuring natural or accidental exposure of wildlife to H_2S; however, wildlife deaths have been reported with blowouts.

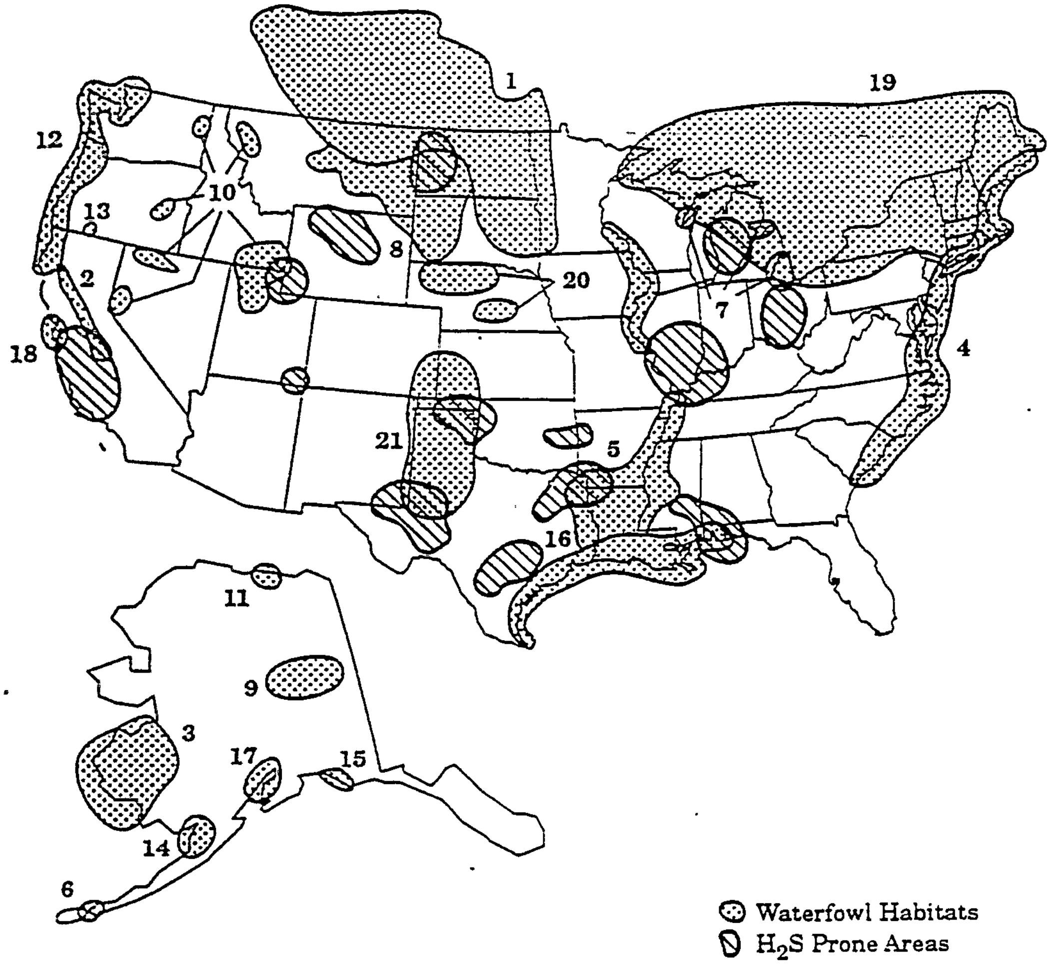
6. High exposure studies have shown young, growing plants to be the most susceptible to H_2S injury (clover, soybean, tomatoes, tobacco, buckwheat).

7. Aquatic LC_{50}s show bluegill = 0.009-0.0478 mg/l.
   NAOEL for mice = 42.5 mg/m^3 (3.05×10^4 ppb).
   LAOEL for mice = 100 mg/m^3 (8×10^4 ppb).

8. Nationwide, vulnerability zones have been characterized as 14 major H_2S prone areas found in 20 states. Texas has 4 discrete H_2S prone areas.

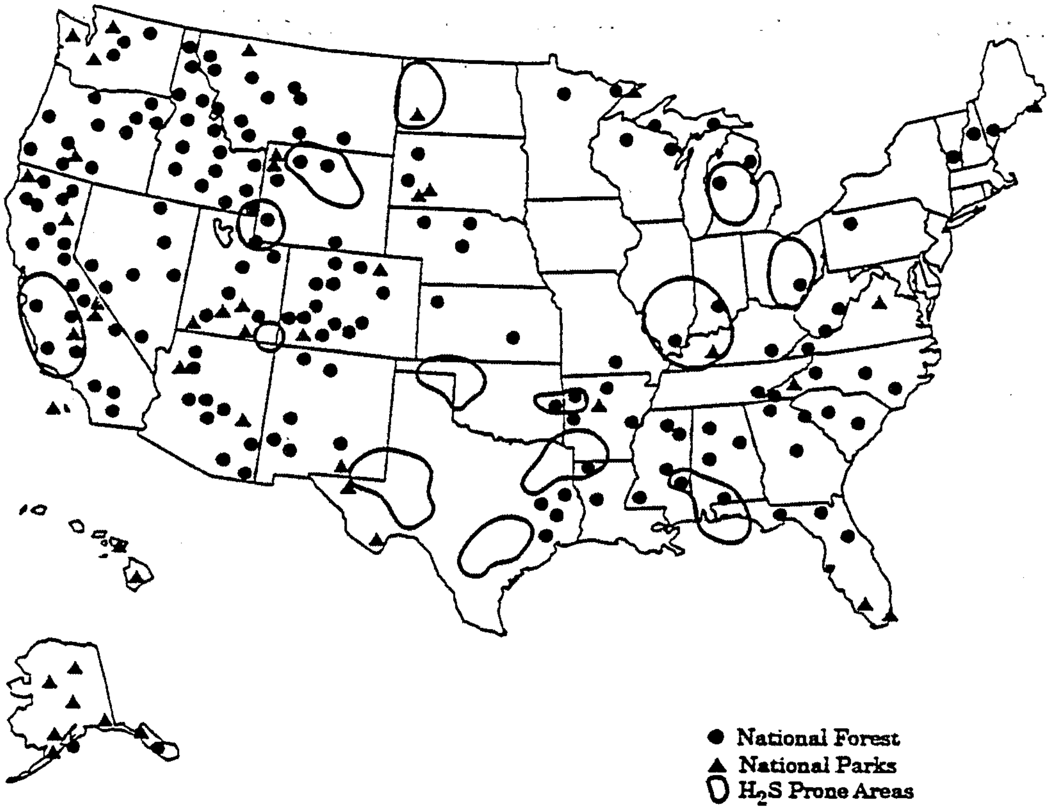
9. North Dakota is the only State known to have routinely monitored ambient H_2S at well sites and surrounding areas.

10. Many oil-and gas producing States require ambient air monitoring for H_2S at gas plants and refineries, but monitoring is not frequently required at oil and gas



Source: Gas Research Institute. 1990.
Coperrider, Boyd, and Stuart. 1986.

Figure III-25. Major H_2S prone areas in relation to waterfowl habitats of major concern (numbers indicate relative priority of concern).



Sources: Gas Research Institute, 1990. Rand McNally, 1992.

Figure III-26. Major H_2S prone areas shown in relation to National Forests and Parks.

extraction facilities, unless H_2S emission violations are suspected or complaints are filed.

11. North Dakota has three background and six special-purpose H_2S monitors. Monitoring periods vary in length from months to over a decade (32.75 years total).

12. At several locations, North Dakota monitoring data verified compliance with State H_2S standards. In two cases, data were from monitoring periods too short to support any conclusions; these were discontinued even though numerous NDAAQS violations were experienced their last year monitored.

13. North Dakota's database showed short-term H_2S concentrations ranging from 0 to 2734 ppb. The median value of all monitoring data was 0 ppb.

14. One North Dakota site had maximum short-term H_2S concentrations an order of magnitude higher than the other eight sites. At this site, more than 3,000 violations were recorded from 1984 to 1986. Concentrations improved greatly from 1986 to 1989, and only one violation occurred after the health-based standards went into effect.

15. Annual average H_2S concentrations at two sites in North Dakota approximated the RfC after introduction of a gas collection system with manifolded flares.

16. North Dakota flare operating efficiencies have been reported to range from 30 to 100 percent. (At 30 percent efficiency, H_2S can be routinely released in significant concentrations.)

17. The risk to the public of an accidental release of H_2S from the extraction of oil and gas is a function of both potential consequences and likelihood of occurrence. Judgements of risk should not be made solely on the basis of consequence analysis alone.
    a. Risks may vary from facility to facility depending on site-specific factors such as the density and distribution of nearby populations and the quality of process safety management and risk management practiced at the facility.
    b. Some facilities present greater risk than others.
    c. Risk reduction must take both consequence and likelihood of occurrence into account.

18. In addition to being toxic, H_2S is corrosive to metals in the presence of moisture and is flammable.
    a. Sour gas is flammable due to its composition of light hydrocarbons and H_2S. However, ignition of sour gas does not generally represent a thermal radiation hazard to the offsite public beyond a distance of about 100 meters.

b. The corrosivity of H_2S in the presence of moisture can cause equipment leakage and other losses in containment.

19. If accidentally released to the air under certain circumstances, H_2S can present a threat to public health and the environment.
    a. Well blowouts, line ruptures, and equipment leakage have caused accidental releases of sour gas with documented impacts on public health and the environment.
    b. The impacts on the public in the United States from sour natural gas releases from extraction activities documented in this study were limited to examples of hospital treatment and evacuation. A number of fatalities have occurred in the workplace. A single incident of the release of carbon dioxide containing H_2S from injection activities to enhance recovery resulted in the 1975 fatalities of eight members of the public.
    c. In this study, several incidents were documented as examples of both livestock and wildlife fatalities resulting from exposure to H_2S from accidental releases of sour gas.
    d. The concentration of H_2S in sour gas may vary from non-lethal levels to lethal levels above 30 percent. Unless there are high concentrations of carbon dioxide and/or hydrogen sulfide, an unprocessed sour gas mixture will usually be less dense than air and will not usually collect at ground level or in low-lying areas if accidentally released.
    e. Releases of sour gas such as from an extinguished flare or from high-pressure equipment failures (e.g., well blowouts and line ruptures) will entrain surrounding air which can cause significant dilution of the hydrogen sulfide and other components in the gas, thereby reducing the potential magnitude of the consequences of its release.
    f. A release of a sour gas mixture that is denser than air and is not significantly diluted through release phenomena (such as a jet from a high pressure source) could, under conservative atmospheric conditions, settle in low-lying areas and present a toxicity hazard. No documented incidents associated directly with oil and gas extraction were identified to support this scenario. Thus, this finding is based on theoretical premises.

20. Atmospheric dispersion modeling of worst-case scenarios shows that accidental releases of sour gas can have a range of impacts from no public impact to doses equivalent to the LC_{01} and AIHA ERPG-3 beyond 10 kilometers from the point of release.
    a. Modeling results indicate that, within a broad range of typical conditions for a <u>vertical</u> well blowout and emission from an extinguished flare, sour gas releases will not cause fatalities to the offsite public. This result would also apply to any similar <u>vertical</u> jet release at wellhead conditions resulting from equipment or line leakage.

b. Modeling results estimate that, in the worst-case, a horizontal release of sour gas from a well blowout (or similar high release rate jet in a horizontal orientation from equipment or piping) could produce fatalities in one percent of the human population exposed at distances up to approximately 10 kilometers.

21. Results from modeling exercises are only gross approximations of what might occur during an actual accidental release. These results are extremely sensitive to factors such as the assumed release rates and assumed meteorological conditions. Precise prediction of downwind effects from an actual release is unlikely for reasons such as:
   a. An actual release may have a different release rate than that assumed for a hypothetical scenario.
   b. The composition of an actual sour gas release may differ from that assumed in a modeling scenario.
   c. The meteorological conditions existing during an actual release may differ from those assumed in a modeling scenario.
   d. The effects of surface roughness (e.g., terrain and obstacles) are not fully understood. It is assumed in the models used that complex terrain and obstacles increase dispersion.
   e. The levels used to predict the onset of toxic effects (i.e., LC_{01} and ERPG-3) are highly uncertain.

22. While analysis of the worst-case scenario can be useful to help facilities and the community surrounding facilities to gain an understanding of the potential magnitude of severe situations, such an analysis does have its limitations. A worst-case scenario should be taken into account along with more probable scenarios when setting priorities for community emergency planning. Note, however, that the worst-case is designed to generate the maximum impact off-site and is considered to be extremely unlikely. The worst-case does not take into account a variety of factors that can significantly reduce downwind impacts.
   a. The worst-case scenario does not take into account the role of process safety management in reducing the probability of loss of containment.
   b. The worst-case scenario does not take into account mitigation actions that can reduce the amount released into the air.
   c. The worst-case scenario assumes terrain and topographical conditions that minimize dispersion of the plume. Actual conditions may result in greater dispersion.
   d. Worst-case meteorological conditions may not exist during an actual release.
   e. The dose that is actually received is uncertain and may be reduced or avoided by sheltering-in-place or evacuation.

23. Technologies have been developed to detect and reduce the amount of sour gas released as a result of breaches in containment. These technologies would serve to protect the public in inhabited areas and to protect wildlife in remote areas with

limited access by facilitating quicker mitigation. These technologies include:

a. Subsurface safety valves;
b. Remotely operated isolation valves;
c. Automatically operated shutoff and isolation valves;
e. Remotely monitored pressure and flow meters;
f. Local and remote audible and visual warning signals; and
g. Automatic flare ignitors and supplemental fuel sources.

In spite of the availability of detection and mitigation measures, all facilities have not uniformly adopted such measures. In addition, the reliability of such equipment and site-specific conditions must be considered before particular technologies are adopted or implemented.

24. Wells drilled in H_2S prone areas may or may not contact H_2S sources.

25. Eight States have a significant overlap of well fields and H_2S prone areas. Therefore, it is roughly estimated that as many as 280,000 oil wells and 54,000 gas wells have the potential to be located in an H_2S prone area. The actual number of sour wells in each State was not available.

26. Population densities in urban areas within ranges of 100,000-249,999 and 50,000-99,999 can be found in H_2S prone areas in California, Texas, Missouri, Florida, Illinois, Kentucky, Oklahoma, Arkansas, Ohio, Michigan, and Wyoming.

27. There have been several documented incidents of wildlife fatalities due to sour oil and gas releases. No incidents have been documented where large-scale wildlife fatalities have been caused by H_2S, and no national statistics on wildlife incidents were found. However, a Wyoming study found 237 animals killed by H_2S in two years.

28. H_2S-prone areas overlap 10 waterfowl habitats of major concern, 18 national forests and 3 national parks.

29. Land use and, therefore, potential human and ecological exposure scenarios can vary enormously around oil and gas wells:
    a. In EPA Regions 6, 8, and 9 which contain the majority of wells in H_2S prone areas (which represent 60 percent of all wells nationwide), 50 to 60 percent of the land is used as range.
    b. In Region 5 (12 percent of U.S. wells), 50 percent of land is farmed.
    c. In California, 1.7 billion bbls of oil reserves are in urban or increasingly developed residential areas.

30. ACGIH's recommended TLV-TWA for H_2S is 1 x 10^4 ppb (14 mg/m^3) and TLV-STEL is 1.5 x 10^4 ppb (21 mg/m^3).

31. AIHA ERPGs for the general public for H_2S are --
ERPG 3 - 1 x 10^5 ppb (1-hr exposure, not life threatening)
ERPG 2 - 3 x 10^4 ppb (1-hr exposure, no irreversible or serious health effects)
ERPG 1 - 100 ppb (1-hr exposure, no mild, transient adverse effects or clearly defined odor).

32. NAS/NRC H_2S guidelines for protecting the general public from the effects of accidental releases are -
90-day continuous exposure guide level - 1 x 10^3 ppb
24-hr emergency exposure guideline level - 1 x 10^4 ppb
10-min emergency exposure guideline level - 5 x 10^4 ppb.

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CHAPTER IV

REGULATORY PROGRAMS AND RECOMMENDED INDUSTRY PROCEDURES

INTRODUCTION

This chapter identifies and reviews the current State and Federal regulatory programs and industry-recommended procedures applicable to either reduce the potential for routine emissions and/or accidental hydrogen sulfide releases from oil and gas production or to mitigate the consequences of such emissions and releases.

STATE REGULATIONS

Currently, there are no national ambient air quality standards (NAAQS) for H_2S. Most oil- and gas-producing States have their own regulations pertaining to H_2S gas. Table IV-1 lists States that have set ambient air quality standards for H_2S emissions.

The EPA gathered and reviewed several States' regulations and related guidance documents and later contacted State agencies to obtain additional information on the unique aspects of the State regulations governing H_2S emissions in the oil and gas industry. EPA staff also met with officials from North Dakota during a trip to North Dakota oil and gas well sites. In addition, the Interstate Oil and Gas Compact Commission (IOGCC) was contacted to obtain information pertaining to regulatory programs (IOGCC, 1990).

This chapter contains a review of existing State regulations for nine States (California, Louisiana, Michigan, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, and Wyoming).

These nine States were chosen for review because of their large production volumes, the potential presence of H_2S in their well fields, and their distribution across the United States. The nine States contain over 68 percent of the total oil wells (419,989 wells/613,810 total U.S. wells) and 54 percent of the gas wells (147,360 wells/272,541 total U.S. wells) producing in the United States in 1991 (Petroleum Independent, 1992). For these States, regulatory agencies are identified, H_2S regulations for routine emissions and accidental releases are described, enforcement programs are discussed, records and programs to track accidental H_2S release are included, and the effectiveness of each State program is assessed qualitatively. The qualitative evaluation identifies existing control standards and the populations or ecosystems the standard is intended to protect.

In addition, these States account for 67 percent of the total U.S. oil production and 87 percent of the total U.S. natural gas production (Petroleum Independent, 1992). State regulations for H_2S emissions from the oil and gas industry in Oklahoma, Texas, Michigan,

Table IV-1. Ambient Air Quality Standards for H_2S

State	Concentration (ppb)	Average Time (hours)
California	30	1
Connecticut	200	8
Kentucky	10	1
Massachusetts	14	24
Minnesota	50[a] 30[b]	0.5 0.5
Missouri	500[a] 30[b]	0.5 0.5
Montana	50[c]	1
Nevada	240	8
New York	10	1
North Dakota	200[d] 100[c]	1 24
Oklahoma	100	0.5
Pennsylvania	100	1
Rhode Island	10	1
Texas	80	0.5
Virginia	160	24
Hawaii	40	1
Delaware	30	1
Indiana	50	1

[a] Not to be exceeded more than two times/year.
[b] Not to be exceeded more than two times/five consecutive days.
[c] Not to be exceeded more than one time/year.
[d] Not to be exceeded more than one time/month.

and California were reviewed in greatest detail because they are major oil and gas producing States. These states have extensive regulations dealing with H_2S in the oil and gas industry. California's air quality program is managed by 33 independent air pollution control districts and its Division of Oil and Gas is divided into 6 districts where District heads have great flexibility in enforcing rules. Therefore, California's program is discussed in the greatest detail.

Selected Oil and Gas Producing States

Oklahoma

The H_2S regulations for Oklahoma (10.3.16, "Operation of Hydrogen Sulfide Areas") were listed in *Guidelines for Petroleum Emergency Field Situations in the State of Oklahoma*, a guidance manual that expands on the regulations. The guidance manual contains sections on characteristics and effects of H_2S, recommended guidelines for safe drilling and production operations in an H_2S environment.

The following agencies regulate oil and gas activities in Oklahoma:

- Oklahoma Corporation Commission (OCC), Oil and Gas Conservation Division
- Oklahoma Air Quality Service
- Osage Indian Tribe (OIT)
- U.S. Bureau of Land Management
- U.S. Environmental Protection Agency.

The OCC has jurisdiction over laws and regulations "relating to the conservation of oil and gas and the prevention of pollution in connection with the exploration, drilling, producing, transporting, purchasing, processing and storage of oil and gas..." (OCC, 1986). The OIT has sole jurisdiction regarding oil and gas operations in Osage County. The U.S. Bureau of Land Management has responsibility for cases where both surface and mineral rights are owned by the Bureau or by an Indian tribe other than the Osage Tribe.

As noted earlier in this chapter, Oklahoma has an H_2S ambient air quality standard. This regulatory program (administered by the Air Quality Service) is used to control routine emissions (through permit) from oil and gas facilities.

The accidental release of H_2S from facilities is regulated by the OCC. Rule 165:10-3-16 of the OCC rules requires operators to assess their facilities for H_2S release potentials that would cause harm to the public. The rule is applicable to all facilities that handle natural gas containing 1×10^5 ppb H_2S or more and have a significant radius of exposure to cause adverse effects on the public with the exception of storage tanks. The "radius of exposure" is that distance from a source where the ground level concentration of hydrogen sulfide resulting from a release of gas from a facility is 1×10^5 ppb or 5×10^5 ppb whichever is applicable in the Rule. The Rule applies as follows:

- Does the facility (drilling, producing, injection, storage, etc.) handle hydrocarbon fluids containing 1 x 10^5 ppb H_2S or more? If yes;

- Determine the 1 x 10^5 ppb radius of exposure using an equation required in the Rule or other methods approved by the Commission. The H_2S escape rate from the facility must be determined as required by the Rule.

- If the 1 x 10^5 ppb radius of exposure is in excess of 50 feet, warning, marker and security provisions must be provided at the facility.

- If the 1 x 10^5 ppb radius of exposure is in excess of 50 feet and includes a public area or if the 5 x 10^5 ppb radius of exposure is in excess of 50 feet and includes a public road or if the 1 x 10^5 ppb radius of exposure is in excess of 3000 feet, control and safety equipment and a contingency plan must be provided for the facility.

- Facility storage tanks near atmospheric pressure containing 5 x 10^5 ppb or greater H_2S must have warning signs, wind indicators and possible fencing. Radius of exposure calculations are not applicable to storage tanks.

- H_2S training, injection or flaring provisions, accident notification and other requirements are addressed in the Rule (personal communication, W. Freeman, Shell Oil, 6/23/93).

The OCC does not keep an emissions inventory of accidental H_2S releases, but it does keep an inventory of wells with actual or potential H_2S problems. Furthermore, an inventory of inspection data is kept by individual inspectors in the State and the local field offices. Any emissions of H_2S exceeding the OCC standard of 2.5 x 10^4 ppb must be reported to the OCC by the emitting facility. Rule 3-2032, H_2S Operation, is intended to provide for the protection of the public's safety in areas where H_2S concentrations greater than 1 x 10^5 ppb may be encountered.

Drilling facilities are not required to submit data periodically to show that they are in compliance with regulations. Facilities report release of H_2S on an "honor system" once permits are granted. When noncompliance is discovered, the OCC can use administrative proceedings to shut down or fine the operation. However, in recent years, there has been no evidence of noncompliance with the H_2S regulations.

The OCC lists training requirements for employees who will work in areas of potential H_2S exposure. The training must cover hazards and characteristics of H_2S, operation of safety and life support systems, and emergency response procedures. OCC safety inspectors attend annual industry-sponsored training programs in order to stay current on safety developments and to check the safety of their breathing equipment. Each H_2S inspector is required to have an H_2S monitor, a manual, H_2S gas monitoring test tubes, and a self-contained air breathing apparatus. Specific H_2S provisions also exist regarding H_2S detection and alarm equipment, accident notification, injection, and flaring. In 1991, the OCC and the industry jointly sponsored an H_2S safety seminar. A film about H_2S safety was presented to regulatory and industry personnel, and questions about H_2S safety were answered. Safety training has also been provided to local police, fire, sheriff and ambulance services, and to interested oil and gas operators, as requested.

The enforcement, field monitoring, and inspection departments of the OCC employ 69 people. The State currently has two H_2S inspectors and a third is anticipated. In 1991, one emergency involving the accidental release of H_2S was reported to the OCC. However, the accident, which resulted in the death of one worker, was not related to the extraction of oil and gas resources.

Texas

Six agencies regulate oil and gas activities in Texas:

- Railroad Commission of Texas
- Texas Water Commission
- Texas Air Control Board
- Texas Parks and Wildlife Department
- U.S. Army Corps of Engineers
- U.S. Environmental Protection Agency.

The Railroad Commission regulates most of the operations of the oil and gas industry but has no authority over the Clean Air Act Amendments. The Railroad Commission is responsible for the well spacing, construction requirements (casing etc.), and most aspects of environmental protection and works with other State Agencies to ensure that their concerns are addressed. The Texas Water Commission works with the Railroad Commission on water quality issues. The Texas Air Control Board has jurisdiction over the regulation of oil field activities that generate air emissions. The Texas Parks and Wildlife Department investigates fish kills and water pollution complaints and evaluates the effects of discharged wastes on fish and wildlife. The Railroad Commission has jurisdiction over all oil and gas activities on Federal lands in Texas, regardless of who owns the mineral rights. The U.S. Army Corps of Engineers has permitting responsibility for activities that would affect statutory wetlands.

The Texas Air Control Board (TACB) is responsible for enforcing the Texas ambient air quality standard for H_2S (discussed previously). Certain allowances are made from the air standard if the hydrogen sulfide affects only property used for other than residential, recreational, business, or commercial purposes, such as industrial property and vacant tracts and range lands not normally occupied by people (i.e., the emission limit is raised to 120 ppb/30 min). If an operator violates these ambient air levels, corrective action must be taken such as flaring, installation of vapor recovery, etc. Consequently, the unauthorized emission of H_2S that exceeds the time weighted averages for the land use discussed above is a violation of regulation and must be addressed by the operator. In addition, the TACB requires permits for facilities that handle sour gas emissions from crude oil storage which also address emergency releases from these type facilities.

Texas regulations on H_2S for drilling, extraction, and abandonment are listed under Statewide Rule 36 - Hydrogen Sulfide Safety, Section 3.36 (051.02.02.036, "Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas," as amended September 1, 1976). The Hydrogen Sulfide Safety Rule in Texas—issued to address accidental releases—applies to facilities that could expose the public to concentrations of H_2S in excess of 1×10^5 ppb as a result of an accidental release. Operators handling hydrocarbon fluids containing 1×10^5 ppb or more H_2S must determine if the Rule applies to their facility. If it does, they must calculate the radius of exposure; determine if the public will be impacted; and, if so, install warning signs, ensure security measures, address storage tank requirements, install appropriate safety equipment, develop contingency plans, provide training and implement other requirements as necessary. In addition, all operators subject to Rule 36 must submit a Certificate of Compliance to the Railroad Commission to demonstrate that they have complied with these requirements. This rule requires that employees working in H_2S areas be trained in the characteristics and effects of the gas. The Railroad Commission of Texas publishes a training manual containing this information. The Texas and Oklahoma regulations are virtually identical. Most of the Texas regulations were discussed in the previous section on Oklahoma regulations. The Hydrogen Sulfide Safety Rule in Texas does require safety equipment, alarm equipment, monitors, etc., but does not specify exact types in an attempt to remain flexible and allow for new technology. It was designed for the protection of the general public rather than industry, since OSHA rules are designed to protect industry workers (personal communication, W. Freeman, Shell Oil, 6/23/93).

In Texas, the Railroad Commission does keep an emissions inventory on accidental H_2S releases. Any emissions of H_2S that are found to be of sufficient volume to present a hazard and/or any H_2S-related accidents must be reported to the Railroad Commission by the emitting facility. Operator certificates are required by the Railroad Commission to demonstrate that prevention and response measures have been taken to address accidental releases of H_2S.

There was one case of noncompliance during 1991, which involved natural gas leaking from a pipeline. The Railroad Commission canceled the Certificate of Compliance for the operators of the well, which prevented the facility from producing or selling the product until the leak was fixed. In 1991, there were emergencies involving the accidental releases of H_2S. Those accidents were discussed in Chapter III.

The enforcement, field monitoring, and inspection departments of the Railroad Commission employ 215 people. Ground testing for traces of H_2S is performed near the wells. Emission data on each well are submitted to the Railroad Commission using the Form of Compliance. When noncompliance is discovered, the Commission uses administrative proceedings to implement the following enforcement actions: enforcement letter, pipeline severance, zero allowable emissions, sealing, permit revocation and/or administrative penalties. The Railroad Commission may also seek civil penalties through the Attorney General's Office.

Michigan

The Michigan regulatory program is published in *Michigan's Oil and Gas Regulations - Act 61* (P.A. 1939 as amended and promulgated rules - Circular No. 15, revised in 1987, MDNR). Most of the regulations in the Michigan guidance were covered in the sections on Texas and Oklahoma regulations.

A review of *Michigan's Oil and Gas Regulations* reveals that the State has a comprehensive set of regulations dealing with H_2S. The Michigan rules require extensive training for all employees and contractors involved in drilling, completing, testing, producing, repair, workover or service operations. Employees must receive training in the following areas: physical properties and physiological effects of H_2S, effects of H_2S on metals and elastomers, emergency escape procedures, location and use of safety equipment, the location and operation of detection and warning systems and the location of primary and secondary briefing areas. Briefing areas are defined in *Michigan's Oil and Gas Regulations* as the areas "nearby where personnel can assemble in case of an emergency." Michigan defines safety equipment as including items such as first aid kits, dry chemical fire extinguisher, ropes, flare guns, portable H_2S detectors and warning signs.

In addition to training requirements, the Michigan oil and gas regulations contain comprehensive rules for the preparation of a contingency drilling plan in order to provide a plan for alerting and protecting personnel and the public in case of an emergency.

Five agencies regulate oil and gas activities in Michigan:

- Michigan Department of Natural Resources (MDNR)
- Michigan Department of Commerce, Public Service Commission
- U.S. Forest Services
- U.S. Bureau of Land Management
- U.S. Environmental Protection Agency.

The Department of Natural Resources is responsible for the well spacing, construction requirements (casing, etc.), and most aspects of environmental protection. The Michigan Public Service Commission regulates the production of gas from dry natural gas reservoirs and the safety of gas pipeline construction. When dealing with split estate situations, the U.S. Forest Service will issue a Special Use Permit which allows an operator to drill within the forest boundary. When both the forest surface and corresponding mineral rights are Federally owned, the U.S. Bureau of Land Management (BLM) issues drilling permits and the U.S. Forest Service issues Surface Use Plans. The BLM issues drilling permits in all cases related to onshore Federal mineral estates (personal communication, T. Alexander, DOE, 2/22/93).

Worker safety issues are the responsibility of the Michigan Department of Labor. Part 57 of the General Industry Safety Standards Commission Safety Standards deals with oil and gas drilling operations safety standards. Under Rule 5717(1), the drilling and servicing of wells containing H_2S shall be conducted as prescribed in the American Petroleum Institute's Recommended Practice No. 49 (API, 1987).

The MDNR's Air Quality Division regulates H_2S emissions from all sources in the oil and gas industry. Rule 336.1403 states: "It is unlawful for a person to cause or allow the emission of sour gas from an oil or natural gas producing or transporting facility or a natural gas processing facility without burning or equivalent control of hydrogen sulfide and mercaptans." The Rule does allow operators with stripper wells to emit small quantities of H_2S unless one complaint is received from the public which would require some type of abatement technique to be imposed. All facilities handling H_2S are subject to these regulations.

The Geological Survey Division (GSD) of the Department of Natural Resources regulates accidental releases of H_2S in the oil and gas industry. In addition, it overlaps with the Air Quality Division on emission controls at production facilities. It appears that two agencies in the MDNR regulate H_2S handling facilities. Under Rule 299.1911-1939, operators handling hydrocarbon fluids containing more than 3×10^5 ppb H_2S must define a Well Class (defined by the radius of exposure in Rule 299.1912) to determine the applicability of the Rule. The radius of exposure is defined using the same dispersion equation as Texas Rule 36. The Rule addresses equipment standards, location standards for drilling and production equipment, contingency planning, training, drilling, testing, production operations, servicing operations and nuisance odor requirements (personal communication, W. Freeman, Shell Oil, 6/23/93).

The enforcement, field monitoring, and inspection departments for oil and gas regulation by the Geological Survey Division (GSD) of the MDNR employ 47 people. Wells are retested one year after the initial well test was performed, to check for compliance with laws. Further periodic tests are required only at the request of the MDNR. When a well is not in compliance, the MDNR can use administrative proceedings to shut down drilling processes and production, stop issuing permits to drill, stop well ownership transfers, and issue fines. Fines are also issued for falsifying records required by the GSD enabling legislation (Act 61, P.A. of 1939, amended). Violation of the Act or a rule or order under the Act carries a penalty of not more than $1,000.00 per day that the violation continues. In 1991, there was no evidence of noncompliance for the release of H_2S.

The MDNR does not keep an emissions inventory of the accidental releases of H_2S from well blowouts and flare gas releases. Emissions of H_2S are reported by industry personnel to MDNR field personnel, who may keep records on the releases. One incident was reported to the MDNR in 1990, which involved a pumper who was working on a storage tank. The exact date and nature of the incident were not available.

California

The following agencies regulate oil and gas activity in California:

- California Department of Conservation, Division of Oil and Gas
- California Water Resources Control Board and the nine Regional Water Quality Control Boards
- California Department of Health Services
- California Department of Fish and Game, Office of Spill Prevention and Response
- California/EPA Department of Toxic Substances Control
- California State Fire Marshall's Office
- California Public Utilities Commission
- California OSHA
- California Air Resources Board and the county or multi-county regional Air Pollution Control Districts
- California Governor's Office of Emergency Services
- State Lands Commission
- California Coastal Commission
- Local government agencies
- U.S. Bureau of Land Management
- U.S. Department of Energy
- U.S. Environmental Protection Agency.

The Division of Oil and Gas of the California Department of Conservation is responsible for the management and conservation of oil and gas resources. The Division issues permits for and inspects the drilling, reworking, and abandonment of oil and gas wells. Under delegated authority from the EPA, the division also issues underground injection control well permits for Class II injection wells.

Division 3 - Oil and Gas, part of the California Code of Civil Procedure, contains the California laws for conservation of petroleum and gas (CDC, 1991). Table IV-2 highlights key sections of the law applicable to H_2S releases. Although, there is no quantitative limit to H_2S emissions, the law grants the supervisor of the Oil and Gas Division, discretionary authority to control H_2S releases to ensure protection of human health and the environment.

California's Code of Regulations contains the oil and gas regulatory program enforced by the Division of Oil and Gas. These regulations are highlighted in Table IV-3. These rules include the definition of the term "critical well," requirements for contingency plans,

Table IV-2. Highlights of California Laws for Conservation of Petroleum and Gas Pertaining to H_2S Emissions

Ch., Art., Section	Subject	Description
1, 4, 3219	Blowout prevention	Where high-pressure gas exists, use adequate casing and safety devices
1, 4, 3224	Order for repair	Authorizes supervisor to order tests or repairs needed to prevent damage to life, health, natural resources, etc.
1, 4, 3228	Abandonment of wells	Protects ground and surface water from gas-bearing strata
1, 4, 3235	Complaint	Authority to investigate complaints
1, 4, 3236	Penalty	For obstructing enforcement, \$100 - \$1,000 or up to 6 months imprisonment per offense
1, 4.1, 3241	Strategy to extract gas in high risk areas	Develop strategy to extract hazardous gases from abandoned wells to protect public health and safety
1, 4.2, 3251	Define "hazardous well"	Poses danger to life, health, or natural resources
3, , 3600	Spacing wells	Well must be at least 100 feet from parcel's boundary or public road

rules include the definition of the term "critical well," requirements for contingency plans, and environmental protection.

The Division of Oil and Gas has also published a guidance document on H_2S, *Drilling and Operating Oil, Gas, and Geothermal Wells in an H_2S Environment* (Dosch and Hodgson, 1986). This guidance document reflects the American Petroleum Institute's publication RP 49, *Safe Drilling of Wells Containing Hydrogen Sulfide* (API, 1987) and recommends safety procedures for H_2S release scenarios. The California Division of Oil and Gas (CDOG) is divided into six districts. Figure IV-1 shows the six districts and the distribution of H_2S in California, presenting parts per million of H_2S gas in some California oil and geothermal fields. Table IV-4 shows the documented concentration by oil field in each district. Three of the districts are discussed here.

District 1 of the Division of Oil and Gas has three oil and gas inspectors and seven energy engineers who inspect well drilling and rework operations. The inspectors wear tri-gas monitors (H_2S, oxygen, and combustibles). The well-permitting program does not specify H_2S limits. All wells are inspected at least once a year. Idle wells must be pressure-tested periodically to minimize casing leaks. Steam flooding, an enhancement process that often creates H_2S, is used frequently in the district. District 1 authorities know of past H_2S incidents leading to human injuries; however, because records are not computerized, exact data are not available (personal communication, K. Carlson, CDOG, 8/27/92).

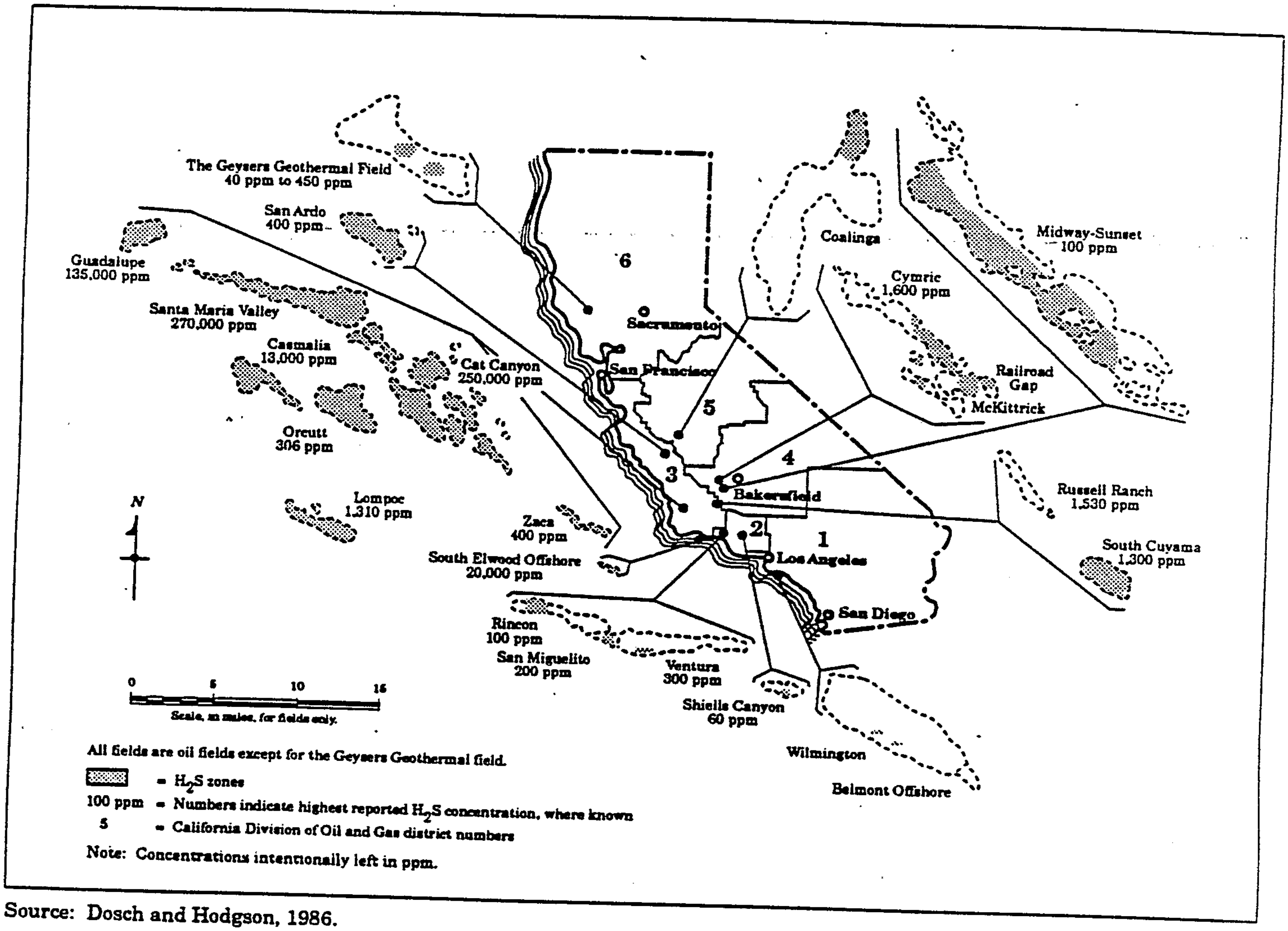
District 3 has 1,929 producing wells and 2,845 shut-in wells (i.e., no production is made on the well; its pump is turned off, the stuffing box is closed, and it is inspected to ensure no leakage). Three field inspectors cover District 3 (personal communication, A. Kollar, CDOG, 8/28/92).

District 4, which includes Kern County, has nine field inspectors, each equipped with an "escape pack" for H_2S protection. An environmental inspection is performed for every lease on every well. The inspection covers the surface area, well condition, tank condition, and operation. There are more than 40,000 wells in Kern County alone. District 4 had no records of H_2S incidents. However, inspectors in Kern County/San Joaquin Air District (described below) have documented incidents of H_2S releases (personal communication, R. Bowles, CDOG, 8/27/92).

The California Air Resources Board is authorized to enforce a statewide ambient air quality limit for H_2S emissions of 30 ppb over one hour's averaging time. However, California's air quality program is managed on a smaller scale by the 33 county or multi-county air pollution control districts (APCDs) shown in Figure IV-2 (CA Air Resources Board, 1991). Each district acts as an independent regulatory agency, establishing and

Table IV-3. Highlights of Title 14, Chapter 4 of the California Code of Regulations – Development, Regulation, and Conservation of Oil and Gas Resources

Article, Section	Subject	Description
Subchapter 1		
1, 1712	Scope	Onshore drilling and production; grants Oil and Gas Division Supervisor authority to establish field rules
2, 1720	Critical well	Addresses distances to public areas and navigable waters
2.1, 1721	Well spacing	Objectives include protecting public health, safety, welfare and the environment
3, 1722	General	Good oilfield practices, blowout prevention and control plan, prompt reporting of significant gas leaks
3, 1724.3	Well Safety Devices	Required of certain critical wells
3, 1724.4	Testing/inspecting Safety Devices	Test at least every 6 months
Subchapter 2	Environmental Protection	Requires covers on well cellars, no excessive leakage including wellheads and pipelines



All fields are oil fields except for the Geysers Geothermal field.

▨ = H_2S zones

100 ppm = Numbers indicate highest reported H_2S concentration, where known

5 = California Division of Oil and Gas district numbers

Note: Concentrations intentionally left in ppm.

Source: Dosch and Hodgson, 1986.

Figure IV-1. Parts per million of H_2S gas in some California oil and geothermal fields. Data compiled in 1976.

Table IV-4. H_2S in California Oil, Gas, and Geothermal Fields

Oil and Gas District	Fields with H_2S Concentrations 1x10^5 ppb or Above	Fields with H_2S Concentrations Under 100 ppm	Fields with H_2S Odor, But With Concentrations Unknown
1	—	—	Wilmington, Huntington Beach, Newport, Torrance, Brea Olinda
2	Rincon, 1 x 10^5 ppb San Miguelito, 2 x 10^5 ppb Ventura, 3 x 10^5 ppb	Shiells Canyon 60 ppm	Aliso Canyon, Bardsdale, Big Mountain, Del Valle, Las Llajas, Oak Park, Oakridge, Ojai, Piru, Santa Paula, Santa Susana, Simi, South Mountain, Tapo Canyon So., Temescal, Torrey Canyon, and West Mountain
3	Casmalia, 1.3 x 10^7 ppb Cat Canyon, 2.5 x 10^8 ppb Cuyama So., 1.3 x 10^6 ppb Elwood So., Offshore, 2 x 10^7 ppb Guadalupe, 1.35 x 10^8 ppb Lompoc, 1.31 x 10^6 ppb Orcutt, 3.06 x 10^5 ppb Russell Ranch, 1.53 x 10^6 ppb San Ardo, 4 x 10^5 ppb Santa Maria Valley, 2.7 x 10^8 ppb Zaca, 4 x 10^5 ppb	—	Capitan Onshore, King City Four Deer
4	Midway Sunset, 1 x 10^5 ppb Cymric, 1.6 x 10^6 ppb	—	North Belridge, South Belridge, Blackwells Corner, Edison, Northeast Edison, Kern River, Lost Hills, McKittrick, Mount Poso, Poso Creek, Railroad Gap, and Wheeler Ridge
5	—	—	Coalinga
6	—	—	—
Geothermal District			
G3	The Geysers, 4x10^4 - 4.5x10^6 ppb	—	—

H_2S in some California oil and geothermal fields. Data compiled in September 1976. (Data in the first two columns are on Figure IV-1).

Source: Dosch and Hodgson, 1986.

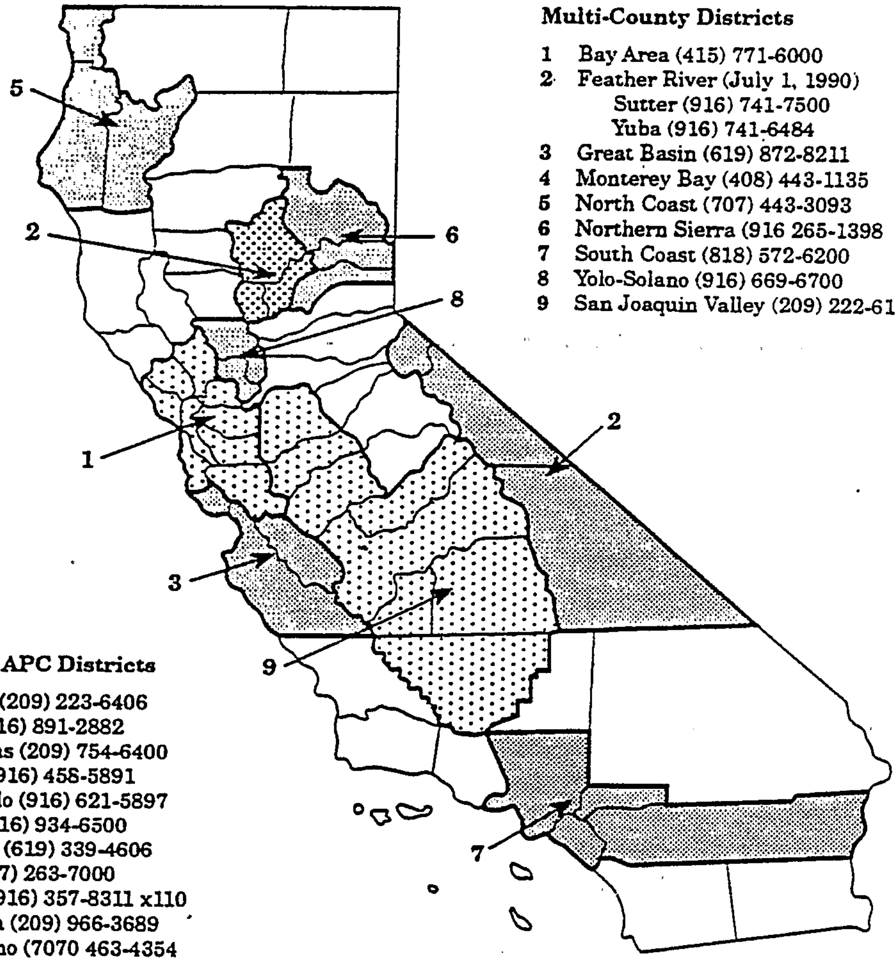
enforcing air quality rules tailored to the district's needs. Districts with significant oil production are:

Ventura County
Santa Barbara County
San Joaquin Unified Air District
South Coast Air Quality Management District
Monterey Bay Unified Air District
Bay Area Air Quality Management District.

This report highlights H_2S emissions programs in four districts: Ventura County, Santa Barbara County, San Joaquin Unified Air District, and the South Coast District.

Ventura County has Rule 54, "Sulfur Compounds," in place for air emissions containing sulfur compounds. This rule, adopted in 1968 and most recently revised in 1983, includes a limit for H_2S not to exceed 1×10^4 ppb by volume at the point of discharge. The point of discharge includes any distinguishable emission point such as valves, flanges, or process vents. There are no control technology regulations for H_2S in Ventura County other than these equipment standards. Another H_2S rule requires that the aboveground average concentration at or beyond the property boundary shall not be in excess of 60 ppb for over 3 minutes. The Ventura County limits were adopted in 1968 when the APCD was formed. Natural emissions of H_2S are low in the county's oil well fields, and H_2S monitoring is only performed when a problem is suspected (i.e., when the odor is detected). The APCD uses hand-held monitoring devices to inspect problem areas. No routine monitoring records are kept on file in Ventura County, but wells are inspected at least once a year, with large wells inspected more frequently (personal communication, K. Duval, Ventura APCD, 8/29/92). Ventura County has an enforcement staff of about 20 people, including 8 field inspectors (personal communication, K. Duval, Ventura APCD, 11/23/92).

Emission standards in Santa Barbara County are basically the same as in Ventura County. However, tighter emission limits are applied in parts of the county with SO_2 (an oxidation product of H_2S) nonattainment areas. Rule 309, "Specific Contaminants," for Santa Barbara County states that sulfur recovery units shall not emit more than 5×10^5 ppb as SO_2 or 1×10^4 ppb as H_2S. Rule 310 for odorous organic sulfides states that concentrations of organic sulfides beyond the property boundary shall not exceed 60 ppb/3 minutes or 30 ppb/hr. For gas produced and used as fuel in equipment on a well site, the sulfur content limit in the county's northern air shed is 7.96×10^5 ppb sulfur; in the southern county air shed, the limit is 2.5×10^5 ppb. Control technologies are not used on well heads for H_2S emissions. However, controls do exist for volatile organic compound (VOC) emissions from well fittings, stuffing boxes, well cellars, sumps and pits. Rules are being developed to require these controls, primarily in the surface area of the well cellar to control the release of VOC. This technology will also control H_2S emissions indirectly. The county's 10 field inspectors inspect wells for all types of emission sources at least once a year. H_2S violations via the total sulfur emission limit are not a problem because by the time



Multi-County Districts

1 Bay Area (415) 771-6000
2 Feather River (July 1, 1990)
Sutter (916) 741-7500
Yuba (916) 741-6484
3 Great Basin (619) 872-8211
4 Monterey Bay (408) 443-1135
5 North Coast (707) 443-3093
6 Northern Sierra (916 265-1398
7 South Coast (818) 572-6200
8 Yolo-Solano (916) 669-6700
9 San Joaquin Valley (209) 222-6111

County APC Districts

Amador (209) 223-6406
Butte (916) 891-2882
Calaveras (209) 754-6400
Colusa (916) 458-5891
El Dorado (916) 621-5897
Glenn (916) 934-6500
Imperial (619) 339-4606
Lake (707) 263-7000
Lassen (916) 357-8311 x110
Mariposa (209) 966-3689
Mendocino (7070 463-4354
Modoc (916) 233-3939 x401
No. Sonoma (707) 433-5911
Placer (916) 889-7130
Sacramento (916) 386-6650
San Bernardino (619) 243-8920
San Diego (619) 694-3307
San Luis Obispo (805) 549-5912
Santa Barbara (805) 961-8800
Shasta (916) 225-5674
Siskiyou (916) 842-8029
Tehama (916) 527-4504
Tuolumne (209) 533-5693
Ventura (805) 654-2806

Source: California Air Resources Board, 1991.

Figure IV-2. Multi-county districts.

the ambient air quality standard is exceeded, the operator has already been alerted to a safety problem and is responding. The county has seven currently active H_2S ambient monitoring stations; however, these are at oil and gas processing facilities, rather than at well fields (personal communication, J. Top, St. Barbara APCD, 8/20/92).

The San Joaquin Unified Air District enforces Rule 407, "Sulfur Compounds," which limits the emission concentration of sulfur compounds at the point of discharge to 0.2 percent volume calculated as SO_2 (or 2 x 10^6 ppb SO_2). This rule, adopted in 1972 and renumbered in 1989, applies to any gas line or vapor control line from a well. Rule 220.1, "New and Modified Stationary Source Review Rules," has a trigger value for H_2S or total reduced sulfur or sulfur compounds other than SO_x of 54.79 lb/day. If this value is exceeded, the responsible party must use Best Available Control Technology (BACT) on the emission source. Rule 220.1 was adopted in September 1991 and revised March of 1992.

The San Joaquin District does not look at or enforce H_2S regulations until the 2 x 10^6 ppb SO_2 emission limit is exceeded, because the rule is based on the impact of SO_2 on human health and the environment, not on the health effects of H_2S. No ambient monitoring of H_2S is required by the district. However, the oil companies are required to keep their own records of SO_2 monitoring for two years. Companies also have H_2S monitoring data, and the State has the authority to request these data at any time (personal communication, M. Amundsen, San Joaquin, 8/21/92).

Kern County, part of the San Joaquin Unified Air District, has three of the largest producing wells in the United States. The county's production volume is exceeded only by Alaska, Texas, and Louisiana. The wells in Kern County produce a unique heavy crude and some use steam injection to enhance pumping. H_2S is a problem in well fields in the county, where numerous stripper wells (defined in Chapter II) are operating. The county has a ten-person enforcement team that performs inspections at least once a year. Steam casing collection systems, valves, fittings, etc., are inspected by staff wearing H_2S monitors. Inspectors in Kern County have been exposed to H_2S in the field. In one case, an inspector was exposed to greater than 1 x 10^6 ppb. The case involved a report from a fire department station downwind of a well and complaints of odor and illness. H_2S was measured at the station at 5 x 10^4 ppb. The source was a leaking underground gas recovery line. Companies are required to keep records of such incidents and report them to CAL OSHA (personal communication, M. Amundsen, San Joaquin Unified Air District, 8/21/92).

During conversations with Kern County representatives, it was noted that an important control technology for H_2S at wells is a casing collection system, which can be added to collect natural gas containing H_2S that has built up in the casing over time. If the natural gas pressure is not relieved, well production is hindered. Companies tend to release this gas to the atmosphere, but a casing collection system can treat the gas by vapor incineration (98 to 99 percent hydrocarbon destruction efficiency). However, the economic incentive to put casing collection systems on stripper wells is normally low due to the low volume of oil produced (personal communication, M. Amundsen, A. Phillips, San Joaquin, 8/21/92).

The South Coast Air Quality Management District has no specific regulations pertaining to H_2S or oil production. Rules in place that indirectly control H_2S emissions include Rule 431.1, "Sulfur Content of Gaseous Fuels," which states that, effective May 1994, natural gas cannot be burned or sold for burning if it contains greater than 4 x 10^4 ppb total sulfur. This rule also requires organic vapor recovery systems, which would recover any H_2S gas along with the volatile organics. Rule 402 could also apply to H_2S, particularly for stripper wells that are too small for permitting. This rule is a nuisance rule that could be used to close wells if, for example, neighbors complained about H_2S odors or other health effects (personal communication, C. Bhatti, South Coast AQMD, 8/25/92). The South Coast District's enforcement program is managed as part of the Stationary Source Compliance Office, which has a staff of 500 (personal communication, C. Bhatti, South Coast AQMD, 11/23/92).

California's Occupational Safety and Health Administration is authorized to administer the Federal OSHA program. There are two OSHA standards that apply to H_2S. One focuses on the maintenance and use of valves. The second is the Permissible Exposure Limit for H_2S. It is difficult to monitor compliance with this limit because operations are outdoors. CAL OSHA maintains a database of occupational accidents. No accidents were found in the database related to H_2S releases at California oil wells dating back to 1982 (personal communication, R. Hayes, CAOSHA, 9/11/92). However, H_2S incidents were recorded in some of the Air Pollution Control Districts and Division of Oil and Gas Districts (personal communication, M. Amundsen, San Joaquin Unified Air District, 8/21/92).

The California Water Resources Control Board is generally responsible for the protection of the State's waters and for preserving all present and anticipated beneficial uses of these waters. The California Department of Health Services is responsible for the regulation of hazardous wastes. It determines which waste streams and constituents are hazardous under California's laws. The State Land Commission has joint responsibility with the Division of Oil and Gas for wells on State-owned, onshore lands.

The Office of Emergency Services administers Chapter 6.95 of the California Health and Safety Code which states that every business handling any hazardous material greater than 55 gal., 500 lb. or 200 cubic feet (gaseous material) must register and develop an emergency response plan and business plan. If the business handles extremely hazardous substances onsite exceeding threshold planning quantities (500 lb for H_2S), a preliminary analysis of the facility must be made to determine if a significant risk potential exists for accidental release of the extremely hazardous substance. If the potential does exist, the facility must develop and submit a "risk management and prevention program" that addresses how to reduce or eliminate the potential for accidental release (personal communication, Dr. F. Lercari, Office of Emergency Services, 9/13/93).

A Comparison of H_2S Regulatory Programs in Four States

Table IV-5 presents a summary of regulatory programs for H_2S across California, Michigan, Oklahoma, and Texas. This summary addresses the area of "state ... control standards, techniques, and enforcement" designated for evaluation in Section 112(n)(5) of the Clean Air Act Amendments. Appendix B tabulates components of the States' regulatory programs in greater detail.

Texas, Oklahoma, and California have H_2S ambient air quality standards in place. The California standard (30 ppb over 1-hr averaging time) is more stringent than the Texas standard (80 ppb over 0.5-hr averaging time) and the Oklahoma standard (100 ppb over 0.5-hr averaging time). Michigan does not have ambient air quality standards for H_2S.

The number of agencies in each State regulating oil and gas operations ranges from two in Oklahoma and Michigan to eleven in California. The enforcement staff, which includes inspectors and field monitoring staff, numbers 69 in Oklahoma, 215 in Texas, and 47 in Michigan. California's air emissions program is regulated by districts. The Santa Barbara District, an area with high concentrations of H_2S in its oil fields, has 10 field inspectors who are also responsible for inspecting other commercial operations. Kern County, California, has a staff of 10 field inspectors who also have other inspection responsibilities.

Michigan, Oklahoma, and Texas each have H_2S-specific regulations related to public safety. In California, State law grants the Director of the Division of Oil and Gas discretion to require additional controls (for areas such as H_2S emissions) on a case-by-case basis. However, none of the four States has specific H_2S standards in place to protect the environment, i.e., ecological protection.

Of the four States reviewed, only Texas maintains an inventory of accidental releases of H_2S from drilling and production operations. However, all four states require notification when threatening accidental releases occur. None of the four States requires reporting of H_2S routine emissions. "Routine" excludes such incidents as vapor recovery unit failures and other equipment upsets.

Texas, Oklahoma, and Michigan require worker safety training for H_2S. California's Division of Oil and Gas, however, provides guidance on worker safety in the form of a publication (Dosch and Hodgson, 1986).

Other Large Producing States

The EPA gathered initial information on several State regulations and later contacted selected State agencies to obtain additional information on the unique aspects of the State regulations governing H_2S emissions in the oil and gas industry. The results of each State review are summarized in the following sections.

Table IV-5. A Comparison of Four States' H_2S Regulatory Programs

H_2S Area	Oklahoma	Texas	Michigan	California
Ambient air quality standard?	0.10 (0.5 hr)	0.08 (0.5 hr)	No	0.03 (1 hr)
Number of State agencies regulating oil/gas	3	4	2	6
Size of enforcement/ inspection staff	69	215	47	*
Specific H_2S regulations for:				
Public Safety	Yes	Yes	Yes	No
Ecological Protection (administered by environmental agency)	No	No	Not clear	No
Inventory of accidental releases kept by State?	No	Yes	No	No
Routine reporting of emissions required?	No	No	No	No
Notification of a threatening accidental release?	Yes	Yes	Yes	Yes
H_2S training required?	Yes	Yes	Yes	Guidance

*Enforcement staff in California (example counties)

Santa Barbara County Air Pollution Control District:	10
Kern County (in San Joaquin Unified Air District):	10
California Division of Oil and Gas – District 7:	10
California Division of Oil and Gas – District 4:	9

Louisiana

Five agencies regulate oil and gas activity in Louisiana:

- Louisiana Department of Natural Resources, Office of Conservation
- Louisiana Department of Environmental Quality
- U.S. Bureau of Land Management
- U.S. Army Corps of Engineers
- U.S. Environmental Protection Agency.

The Louisiana Department of Natural Resources, Office of Conservation, regulates all subsurface and surface disposal of oil- and gas-associated wastes (*Statewide Order Governing the Drilling for the Producing of Oil and Gas in the State of Louisiana*). The office has primary responsibility for all classes of underground injection control wells. The Office of Conservation coordinates with the Louisiana Department of Environmental Quality, Office of Water Resources, on any problem dealing with discharges in the oil and gas industry. The U.S. Bureau of Land Management has jurisdiction over lease arrangements and post-lease activity on Federal lands where the mineral rights are Federally held. The Office of Conservation does not keep an emissions inventory for accidental H_2S releases. Any emissions of H_2S that exceed the Office of Conservation standard must be reported to the Office by the emitting facility.

The enforcement, field monitoring, and inspection departments of the Office of Conservation employ 34 inspectors. Emission data are sent to the Office of Conservation when an accidental release has occurred at the well site. The Office of Conservation, through administrative proceedings, can respond with the following enforcement actions when compliance is not met: compliance letters, compliance orders, civil penalty assessments, suspension/revocation of permits and pipeline severance.

In recent years, there has been no evidence of noncompliance and no emergencies involving the release of H_2S from oil or gas wells. The drilling process is not a significant threat because underground sources of H_2S are much deeper than the wells being drilled.

New Mexico

Five agencies have responsibilities for regulating oil and gas activities in New Mexico:

- New Mexico Oil Conservation Division of the Energy, Minerals and Natural Resources Department (OCD)
- New Mexico Oil Conservation Commission
- New Mexico Water Quality Control Commission
- U.S. Environmental Protection Agency

- U.S. Bureau of Land Management.

The Oil Conservation Division of the Energy, Minerals and Natural Resources Department is responsible for regulating oil and gas industry exploration and drilling, production, and refining. Its duties include regulating "nonhazardous" liquid and solid wastes from these operations to protect water quality, public health, and the environment. The Oil Conservation Commission works in conjunction with the Oil Conservation Division. The Commission initiates rules and orders to be administered by the Division. The Water Quality Control Commission develops water quality control standards and water pollution regulations. The U.S. Bureau of Land Management has jurisdiction over all Federally owned land, with the exception of Indian lands.

The Oil Conservation Division of Energy Resources (OCD) keeps emissions inventories at the district level. There are four districts in the State of New Mexico; any accidental release of H_2S must be reported to the district division of the OCD. The enforcement, field monitoring and inspection departments of the OCD employ 18 people. Inspections are made by each district OCD office. In recent years, there has been no evidence of noncompliance with the H_2S regulations set forth by the OCD, and no emergencies involving H_2S have been reported.

New Mexico's Oil Conservation Commission Rule 118 is intended to provide for the protection of the public safety in areas where H_2S concentrations greater than 1×10^5 ppb may be encountered. This rule adopts the guidance of the American Petroleum Institute publications RP 49 and RP 55 (discussed later in this chapter) and covers drilling, extraction, and abandonment.

North Dakota

Five agencies regulate oil and gas activities in North Dakota:

- North Dakota Industrial Commission, Oil and Gas Division
- North Dakota State Department of Health and Consolidated Laboratories
- U.S. Department of Agriculture, Forest Service
- U.S. Bureau of Land Management
- U.S. Environmental Protection Agency.

The North Dakota Industrial Commission, Oil and Gas Division, has regulatory authority over the drilling and production of oil, and is responsible for protecting the correlative rights of the mineral owners, preventing waste, and protecting all sources of drinking water. The Bureau of Land Management has jurisdiction over drilling and production on Federal lands, but the operator must obtain a permit from the Division of Oil and Gas. Drilling on forest land must comply with the rules of the U.S. Forest Service.

Any well completed or recompleted on or after July 1, 1987 must be registered with the State Department of Health and Consolidated Laboratories (NDSDH&CL). The registration process includes completion and submittal of a form which provides information about the well operator, well equipment (such as size and number of storage tanks, existence of a heater treater and type of fuel on which it is fired, flare stack height, etc.), surface equipment location, and disposition of produced gas. This form, submitted along with an analysis showing the H_2S concentration of any produced gas, constitutes registration. Information derived from the registration is entered into a shared database, which is used by the North Dakota Industrial Commission's Oil and Gas Division, for storing production data; thus, an emissions inventory which represents actual emissions can be generated from the database for all registered wells. H_2S concentrations in wellhead gas are field-pool specific; for example, within the Little Knife Oil Field, gas produced from the Madison Pool will have an H_2S concentration of approximately 9.56 percent, gas produced from the Red River Pool will be approximately 7.91 percent H_2S, and gas produced from the Duperow and Bakken pools is likely to contain only negligible amounts of H_2S. H_2S data from the registrations are, therefore, entered into the database as field-pool specific data (personal communication, D. Harman, NDSDH&CL, 5/19/93).

The enforcement, field monitoring, and inspection departments of the Division of Oil and Gas employ 14 people. The NDSDH&CL handles most of these complaint-related inspections. The Division of Oil and Gas can shut down an operation and fine up to $12,500 per day when compliance is not met. The NDSDH&CL can impose a fine and/or imprisonment.

H_2S typically constitutes between 4 and 10 percent of the oil and gas found in North Dakota. Because of this prevalence, the State has established an ambient air quality standard (shown in Table IV-1).

The NDSDH&CL typically becomes more involved in situations where routine emissions (as opposed to catastrophic/episodical releases) from a production facility result in excessive ambient concentrations. This scenario typically manifests itself in the form of citizen complaints. In these situations, it has been the Department's experience that an equipment problem, such as flare stack ignitor malfunction (i.e., low efficiency flare), storage tank gasket degradation and leakage, etc., has been the primary cause. Correction of the immediate problem and implementation of a more rigorous maintenance schedule will typically resolve these cases (personal communication, D. Harman, NDSDH&CL, 5/19/93). Acute, unpredictable releases of H_2S, such as natural gas pipeline rupture, etc., are typically handled by the North Dakota Industrial Commission; however, the Industrial Commission has had no reports of emergencies involving accidental releases of H_2S in the past two years.

Pennsylvania

Six agencies regulate oil and gas activities in Pennsylvania:

- Department of Environmental Resources,
- Bureau of Oil and Gas Management (BOGM)
- U.S. Environmental Protection Agency, Region III
- Pennsylvania Fish Commission
- U.S. Forest Service
- U.S. Bureau of Land Management.

The Bureau of Oil and Gas Management (BOGM) was created to coordinate and combine all regulatory activities of the oil and gas industry (*Oil and Gas Operators' Manual*). The U.S. Environmental Protection Agency issues permits for underground injection and secondary recovery. The Pennsylvania Fish Commission identifies pollution of surface waters and takes appropriate action under the Pennsylvania Fish and Boat Code.

The BOGM does keep records of any accidental releases; however, routine emission rates are not reported. Nearly all of Pennsylvania's H_2S problems have occurred in the northern part of the State, around Lake Erie.

The enforcement, field monitoring, and inspection departments of the BOGM employ 38 people. The Department of Environmental Resources has the following enforcement options available when compliance is not met: notice of violation, citation for summary offense, misdemeanor, civil penalty, injunction, administrative order, consent order and agreement, permit suspension and/or revocation, and bond forfeiture.

Six wells near Lake Erie have significant concentrations of H_2S that could be a threat to the surrounding environment and people. One incident in 1990 involved discharges of H_2S from a well blowout. Local authorities evacuated a neighboring town until the H_2S could be contained and the well plugged. The blowout did not cause any negative health effects or other types of injury.

In the past, Pennsylvania explored the possibility of establishing a committee that would include consultants, gubernatorial appointees, and citizens to examine H_2S in relation to the oil and gas industry and determine if a serious problem exists. It is understood that this project is currently inactive due to budget limitations.

Wyoming

There are four agencies that regulate oil and gas activities in Wyoming:

- Wyoming Oil and Gas Conservation Commission
- Wyoming Department of Environmental Quality
- U.S. Bureau of Land Management
- U.S. Environmental Protection Agency.

The Oil and Gas Conservation Commission has the general authority over oil and gas production in the State. The Department of Environmental Quality is responsible for land applications of all types of exploration and production wastes. The Bureau of Land Management is responsible for all drilling and production on Federal lands.

The Wyoming Oil and Gas Conservation Commission does keep emissions inventories on accidental releases of H_2S. Any accidental release of the gas must be reported to the Commission immediately.

The enforcement, field monitoring, and inspection departments of the Oil and Gas Conservation Commission employ ten people. The Commission has the following enforcement options when compliance is not met: civil assessments, permits denial and revocations, and bond forfeiture.

In 1989, approximately 2,982 stripper wells in Wyoming produced over 5 million barrels of oil. In recent years, there have been no signs of noncompliance; however, there have been emergencies involving accidental H_2S releases.

FEDERAL REGULATORY PROGRAMS

Current Federal regulations potentially applicable to the oil and gas production industry's handling of hydrogen sulfide are summarized below. These include regulations of the Occupational Safety and Health Administration (OSHA), Bureau of Land Management, (BLM), U.S. Geological Survey, (USGS), Superfund Amendments and Reauthorization Act (SARA) Title III, the Clean Air Act, and others. Although the OSHA standards are applicable only to workers, they are analyzed as guidelines for reducing exposure to H_2S from both accidental releases and routine emissions.

OSHA Regulations

Currently, hydrogen sulfide emissions from oil and gas exploration and drilling are not directly addressed by OSHA regulations. The regulations that are in effect to protect workers are: OSHA Standards for General Industry (29 CFR Part 1910.1000), and the respirator standards (29 CFR Part 1910.134) and the OSHA Process Safety Management Standards (listed in Chapter III). Industries in which hydrogen sulfide occurs in quantities in excess of 1500 pounds are covered in the Process Safety Management of Highly Hazardous

Chemicals Standard (29 CFR 1910.119), but retail facilities and remote, unmanned operations are exempted. Oil and gas well drilling or servicing operations are also exempted. The potential exists that oil and gas operations that are the focus of this Report to Congress may be exempt from this OSHA standard if the facility is remotely located or if servicing operations include those studied in this Report. Table IV-6 lists current and proposed regulations pertaining to hydrogen sulfide.

Current Regulations

General Industry Standards (29 CFR 1910.1000). Acceptable concentrations for chemical exposure are listed in Section 1910 under Table Z-1-A., Limits for Air Contaminants, of the General Industry Standard (1910.1000). Effective December 31, 1992, the permissible exposure limit (PEL) time weighted average (TWA) for H_2S is 1 x 10^4 ppb) (14 mg/m^3). That is, an 8-hour time weighted average, such that an employee's exposure to hydrogen sulfide in any 8-hour workshift of a 40-hour workweek, shall not exceed 1 x 10^4 ppb. Also for hydrogen sulfide, the short-term exposure limit (STEL) is 1.5 x 10^4 ppb (21 mg/m^3). The 1.5 x 10^4 ppb STEL is the employee's 15-minute (time weighted average) exposure, which shall not be exceeded at any time during the workday. The basis for the STEL is eye irritation.

The transitional OSHA standard, whose levels have been in effect since 1966, are ceiling limits and are listed in Table Z-2 of the OSHA standard. The acceptable ceiling concentration for hydrogen sulfide is 2 x 10^4 ppb, with an acceptable maximum peak above the ceiling concentration of 5 x 10^4 ppb lasting no more than 10 minutes, and occurring only once in an 8-hour shift, if no other measurable exposure occurs. The definition of a ceiling is the employee's exposure that shall not be exceeded during any part of the workday. If instantaneous monitoring is not feasible, then the ceiling shall be assessed as a 15-minute time weighted average exposure that shall not be exceeded at any time over a working day.

Respirator Standards (29 CFR 1910.134). The OSHA Personal Protective Equipment Standard (29 CFR 1910.134) outlines the types of personal protective devices (respirators) that should be worn when the ambient concentration exceeds the standards. Specific rules pertaining to hydrogen sulfide are not included in the standard. Covered in the standard are rules requiring written standard operating procedures, and employee training and screening for ability to use the equipment. Respirator selection, use, inspection and maintenance, storage, and cleaning are covered in the standard, as is air quality in supplied air respirators.

Process Safety Management of Highly Hazardous Chemicals (29 CFR 1910.119). The CAAA instructed OSHA (in section 304), in coordination with EPA, to promulgate a chemical process safety standard to prevent accidental releases of chemicals that could pose a threat to employees. This standard was finalized in February 1992 (57 *Federal Register* 6356).

The OSHA requirements for employers include standards to:

Table IV-6. Summary of Occupational Exposure Standards for H_2S

Agency/Association	Background	Standard or Guideline
Occupational Safety and Health Administration (OSHA)[a] General Industry Standards 29 CFR 1910.1000	Current: Lists acceptable concentrations for chemical exposure in the work environment. H_2S – listed under Table Z-1-A.	TWA 10 ppm 8-hour Time Weighted Average (TWA) STEL 15 ppm 15-minute Short Term 29 Exposure Limit (STEL)
OSHA Respirator Standards 29 CFR 1910.134	Current: Covers respirator selection, use, inspection and maintenance, storage and cleaning. Requires standard operating procedures; employee screening and training.	No specific rules pertaining to H_2S
OSHA Process Safety Management of Highly Hazardous Chemicals Standards 29 CFR 1910.119	Current: Remote unmanned facilities and drilling and servicing exempted. Purpose: To prevent or minimize the consequences of catastrophic releases of highly hazardous chemicals. Some elements specified by the 1990 Clean Air Act Amendments.	Threshold quantity for H_2S: 1500 pounds; meaning that the potential exists for a catastrophic accident at facilities with more than 1500 pounds on site.
OSHA Oil and Gas Well Drilling and Servicing Standards 29 CFR 1910.270	Proposed: 1983 proposal; OSHA still supports a specific standard for oil and gas production, thus their exemption from 29 CFR 1910.119 above.	Specifics pertaining to H_2S include: monitoring programs, personal protective devices, automatic flare ignitors, spark arrestors, drilling mud programs.
National Institute for Occupational Safety and Health (NIOSH)[b] Criteria Document for a Recommended Standard for Occupational Safety and Health	Recommendations for safe levels of worker exposure to H_2S. Standards developed for healthy workers, not for the public at large.	H_2S ceiling conc.: 15 mg/m^3 (approx. 1 x 10^4 ppb), 10-minute sampling, 10-hour workday, 40-hour workweek. Evacuation: 70 mg/m^3 (approx. 5 x 10^4 ppb)
American Conference of Governmental Industrial Hygienists (ACGIH)[b] Threshold Limit Values for Chemical Substances in the Work Environment	Professional organization of industrial hygienists which publishes annually updated Threshold Limit Values (TLVs) as guidelines in the control of ocupational health standards.	TLV-TWA: 1 x 10^4 ppb, for an 8-hour workday, 40-hour workweek. TLV-STEL: 1.5 x 10^4 ppb, 15-minute weighted average, not more than 4 times/dayday.

[a] Federal regulatory agency with enforceable standards; 25 of the States and territories run their own occupational safety programs.

[b] Recommended standard.

1) Develop and maintain written safety information identifying workplace chemical and process hazards, equipment, and process technology;

2) Perform a process hazard analysis which shall include an estimate of workplace effects of a range of releases and their health and safety effects on employees;

3) Consult with employees and their representatives on the conduct and development of the process safety management program.

4) Develop and implement written operating procedures for the chemical process;

5) Provide training to employees;

6) Evaluate and monitor contractor safety standards and performance;

7) Perform pre-startup safety reviews for new and modified facilities;

8) Establish maintenance systems for critical process related equipment;

9) Establish and implement written procedures to manage changes to the process;

10) Investigate every incident that has resulted or could result in a major accident;

11) Establish and implement a plant emergency action plan.

OSHA issued its final process safety standard on February 24, 1992.

Appendix A to the process safety standard (1910.119), lists the chemicals that present a potential for a catastrophic event with respective threshold quantities. For H_2S, the threshold quantity is 1500 pounds. This means that facilities with 1500 lbs or greater of H_2S on-site would be subject to the process safety management standard. OSHA further requires that the 25 States and territories with their own occupational safety organizations adopt similar rules within 6 months.

Although hydrogen sulfide is covered in this standard, oil and gas drilling or servicing operations are exempted, along with retail facilities and normally unoccupied remote facilities. OSHA explains the reason for the drilling and servicing exemptions in its preamble to the final rulemaking (57 FR 6369), stating that "OSHA continues to believe that oil and gas well drilling and servicing operations should be covered in a standard designed to address the uniqueness of the industry." This exclusion is retained in the final standard since OSHA continues to believe that a separate standard dealing with such operation is necessary. The potential exists that oil and gas operations that are the focus of this Report to Congress may be exempt form this OSHA standard if the facility is remotely located or if servicing operations include those studied in this Report. Table IV-6 lists current and proposed regulations pertaining to hydrogen sulfide.

Proposed Regulations

In 1983, OSHA proposed an Oil and Gas Well Drilling and Servicing Standard (48 FR 57202). The proposed standard would supplement the general standards already in effect and address the operation's unique hazards, such as those related to the unusual equipment, special situations dictated by the locations of operations, and hazards resulting from well pressures. According to the Bureau of Labor Statistics, the oil and gas well drilling and servicing industry was ranked among the most hazardous industries in the United States. OSHA estimated that 95,000 workers at approximately 5,400 rigs were employed in various occupations relating to oil and gas well drilling and servicing operations. The National Institute for Occupational Safety and Health (NIOSH) conducted a study of the oil and gas industry and provided OSHA with recommendations for developing a standard. In addition to a discussion of the Bureau of Labor Statistics injury data, NIOSH's "Comprehensive Safety Recommendation - Land Based Oil and Gas Well Drilling" also referenced in an early draft a study of data NIOSH received on fatalities and injuries occurring between 1973 and 1978 in Texas and California drilling operations. NIOSH applied these statistics for the entire drilling industry and concluded that the injury incidence and severity rates for the oil and gas drilling industry were more than six times the rate of general industry. However, these statistics include hazards other than H_2S.

In 1973 OSHA decided to regulate this industry under its Construction Safety Standards (29 CFR 1926); however, the applicability of this rule was contested by the industry. As a result of the industry contention, the Occupational Safety and Health Review Commission (OSHRC) ruled several times that the construction standards were not applicable. According to OSHRC, employers engaged in oil and gas well drilling and servicing should be subject to the general industry standards found in 29 CFR 1910. New enforcement problems emerged as a result of applying general industry standards. At the time of the issuance of the proposed standard, OSHA data showed that the oil and gas industry received a higher percentage of citations than any other industry. These citations are issued only when a standard does not exist to address the hazard, but the hazard is well recognized as a potential source of serious injury. OSHA felt that the high number of citations indicated the need for standards directed to these hazards in order to assist employers in meeting their obligations under the Occupational Safety and Health Act. They stated that it was apparent that the general industry standards either did not address or inadequately addressed hazards unique to oil and gas production, possibly even contributing to the higher injury and illness rate experienced by this industry. With the help of data from numerous studies of injury and illness in the oil and gas production industry, and input from numerous states, trade associations, labor unions and industry representatives, the draft oil and gas standards were proposed in 1983. No known action on this proposal has occurred since then. Currently, the proposed oil and gas well drilling and servicing rule has not been withdrawn, but it is also not on the regulatory agenda for finalizing.

OSHA proposed specific requirements for drilling, servicing, and special services operations performed in areas where a potential for exposure to H_2S gas exists. The requirements proposed establishing and implementing a monitoring program in specified areas of the rig. The monitoring program would be applicable where the potential exists for H_2S exposure, including areas where data are unavailable or inconclusive with respect to the potential H_2S exposure. The program would use automatic environmental monitoring systems connected to an employee alarm system. Details of the program and its procedures would be required from the regulated community in written form. Testing and maintenance of the monitoring system would also be regulated under the proposal, because improperly maintained or untested systems may lead to a false sense of security for employees who rely on them for warning.

Specific respiratory protection equipment requirements were also included in the proposed regulation. All employees working in an area of potential hydrogen sulfide exposure would be required to wear or carry an approved escape-type, self-contained breathing apparatus. An approved positive-pressure respirator would be required for employees who remain in or return to the danger area.

In Appendix A to the proposed rule, OSHA also suggested the following practices to control or limit hydrogen sulfide exposure:

- automatic ignitors on the flare from the degasser, choke manifold, and mud-gas separator to burn off hydrogen sulfide;
- spark arrestors for all internal combustion engines to lessen the chance of the engine serving as a source of ignition in the event of a blowout;
- regular checking of drilling mud to assure it has the right constituents and pH to counteract H_2S;
- addition of hydrogen sulfide neutralizer to the drilling mud to prevent the gas from reaching the surface;
- installation of H_2S monitoring systems on all rigs working within 1000 feet of known or suspected H_2S zones.

Although the oil and gas well drilling and servicing rule (1910.270) was proposed in 1983 and has not been enacted, OSHA has continued to express a preference for a specific regulation pertaining to the oil and gas drilling and servicing operation in 1992, by exempting these industries from the Process Safety Management of Highly Hazardous Chemicals; Explosives and Blasting Agents Final Rule (29 CFR 1910.109 and 1910.119; 57 FR 6356).

Impact of OSHA Regulations on Occupational and Human Health

OSHA regulations are designed to protect the worker rather than the general public or the environment. In this respect, they set levels that protect the health of workers exposed for a 40-hour workweek, rather than residents who may be exposed continuously. The OSHA permissible exposure limit (PEL) for H_2S is 10 ppb. Levels set to protect human health in general are often much more conservative since they are often based on models which assume exposure scenarios in which the person is exposed 24-hours a day for a lifetime. Non-occupational health effects levels may also account for possible developmental effects on young children and the effects of pollutants on those whose health is already compromised due to age or a chronic condition.

Four OSHA standards have the potential to protect workers exposed to H_2S. Two of these OSHA standards could apply to both workers and the public, while the other two apply specifically to workers. The OSHA general industry air contaminants and respirator standards protect the worker from H_2S exposures above certain levels. These standards address the protection of the worker from an exposure in excess of a set level through the use of personal protective equipment. The public is not protected through these two standards, since they aim to protect workers from contact with H_2S rather than prevent the release of the H_2S into the atmosphere. The process safety management standard and the proposed oil and gas well drilling and servicing standard have the potential to protect both the worker and the general public by preventing the release of H_2S.

National Institute for Occupational Safety and Health

Recommendations for safe levels of worker environmental exposure to H_2S are presented in the May 1977, *National Institute for Occupational Safety and Health (NIOSH) Criteria Document for a Recommended Standard for Occupational Exposure to Hydrogen Sulfide* (NIOSH, 1977). Hydrogen sulfide was cited as the leading cause of sudden death in the workplace (Ellenhorn and Barceloux, 1988). It was recognized as a serious hazard to the health of workers employed in energy production from hydrocarbon or geothermal sources, in the production of fibers or sheets from viscous syrup, in the production of deuterium oxide (heavy water), in tanneries, sewers, sewage treatment and animal waste disposal, in work below ground, fishing boats, and in chemical operations. Table IV-6 presents specific work practices recommended by NIOSH for the gas and oil industry.

A ceiling concentration was proposed to prevent eye effects and other adverse effects, including anorexia, nausea, weight loss, insomnia, fatigue, and headache, from prolonged exposure to hydrogen sulfide at low concentrations. The proposed ceiling concentration would also prevent acute eye effects, unconsciousness, and death, which can rapidly follow exposure to hydrogen sulfide at high concentrations. NIOSH suggests no employee be exposed to hydrogen sulfide at a ceiling concentration greater than 15 mg/m^3 (approximately 1×10^4 ppb), as determined with a sampling period of 10 minutes, for up to a 10-hour work shift in a 40-hour workweek. Evacuation of the area shall be required if the concentration of hydrogen sulfide equals or exceeds 70 mg/m^3 (approximately 5 x 10^4 ppb). NIOSH warns that the standard was not developed for the population-at-large, and any extrapolation beyond occupational exposures is not warranted.

The document includes monitoring requirements for all areas where there is occupational exposure to H_2S. First, there should be personal monitoring to detect each employee's ceiling exposure, with source and area monitoring as a supplement. The monitoring should be done quarterly, or as recommended by an industrial hygienist. Recording automatic monitors would be permitted to show short-term (less than 1-minute) peaks of up to 5 x 10^4 ppb, as long as no more than one occurs in any 30-minute period. These recording automatic monitors should be set up to signal spark-proof audible or visual alarms. They should have different alarms to signal concentrations of 1 x 10^4 ppb as an alert level to employees and 5 x 10^4 ppb as the level for employee evacuation.

The Secretary of Labor weighs NIOSH's recommendations, along with other considerations such as feasibility and means of implementation, in developing regulatory standards. The criteria document also contains sections on medical screening and followup of exposed employees, labeling and posting of H_2S hazards, personal protective equipment, hazard information for employees, work practices, sanitation, and monitoring and recordkeeping.

Bureau of Land Management

If a sour oil and gas well is located on Federal or Indian land, the facility operator or owner is subject to the requirements imposed by the Onshore Oil and Gas Order No. 6 developed by the Bureau of Land Management. This order requires submittal of a public protection plan by operators of sour oil and gas facilities upon detection of the potential to release a hazardous volume of H_2S (defined as concentrations of H_2S that exceed 1 x 10^5 parts per billion in the gas stream). Site-specific conditions are also criteria for determining whether or not a facility needs to submit a public protection plan. These conditions include (1) proximity to public buildings, public gathering centers, and roadways used for public use; and (2) radius and concentration of exposure. The order also has requirements for danger signs, fencing and gates, and wind direction indicators. Additional requirements include well control equipment, corrosion protection, and automatic safety valves or shutdowns for accidental release prevention.

The Bureau of Land Management does have procedures for enforcing Onshore Oil and Gas Order No. 6. Penalties for failure to comply with are cited in 43 C.F.R. 3163.1 (1992).

Minerals Management Service

The Minerals Management Service (Department of the Interior) Outer Continental Shelf Standard, MMS-OCS-1, Safety Requirements for Drilling Operations in a H_2S

Environment is the name for the former U.S. Geological Survey Outer Continental Shelf (OCS) Standard No.1. In February of 1976, the Conservation Division of the U. S. Geological Survey (USGS) released offshore rules for safety and pollution prevention in Standard No. 1, Safety Requirements for Drilling Operations in a Hydrogen Sulfide Environment (USGS, 1976). Required details of a contingency plan for emergency hydrogen sulfide situations are listed in the standard, and each platform is required to have the plan developed prior to drilling. The standard also specifies details of the personnel training program, and type, storage location and use of personnel protective equipment. Finally, the standard requires state-of-the-art equipment for blowout prevention, and specifies details of the mud program, well-testing procedures and flare system.

The standard requires H_2S monitoring equipment at all wells, except when drilling in areas known to be free of hydrogen sulfide. Upon encountering hydrogen sulfide, the safety requirements of the rules go into effect, and when concentrations reach 2×10^4 ppb the remainder of the rules dealing with hydrogen sulfide's corrosive effects must be observed. The precautions in the American Petroleum Institute Recommended Practice for Safe Drilling of Wells Containing Hydrogen Sulfide, (API RP 49) are considered supplemental to the requirements of the standard (API, 1987).

Two separate operational conditions are outlined with requirements for warning flags and notification of authorities. Moderate danger, when the threshold limit value of 10 ppm is reached, requires the display of signs and flags reading "DANGER - HYDROGEN SULFIDE - H_2S." If the concentration reaches 2×10^4 ppb, protective-breathing apparatus is required to be worn by all working personnel, and non-working personnel are required to evacuate to safe briefing areas. Extreme danger, when H_2S reaches the injurious level (5×10^4 ppb), is the point when all personnel (or all non-working personnel as appropriate) are required to evacuate. Radio communications are required to alert all known air and water craft in the immediate vicinity of the danger.

The Minerals Management Service is in the process of reproposing its standards for hydrogen sulfide.

CERCLA and EPCRA

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) of 1980 establishes broad Federal authority to deal with releases or threatened releases of hazardous substances from vessels and facilities. The Act defines a set of hazardous substances chiefly by reference to other environmental statutes; currently there are over 700 CERCLA hazardous substances. Commonly known as "Superfund," CERCLA requires that the person in charge of a vessel or facility notify the National Response Center as soon as that person has knowledge of a release of a hazardous substance in an amount equal to or greater than the reportable quantity (RQ) for that substance. Currently, hydrogen sulfide is listed as a CERCLA hazardous substance with a reportable quantity of 100 pounds.

On October 17, 1986, the President signed into law the Superfund Amendments and Reauthorization Act of 1986 (SARA), which revises and extends the authorities established under CERCLA and other laws. The Emergency Planning and Community Right-to-Know Act (EPCRA), enacted in 1986 as Title III of SARA, establishes new authorities for emergency planning and preparedness, community right-to-know reporting, and toxic chemical release reporting. It is intended to encourage and support emergency planning efforts at the State and local levels and to provide citizens and local governments with information concerning potential chemical hazards present in their communities. EPCRA is organized into three subtitles (A-C), each containing a number of subsections.

Subtitle A establishes the framework for State and local emergency planning. Section 301 requires each State to establish an emergency response commission and local emergency planning committees. Section 303 governs the development of comprehensive emergency response plans by local emergency planning committees and provision of facility information to the committee. Section 302 requires EPA to publish a list of extremely hazardous substances and threshold planning quantities (TPQs) for such substances. This list was established by EPA to identify chemical substances that could cause serious irreversible health effects from accidental releases. The list includes hydrogen sulfide, with a threshold planning quantity of 500 pounds. Any facility where an extremely hazardous substance is present in an amount in excess of the threshold planning quantity is required to notify the State commission and be included in local planning efforts. Section 304 establishes requirements for immediate reporting of certain releases of reportable quantities of extremely hazardous substances, and CERCLA Hazardous Substances, to the local planning committees and State emergency response commissions. These requirements are similar to the release reporting provisions under Section 103 of CERCLA. Section 304 also requires follow-up reports on each release, its effects, and response actions taken.

Only those sour oil and gas wells and well-site facilities that have 500 pounds or more of H_2S present at the well facility are subject to the planning requirements. The reportable quantity of H_2S is 100 pounds. Therefore, releases into the environment at or above 100 pounds must be reported in accordance with CERCLA 103 and EPCRA 304.

Subtitle B provides the mechanism for community awareness of hazardous chemicals present in the locality. This information is critical for effective local contingency planning. If the owner or operator of a facility is required to prepare or have available a Material Safety Data Sheet (MSDS) for a hazardous chemical under the Occupational Safety and Health Act of 1970 and regulations promulgated under that Act, Section 311 requires that owner or operator to submit MSDSs, or a list of the chemicals for which the facility is required to have an MSDS, to the local emergency planning committees, State emergency response commissions, and local fire departments. Under Section 312, owners and operators of facilities that must submit an MSDS under Section 311 are also required to submit chemical inventory information on the hazardous chemicals present at the facility. The threshold for reporting for H_2S under sections 311 and 312 is 500 pounds. Only facilities that have more than the threshold quantity need to report under sections 311 and 312, unless

MSDS or inventory information is specifically requested by the State Emergency Response Commission (SERC) or Local Emergency Planning Committee (LEPC). The owner or operator must submit an inventory form containing an estimate of the maximum amount of hazardous chemicals present at the facility during the preceding year, an estimate of the average daily amount of hazardous chemicals at the facility, and the location of these chemicals at the facility. Section 313 requires that certain facilities with ten or more employees that manufacture, process, or use a "toxic chemical" in excess of a statutorily-prescribed quantity submit annual information on the chemical and releases of the chemical into the environment. This information must be submitted to EPA and to the appropriate State offices annually. Hydrogen sulfide is not listed as a toxic chemical for which annual release information is required.

Subtitle C contains general provisions concerning trade secret protection, enforcement, citizen suits, and public availability of information.

Clean Air Act Section 112(r) - Accident Prevention

The Clean Air Act Amendments of 1990 established programs to prevent accidental releases of extremely hazardous substances and to assure that mitigation and response measures are in place in the event that a release does occur. Section 112(r) of the Clean Air Act establishes the responsibility for prevention of releases of extremely hazardous substances as the general duty of owners and operators of facilities that produce, process, handle or store such substances. Section 112(r) also requires that EPA promulgate a list of at least 100 substances that could cause death, injury or serious adverse effects to human health or the environment. Facilities with threshold quantities of the listed substances will be required to establish risk management programs and to prepare risk management plans. The statute requires EPA to promulgate regulations concerning risk management plans and other aspects of accident prevention. H_2S is one substance to which these requirements will apply as mandated in the statute.

The general duty clause is intended to establish as a responsibility of the facility owner the prevention of accidental releases and minimization of the consequences of accidental releases which do occur. Responsibilities include the conduct of appropriate hazard assessments and the design, operation, and maintenance of a safe facility. This means that facilities must be equipped for release mitigation and community protection should a release occur. The clause in the Clean Air Act Amendments refers to and is correlated with the general duty clause contained in the Occupational Safety and Health Act administered by OSHA. The OSHA clause was designed for situations for which there is no specific OSHA regulation or standard. Recognition of the hazard by the owner or operator, or within an industry, of the industry has been one standard under the OSHA general duty clause (U.S. Senate 1989). Therefore, the general duty clause places on the owners and operators of facilities the responsibility to adhere to applicable industry codes and standards for safety, accident prevention, and response.

The accidental release prevention list criteria include severity of acute adverse health effects, likelihood of accidental release, and potential magnitude of human exposure. A threshold quantity is to be established for each regulated substance to account for toxicity, dispersibility, reactivity, volatility, combustibility, or flammability of the substance and the amount anticipated to cause adverse health effects in an accidental release. The list and threshold quantities were proposed on January 19, 1993 (58 FR 5102). H_2S is listed as a toxic, and other substances present at oil and gas sites, such as methane, ethane, propane, and other hydrocarbons, are listed as flammables. Facilities with threshold quantities of the regulated substances will be required to prepare risk management plans (RMPs) and implement risk management programs. The RMPs will include a summary of assessments of offsite consequences for a range of accidental releases (including worst-case accidental releases) and a history of accidental releases. Facilities must also describe release prevention and emergency response programs developed under the risk management regulations as part of the RMP process.

Clean Air Act - PSD Program

There is no NAAQS which addresses hydrogen sulfide; however, emissions of H_2S are regulated under the Prevention of Significant Air Quality Deterioration (PSD) Program. PSD is designed to allow for industrial growth within specific air quality goals. The basic goals of the PSD regulations are (1) to ensure that economic growth will occur in harmony with the preservation of existing clean air resources to prevent any new nonattainment problems; (2) to protect the public health and welfare from any adverse effect which might occur even at air pollution levels better than the national ambient air quality standards; and (3) to preserve, protect and enhance the air quality in areas of special national or regional natural, recreational, scenic, or historic value, such as national parks and wilderness areas.

PSD permits are required for stationary sources located in areas designated, pursuant to section 107 of the CAA, as attainment or unclassifiable for a criteria pollutant. Major sources or modifications are those emitting either at least 100 tons per year or 250 tons per year of any pollutant regulated under the CAA, depending on the source category of the PSD listed pollutants. Major sources in nonattainment areas would be regulated under permit requirements persuant to Part D under title I of the CAA.

The CAA has set significance levels, below which a PSD permit is not required. Two tables set the significance values, one for defining significant emissions changes, in tons per year; and the other for defining significant air quality changes, in $\mu g/m^3$. For hydrogen sulfide, the applicable emissions threshold is the significant emission rate of 10 tons per year. An exemption from the monitoring provision of the permitting regulations for hydrogen sulfide is set as a 1-hour average concentration of 0.02 $\mu g/m^3$. Hydrogen sulfide emissions are also counted as part of the Total Reduced Sulfur and Reduced Sulfur, both having significance values set at 10 tons per year. These pollutant classes are regulated primarily to avoid nuisance (odor) problems.

The applicability of the PSD permit program to oil and gas extraction wells would be dependent on the amount of emissions and the grouping of the wells (i.e., whether several wells would be combined for calculation of emissions). In general, it appears that most oil and gas extraction wells would not likely be subject to PSD regulations based on the applicability criteria.

INDUSTRY-RECOMMENDED SAFETY AND ENVIRONMENTAL PROTECTION PROCEDURES

This section summarizes selected industry standards and practices for managing H_2S releases to the atmosphere. The American Petroleum Institute (API) has developed and published design, construction, and operating standards. Certain aspects of these standards pertaining to accidental release prevention were discussed in the previous chapter.

API Recommended Practices

The American Petroleum Institute (API), an industry-wide technical organization, has published several recommended practices (RP) pertaining to hydrogen sulfide in the oil and gas production industry. These voluntary guidelines are intended to maintain worker and public safety and health. Table IV-7 lists API Recommended Practices pertinent to production and operations in formations containing H_2S.

Control Standards

API RP 49, Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide (April 15, 1987) and API RP 55, Recommended Practices for Conducting Oil and Gas Production Operations Involving Hydrogen Sulfide (October 1981; reissued March, 1983; and preparation of a second edition began in 1990) are the two main documents dealing with H_2S in oil and gas production. It is expected that the revised RP 55 will provide information similar in scope to that in the document currently under revision, but with additional detail and more current references. These recommended practices do not set a control level for H_2S emissions; rather they identify situations to which the practices apply. They are applicable in oil and gas operations where the potential exists for atmospheric concentrations of H_2S to reach 2×10^4 ppb. They also apply "where the fluids handled contain sufficient H_2S to produce a partial pressure above 0.05 pounds per square inch absolute (psia) and the total pressure is 65 psia or greater, or where internal or external stresses are present which could result in pipe or equipment failure due to sulfide stress cracking and/or hydrogen embrittlement" (API, 1987). In these cases, materials must meet National Association of Corrosion Engineers (NACE) standards.

Control Techniques

The control techniques discussed in the API Recommended Practices take two approaches to worker and public safety. First, when hydrogen sulfide has already been

Table IV-7. Reviewed American Petroleum Institute* Documents Pertaining to H_2S in Oil and Gas Production

Document	Date	Title	Topics Covered
Recommended Practice 49 (RP49)	2nd Edition April 15, 1987	Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide	Personnel training and protective equipment. Locations. Rig and well equipment. Rig operations in H_2S environments. Contingency planning and emergency procedures. Properties and effects of H_2S and SO_2. Sour environment definition.
Recommended Practice 51 (RP51)	1st Edition October 1974 Reissued May 1982	API Recommended Onshore Production Operating Practices for Protection of the Environment	Producing wells. Lease roads, gathering systems and pipelines. Production and water handling facilities. Oil discharge – prevention and cleanup.
Recommended Practice 53 (RP53)	2nd Edition May 25, 1984	Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells	Arrangement (surface and subsea) and/or installation of: blowout preventers, choke and kill units and lines, closing units, auxilliary equipment, pipe stripping, marine riser systems. Inspection and testing. Sealing components. Blowout modifications for H_2S environments.
Recommended Practice 54 (RP54)	2nd Edition May 1, 1992	Recommended Practices for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations	Injuries and first aid. Protective equipment. Fire prevention. Drilling and well servicing rig equipment and electrical systems. Wireline service. Stripping and snubbing. Drill stem testing. Operations (including H_2S environment).
Recommended Practice 55 (RP55)	1st Edition October 1981 Reissued March 1983 (revision in progress)	Recommended Practices for Conducting Oil and Gas Production Operations Involving Hydrogen Sulfide	Personnel training and protective equipment. Contingency plans and emergency procedures. Design, construction, and operating procedures. Surveillance and maintenance. Continuous H_2S monitoring equipment. Supplementary guidance and reference material for H_2S operations.
Specification 6A (SPEC 6A)	16th Edition October 1, 1989	Specification for Wellhead and Christmas Tree Equipment, Supplement 1 and 2	Design and performance. Materials. Welding. Quality control. Equipment marking, shipping, storing, and specific requirements.

*American Petroleum Institute; 1220 L Street, Northwest; Washington, DC 20005.

released, worker and public safety is protected through the use of monitoring programs, personal protective devices and contingency plans for evacuations. Second, the engineering approach uses design, construction, and operating procedures to prevent the release of hydrogen sulfide to the atmosphere. The prevention of equipment damage due to corrosion (sulfide stress cracking) and the techniques for prevention of blowouts in API RP 53, Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells, are two main considerations in this more site- specific engineering control technique.

API RP 49, which deals with drilling in a hydrogen sulfide environment, contains the following recommendations for well siting in order to protect workers from the effects of hydrogen sulfide accumulation at the well site: "Rig components should be arranged on a location such that prevailing winds blow across the rig in a direction that will disperse any vented gas from the areas of the wellhead, choke manifold, flare stack or line, mud/gas separator, drilling fluid tanks, reserve pits, shale shaker, and degasser away from any potential ignition source (i.e., engines, generators, compressors, crew quarters, etc.) and areas used for personnel assembly. All equipment should be located and spaced to take advantage of prevailing winds and to provide for good air movement to eliminate as many sources of potential gas accumulation as possible" (API, 1987).

Other siting recommendations in API RP 49, shown in Figure III-4, are the use of caution signs at entrance and exit roads to warn of hydrogen sulfide concentrations above 2×10^4 ppb and danger flags to warn of extreme danger when the concentration exceeds 5×10^4 ppb. These signs are required to stay in place when flaring of the hydrogen sulfide could produce sulfur dioxide concentrations in excess of 5×10^3 ppb. Protection or briefing centers should be placed upwind or perpendicular to the prevailing wind, with wind direction indicators easily visible from the briefing location and all work locations. Mechanical ventilation, large fans or bug blowers, should be available for use during light wind conditions to prevent the hydrogen sulfide from accumulating in low lying locations. The locations of drilling fluid systems, power plants, burn pits, and flare stacks are also discussed from the vantage point of worker safety after the release of hydrogen sulfide.

Both API RP 49 (pertaining to drilling in a hydrogen sulfide environment) and API RP 55 (dealing with production operations) contain recommendations for personnel training. RP 55 training program topics include: the effects upon humans of various concentrations of hydrogen sulfide; protective equipment, including the use of self contained breathing apparatus rather than canister type gas masks (a filtering type mask is not appropriate for protection from hydrogen sulfide); monitoring devices; emergency procedures; material selection; and the importance of ventilation. Monitoring equipment that would set off a visual alarm at 1×10^4 ppb and an audible one at 2×10^4 ppb is recommended. Breathing equipment requirements are also discussed, including selection and storage (where they are readily available in an emergency).

Contingency plans are outlined in Section 4 of API RP 55 (API, 1983). They are recommended for each operation that has the potential for an accidental release capable of exposing the public to hazardous concentrations of hydrogen sulfide. Contingency plans should include the locations of: equipment that contains hydrogen sulfide, residences and other public facilities, evacuation routes, safety equipment, telephones, and designated briefing areas for employees. The contingency plan should also include procedures for calculating the dispersion of releases and lists of emergency telephone numbers. Finally, it is suggested that public and local officials should be briefed about the potential hazard prior to an incident, and that periodic tests of the contingency plan should be conducted.

RP 55 also covers protection of workers from the toxic effects of hydrogen sulfide due to build-up of gas concentration in confined areas. Protective equipment or purging is recommended for vessels that have previously held hydrogen sulfide. Extreme caution should be used when entering buildings containing equipment used to handle fluids containing hazardous concentrations of hydrogen sulfide. Routine use of personal protective devices is suggested in these instances.

API RP 54, Recommended Practices for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations (May 1, 1992) also addresses some aspects of personal protection from the toxic effects of hydrogen sulfide (API, 1992). This document was released after OSHA's implementation of the 1×10^4 ppb time-weighted average standard. RP 54 does not mention any specific standard or level, rather it refers the reader back to API RP 49 and API RP 55, which state that they apply to oil and gas operations where the potential exists for atmospheric concentrations to reach 2×10^4 ppb (the old OSHA ceiling standard), or where the gas could cause corrosion of the equipment. API does caution throughout their documents that the latest local, State and Federal regulations should be consulted.

Engineering controls used to prevent the production of, or the release of, hydrogen sulfide to the atmosphere are covered in the recommended practices for drilling and production (RP 49 and RP 55). API RP 55, pertaining to production, warns of the potential for introducing sulfur-reducing bacteria, which produce hydrogen sulfide, into a formation during pressure maintenance or water flooding operations (i.e., enhanced oil recovery). Operators are warned to be aware of the possibility and to act quickly if introduction occurs. If care is taken to prevent the bacteria from being introduced into formations that do not contain hydrogen sulfide, the danger of hydrogen sulfide pollution will be prevented.

Other engineering controls such as those used in design, construction, and operating practices are covered in Section 5 of RP 55. API recommends that construction materials meet specifications of the National Association of Corrosion Engineers (NACE) Standard MR-01-75: Material Requirements for Sulfide Stress Cracking Resistant Metallic Material for Oil Field Equipment. These materials include all those that are exposed to fluids containing hydrogen sulfide and critical to its containment. Process factors for consideration are discussed, including the concentration of hydrogen sulfide, the maximum atmospheric temperatures expected, pressure, pH, water content of fluids, mechanical stresses, corrosional or scale effects on the system, and any others unique to each situation. Finally, piping design should eliminate dead or slow-flow areas where fluids containing hydrogen sulfide gas can collect.

Drilling fluids are important to the control of the drilling environment. According to API RP 49 (Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide), the following practices help to maintain environmental control: maintenance of a pH of 10 or higher to neutralize hydrogen sulfide (failing to maintain proper pH can cause release of hydrogen sulfide from the drilling fluid system), the use of chemical sulfide scavengers, and the use of oil-based drilling fluids. When hydrogen sulfide gas is breaking out of drilling fluids, the fluids should be routed through a mud-gas separator until the level is reduced to a safe one. Corrosion inhibitors that create a film which protects the equipment from pitting and eventual sulfide stress cracking are also recommended. Finally, extreme caution is urged in storing fluids that have been exposed to hydrogen sulfide, and in entering enclosed areas where drilling fluids have been stored.

Drill stem, casing, tubing, and wellhead selection must meet specifications of API, NACE, the American Society of Mechanical Engineers, and the American National Standards Institute, detailed in Section 5 of RP 49. Section 5 also covers procedures for limited entry tests and equipment considerations for blowout preventer units, closing units, remote choke control lines, and kill lines. Hydrogen sulfide considerations in mud/gas separators, degassers and flare system are also discussed.

Abandonment procedures are included in API RP 55, with the disclaimer that the suggested procedures do not supersede local, State or Federal regulations. Section 6.5 discusses spontaneous combustion of iron sulfide, which is produced by the reaction of H_2S with steel. Because spontaneous combustion is possible when iron sulfide is exposed to air, RP 55 suggests that iron sulfide be kept wet until it can be burned or buried. Iron sulfide also poses a hazard during well servicing operations. Acids react with the iron sulfide to produce H_2S. Damage may also occur in pipes exposed alternately to hydrogen sulfide and air. API stresses the use of monitoring equipment when well servicing operations are performed on wells where a hydrogen sulfide hazard exists.

Hydrogen sulfide in oil and gas production is also mentioned in API RP 51, API Recommended Onshore Production Operating Practices for Protection of the Environment (October 1974, reissued May 1982). General information on the protection of personnel and equipment are presented in this document (API, 1982).

FINDINGS

1. Eighteen States have short-term H_2S ambient air quality standards. Four of the nine major oil and gas producing States reviewed in this report do not have ambient air standards.

2. Ambient air quality standards range from 160 ppb per 24 hr average time to 50 ppb per 0.5 hr average time.

3. The number of State agencies involved in controlling oil and gas operations varies widely.

4. The size of enforcement staffs at the State level varies greatly, with some staff having inspection responsibility beyond oil and gas operations.

5. No specific H_2S environmental (i.e., ecological) protection standards were found for Texas, Michigan, Oklahoma and California.

6. Not all States maintain notification requirements for accidental releases of H_2S from oil and gas wells. Some do require notification when a threatening accidental release occur.

7. Reporting of routine H_2S emissions is not required in Texas, Oklahoma, Michigan, or California. "Routine" excludes such incidents as vapor recovery unit failures and other equipment upsets.

8. NIOSH suggests no employee be exposed to H_2S at a ceiling concentration greater than 15 mg/m^3 (about 1×10^4 ppb) for up to a 10 hr work shift in a 40 hr work week. Evacuation is required if the concentration equals or exceeds 70 mg/m^3 (5×10^4 ppb).

9. NIOSH requires monitoring in work areas with alarms sounding at 1×10^4 ppb and 5×10^4 ppb.

10. The Minerals Management Service requires for offshore rigs drilling in an H_2S environment: contingency plan, personnel training, state-of-the-art blowout prevention equipment, monitoring equipment and response procedures at 1×10^4, 2×10^4, and 5×10^4 ppb. Special mud programs, well-testing procedures, and flare systems are also required. This Federal regulatory program does not have an equivalent onshore program.

11. The PSD permit program applies to significant emissions of H_2S from new sources emitting greater than 250 tons per year (or 100 tons per year for certain source categories) of any regulated pollutant, i.e., major PSD sources. It also applies to modifications of existing facilities if the net emissions increase of H_2S from the modification is significant. In either case, the significant emission rate for H_2S is 10 tons per year. Also, permits do not require monitoring if the 1-hr average concentration is below 0.014 ppb (0.02 μg/m^3). H_2S is also regulated under the PSD program for its nuisance odor as part of a larger group of Total Reduced Sulfur and Reduced Sulfur (significant $\geq$ 10 tons/yr).

12. Accidental releases of H_2S can be prevented by application of process safety management principles. The following are among the ways that these principles are adopted:

    a. Under the Clean Air Act, as amended, industry has a responsibility to identify hazards, take the actions necessary to prevent chemical accidents, and to take action to mitigate accidents in the event that they do occur.
    b. OSHA has promulgated a process safety management standard that requires facilities to implement process safety management programs for chemicals including H_2S to protect workers from accidents. These same measures can also prevent chemical accidents that might affect the public. However, the OSHA requirements do not apply to remote or unstaffed facilities such as most oil and gas well sites.
    c. Under the Clean Air Act, as amended, EPA must promulgate rules that require facilities handling H_2S to implement a risk management plan designed to prevent chemical accidents that adversely affect the public.
    d. The Bureau of Land Management's Onshore Oil and Gas Order No. 6 addresses the prevention of accidental releases of H_2S on Federal or Indian lands.
    e. Several State programs address the prevention of accidental releases of H_2S. States with such programs include Oklahoma, Texas, Michigan, California, and New Mexico.
    f. Voluntary industry initiatives (e.g., codes, standards, recommended practices) such as the API RP 55, Recommended Practices for Conducting Oil and Gas Operations Involving H_2S, which is currently being revised, have been implemented by many facilities.

13. A number of Federal and State requirements exist for emergency planning in the event that an accidental release of H_2S occurs.

    a. Facilities handling quantities of H_2S greater than threshold amounts are subject to the emergency planning requirements of the Emergency Planning and Community Right-to-Know Act (EPCRA).
    b. The accidental release prevention provisions of the Clean Air Act Amendments will require facilities handling amounts of H_2S above threshold quantities to implement an emergency response program.
    c. For Federal and Indian lands, the Bureau of Land Management requires public protection plans for sour oil and gas production operations that meet certain criteria.
    d. Several States require contingency plans in the event of accidental H_2S releases. State requirements include those of Oklahoma, Texas, Michigan, California, and New Mexico.

e. API RP 55 recommends that contingency plans be developed for oil and gas extraction facilities where an accidental release of H_2S could be immediately hazardous to life or health.

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CHAPTER V
RECOMMENDATIONS

ROUTINE EMISSIONS

From the limited data available, there appears to be no evidence that a significant threat to public health or the environment exists from routine H_2S emissions from sour oil and gas extraction. States and industry are encouraged to evaluate existing design, construction, and operation principles within the framework of process safety management. EPA recommends no further legislation pertaining to routine H_2S emissions from oil and gas extraction at this time.

ACCIDENTAL RELEASES

General

The EPA recommends no further legislative action pertaining to accidental H_2S releases from oil and gas extraction activities at this time. The regulations already promulgated, and being developed, under the authorities provided to EPA in CERCLA, EPCRA, and the accidental release prevention provisions of the CAA, provide a good framework for the prevention of accidental releases and preparedness in the event that they occur.

- EPA should track implementation of current and future industry standards and recommended practices at sour oil and gas extraction facilities. An example of such industry standards is the American Petroleum Institute Recommended Practices for Conducting Oil and Gas Production Operations Involving Hydrogen Sulfide (API RP55). EPA should consider outreach specifically directed at non-participating sectors.

- The EPA should participate in the investigation of any accidental releases associated with H_2S that cause or have the potential to cause public impacts in order to determine the root cause of such accidents. Such investigations should be coordinated with the Occupational Safety and Health Administration (OSHA) in order to encompass worker safety issues.

- The EPA should continue to investigate the need for additional rulemaking under the accidental release prevention provisions of the Clean Air Act to require implementation of certain prevention, detection, monitoring and mitigation efforts at facilities where extremely hazardous substances (such as H_2S) could generate dense gas clouds and impact the public. The level of voluntary industry initiatives and degree of participation, and accident history should be taken into account.

Facility and Local Emergency Planning Committee (LEPC)

Facilities that handle hazardous substances that could form dense vapor clouds if accidentally released, such as H_2S, should work closely with their LEPC to prevent accidents and to be prepared to respond to such accidents.

- Facilities should identify and thoroughly understand the hazards and conditions that can lead to accidental releases and the potential impacts on the public. These hazards and potential impacts should be communicated to the LEPC.
- All sour oil and gas extraction facilities and the LEPC for that area should conduct drills and exercises with workers, the community, first responders and others to test mitigation, response, and medical treatment for a simulated major H_2S accident. All such facilities should have training programs in place for H_2S emergencies.

Preparedness and Response

All sour oil and gas extraction facilities should actively conduct outreach efforts to ensure that the community is aware of the hazards of H_2S, that protective measures are in place to prevent public health impacts, and that proper actions will be taken during an emergency. Such outreach should be conducted through the LEPCs.

- All sour oil and gas extraction facilities should able to rapidly detect, mitigate, and respond to accidental releases in order to minimize the consequences. Site-specific risk factors should be taken into account.
- Because a general duty exists to design, operate, and maintain a safe facility, owners and operators of sour oil and gas facilities should use appropriate equipment for the facility to provide public safety and should implement a program to remedy the effects of wear and tear and corrosion on equipment.
- In addition to regular inspection of all equipment, owners and operators should pay particular attention to corrosion monitoring of existing flow and gathering lines and to the condition of temporarily abandoned equipment. Remedial action should be taken before accidental releases occur.
- EPA should foster the development and continued refinement of release detection and mitigation systems for hazardous substances, such as H_2S, in order to improve their reliability and effectiveness.
- All facilities that handle oil and gas with potentially harmful levels of H_2S should have proper medical treatment supplies and trained personnel available and should ensure that first responders, hospitals, and clinics in the area are prepared to treat H_2S exposure.

Research and Further Studies

- Further study on the acute exposure levels of H_2S that result in irreversible health effects or lethality in humans should be continued in order to improve emergency planning tools such as atmospheric dispersion models.

- Further research on the effects of surface roughness and obstacles on dense-gas dispersion behavior should be continued to determine their influences on toxic substance concentrations in a dispersing vapor cloud. The Liquefied Gaseous Fuels Spill Test Facility could be used for spill tests to assist in this research.

- EPA should continue to study the issues surrounding worst-case releases, their consequences, and the likelihood of worst-case or other significant releases for extremely hazardous substances and the role and relationship of these issues to prevention, preparedness, and response.

GLOSSARY

Abandon: To cease producing oil or gas from a well when it becomes unprofitable. A wildcat may be abandoned after it has been proven nonproductive. Usually, before a well is abandoned, some of the casing is removed and salvaged and one or more cement plugs are placed in the borehole to prevent migration of fluids between the various formations. In many States, wells may not be abandoned unless approved by an official regulatory agency.

Accidental Release: The unanticipated emissions of a regulated substance or other extremely hazardous substance into the air from a stationary source.

Acid: Any chemical compound, one element of which is hydrogen, that dissociates in solution to produce free-hydrogen ions. For example, hydrochloric acid, HCl, dissociates in water to produce hydrogen ions, H^+, and chloride ions, Cl^-.

Additive: A substance or compound added in small amounts to a larger volume of another substance to change some characteristic of the latter. In the oil industry, additives are used in lubricating oil, fuel, drilling mud, and cement for cementing casing.

Air drilling: A method of rotary drilling that uses compressed air as its circulation medium. This method of removing cuttings from the wellbore is as efficient or more efficient than the traditional methods using water or drilling mud; in addition, the rate of penetration is increased considerably when air drilling is used. However, a principal problem in air drilling is the penetration of formations containing water, since the entry of water into the system reduces its efficiency.

Alkalinity: The combining power of a base, or alkali, as measured by the number of equivalents of an acid with which it reacts to form a salt.

Annular injection: Long-term disposal of wastes between the outer wall of the drill stem or tubing and the inner wall of the casing or open hole.

Annulus or annular space: The space around a pipe in a wellbore, the outer wall of which may be the wall of either the borehole or the casing.

API: The American Petroleum Institute. Founded in 1920, this national oil trade organization is the leading standardizing organization on oil-field drilling and production equipment. It maintains departments of transportation, refining, and marketing in Washington, D.C., and a department of production in Dallas.

Artificial lift: Any method used to raise oil to the surface through a well after reservoir pressure has declined to the point at which the well no longer produces by means of natural energy. Artificial lift may also be used during primary recovery if the initial reservoir pressure is inadequate to bring the hydrocarbons to the surface. Sucker-rod pumps, hydraulic pumps, submersible pumps, and gas lift are the most common methods of artificial lift.

Barrel (bbl): A measure of volume for petroleum products. One barrel (1 bbl) is equivalent to 42 U.S. gallons or 158.97 liters. One cubic meter (1 m^3) equals 6.2897 bbl.

Basin: A synclinal structure in the subsurface, formerly the bed of an ancient sea. Because it is composed of sedimentary rock and its contours provide traps for petroleum, a basin is a good prospect for exploration. For example, the Permian Basin in West Texas is a major oil producing area.

Bit: The cutting or boring element used in drilling oil and gas wells. Most bits used in rotary drilling are roller-cone bits. The bit consists of the cutting element and the circulating element. The circulating element permits the passage of drilling fluid and uses the hydraulic force of the fluid stream to improve drilling rates. In rotary drilling, several drill collars are joined to the bottom end of the drill-pipe column for added weight. The bit is attached to the end of the drill collar.

Blowdown: The emptying or depressurizing of a material from a vessel. The material thus discarded.

Blowout preventer (BOP): Equipment installed at the wellhead, at surface level on land rigs and on the seafloor of floating offshore rigs, to prevent the escape of pressure either in the annular space between the casing and drill pipe or in an open hole during drilling and completion operations.

Blow out: To suddenly expel oil-well fluids from the borehole with great velocity. To expel a portion of water and steam from a boiler to limit its concentration of minerals.

Borehole: The wellbore; the hole made by drilling or boring.

Casing: Steel pipe placed in an oil or gas well as drilling progresses to prevent the wall of the well from caving in during drilling and to provide a means of extracting petroleum if the well is productive.

Casing string: Casing is manufactured in lengths of about 30 ft, each length or joint being joined to another as casing is run in a well. The entire length of all the joints of casing is called the casing string.

Cement: A powder consisting of alumina, silica, lime, and other substances which hardens when mixed with water. Extensively used in the oil industry to bond casing to the walls of the wellbore.

Cement plug: A portion of cement placed at some point in the wellbore to seal it.

Christmas tree: Assembly of fittings and valves at the tip of the casing of an oil well that controls the flow of oil from the well.

Close-in: A well capable of producing oil or gas, but temporarily not producing.

Collar: A coupling device used to join two lengths of pipe. A combination collar has left-hand threads in one end and right-hand threads in the other. A drill collar.

Commercial production: Oil and gas output of sufficient quantity to justify keeping a well in production.

Completion fluid: A special drilling mud used when a well is being completed. It is selected not only for its ability to control formation pressure, but also for its properties that minimize formation damage.

Completion operations: Work performed in an oil or gas well after the well has been drilled to the point at which the production string of casing is to be set. This work includes setting the casing, perforating, artificial stimulation, production testing, and equipping the well for production. It is done prior to the commencement of the actual production of oil or gas in paying quantities, or in the case of an injection or service well, prior to when the well is plugged and abandoned.

Corrosion: A complex chemical or electrochemical process by which metal is destroyed through reaction with its environment. Rust is an example of corrosion.

Crude oil: Unrefined liquid petroleum. It ranges in gravity from 9° to 55° API and in color from yellow to black, and it may have a paraffin, asphalt, or mixed base. If a crude oil, or crude, contains a sizable amount of sulfur or sulfur compounds, it is called a sour crude; if it has little or no sulfur, it is called a sweet crude. In addition, crude oils may be referred to as heavy or light according to API gravity, the lighter oils having the higher gravities.

Cuttings: The fragments of rock dislodged by the bit and brought to the surface in the drilling mud. Washed and dried samples of the cuttings are analyzed by geologists to obtain information about the formations drilled.

Demulsify: To resolve an emulsion, especially of water and oil, into its components.

Desander: A centrifugal device used to remove fine particles of sand from drilling fluid to prevent abrasion of the pumps. A desander usually operates on the principle of a fast-moving stream of fluid being put into a whirling motion inside a cone-shaped vessel.

Desilter: A centrifugal device, similar to a desander, used to remove very fine particles, or silt, from drilling fluid to keep the amount of solids in the fluid to the lowest possible level. The lower the solids content of the mud, the faster the rate of penetration.

Disposal well: A well into which salt water is pumped; usually part of a saltwater-disposal system.

Drill: To bore a hole in the earth, usually to find and remove subsurface formation fluids such as oil and gas.

Drill collar: A heavy, thick-walled tube, usually steel, used between the drill pipe and the bit in the drill stem to weight the bit in order to improve its performance.

Drill cutting: The formation rock fragments that are created by the drill bit during the drilling process.

Drilling fluid: The circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. A water-based drilling fluid is the conventional drilling mud in which water is the continuous phase and the suspended medium for solids, whether or not oil is present. An oil-based drilling fluid has diesel, crude, or some other oil as its continuous phase with water as the dispersed phase. Drilling fluids are circulated down the drill pipe and back up the hole between the drill pipe and the walls of the hole, usually to a surface pit. Drilling fluids are used to lubricate the drill bit, to lift cuttings, to seal off porous zones, and to prevent blowouts. There are two basic drilling media: muds (liquid) and gases. Each medium comprises a number of general types. The type of drilling fluid may be further broken down into numerous specific formulations.

Drill pipe: The heavy seamless tubing used to rotate the bit and circulate the drilling fluid. Joints of pipe 30 ft long are coupled together by means of tool joints.

Drill site: The location of a drilling rig.

Drill stem: The entire length of tubular pipes, composed of the kelly, the drill pipe, and drill collars, that make up the drilling assembly from the surface to the bottom of the hole.

Drill string: The column, or string, of drill pipe, not including the drill collars or kelly. Often, however, the term is loosely applied to include both the drill pipe and drill collars.

Emulsion: A mixture in which one liquid, termed the dispersed phase, is uniformly distributed (usually as minute globules) in another liquid, called the continuous phase or dispersion medium. In an oil-water emulsion, the oil is the dispersed phase and the water the dispersion medium; in a water-oil emulsion the reverse holds. A typical product of oil wells, water-oil emulsion also is used as a drilling fluid.

Embrittlement: Through chemical reactions with H_2S, steel and other materials become more brittle and more likely to break.

Emulsion breaker: A system, device, or process used for breaking down an emulsion and rendering it into two or more easily separated compounds (like water and oil). Emulsion breakers may be (1) devices to heat the emulsion, thus achieving separation by lowering the viscosity of the emulsion and allowing the water to settle out; (2) chemical compounds, which destroy or weaken the film around each globule of water, thus uniting all the drops; (3) mechanical devices such as settling tanks and wash tanks; or (4) electrostatic treaters, which use an electric field to cause coalescence of the water globules. This is also called electric dehydration.

Enhanced oil recovery (EOR): A method or methods applied to depleted reservoirs to make them productive once again. After an oil well has reached depletion, a certain amount of oil remains in the reservoir, which enhanced recovery is targeted to produce. EOR can encompass secondary and tertiary production.

EPA: United States Environmental Protection Agency.

Exploration: The search for reservoirs of oil and gas, including aerial and geophysical surveys, geological studies, core testing, and the drilling of wildcats.

Extraction: The physical removal of oil and gas from a well.

Field: A geographical area in which a number of oil or gas wells produce from a continuous reservoir. A field may refer to surface area only or to underground productive formations as well. In a single field, there may be several separate reservoirs at varying depths.

Flare: Combustion of wastegases, such as H_2S or natural gas, which are not able to be profitably brought to market.

Flowing well: A well that produces oil or gas without any means of artificial lift.

Formation: A bed or deposit composed throughout of substantially the same kinds of rock; a lithologic unit. Each different formation is given a name, frequently as a result of the study of the formation outcrop at the surface and sometimes based on fossils found in the formation.

Gas plant: A plant for the processing of natural gas, by other than solely mechanical means, for the extraction of natural gas liquids, and/or the fractionation of the liquids into natural gas liquid products such as ethane, butane, propane, and natural gasoline.

Heater-treater: A vessel that heats an emulsion and removes water and gas from the oil to raise it to a quality acceptable for pipeline transmission. A heater-treater is a combination of a heater, free-water knockout, and oil and gas separator.

Hydrocarbons: Organic compounds of hydrogen and carbon, whose densities, boiling points, and freezing points increase as their molecular weights increase. Although composed of only two elements, hydrocarbons exist in a variety of compounds because of the strong affinity of the carbon atom for other atoms and for itself. The smallest molecules of hydrocarbons are gaseous; the largest are solid.

Ignitability (RCRA): The hazardous characteristic of ignitability for purposes of RCRA is defined in 40 CFR 261.21 and is generally a liquid with a flash point less than 140 degrees F., a non-liquid that causes fire under a friction condition, an ignitable compressed gas, or is an oxidizer.

Inhibitor: An additive used to retard undesirable chemical action in a product. It is added in small quantities to gasolines to prevent oxidation and gum formation, to lubricating oils to stop color change, and to corrosive environments to decrease corrosive action.

Injection well: A well in which fluids have been injected into an underground stratum to increase reservoir pressure.

Kelly: A pipe attached to the top of a drill string and turned during drilling. It transmits twisting torque from the rotary machinery to the drill string and ultimately to the bit.

LC_{50} (median lethal concentration): The concentration of a chemical required to cause death in 50% of the exposed population when exposed for a specified time period, and observed for a specified period of time after exposure. Refers to inhalation exposure concentration in the context of air toxics (may refer to water concentration for tests of aquatic organisms or systems).

Lease: A legal document executed between a landowner (or a lessor) and a company or individual, as lessee, that grants the right to exploit the premises for minerals or other products. The area where production wells, stock tanks, separators, and production equipment are located.

Lowest-observed-adverse-effect level (LOAEL): The lowest dose or exposure level of a chemical in a study at which there is a statistically or biologically significant increase in the frequency or severity of an adverse effect in the exposed population as compared with an appropriate, unexposed control group.

Mud: The liquid circulated through the wellbore during rotary drilling and workover operations. In addition to its function of bringing cuttings to the surface, drilling mud cools and lubricates the bit and drill stem, protects against blowouts by holding back subsurface pressures, and deposits a mud cake on the wall of the borehole to prevent loss of fluids to the formation. Although it originally was a suspension of earth solids (especially clays) in water, the mud used in modern drilling operations is a more complex, three-phase mixture of liquids, reactive solids, and inert solids. The liquid phase may be fresh water, diesel oil, or crude oil and may contain one or more conditioners.

Natural gas: Naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface. The principal hydrocarbon constituent is methane.

No-observed-adverse-effect level (NOAEL). The highest experimental dose at which there is no statistically or biologically significant increases in frequency or severity of adverse health effects, as seen in the exposed population compared with an appropriate, unexposed population. Effects may be produced at this level, but they are not considered to be adverse.

Odor perception threshold: The lowest concentration at which a substance is first able to be smelled.

Oil base muds: A drilling fluid that is a water-oil emulsion with oil as the continuous phase. The oil content ranges from 50-98% oil. Oil muds are used to reduce drilling torque and to stabilize reactive shales that impede the drilling process.

Oil and gas separator: An item of production equipment used to separate the liquid components of the well stream from the gaseous elements. Separators are vertical or horizontal and are cylindrical or spherical in shape. Separation is accomplished principally by gravity, the heavier liquids falling to the bottom and the gas rising to the top. A float valve or other liquid-level control regulates the level of oil in the bottom of the separator.

Oil field: The surface area overlying an oil reservoir or reservoirs. Commonly, the term includes not only the surface area but also the reservoir, wells, and production equipment.

Operator: The person or company, either proprietor or lessee, actually operating an oil well or lease.

Packer: A piece of downhole equipment, consisting of a sealing device, a holding or setting device, and an inside passage for fluids. It is used to block the flow of fluids through the annular space between the tubing and the wall of the wellbore by sealing off the space. The packer is usually made up in the tubing string some distance above the producing zone. A sealing element expands to prevent fluid flow except through the inside bore of the packer and into the tubing. Packers are classified according to configuration, use, and method of setting and whether or not they are retrievable (i.e., whether they can be removed when necessary, or whether they must be milled or drilled out and thus destroyed).

Perforate: To pierce the casing wall and cement to provide holes through which formation fluids may enter, or to provide holes in the casing so that materials may be introduced into the annulus between the casing and the wall of the borehole. Perforating is accomplished by lowering into the well a perforating gun, or perforator, that fires electrically detonated bullets or shaped charges from the surface.

Permeability: A measure of the ease with which fluids can flow through a porous rock.

pH: A measure of the acidity or alkalinity of a solution, numerically equal to 7 for neutral solutions, increasing with increasing alkalinity and decreasing with increasing acidity.

Primary recovery: Oil production in which only existing natural energy sources in the reservoir provide for movement of the well fluids to the wellbore.

Produced water: The water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas. It can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

Producing zone: The zone or formation from which oil or gas is produced.

Production: The phase of the petroleum industry that deals with bringing the well fluids to the surface and separating them. Production also includes storing, gauging, and otherwise preparing the product for the pipeline.

Production casing: The last string of casing or liner that is set in a well, inside of which is usually suspended the tubing string.

RCRA (Resource Conservation and Recovery Act): The Federal statute enacted in 1976 (and subsequent amendments) which amended the Solid Waste Disposal Act. Among other things, RCRA and its amendments established and/or augmented three significant programs: the hazardous waste management program, the solid waste program, and the underground storage tank program.

Reference concentration (RfC): An estimate (with uncertainty spanning perhaps an order of magnitude) of a daily inhalation exposure of the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime.

Reservoir: A subsurface, porous, permeable rock body in which oil or gas or both are stored. Most reservoir rocks are limestones, dolomites, sandstones, or a combination of these. The three basic types of hydrocarbon reservoirs are oil, gas, and condensate. An oil reservoir generally contains three fluids--gas, oil, and water--with oil the dominant product. In the typical oil reservoir, these fluids occur in different phases because of the variance in their gravities. Gas, the lightest, occupies the upper part of the reservoir rocks; water occupies, the lower part; and oil occupies, the intermediate section. In addition to occurring as a cap or in solution, gas may accumulate independently of the oil; if so, the reservoir is called a gas reservoir. Associated with the gas, in most instances, are salt water and some oil. In a condensate reservoir, the hydrocarbons may exist as a gas, but when brought to the surface, some of the heavier ones condense to a liquid or condensate. At the surface the hydrocarbons from a condensate reservoir consist of gas and a high gravity crude (i.e., the condensate). Condensate wells are sometimes called gas-condensate reservoirs).

Rig: The derrick, drawworks, and attendant surface equipment of a drilling or workover unit.

Routine emissions: The anticipated emissions of a regulated substance or other extremely hazardous substance into the air from a stationary source during its normal operation.

Secondary recovery: Any method by which an essentially depleted reservoir is restored to producing status by the injection of liquids or gases (from extraneous sources) into the wellbore. This injection effects a restoration of reservoir energy, which moves the formerly unrecoverable secondary reserves through the reservoir to the wellbore.

Shale shaker: A series of trays with sieves that vibrate to remove cuttings from the circulating fluid in rotary drilling operations. The size of the openings in the sieve is carefully selected to match the size of the solids in the drilling fluid and the anticipated size of cuttings. It is also called a shaker.

Short-term exposure limit (STEL): A time-weighted average that the American Conference of Government and Industrial Hygienists (ACGIH) indicates should not be exceeded any time during the work day. Exposures at the STEL should not be longer than 15 minutes and should not be repeated more than 4 times per day. There should be at least 60 minutes between successive exposure at the STEL.

Shut-in well: A non-producing well with its pump turned off, and the stuffing box closed, which has been inspected to ensure there is no leakage.

Sour: Containing hydrogen sulfide or caused by hydrogen sulfide or another sulfur compound.

Stripper well: A well nearing depletion that produces a very small amount of oil or gas.

Tail gas: gas that leaves a sulfur recovery process after most of the H_2S has been converted to SO_2.

Tank battery: A group of production tanks located in the field, used for storage of crude oil.

Tertiary recovery: A recovery method used to remove additional hydrocarbons after secondary recovery methods have been applied to a reservoir. Sometimes more hydrocarbons can be removed by injecting liquids or gases (usually different from those used in secondary recovery and applied with different techniques) into the reservoir.

Threshold limit value (TLV): The concentration of a substance below which no adverse health effects are expected to occur for workers, assuming exposure for 8 hours per day, 40 hours per week. TLVs are published by the American Conference of Governmental Hygienists (ACGIH). This listing may be useful in identifying substances used in the workplace and having the potential to be emitted into the ambient air.

Time-weighted average (TWA): An approach to calculating the average exposure over a specified time period.

Tubing: Small-diameter pipe that is run into a well to serve as a conduit for the passage of oil and gas to the surface.

Uncertainty factor (UF): One of several, generally 10-fold factors, applied to a NOAEL or a LOAEL to derive a reference dose (RfD) from experimental data. UFs are intended to account for (a) the variation in the sensitivity among the members of the human population; (b) the uncertainty in extrapolating animal data to humans; (c) the uncertainty in extrapolating from data obtained in a less-than-lifetime exposure study to chronic exposure; and (d) the uncertainty in using a LOAEL rather than a NOAEL for estimating the threshold region.

Volatile: Readily vaporized.

Waterflood: A method of secondary recovery in which water is injected into a reservoir to remove additional quantities of oil that have been left behind after primary recovery. Usually, a waterflood involves the injection of water through wells specially set up for water injection and the removal of the water and oil from the wells drilled adjacent to the injection wells.

Wellbore: A borehole; the hole drilled by the bit. A wellbore may have casing in it or may be open (i.e., uncased); or a portion of it may be cased and a portion of it may be open.

Well completion: The activities and methods necessary to prepare a well for the production of oil and gas; the method by which a flow line for hydrocarbons is established between the reservoir and the surface. The method of well completion used by the operator depends on the individual characteristics of the producing formation or formations. These techniques include open-hole completions, conventional perforated completions, sand-exclusion completions, tubingless completions, multiple completions, and miniaturized completions.

Wellhead: The equipment used to maintain surface control of a well, including the casinghead, tubing head, and Christmas tree.

Workover: One of more of a variety of remedial operations performed on a producing oil well to try to increase production. Some examples of workover operations are deepening, plugging back, pulling and resetting the liner, and squeeze-cementing.

Workover fluids: A special drilling mud used to keep a well under control when it is being worked over. A workover fluid is compounded carefully so it will not cause formation damage.

APPENDIX A

BACKGROUND INFORMATION ON THE OIL AND GAS PRODUCTION INDUSTRY

APPENDIX A

BACKGROUND INFORMATION ON THE OIL AND GAS PRODUCTION INDUSTRY

EXPLORATION AND DEVELOPMENT

Although geological and geophysical studies provide information about potential accumulations of petroleum, only exploratory drilling can confirm the presence of petroleum.

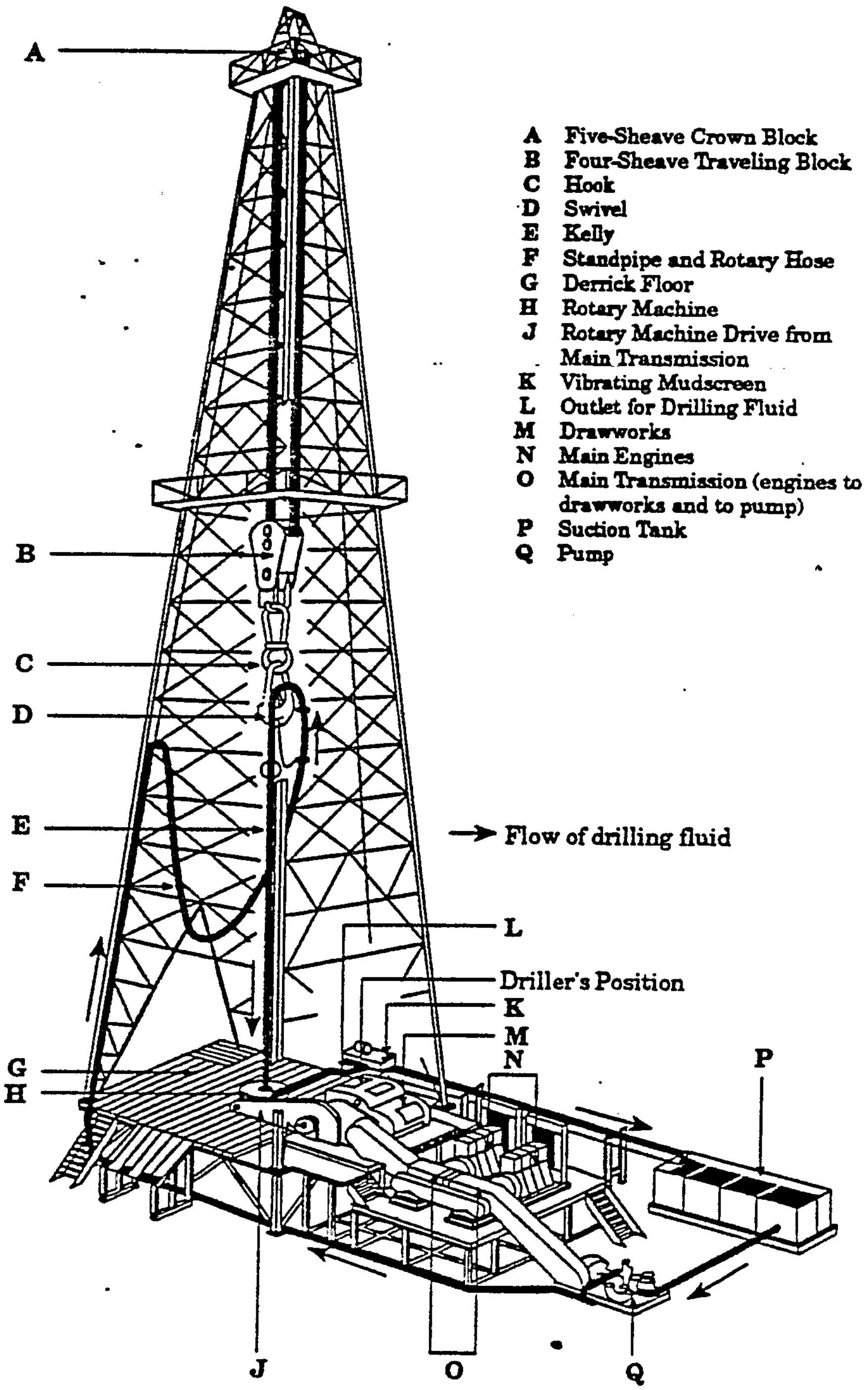
Rotary drilling, the primary drilling method in the United States, provides a safe way to control high-pressure oil/gas/water flows and allow for the simultaneous drilling of the well and removal of cuttings. This makes it possible to drill wells over 30,000 feet deep. Figure A-1 illustrates the process. Most rotary drilling operations employ a circulation system using a water- or oil-based fluid, called "mud" because of its appearance. The mud is pumped down the hollow drill pipe and across the face of the bit to provide lubrication and remove cuttings. Cuttings are removed at the surface by shale shakers, desanders, and desilters; they are then deposited in the reserve pit excavated or constructed next to the rig. Air drilling, which is considerably faster and less expensive than drilling with water- or oil-based fluids, is used in areas where high pressure or water-bearing formations are not anticipated.

Potential producing zones are normally measured and analyzed during exploratory drilling. If evidence of hydrocarbons is found, a drill stem test can show whether commercial quantities of oil and gas are present. If so, the well is prepared for production. This is called "completion." The most common method is the "cased hole" completion. Production casing is run into the hole and cemented permanently in place. Then one or more strings of production tubing are set in the hole, productive intervals are isolated with packers, and surface equipment is installed. The well is not actually completed until a gun or explosive charge perforates the production casing and begins the flow of petroleum into the well (U.S. EPA, 1987). Figure A-2 shows a cross section of a common well.

While a well is being drilled, heavy fittings have to be installed at the surface where the casing is attached, as each string of casing is inserted into the hole. Each part of the casing head is supported by a part of the casing head which was installed at the top of the next larger string of casing when it was run (U.S. EPA, 1987).

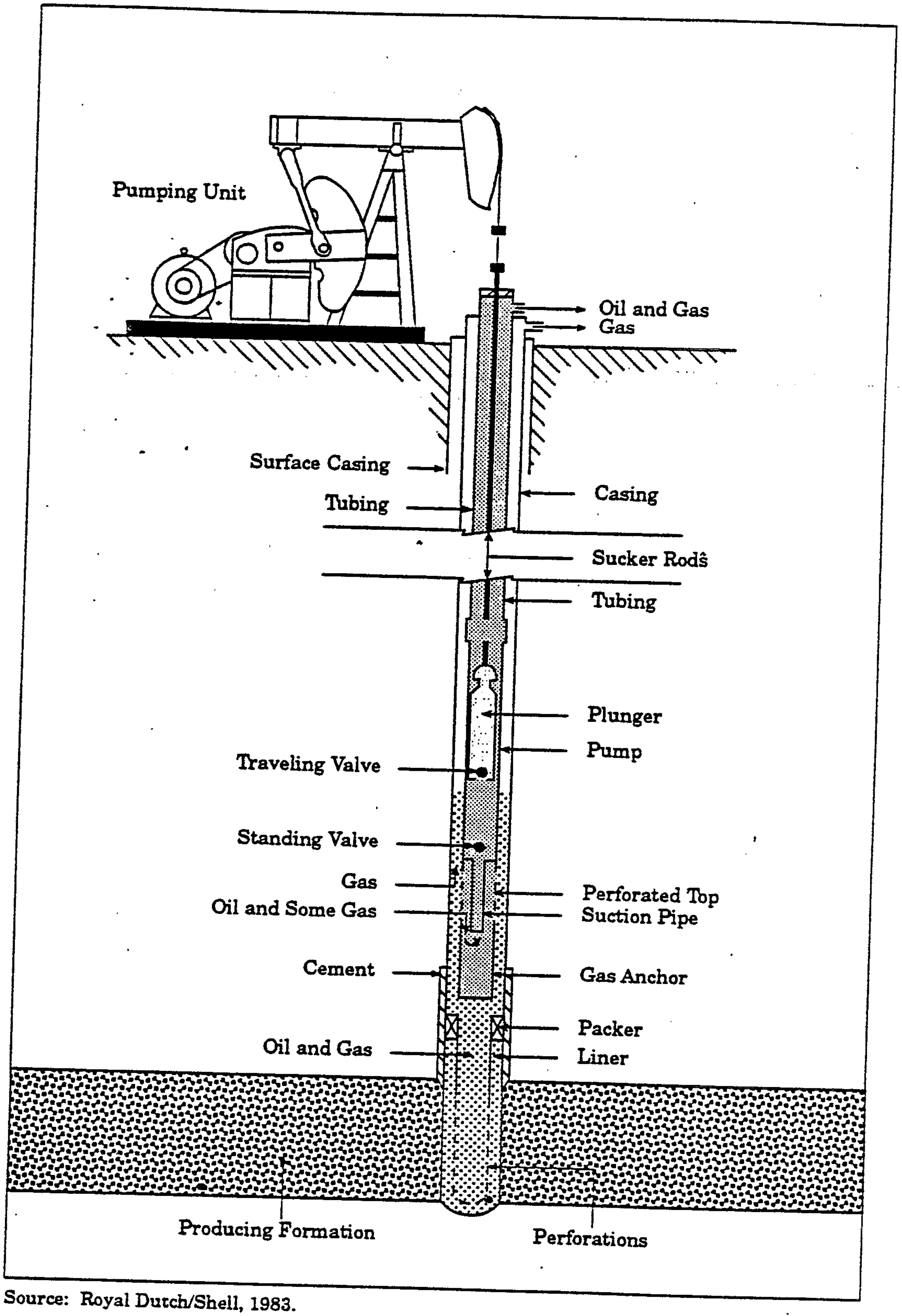
HOW OIL AND GAS ARE PRODUCED

Production operations generally include all activities associated with the recovery of oil and gas from geologic formations. They can be divided into activities associated with downhole operations and activities associated with surface operations. Downhole operations include primary secondary, and tertiary recovery methods, well workovers, and well stimulation activities. Activities associated with surface operations include oil/gas/water



Source: Royal Dutch/Shell, 1983.

Figure A-1. Rotary drilling rig.



Source: Royal Dutch/Shell, 1983.

Figure A-2. Cross section of a well pumping installation.

separation, fluid treatment, and disposal of produced water. The term "extraction" is commonly used to refer to activities associated with getting oil or gas to the surface; production includes both extraction and the surface operations involved in processing the materials extracted from the well. Production, as discussed in this report, is limited to the processing and storage that occurs at the well site. Transportation and further processing is not included in the scope of this report.

Downhole Operations

The initial production of oil or gas from the reservoir is called primary recovery. Natural pressure or artificial lift methods (surface or subsurface pumps and gas lifts) are used to bring the gas or oil out of the formation and to the surface (see Figure A-3). High-pressure gas can also be injected to lift the oil from the reservoir.

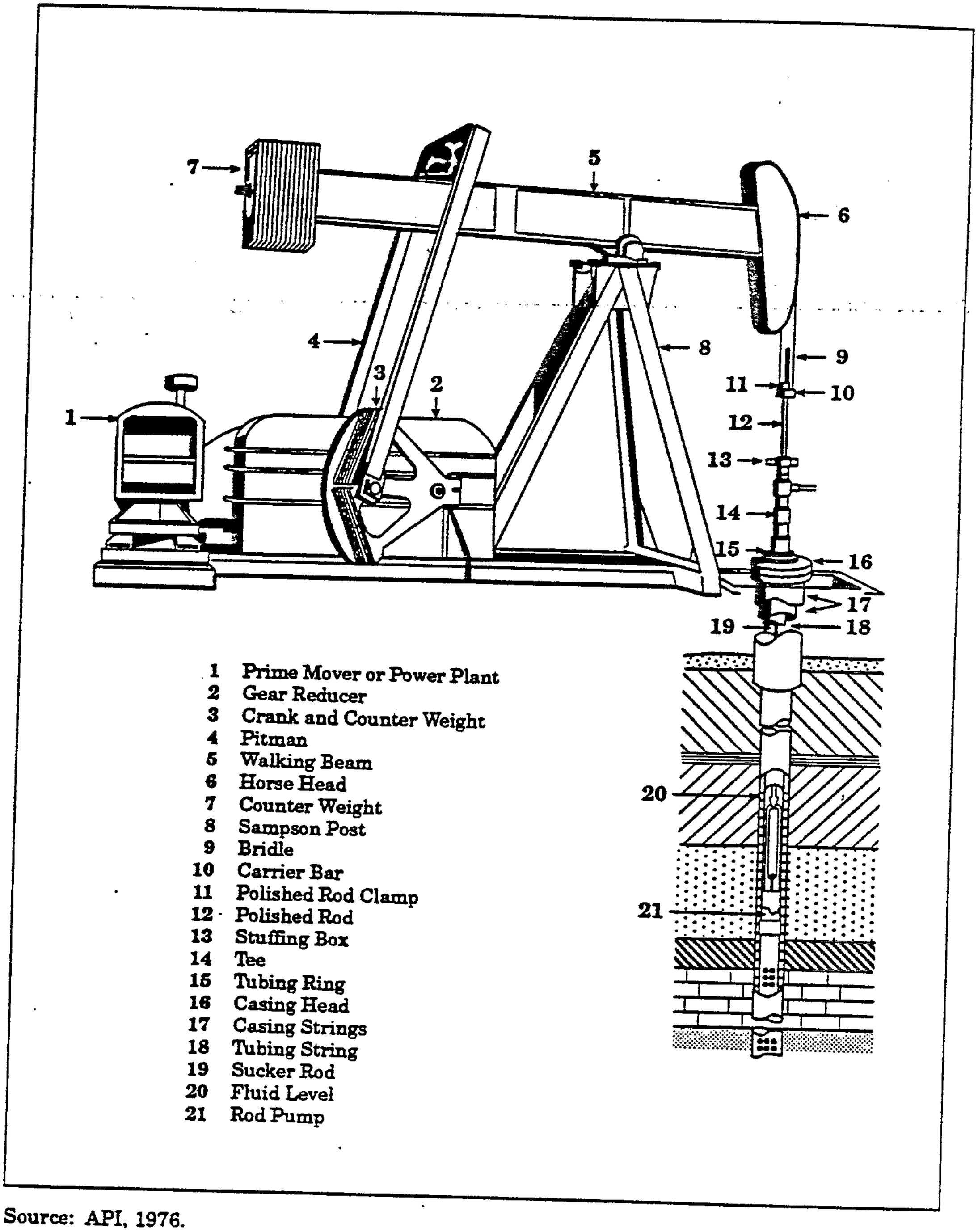
During the primary recovery stage, natural pressure in the reservoir may decline and artificial lift may be needed. One of three general types of pumps may be used: (1) pumps at the bottom of the hole run by a string of rods; (2) pumps at the bottom of the hole run by high-pressure liquids; and (3) bottom-hole centrifugal pumps (API, 1976).

The pumping unit includes a complete set of surface equipment that imparts an up-and-down motion to the sucker-rod string, which is connected the bottom-hole pump. Figure A-2 shows the parts of such as unit. Deep wells often require the long-stroke pumping provided by hydraulic units.

A stuffing box is used in a pumping well to pack or seal off the pressure inside the tubing so that liquid and gas cannot leak outside the polished rod. A stuffing box consists of flexible material or packing housed in a box which provides a method of compressing the packing. The packing material gradually wears out and must be replaced before it loses its effectiveness as a seal (API, 1976).

Primary recovery methods alone can produce oil and gas from most reservoirs, but over the life of the well production gradually decreases. Some form of secondary recovery will eventually be needed in nearly all wells. Secondary recovery methods inject gas or liquid into the reservoir to maintain pressure. The most frequent method is waterflooding, which involves injecting treated water (seawater, fresh water or produced water) into the formation through a separate well.

When secondary recovery methods are no longer adequate, the last portion of the oil that can be economically produced is recovered by tertiary methods. These include chemical, physical, and thermal methods or some combination. Chemical methods involve injection of fluids containing substances such as surfactants and polymers. Miscible oil recovery methods inject gases such as carbon dioxide and natural gas that combine with the oil. Thermal recovery methods include steam injection and *in situ* combustion (or "fire flooding"). The injected gases or fluids from secondary and tertiary recovery operations are



Source: API, 1976.

Figure A-3. Main parts of a pumping unit.

dissolved or mixed with the oil produced by the well and must be removed during surface production operations (U.S. EPA, 1987).

Workovers are another type of downhole production operation. Workovers are used to restore or increase production when downhole mechanical failures or blockages, such as sand or paraffin deposits have inhibited the flow of a well. Fluids circulated into the well for a workover must be compatible with the formation and must not adversely affect permeability. The workover fluid may be reclaimed or disposed of when the well is put back into production. Workover fluids are similar to completion fluids, which are special fluids used when the well is completed (ready for the production phase), to minimize formation damage and control potential problems such as H_2S corrosion.

Other chemicals are used periodically or continuously to inhibit corrosion, reduce friction, or simply keep the well flowing (U.S. EPA, 1987).

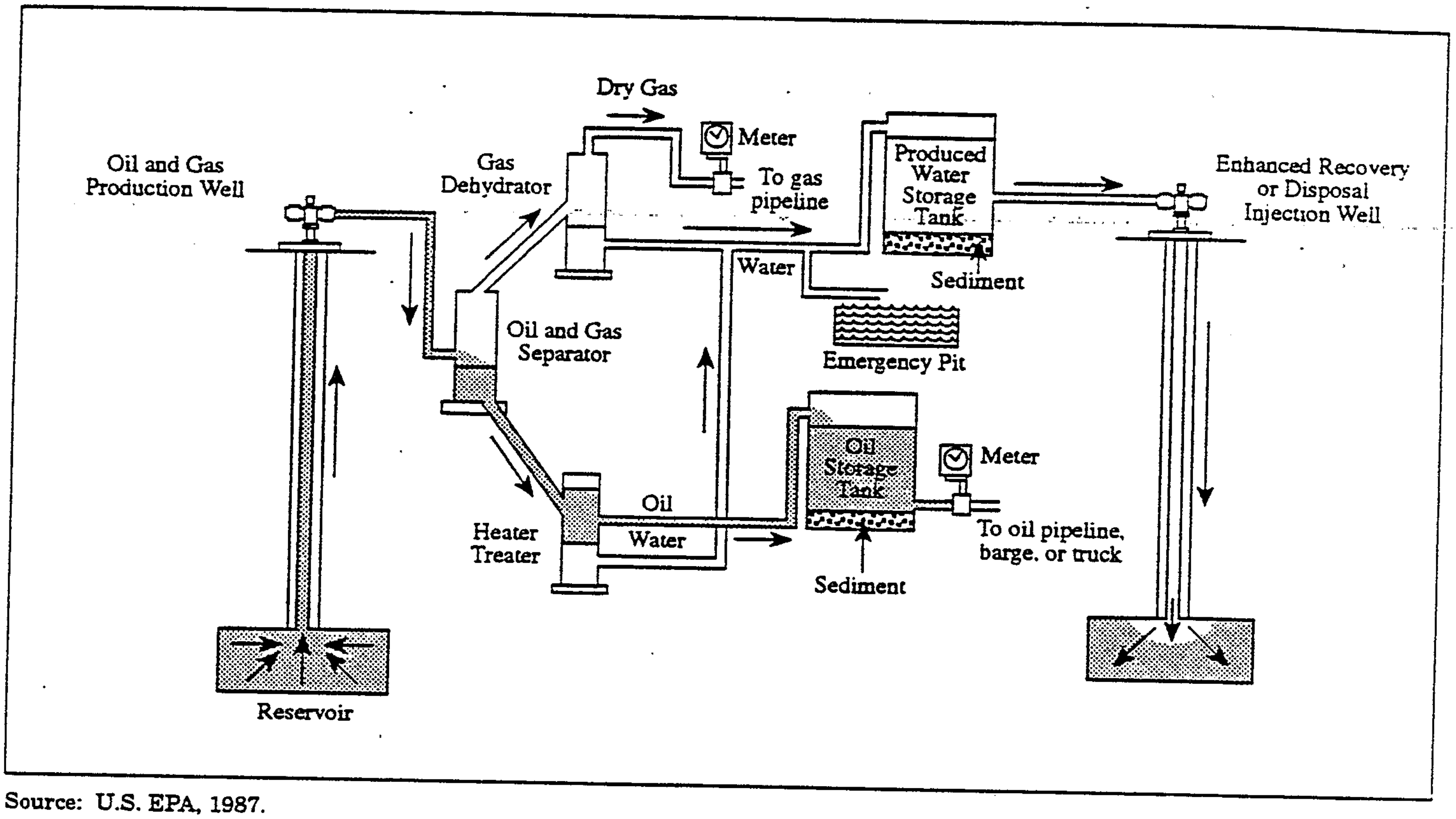
Surface Operations

As fluids are pumped to the surface, they are collected and treated to separate the various components (oil, gas, gas liquids, and water). Figure A-4 shows the separation process. These surface operations become more complex as secondary and tertiary recovery methods are employed. The ratio of water and other fluids to oil tends to increase as producing reservoirs are depleted. In new wells little or no water may be produced. The volume of water produced by stripper wells varies greatly. Stripper wells may produce more than 100 barrels of water for every barrel of oil, especially if waterflooding is used as a secondary recovery (U.S. EPA, 1987).

Separation involves the use of equipment to separate the gas, oil and water from each other. The actual separation may be accomplished in a single step or several steps depending on the relative amounts and the physical characteristics of the material which is delivered to the surface. Complete separation may require several stages involving different pressures, temperatures, and possibly additives if the material is delivered to the surface at a high pressure and the oil and gas are present in an emulsion.

After separation, the gas is transported by pipeline to a gas processing facility if the quantities from a specific well are adequate. If the quantities are inadequate, the gas is flared (burned). Gas processing facilities remove inerts (N_2, CO_2), hydrogen sulfide (H_2S), and liquids (oil and water) to produce pipeline quality gas which has a nominal heating value of 1000 BTU per cubic foot. Gas can also be re-injected into the well if necessary to help manage the reservoir or the production from the well.

Oil that is recovered from the separators at the well is placed in tanks and transported to a refinery for processing. This transportation is by pipeline if the quantities are adequate to justify installation of a pipeline or by truck if the production is small.



Source: U.S. EPA, 1987.

Figure A-4. Typical extraction operation showing separation of oil, gas, and water.

Water recovered from the separators at the well is placed in tanks or pools. This water will ultimately be reinjected into the producing formation, injected into a disposal well, or discharged. Reinjection into the producing formation and injection into a disposal well are the most common methods for water disposal; discharge is rarely used. Permits are usually required for these water disposition options.

The equipment used at the surface to control the well is called the well head. If high production or significant gas pressure is expected, the well head is usually built of cast or forged steel, and machined to a close fit. These sealed fittings prevent well fluids from blowing or leaking at the surface. Parts of the well head may be designed to hold pressures up to 20,000 lb per sq in (psi). Some well heads are just simple assemblies to support the weight of the tubing in the well, and may not be built to hold pressure. For stripper wells, or other low-production, low-pressure wells, a simple well head can be used as long as only small amounts of gas are produced with the oil (API, 1976).

High pressures or corrosive gases such as H_2S require well heads with special valves and control equipment to control the flow of oil and gas from the well. These are constructed of heavy metal and installed above the casing head or tubing head before the well is completed. This collection of valves is called a Christmas tree because of its shape and the large number of fittings branching out above the well head. The tree diverts fluids through alternative chokes (API, 1976).

Safety measures should be adequate to prevent high pressure wells from going out of control. Equipment is available that automatically shuts off production if there is damage to the wellhead or to automatic surface safety valves at the wellhead.

Simpler types of Christmas trees can be used on low pressure or pumping wells. Pressure gauges on the well head and Christmas tree measure the pressure in the casing and tubing. If the pressures under various operating conditions are known, better control can be maintained (API, 1976).

OVERVIEW OF THE INDUSTRY

The U.S. petroleum industry drilled its first oil well in 1859. Since that first well, the oil and gas industry has grown to be extremely complex and diverse. In 1990, approximately 869,887 wells in over 33 States were producing oil and gas in the United States. The oil and gas obtained from these wells is found at depths ranging from 30 feet to 30,000 feet below the earth's surface. The major U.S. areas of onshore production include the southwest (including California), the midwest, and Alaska, with lesser contributions from the Appalachians. Table A-1 lists production estimates for the oil and gas producing States. In 1990-1991, Texas led all States in oil and natural gas production, turning out 705 million barrels of oil and 6.3 trillion cubic feet of natural gas (Petroleum Independent, 1992). Figure A-5 shows U.S. oil and gas production by State. The bar graph in Figure A-6 shows distribution of States containing more than 70 percent of gas wells in the U.S. Some of these

Table A-1. 1991 Oil and 1990 Gas Production Estimates

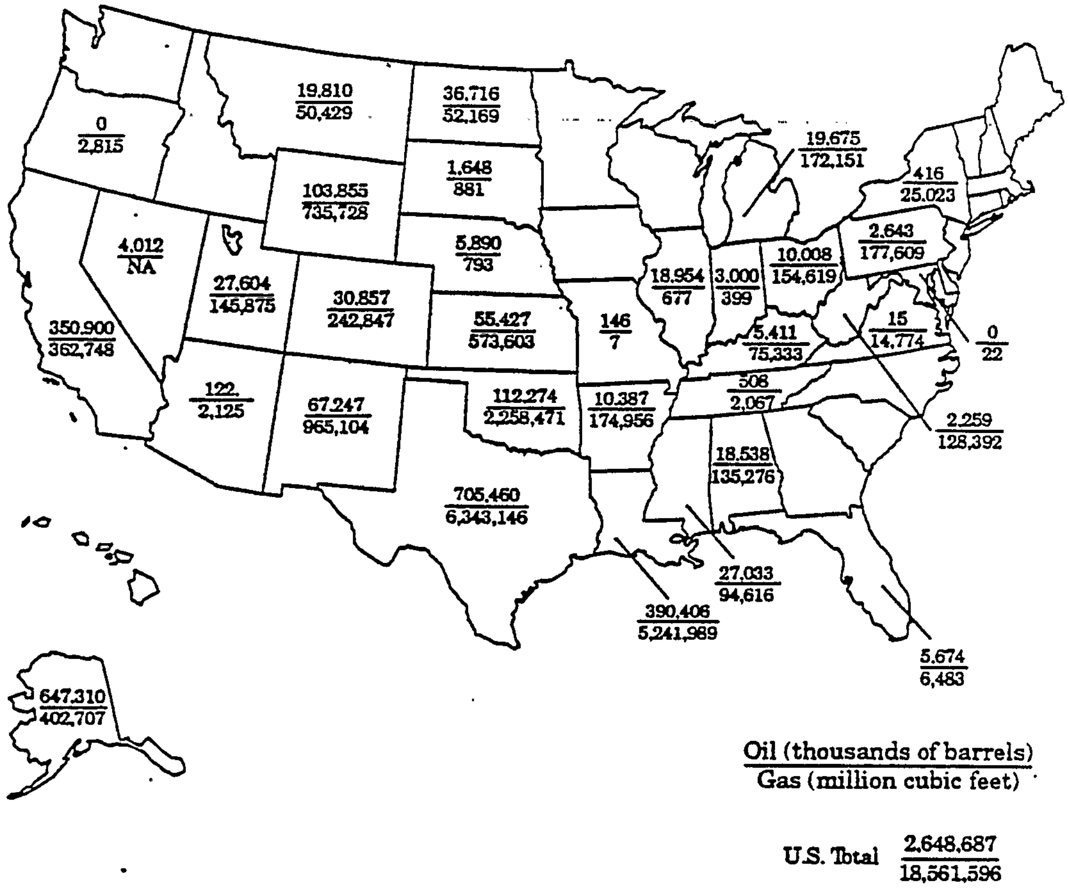
State	Number of Producing Oil Wells[a]	Oil Production (thousands of barrels)[b]	Number of Producing Gas Wells[a]	Gas Production (million cubic feet)[b]
Alabama	872	18,538	2,038	135,276
Alaska	1,466	647,310	109	402,907
Arizona	22	122	NA	2,125
Arkansas	7,265	10,387	3,460	174,956
California	43,375	350,900	1,169	362,748
Colorado	6,596	30,857	5,097	242,897
Florida	83	5,674	NA	6,483
Illinois	31,874	19,954	356	677
Indiana	7,506	3,000	1,311	399
Kansas	45,470	55,427	14,043	573,603
Kentucky	22,741	5,411	11,713	75,333
Louisiana	23,812	390,406	13,530	5,241,989
Maryland	0	0	NA	22
Michigan	4,570	19,675	1,438	172,151
Mississippi	2,168	27,033	629	94,616
Missouri	854	146	NA	7
Montana	3,854	19,810	2,428	50,429
Nebraska	1,440	5,890	NA	793
Nevada	46	4,012	NA	NA
New Mexico	18,546	67,247	19,537	965,104
New York	4,043	416	5,406	25,023
North Dakota	3,546	36,716	103	52,169
Ohio	30,089	10,008	34,697	154,619
Oklahoma	95,468	112,274	27,919	2,258,471
Oregon	0	0	NA	2,815
Pennsylvania	22,338	2,643	30,000	177,609
South Dakota	149	1,648	52	881
Tennessee	736	508	527	2,067
Texas	188,829	705,460	48,075	6,343,146
Utah	1,972	27,604	742	145,875
Virginia	25	15	819	14,774
West Virginia	15,950	2,143	37,000	178,000
Wyoming	11,397	103,855	2,431	735,728
Federal Waters	4,468	NA	3,591	NA
Other	25	NA	147	NA
U.S.	601,520	2,684,687	268,367	18,561,596

Combined Source: Petroleum Independent, September 1992, attributes the individual column sources to:

[a] World Oil.

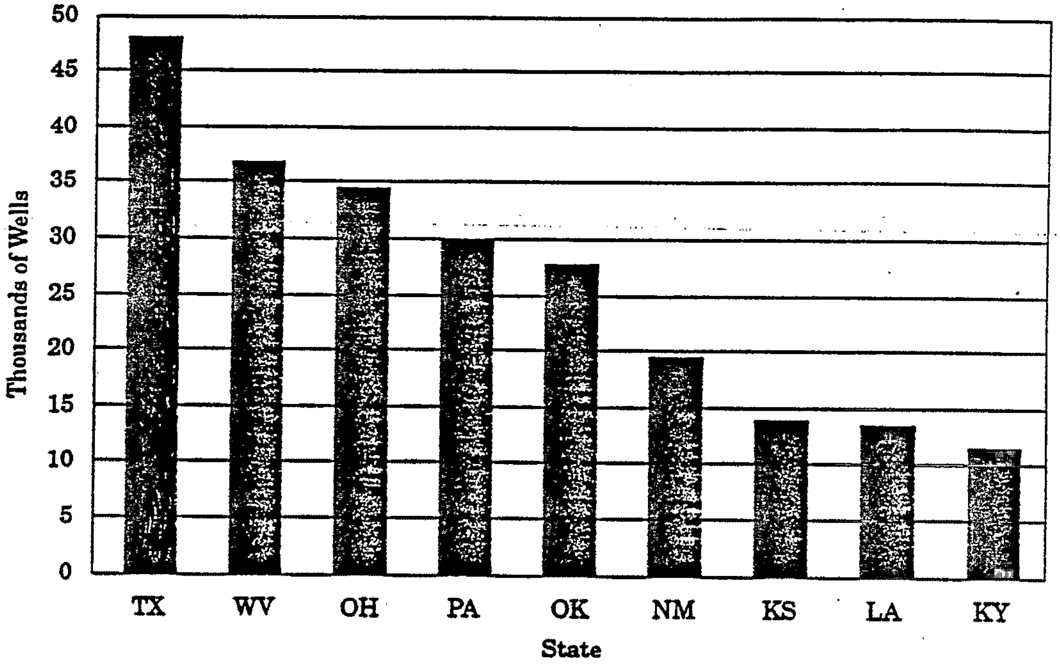
[b] Energy Information Administration.

–NA Not available.



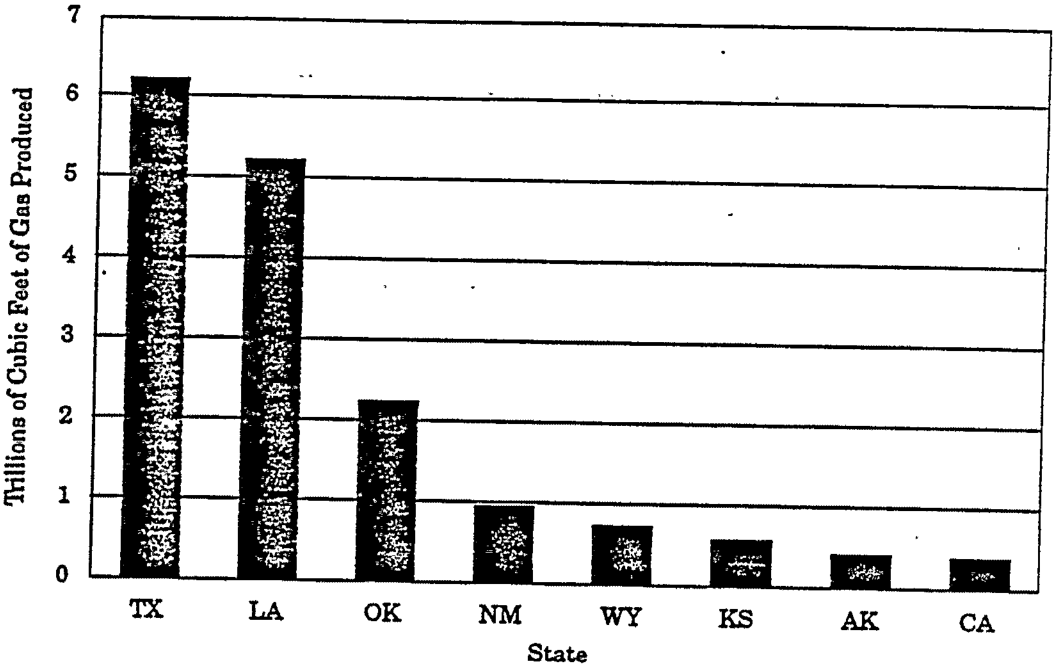
Combined Source: Petroleum Independent, September 1992, attributes the oil and gas sources to: World Oil Energy Information Administration.

Figure A-5. 1991 U.S. oil and gas production by State.



Source: World Oil (in Petroleum Independent, September 1992)

Figure A-6. States with the most producing gas wells in 1990.



Source: Energy Information Administration (in Petroleum Independent, September 1992).

Figure A-7. Gas production in 1990 from the top producing states.

States, however, are not the largest gas producers. Figure A-7 shows that Texas, Louisiana, Oklahoma, New Mexico, Wyoming, Kansas, Alaska, and California account for 92 percent of domestic gas production. Alaska, California, Louisiana, and Texas account for 78 percent of domestic oil production.

Principal Production Industry Groups

The industry can be divided into four groups. The first group consists of the major oil companies. These companies are highly vertically integrated, which means that they perform both "upstream" activities (oil exploration, development and production) and "downstream" activities (transportation, refining and marketing).

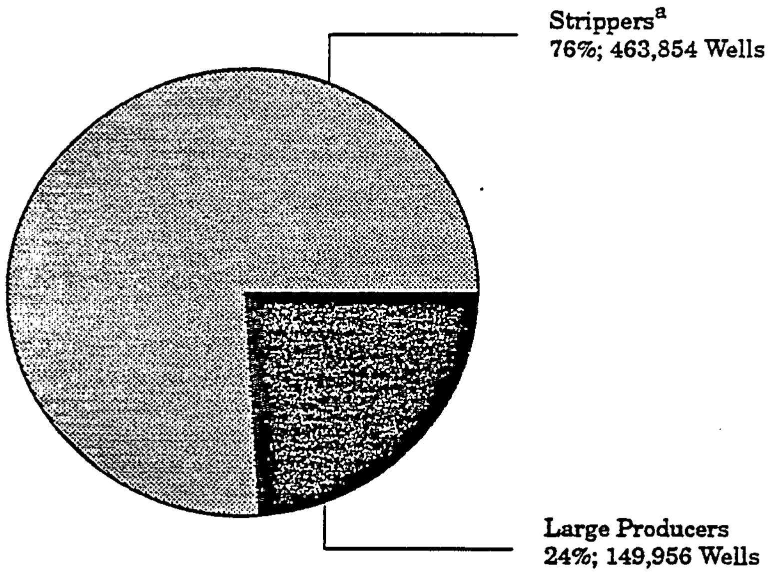
The second group is the large independents. These companies primarily explore, develop, and produce oil and gas, but do not perform downstream activities. Some large independents produce oil and gas only, while others provide such additional services as contract drilling and pipeline operations.

The third group is the small independents. Little information is available that would characterize this group quantitatively. However, small independents are known to have fewer wells and/or lower production wells. The lower operating expenses of small independents makes it more affordable to continue producing small quantities from low volume wells.

The fourth group consists of companies that provide a variety of specialized services to the oil and gas drilling rigs and platforms, such as designing, manufacturing, and installing specialized hardware. They also provide geophysical support, drilling mud, and logging services.

Diversity of Production

Production from individual wells varies greatly from a high of 11,500 barrels per day to less than 10 barrels per day. As shown in Figure A-8, over 70 percent of U.S. oil wells are "stripper" wells. The definition of a stripper well varies from State to State. However, these wells are generally defined as wells that produce 10 barrels of oil per day or less, or 100 thousand cubic feet (mcf) of gas per day or less. In 1990, 463,854 stripper wells existed and produced a total of 383,197,000 barrels of oil (NSWA, 1991). Stripper well production is shown in Table A-2. Figure A-9 shows that stripper wells produced 14 percent of the 2,684,687,000 barrels of oil produced in the United States in 1990 (U.S. EIA, 1991; U.S. EIA, 1987). Figure A-10 shows the proportion of stripper wells in the 10 States with the largest numbers of wells overall. In all 10 States, stripper wells comprised more 50 percent of producing wells. However, Figure A-11 demonstrates that in the 10 top oil producing States, oil from stripper wells is relatively low in volume. These wells typically are near depletion of recoverable natural resources and produce only a small quantity of oil or gas.



[a] Strippers are defined as those producing 10 barrels a day or less.

Source: Interstate Oil and Gas Compact Commission and National Stripper Well Association.

Figure A-8. Number of producing oil wells in the U.S. in 1990.

Table A-2. 1990 Oil Production from Stripper Wells by State

Location	Number of Producing Wells[a]	Number of Producing Stripper[c] Wells	Percentage of Producing Wells Which Are Stripper Wells*	Amount of Crude Oil Produced (thousands of barrels)[b]
Alabama	872	514	58%	18,538
Alaska	1,466	0	0%	647,310
Arizona	22	12	55%	122
Arkansas	7,265	7,290	NA*	10,387
California	43,375	26,128	60%	350,900
Colorado	6,596	5,234	79%	30,857
Florida	83	0	0%	5,674
Illinois	31,874	33,700	NA*	19,954
Indiana	7,506	5,764	77%	3,000
Kansas	45,470	45,227	99%	55,427
Kentucky	22,741	19,330	85%	5,411
Louisiana	23,812	17,695	74%	390,406
Michigan	4,570	3,967	87%	19,675
Mississippi	2,168	615	28%	27,033
Missouri	854	375	44%	146
Montana	3,854	3084	80%	19,810
Nebraska	1,440	1,269	88%	5,890
Nevada	46	0	0%	4,012
New Mexico	18,546	15,261	82%	67,247
New York	4,043	3,748	93%	416
North Dakota	3,546	1,205	34%	36,716
Ohio	30,089	29,576	98%	10,008
Oklahoma	95,468	73,345	77%	112,274
Pennsylvania	22,338	21,800	98%	2,643
South Dakota	149	26	17%	1,648
Tennessee	736	923	NA*	508
Texas	188,829	127,790	68%	705,460
Utah	1,972	1,026	52%	27,604
Virginia	25	22	88%	15
West Virginia	15,950	15,975	NA	2,143
Wyoming	11,397	2,953	26%	103,855
U.S.	601,520	463,854	77%	2,684,687

Combined Source: Petroleum Independent, September 1992, attributes the individual column sources to:

[a] World Oil.

[b] Energy Information Administration.

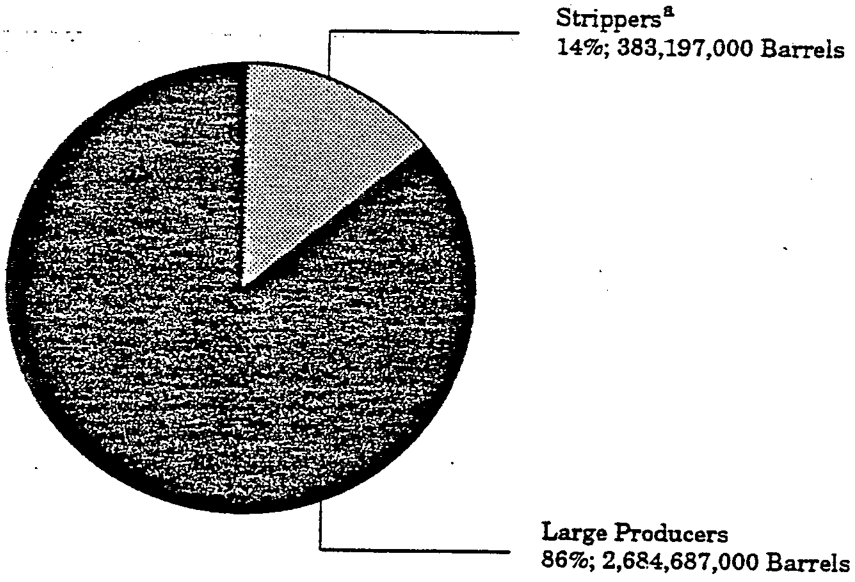
[c] Interstate Oil and Gas Compact Commission and National Stripper Well Association.

*Petroleum Independent warns "[number of producing stripper wells]-data cannot be compared to "Producing Oil Wells" table due to different sources and technology."

NA Unable to calculate.

Table A-2. 1990 Oil Production from Stripper Wells by State (continued)

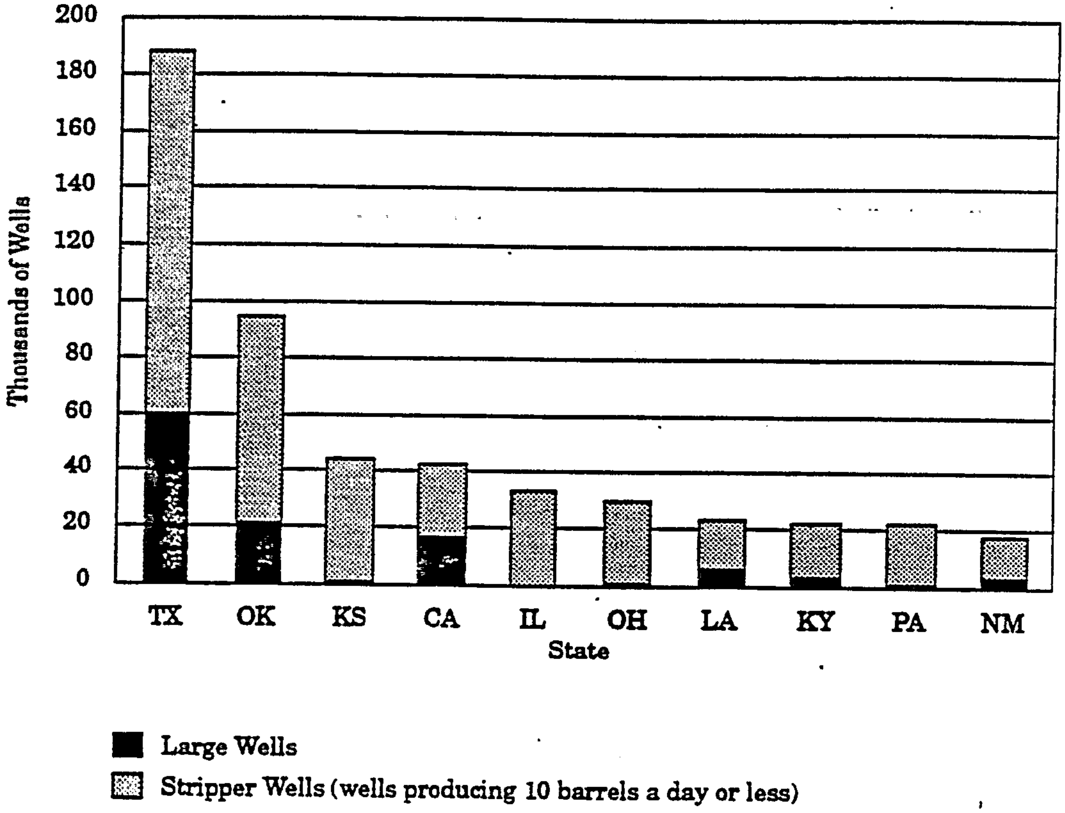
Amount of Crude Oil Produced from Stripper Wells (thousands of barrels)[c]	Percentage of Crude Oil Produced from Stripper Wells
1,486	8%
0	0%
26	21%
5,693	55%
36,405	10%
5,698	19%
0	0%
18,520	93%
3,002	NA*
40,873	74%
4,338	80%
7,154	2%
4,599	23%
802	3%
120	82%
2,449	12%
2,011	34%
0	0%
14,296	21%
383	92%
2,053	6%
7,271	73%
78,599	70%
2,622	99%
64	4%
419	83%
135,850	19%
1,035	4%
12	80%
2,122	99%
5,297	5%
389,197	14%



[a] Strippers are defined as those producing 10 barrels a day or less.

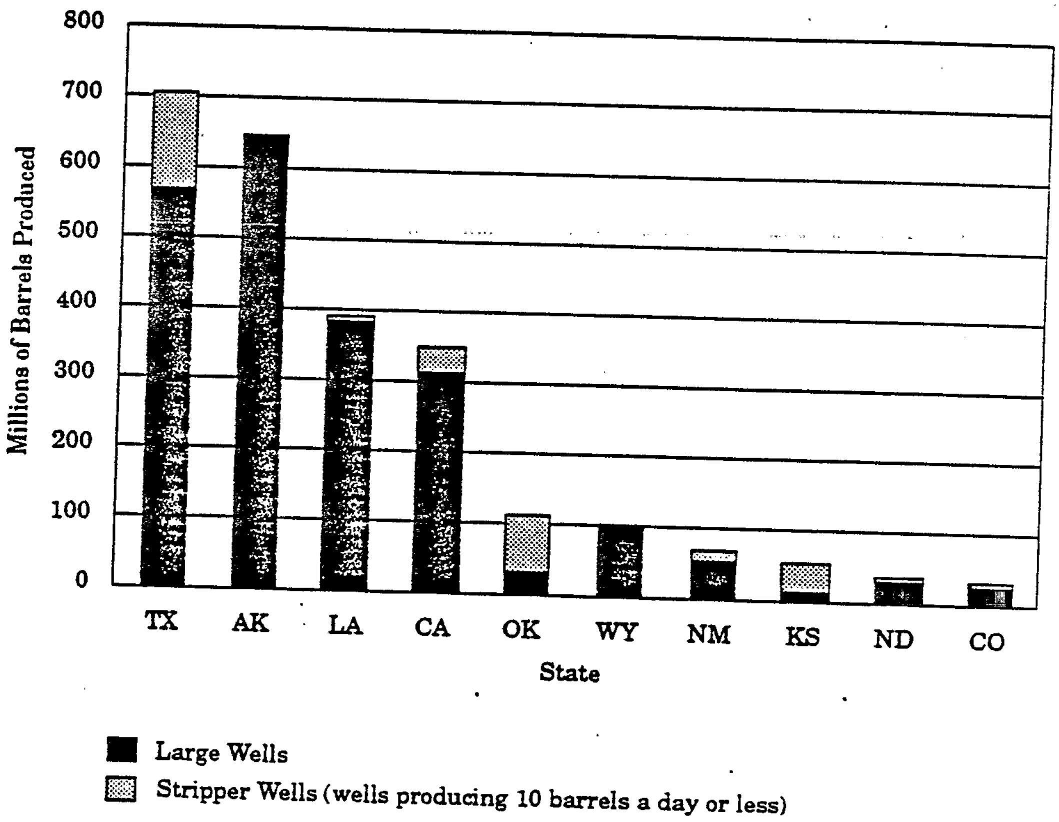
Source: Interstate Oil and Gas Compact Commission and National Stripper Well Association.

Figure A-9. 1990 U.S. oil production.



Source: World Oil (in Petroleum Independent, September 1992).

Figure A-10. States with the largest number of producing oil wells in 1990.



Source: World Oil (in Petroleum Independent, September 1992).

Figure A-11. Oil production in 1990 from the top producing states.

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APPENDIX B

SUBJECTS OF STATE H_2S REGULATIONS AND GUIDELINES

Table B-1. Subjects of State H_2S Regulations and Guidelines

Regulations and Guidelines	Oklahoma	Texas	Michigan	California*
Characteristics and Effects of H_2S (including emergency rescue, resuscitators, effects on metal and artificial respiration)	NA	●	●	●
Initial Testing	●	NA	●	●
Periodic Gas Analyses	●	NA	NA	NA
Nuisance Odors	●	NA	NJ	NA
Guidelines for Safe Drilling Operations				
A. Location Requirements	●	●	●	●
B. Drilling Equipment (Including blowout preventer, controls, piping and accessories, etc.)	●	●	●	●
C. Monitoring Equipment (including alarm systems and gas detection equipment)	●	●	●	●
D. Personal Protective Equipment (including all personnel, breathing apparatus, equipment specs., etc.)	●	●	●	●
E. Employee Physical Requirements	NA	●	NA	NA
F. Training Requirements	●	●	●	NA
G. Drills and Orientations	●	●	●	●
H. Maintenance of Equipment	●	●	●	●
I. Warning Systems	●	●	●	●
J. Evacuation	●	●	●	●
Guidelines for Safe Production Operations				
A. Applicability	NA	●	●	NA
B. General Provisions	NA	●	●	NA
1. Concentration Determination	●	●	●	NA
2. Radius of Evacuation (ROE)	●	●	●	●
3. Escape Rate Volume Determinators	●	●	●	NA
4. Storage Tank Provisions	●	●	●	NA
5. . . . ppm ROE in excess of . . . feet	●	●	●	●
6. Implementation	●	●	●	NA
7. Control and Safety Equipment	●	●	●	●
8. Contingency Plan	●	●	●	●
9. Training	●	●	●	NA
10. Injection Provision	●	●	●	NA
11. Certificate of Compliance Provision	●	●	●	NA
12. Accident Notification	●	●	●	●

NA Not available in reviewed literature.
• The subject was identified under the State's H_2S regulations or guidelines.
A Rule 36 references API RP19.
NJ Not under Congressional jurisdiction.
MMIOSH Required by Michigan OSHA.
*CA grants the supervisor of the Oil and Gas Division discretionary authority to control H_2S releases.

APPENDIX C

ATMOSPHERIC DISPERSION CALCULATIONS FOR H_2S RELEASES FROM OIL AND GAS EXTRACTION FACILITIES

APPENDIX C

ATMOSPHERIC DISPERSION CALCULATIONS FOR H_2S RELEASES FROM OIL AND GAS EXTRACTION FACILITIES

INTRODUCTION

The purpose of this appendix is to provide supporting details for the analyses of atmospheric dispersion of H_2S conducted for this report. In Chapter III, computer models were used, together with information on published studies of sour gas releases, to examine the range of predictions of the distances of concern for scenarios of H_2S releases from wellheads or pipelines. The inputs to the analyses are reviewed, and the outputs of three sample calculations for two of the scenarios are described. Outputs for a horizontal wellhead release are described for calculations using the SLAB and SAPLUME models. The output for a vertical wellhead release using the DEGADIS model is also described.

SUMMARY INPUT AND OUTPUT DATA

Summary data for the wellhead blowout and pipe rupture scenarios are presented in Tables C-1 and C-2, respectively. As described in Chapter III, analyses for wellhead blowouts were conducted using the SLAB, DEGADIS, and SAPLUME models. Analyses of the pipe rupture scenarios were conducted using the SACRUNCH and SAPLUME models.

The wellhead blowout scenarios in Chapter III result from various assumed flow rates as presented again in Table C-1. The following discussion presents some justification for the choice of these flow rates. Flow rates are functions of such factors as rock permeabilities, gas properties, depth, and tube and casing diameters. In practice, there are large variabilities in these parameters. One measure of the potential rate of flow from a well is the Calculated Absolute Open Flow Rate (CAOF), which is the rate of flow of gas into the well bore when the pressure is atmospheric. A sample of 15 wells in western Wyoming had CAOFs with a geometrical mean of $4.7\text{x}10^6$ standard cubic feet per day (scf/d) or $1.3\text{x}10^5$ cubic meters per day (m^3/d) (Layton et al., 1983). The 95 percent confidence interval spanned the range from $2.1\text{x}10^5$ scf/d ($5.9\text{x}10^3$ m^3/d) to 10^8 scf/d ($2.8\text{x}10^6$ m^3/d). Alp et al. (1990) considered CAOFs of between $5\text{x}10^4$ and $5\text{x}10^6$ m^3/d as representative of wells in Alberta and chose 10^6 m^3/d as representative for the purposes of risk analysis. The Quest report (1992) considered CAOFs in the range $2.2\text{x}10^5$ to $7.3\text{x}10^6$ m^3/d for a system of wells in southwestern Wyoming. The actual flow rates out of a ruptured well will be less than the CAOF because of frictional effects in the pipework. By contrast, the Quest report and Layton et al. use the CAOF as a conservative estimate of flow rate. Based on the above discussions, a flow rate of $2\text{x}10^7$ scf/d was chosen for representative calculations, with a flow rate of 10^8 scf/d being taken as an example of a very high flow rate.

TABLE C-1

SUMMARY OF INPUT AND OUTPUT DATA WELLHEAD BLOWOUT SCENARIOS

SCENARIO[a]	A	B	C	D	D(E)*
INPUTS					
Flow rate (m^3/d)	$6x10^5$	$6x10^5$	$6x10^5$	$6x10^5$	$3x10^6$
Vol. % H_2S	7.5	27	15	30	30
Density[b] @ 0°C (kg/m^3)	0.862	1.293	1.038	1.128	1.128
Release temperature (°C)	0	0	0	0	0
Total release rate (kg/s)	5.99	8.98	7.21	7.83	39.2
Release rate of H_2S (kg/s)	0.79	2.85	1.58	3.17	15.8
Ambient temperature (°C)	5	5	5	5	5
Relative humidity (%)	75	75	75	75	75
Atmospheric stability category	F	F	F	F	F
Windspeed (m/s)	1.5	1.5	1.5	1.5	1.5
Surface roughness length (m)	0.1	0.1	0.1	0.1	0.1
Effective area of release (m_2)	0.02	0.02	0.02	0.02	0.1
OUTPUTS: HORIZONTAL RELEASE					
SLAB:					
Distance to:					
LC_{01}(m)	700	2,800	1,500	2,900	7,000
ERPG-2(m)	2,800	7,000	4,700	7,000	>10,000
SAPLUME:					
Distance to:					
LC_{01} (m)	1,000	2,700	1,500	3,000	>10,000
ERPG-2(m)	3,100	10,000	5,700	10,000	>10,000
OUTPUTS: VERTICAL RELEASE					
SLAB:					
Distance to:					
LC_{01}(m)	0	0	0	0	0
ERPG-2(m)	0	0	0	0	0
DEGADIS:					
Distance to:					
LC_{01}(m)	0	0	0	0	0
ERPG-2(m)	0	0	0	0	0
SAPLUME:					
Distance to:					
LC_{01}(m)	0	0	0	0	0
ERPG-2(m)	0	0	0	0	0

[a] Scenarios from Table III-7.

[b] For comparison, density of air @ 0°C=1.293 kg/m^3.

* E=Extreme Case.

TABLE C-2

PIPE RUPTURE SCENARIOS
INPUTS AND OUTPUTS (SADENZ MODEL)

Parameters/Scenario	Composition A[a], rupture of 4" diameter pipeline[b]	Composition D[a], rupture of 16" diameter pipeline[c]
INPUTS		
Total mass released (kg)[d]	640	31,000
Total mass of H_2S (kg)	84	12,500
Duration of release (s)[d]	16	310
Density @ 0°C (kg/m^3)	0.862	1.128
Release temperature (°C)	0 (32 °F)	0 (32 °F)
Ambient temperature (°C)	5 (41 °F)	5 (41 °F)
Relative humidity (%)	75	75
Atmospheric stability category	F	F
Windspeed (m/s)	1.5	1.5
Surface roughness length(m)	0.1	0.1
OUTPUTS		
Distance to:		
LC_{01} (m)	600	4,300
ERPG-2 (m)	750	5,600

---

[a] Composition from Table III-5.
[b] Spacing between emergency shutdown valves is 1,000 m.
[c] Spacing between emergency shutdown valves is 3,000 m.
[d] From Figure III-22.

Table C-1 also presents values for the effective area of release. These values are derived by dividing the volumetric release rate by the velocity of release and were not the bases for the release scenarios. As stated in Chapter III, the velocity of release was assumed to be "choked," or limited, to sonic velocity (approximately 330 m/s) as a result of the high initial gas pressure.

The temperature of the gas in a well prior to expansion to atmospheric pressure through a rupture depends on the depth of the gas reservoir. The amount of cooling that results from expansion to atmospheric pressure as a result of release depends on the initial pressure and the composition. Alp et al. (1990) assume a representative release temperature of 15°C (288 K) at atmospheric pressure. In the Quest report, the authors assume a reservoir temperature of 60°C and calculate expansion temperatures of between -9°C and 3°C. The calculated results of wellhead blowout and pipeline rupture scenarios in this study are based on a representative release temperature of 0°C. This temperature is below the assumed ambient temperature of 5°C.

Atmospheric conditions characterized by low turbulence and low wind speed provide for decreased dilution of a released chemical with the surrounding air. Thus, these conditions are directionally conservative in terms of potential exposure to accidental releases. Atmospheric thermal stability, impacted by the difference between surface and air temperatures, is often described by Pasquill atmospheric stability categories. These categories range from high turbulence (A) through low turbulence (F). The "F" category is typical of still, nighttime conditions (AIChE, 1989). This category was chosen for the calculations conducted to conservatively evaluate the wellhead blowout and pipeline rupture scenarios. Wind speeds of less than 2 m/s are considered low and create little turbulence. The calculations used in this study's analyses assume a wind speed of 1.5 m/s to conservatively simulate nonturbulent conditions. Actual conditions of A - D stability and higher wind speeds will cause more rapid dilution of an accidental release and will result in a decreased affected distance. The assumption that conditions of low wind speed and stable atmospheric conditions exist uniformly for extended distances also provides conservatism to the analyses.

Terrain is another factor that may influence atmospheric dispersion of a release. The surface roughness length is a measure of the "roughness" of the terrain. Roughness is a function of the type of terrain and the presence of such features as trees and buildings. The models in this study assume that the study of the behavior of dense gas flow around obstacles and through rough terrain is controversial and is an area where further research is needed. Rough terrain will cause more turbulence to atmospheric flows above it than smooth terrain. The value of surface roughness length, 0.1 m, used in the calculated dispersion predictions, is considered to be an intermediate roughness length and typical of highly vegetated rural terrain. It should be noted that lower, more conservative values would be more appropriate in flat, barren terrain.

SAMPLE SLAB CALCULATIONS

SLAB Input

The following illustrates how the input is prepared for SLAB, using composition D from Table III-5 as an example. The SLAB input is displayed on Table C-3. The SLAB users' manual provides further guidance (Ermak, 1989).

Line 1: IDSPL is the spill source type. For an evaporating pool, IDSPL =1. For a horizontal jet release IDSPL=2. For a vertical jet release IDSPL=3. For a puff, IDSPL = 4. For the present example, the release is assumed to be horizontal, IDSPL=2.

Line 2: NCALC is a numerical substep parameter. The code developer recommends using NCALC=1. However, NCALC can be increased if numerical stability problems are encountered.

Line 3: WMS is the molecular weight of the wellhead gas in kg/gmole. From Table III-6, it is 0.0252 kg/gmol (from 25.2 g/gmol). Note, however, that the value given in Table C-3 is 0.0289 kg/gmol, for the following reason. Initially, the dilution of the plume is dominated by entrainment caused by its high momentum (its initial velocity equals that of sound). There is considerable dilution in this early phase and, by the time it is over, the density of the plume is only slightly less than that of the surrounding atmosphere. Work on marginally buoyant plumes shows that they are not likely to lift off the ground (Briggs, 1973). However, SLAB runs with WMS = 0.0252 kg/gmol show predicted plume rise that continues to a height of over 100 m. This is regarded as physically unrealistic and the computer model is "fooled" into ignoring plume rise by setting WMS equal to the effective molecular weight of air which is 28.9 g/gmol (0.0 289 kg/gmol). As noted above, this is thought to be physically realistic. The results predicted in this way will be conservative if plume rise does in fact take place.

Line 4: CPS is the vapor heat capacity at constant pressure. Similar to the above molecular weight calculation, the gas mixture vapor heat capacity is calculated by summing the product of the constituents' mole percent and vapor heat capacity. For composition D it is approximately 1,500 J/kg/K.

Line 5: TBP is the boiling point of the released material. For a pure vapor release, SLAB does not in fact use this quantity, which has been arbitrarily set equal to the boiling point of methane, 111.5K.

Line 6: CMEDO is the liquid mass fraction in the initial release and is set to zero because the release is pure vapor.

Lines 7, 8: DHE=509,880 (J/kg) and CPSL=3,349 (J/kg/K) are the heat of vaporization and the liquid specific heat for methane. Their values are taken from Table 2 of the SLAB

Users' Guide. When the released material is pure vapor, as it is in the present case, and the temperature of the cloud does not drop below the boiling point, these values are adequate because the liquid properties will not be used in the SLAB calculation. However, a value for all SLAB input properties must be specified whether they are used or not.

Line 9: RHOSL is the liquid density of the released material. This is another quantity that is not used in the calculations. It has been set equal to the density of water (1,000 kg/m^3).

Lines 10,11: SPB and SPC are parameters that go into the saturated vapor pressure formula:

$$P_s = P_a * \exp[SPA - SPB/(T + SPC)],$$

where P_s is the saturated vapor pressure, P_a is the ambient pressure (1.01×10^5 N/m^2), SPA is defined in the code and T is the local cloud temperature. Table 2 of the SLAB Users' Guide contains some values of SPB and SPC, but not for the mixture modeled here. When these values are unknown, the Users' Guide recommends default values of SPB = -1 and SPC = 0. The code then uses the Clapeyron equation to define the value of SPB. When the released material is pure vapor, as it is in the present case, and the temperature of the cloud does not drop below the boiling point, this default is adequate because the saturation pressure will not be used in the SLAB calculation. However, a value for all SLAB input properties must be specified whether they are used or not.

Lines 12-17: These lines specify the spill parameters. TS is the temperature of the released material, taken to be 273K. QS is the rate of release, estimated at 20 million scfd (7.69 kg/s). AS is the effective area of the release, 1.93×10^{-2} m^2, obtained by dividing the volumetric flow rate by the speed of sound (340 m/s). TSD is the duration of the release, 3,600.s, the assumed duration of release for a wellhead blowout. QTIS is zero except when modeling an instantaneous puff release. Finally, HS is the height of the release, arbitrarily taken to be 5 m (close to the ground).

Line 18: TAV is the concentration averaging time. This is set equal to 3,600 to be consistent with the exposure time of concern.

Line 19: XFFM is the maximum downwind extent of the calculation. A value of 10 km is used in order to obtain cloud concentration results at large distances away from the release. It is set to 2×10^4 m, which should be enough to ensure that any results of interest lie within this distance.

Lines 20-23: ZP(I) allows the user to specify up to four heights at which the concentration is calculated as a function of downwind distance. ZP(1) is set to 1.6 m (approximate head elevation above grade). The remaining ZP(I)s are zero, which means that SLAB only considers the first height.

Lines 24-29: These lines specify the meteorological conditions. ZO is the surface roughness length, which is set to 0.1 m, depicting a relatively smooth surface. ZA is the height at which the windspeed is measured (10 m). UA is the windspeed at height ZA (1.5 m/s). TA is the ambient temperature (273K). RH is the relative humidity (75%, chosen as being typical of Category F weather conditions). Finally, STAB is the stability class (F=stable). The weather conditions (Category F with a low windspeed of 1.5 m/s) have been chosen to simulate unfavorable (close to worst case) conditions.

Line 30: TER is the end of file designator. TER < 0 terminates the run.

SLAB Output

A partial SLAB output corresponding to the inputs of Table C-3 is given in Table C-4. The interpretation is as follows. The first column gives the downwind distance, x. The second column gives the time at which the maximum concentration arrives at x and the third gives the duration of cloud passage. As can be seen, the duration of passage remains equal to the duration of release until the cloud has traveled several kilometers downwind. The fourth column gives the approximate half-width of the plume, bbc. The remaining six columns give the average concentration (volume fraction) at a height of 1.6 m (as chosen in the SLAB input) for six off-axis distances that are multiples of bbc, 0.5, 1.0, 1.5, etc. The predicted concentrations are zero close in because the plume was arbitrarily released at a height of 5 m. As the plume broadens, the concentrations at height 5 m rise above zero to a maximum at about 25 m to 30 m downwind and then begin to decline as the plume dilutes further.

The effective ERPG-2 is 100 ppm and the effective LC_{01} is about 4.7 x 10^5 ppb. These number values are derived as follows: the ERPG-2 for pure H_2S for an exposure time of 1 hour is 3 x 10^4 ppb. The volume concentration of H_2S in composition D is 30 percent (see Table III-5). Therefore, the overall concentration of the total released material when the H_2S in it is at 3 x 10^4 ppb is 30/0.3 = 1 x 10^5 ppb. Similarly, the LC_{01} for pure H_2S is 1.4 x 10^5 ppb for an exposure time of 1 hour (see Chapter III). Therefore, the effective LC_{01} for the plume is 140/0.3 = 4.7 x 10^5 ppb. As explained in Chapter III, the ERPG-2 is regarded as a threshold at which emergency response might be necessary and the LC_{01} is an approximate threshold for the occurrence of fatalities among the affected population. Reading down the column headed "y/bbc=0," the concentrations first fall below 4.7 x 10^5 ppb (= a volume fraction of $4.7\text{x}10^{-4}$) at a distance of about 3 km and below 1 x 10^5 ppb (= a volume fraction of $1.0\text{x}10^{-4}$) at a distance of about 7 km.

SAMPLE DEGADIS CALCULATIONS

DEGADIS Input

Table C-5 displays the DEGADIS input for the same case as was prepared for SLAB in Table C-3 except that DEGADIS can only simulate a vertical jet release. The chosen values for most of the parameters have already been explained in the section on SLAB.

Lines 1-4 allow the user to input up to four lines of title.

Line 5 requires the windspeed (1.5 m/s) and the height at which the windspeed is measured (10 m).

Line 6 gives the surface roughness length (0.1 m).

Line 7 requires the parameter INDVEL, the atmospheric stability category (F=6) and the Monin-Obukhov length RML. For INDVEL=1 (the present case) the model calculates RML from the stability category and the surface roughness length, so the user does not need to specify a value for RML.

Line 8 requires the ambient temperature (273K), the ambient pressure (1 atmosphere) and the relative humidity (75%).

Line 9 gives the surface temperature, which is here set equal to the ambient temperature (273K).

Line 10 is a name for the released gas, in this case CPD for ComPosition D.

Line 11 is the molecular weight, 25.2.

Line 12 is the averaging time, taken to be equal to the duration of release, 3,600 s. It is used to calculate the increase in the effective width of the plume as a function of exposure time.

Line 13 is the temperature of the released gas, 273K.

Line 14 contains the upper level of concern (470 ppm, expressed as a volume fraction), the lower level of concern (100 ppm) and the height at which the concentrations are calculated (1.6 m).

Line 15 contains first a variable INDHT=0, meaning that heat transfer from the ground is not included, which does not matter here because the plume, air, and ground all have the same temperature. The second entry is the specific heat of the released gas at constant pressure (1,500 J/kg/K). The third entry, CPP=0, indicates that an approximation was made in which the specific heat does not vary with temperature.

Line 16 is a parameter "NDEN" that is used to specify the density profile of the released material. For NDEN=0, the release is assumed to be an ideal gas with specific heat at constant pressure 1500J/kg/K. Water condensation effects are taken into account.

Line 17 is the mass rate of release, 7.69 kg/s.

Table C-3. SLAB Input - Horizonal Wellhead Release

Value	Parameter	Line No.
2 (horizontal), 3 (vertical)	IDSPL	1
1	NCALC	2
0.0289	WMS	3
1500.	CPS	4
111.50	TBP	5
0.0	CMEDO	6
509,880.	DHE	7
3,349.	CPSL	8
1,000.	RHOSL	9
-1.0	SPB	10
0.0	SPC	11
273.	TS	12
7.69	QS	13
1.93×10^{-2}	AS	14
3,600.	TSD	15
0.	QTIS	16
5.	HS	17
3,600.	TAV	18
20,000.	XFFM	19
1.6	ZP(1)	20
0.	ZP(2)	21
0.	ZP(3)	22
0.	ZP(4)	23
0.1	ZO	24
10.	ZA	25
1.5	UA	26
273.	TA	27
75.	RH	28
F	STAB	29
-1.	TER	30

Table C-4. Partial SLAB Output

Time Averaged (TAV = 3,600 s) Volume Concentration: Concentration in the z = 1.60 Plane.

Downwind Distance x (m)	Time of Max Conc (s)	Cloud Duration (s)	Effective Half Width bbc (m)	Average Concentration (Volume Fraction) at (x,y,z), y/bbc =					
				0.0	0.5	1.0	1.5	2.0	2.5
1.00	1.80×10^{3}	3.60×10^{3}	6.95×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.02	1.80×10^{3}	3.60×10^{3}	7.73×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.05	1.80×10^{3}	3.60×10^{3}	8.71×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.08	1.80×10^{3}	3.60×10^{3}	9.92×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.13	1.80×10^{3}	3.60×10^{3}	1.14×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.18	1.80×10^{3}	3.60×10^{3}	1.32×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.24	1.80×10^{3}	3.60×10^{3}	1.54×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.32	1.80×10^{3}	3.60×10^{3}	1.81×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.41	1.80×10^{3}	3.60×10^{3}	2.14×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.52	1.80×10^{3}	3.60×10^{3}	2.54×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.66	1.80×10^{3}	3.60×10^{3}	3.03×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.84	1.80×10^{3}	3.60×10^{3}	3.63×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
2.05	1.80×10^{3}	3.60×10^{3}	4.36×10^{-1}	8.35×10^{-41}	5.76×10^{-41}	1.88×10^{-41}	2.84×10^{-42}	1.93×10^{-43}	5.61×10^{-45}
2.31	1.80×10^{3}	3.60×10^{3}	5.24×10^{-1}	1.18×10^{-28}	8.13×10^{-29}	2.65×10^{-29}	4.02×10^{-30}	2.79×10^{-31}	8.76×10^{-33}
2.63	1.80×10^{3}	3.60×10^{3}	6.31×10^{-1}	3.14×10^{-20}	2.16×10^{-20}	7.03×10^{-21}	1.07×10^{-21}	7.54×10^{-23}	2.42×10^{-24}
3.01	1.80×10^{3}	3.60×10^{3}	7.61×10^{-1}	1.99×10^{-14}	1.37×10^{-14}	4.45×10^{-15}	6.79×10^{-16}	4.82×10^{-17}	1.58×10^{-18}
3.49	1.80×10^{3}	3.60×10^{3}	9.17×10^{-1}	1.86×10^{-10}	1.28×10^{-10}	4.16×10^{-11}	6.36×10^{-12}	4.55×10^{-13}	1.51×10^{-14}
4.08	1.80×10^{3}	3.60×10^{3}	1.10	9.38×10^{-8}	6.45×10^{-8}	2.10×10^{-8}	3.21×10^{-9}	2.30×10^{-10}	7.71×10^{-12}
4.79	1.80×10^{3}	3.60×10^{3}	1.33	6.31×10^{-6}	4.34×10^{-6}	1.41×10^{-6}	2.16×10^{-7}	1.55×10^{-8}	5.23×10^{-10}
5.67	1.80×10^{3}	3.60×10^{3}	1.60	1.07×10^{-4}	7.33×10^{-5}	2.38×10^{-5}	3.65×10^{-6}	2.63×10^{-7}	8.89×10^{-9}
6.75	1.80×10^{3}	3.60×10^{3}	1.91	6.99×10^{-4}	4.81×10^{-4}	1.56×10^{-4}	2.39×10^{-5}	1.73×10^{-6}	5.87×10^{-8}
8.07	1.80×10^{3}	3.60×10^{3}	2.28	2.41×10^{-3}	1.66×10^{-3}	5.37×10^{-4}	8.24×10^{-5}	5.95×10^{-6}	2.03×10^{-7}
9.68	1.80×10^{3}	3.60×10^{3}	2.72	5.35×10^{-3}	3.68×10^{-3}	1.19×10^{-3}	1.83×10^{-4}	1.32×10^{-5}	4.51×10^{-7}
1.17×10^{1}	1.80×10^{3}	3.60×10^{3}	3.22	8.87×10^{-3}	6.09×10^{-3}	1.98×10^{-3}	3.03×10^{-4}	2.19×10^{-5}	7.48×10^{-7}
1.41×10^{1}	1.81×10^{3}	3.60×10^{3}	3.79	1.22×10^{-2}	8.38×10^{-3}	2.72×10^{-3}	4.17×10^{-4}	3.02×10^{-5}	1.03×10^{-6}
1.71×10^{1}	1.81×10^{3}	3.60×10^{3}	4.43	1.49×10^{-2}	1.03×10^{-2}	3.33×10^{-3}	5.11×10^{-4}	3.70×10^{-5}	1.27×10^{-6}
2.07×10^{1}	1.81×10^{3}	3.60×10^{3}	5.11	1.69×10^{-2}	1.16×10^{-2}	3.78×10^{-3}	5.80×10^{-4}	4.20×10^{-5}	1.43×10^{-6}
2.52×10^{1}	1.81×10^{3}	3.60×10^{3}	5.79	1.82×10^{-2}	1.25×10^{-2}	4.05×10^{-3}	6.22×10^{-4}	4.50×10^{-5}	1.54×10^{-6}
3.07×10^{1}	1.81×10^{3}	3.60×10^{3}	6.55	1.84×10^{-2}	1.27×10^{-2}	4.11×10^{-3}	6.31×10^{-4}	4.57×10^{-5}	1.57×10^{-6}

(continued)

Table C-4 (cont)

Time Averaged (TAV = 3,600 s) Volume Concentration: Concentration in the z = 1.60 Plane.

Downwind Distance x (m)	Time of Max Conc (s)	Cloud Duration (s)	Effective Half Width bbc (m)	Average Concentration (Volume Fraction) at (x,y,z), y/bbc =					
				0.0	0.5	1.0	1.5	2.0	2.5
3.74×10^{1}	1.82×10^{3}	3.60×10^{3}	7.42	1.80×10^{-2}	1.23×10^{-2}	4.01×10^{-3}	6.15×10^{-4}	4.45×10^{-5}	1.52×10^{-6}
4.56×10^{1}	1.82×10^{3}	3.60×10^{3}	8.39	1.70×10^{-2}	1.17×10^{-2}	3.78×10^{-3}	5.80×10^{-4}	4.20×10^{-5}	1.43×10^{-6}
5.57×10^{1}	1.83×10^{3}	3.60×10^{3}	9.47	1.56×10^{-2}	1.08×10^{-2}	3.49×10^{-3}	5.35×10^{-4}	3.88×10^{-5}	1.33×10^{-6}
6.81×10^{1}	1.83×10^{3}	3.60×10^{3}	1.07×10^{1}	1.42×10^{-2}	9.77×10^{-3}	3.17×10^{-3}	4.86×10^{-4}	3.52×10^{-5}	1.20×10^{-6}
8.32×10^{1}	1.84×10^{3}	3.60×10^{3}	1.20×10^{1}	1.28×10^{-2}	8.77×10^{-3}	2.85×10^{-3}	4.37×10^{-4}	3.16×10^{-5}	1.08×10^{-6}
1.02×10^{2}	1.85×10^{3}	3.60×10^{3}	1.34×10^{1}	1.14×10^{-2}	7.81×10^{-3}	2.53×10^{-3}	3.89×10^{-4}	2.82×10^{-5}	9.63×10^{-7}
1.25×10^{2}	1.86×10^{3}	3.60×10^{3}	1.51×10^{1}	1.00×10^{-2}	6.90×10^{-3}	2.24×10^{-3}	3.43×10^{-4}	2.49×10^{-5}	8.50×10^{-7}
1.52×10^{2}	1.87×10^{3}	3.60×10^{3}	1.70×10^{1}	8.80×10^{-3}	6.05×10^{-3}	1.96×10^{-3}	3.01×10^{-4}	2.18×10^{-5}	7.44×10^{-7}
1.87×10^{2}	1.89×10^{3}	3.60×10^{3}	1.92×10^{1}	7.68×10^{-3}	5.28×10^{-3}	1.71×10^{-3}	2.63×10^{-4}	1.90×10^{-5}	6.51×10^{-7}
2.29×10^{2}	1.90×10^{3}	3.60×10^{3}	2.18×10^{1}	6.65×10^{-3}	4.57×10^{-3}	1.48×10^{-3}	2.27×10^{-4}	1.65×10^{-5}	5.61×10^{-7}
2.80×10^{2}	1.93×10^{3}	3.60×10^{3}	2.49×10^{1}	5.71×10^{-3}	3.92×10^{-3}	1.27×10^{-3}	1.95×10^{-4}	1.41×10^{-5}	4.84×10^{-7}
3.43×10^{2}	1.96×10^{3}	3.60×10^{3}	2.87×10^{1}	4.85×10^{-3}	3.33×10^{-3}	1.08×10^{-3}	1.66×10^{-4}	1.20×10^{-5}	4.10×10^{-7}
4.20×10^{2}	1.99×10^{3}	3.60×10^{3}	3.33×10^{1}	4.07×10^{-3}	2.80×10^{-3}	9.09×10^{-4}	1.39×10^{-4}	1.01×10^{-5}	3.44×10^{-7}
5.15×10^{2}	2.04×10^{3}	3.60×10^{3}	3.91×10^{1}	3.38×10^{-3}	2.32×10^{-3}	7.55×10^{-4}	1.16×10^{-4}	8.38×10^{-6}	2.89×10^{-7}
6.30×10^{2}	2.09×10^{3}	3.60×10^{3}	4.65×10^{1}	2.77×10^{-3}	1.91×10^{-3}	6.19×10^{-4}	9.49×10^{-5}	6.87×10^{-6}	2.36×10^{-7}
7.73×10^{2}	2.15×10^{3}	3.60×10^{3}	5.58×10^{1}	2.25×10^{-3}	1.54×10^{-3}	5.01×10^{-4}	7.68×10^{-5}	5.57×10^{-6}	1.90×10^{-7}
9.47×10^{2}	2.23×10^{3}	3.60×10^{3}	6.75×10^{1}	1.80×10^{-3}	1.24×10^{-3}	4.02×10^{-4}	6.16×10^{-5}	4.46×10^{-6}	1.49×10^{-7}
1.16×10^{3}	2.33×10^{3}	3.60×10^{3}	8.23×10^{1}	1.43×10^{-3}	9.82×10^{-4}	3.19×10^{-4}	4.89×10^{-5}	3.54×10^{-6}	1.22×10^{-7}
1.42×10^{3}	2.45×10^{3}	3.60×10^{3}	1.01×10^{2}	1.12×10^{-3}	7.73×10^{-4}	2.51×10^{-4}	3.85×10^{-5}	2.79×10^{-6}	9.64×10^{-8}
1.74×10^{3}	2.60×10^{3}	3.60×10^{3}	1.24×10^{2}	8.81×10^{-4}	6.05×10^{-4}	1.96×10^{-4}	3.01×10^{-5}	2.18×10^{-6}	7.55×10^{-8}
2.13×10^{3}	2.78×10^{3}	3.60×10^{3}	1.52×10^{2}	6.86×10^{-4}	4.71×10^{-4}	1.53×10^{-4}	2.35×10^{-5}	1.70×10^{-6}	5.91×10^{-8}
2.62×10^{3}	3.00×10^{3}	3.60×10^{3}	1.86×10^{2}	5.31×10^{-4}	3.65×10^{-4}	1.19×10^{-4}	1.82×10^{-5}	1.32×10^{-6}	4.37×10^{-8}
3.21×10^{3}	3.27×10^{3}	3.60×10^{3}	2.28×10^{2}	4.08×10^{-4}	2.81×10^{-4}	9.11×10^{-5}	1.40×10^{-5}	1.01×10^{-6}	3.52×10^{-8}
3.93×10^{3}	3.60×10^{3}	3.60×10^{3}	2.77×10^{2}	3.09×10^{-4}	2.13×10^{-4}	6.90×10^{-5}	1.06×10^{-5}	7.65×10^{-7}	2.70×10^{-8}
4.82×10^{3}	4.10×10^{3}	3.87×10^{3}	3.40×10^{2}	2.05×10^{-4}	1.41×10^{-4}	4.58×10^{-5}	7.02×10^{-6}	5.10×10^{-7}	1.76×10^{-8}
5.94×10^{3}	4.70×10^{3}	4.19×10^{3}	4.14×10^{2}	1.39×10^{-4}	9.57×10^{-5}	3.11×10^{-5}	4.77×10^{-6}	3.46×10^{-7}	1.09×10^{-8}
7.33×10^{3}	5.45×10^{3}	4.58×10^{3}	5.02×10^{2}	9.06×10^{-5}	6.22×10^{-5}	2.02×10^{-5}	3.10×10^{-6}	2.24×10^{-7}	8.61×10^{-9}
9.07×10^{3}	6.36×10^{3}	5.03×10^{3}	6.05×10^{2}	5.27×10^{-5}	3.62×10^{-5}	1.17×10^{-5}	1.80×10^{-6}	1.31×10^{-7}	4.02×10^{-9}
1.13×10^{4}	7.47×10^{3}	5.57×10^{3}	7.23×10^{2}	2.55×10^{-5}	1.75×10^{-5}	5.70×10^{-6}	8.73×10^{-7}	6.35×10^{-8}	2.33×10^{-9}
1.40×10^{4}	8.84×10^{3}	6.11×10^{3}	8.62×10^{2}	1.46×10^{-5}	1.00×10^{-5}	3.26×10^{-6}	5.00×10^{-7}	3.61×10^{-8}	1.59×10^{-9}
1.75×10^{4}	1.05×10^{4}	6.67×10^{3}	1.02×10^{3}	1.04×10^{-5}	7.13×10^{-6}	2.31×10^{-6}	3.55×10^{-7}	2.58×10^{-8}	6.70×10^{-10}
2.20×10^{4}	1.26×10^{4}	7.49×10^{3}	1.21×10^{3}	5.98×10^{-6}	4.11×10^{-6}	1.33×10^{-6}	2.05×10^{-7}	1.48×10^{-8}	4.55×10^{-10}

Table C-5. Input for DEGADIS Simulation of a Vertical Wellhead Release

Value			Line Number
Release from a			1
Well Head:			2
Verticle Jet Simulation			3
			4
1.5	10.		5
0.1			6
1	6	0.	7
273.	1.	75.	8
273.			9
CPD			10
25.2			11
3,600.			12
273.			13
$4.7x10^{-4}$	$1.0x10^{-4}$	1.6	14
0	1,500.	0.0	15
0			16
7.69			17
5.0	0.0192		18
3,600.			19
50.			20

Line 18 contains the height of release (5 m) and the effective diameter (0.0192 m)

Line 19 is the duration of release, 3,600 s.

Line 20 is the distance between points at which DEGADIS calculates the output.

DEGADIS Output

A partial DEGADIS output is given in Table C-6. The first column gives the distance downwind and the second gives the elevation. As can be seen, the plume rises substantially because of its initial momentum. The third column gives the concentration of the released gas as a mole fraction, the fourth column gives the concentration in kg/m^3 and the fifth column gives the density in kg/m^3. As can be seen, the density rapidly approaches that of the surrounding air, 1.29 kg/m^3. The fifth column gives the temperature of the plume, which remains constant at 273K because the released plume and the air both have that temperature. The sixth column gives the plume horizontal standard deviation, σ y, and the seventh column gives the vertical standard deviation, σ z (the concentration across the plume is approximated by a Gaussian distribution in DEGADIS). As can be seen, at a height of 1.60 m, the predicted width of the plume (the distance across the wind to the upper or lower Levels of Concern, LC_{01} and ERPG-2) is zero so that LOCs are not predicted to be seen at ground level. This is a typical result for vertical jets of sour gas in stable weather conditions, whether DEGADIS, SLAB, or SAPLUME is used.

SAMPLE SAPLUME CALCULATIONS

SAPLUME Input

Table C-7 contains the input for the model SAPLUME corresponding to Table C-3, which contains the SLAB input for a horizontal release with composition D. The first few lines of input begin with four asterisks and are title cards, followed by a blank which tells the code that the titles have ended. Each subsequent line or group of lines begins with a keyword, followed by numbers in exponential notation to three significant figures.

"SITE" tells SAPLUME that there is a site with one radius and one sector (this is the default when the model is not considering a real site). The following line gives the one radius, arbitrarily set at 10,000 m, with one person arbitrarily set at that point (in the mode of operation chosen for the current problem, the model ignores these numbers).

"WEATHER" specifies that one weather condition only, category F, is being considered (because the 1.000 that follows WEATHER begins at space 61. For E the space would be 51, for D, 41 and so forth. The model can consider all six weather categories at once with up to four velocity subdivisions in each.) In this case, there is one velocity subdivision, specified as 1.5 m/s (first line after weather), and the probability that the wind blows into the one sector is unity (second line after weather).

Table C-6. Partial DEGADIS Output - Vertical Jet

Release from a Wellhead Pipeline Vertical Jet Simulation

								At z = 1.60 m				
Downwind Distance (m)	Elevation (m)	Mole Fraction	Concentration (kg/m^3)	Density (kg/m^3)	Temperature (K)	σ y (m)	σ z (m)	Mole Fraction	Width to mol%: 1.00×10^{-2} (m)	Width to mol%: 4.70×10^{-2} (m)	Maximum Mole Fraction	Elevation for Maximum Mole Fraction (m)
1.000×10^{-30}	5.15	1.00	1.13	1.13	273	1.060×10^{-2}	1.059×10^{-2}	.000	0	0	1.00	5.15
29.5	120.	8.279×10^{-4}	9.314×10^{-4}	1.29	273	12.1	12.0	.000	0	0	8.279×10^{-4}	120.
61.4	142.	5.644×10^{-4}	6.349×10^{-4}	1.29	273	16.0	15.6	.000	0	0	5.644×10^{-4}	142.
99.6	157.	4.254×10^{-4}	4.786×10^{-4}	1.29	273	19.2	18.4	.000	0	0	4.254×10^{-4}	157.
142.	169.	3.425×10^{-4}	3.853×10^{-4}	1.29	273	22.0	20.6	.000	0	0	3.425×10^{-4}	169.
191.	180.	2.832×10^{-4}	3.186×10^{-4}	1.29	273	24.6	22.4	.000	0	0	2.832×10^{-4}	180.
240.	188.	2.432×10^{-4}	2.736×10^{-4}	1.29	273	27.0	23.9	.000	0	0	2.432×10^{-4}	188.
289.	196.	2.140×10^{-4}	2.408×10^{-4}	1.29	273	29.2	25.2	.000	0	0	2.140×10^{-4}	196.
339.	202.	1.915×10^{-4}	2.155×10^{-4}	1.29	273	31.4	26.3	.000	0	0	1.915×10^{-4}	202.
389.	207.	1.736×10^{-4}	1.953×10^{-4}	1.29	273	33.4	27.2	.000	0	0	1.736×10^{-4}	207.
438.	212.	1.588×10^{-4}	1.786×10^{-4}	1.29	273	35.5	28.1	.000	0	0	1.588×10^{-4}	212.
488.	217.	1.464×10^{-4}	1.647×10^{-4}	1.29	273	37.5	28.8	.000	0	0	1.464×10^{-4}	217.
538.	221.	1.358×10^{-4}	1.528×10^{-4}	1.29	273	39.4	29.5	.000	0	0	1.358×10^{-4}	221.
588.	225.	1.267×10^{-4}	1.425×10^{-4}	1.29	273	41.4	30.1	.000	0	0	1.267×10^{-4}	225.
638.	228.	1.187×10^{-4}	1.335×10^{-4}	1.29	273	43.4	30.7	.000	0	0	1.187×10^{-4}	228.
688.	231.	1.116×10^{-4}	1.255×10^{-4}	1.29	273	45.3	31.2	.000	0	0	1.116×10^{-4}	231.
738.	234.	1.053×10^{-4}	1.185×10^{-4}	1.29	273	47.2	31.7	.000	0	0	1.053×10^{-4}	234.
787.	237.	9.965×10^{-5}	1.121×10^{-4}	1.29	273	49.2	32.2	.000	0	0	9.965×10^{-5}	237.
837.	240.	9.457×10^{-5}	1.064×10^{-4}	1.29	273	51.1	32.6	.000	0	0	9.457×10^{-5}	240.
887.	242.	8.995×10^{-5}	1.012×10^{-4}	1.29	273	53.1	33.0	.000	0	0	8.995×10^{-5}	242.
937.	245.	8.575×10^{-5}	9.647×10^{-5}	1.29	273	55.0	33.4	.000	0	0	8.575×10^{-5}	245.
987.	247.	8.190×10^{-5}	9.213×10^{-5}	1.29	273	56.9	33.8	.000	0	0	8.190×10^{-5}	247.
1.037×10^{3}	249.	7.836×10^{-5}	8.816×10^{-5}	1.29	273	58.9	34.2	.000	0	0	7.836×10^{-5}	249.
1.087×10^{3}	251.	7.510×10^{-5}	8.449×10^{-5}	1.29	273	60.8	34.5	.000	0	0	7.510×10^{-5}	251.
1.137×10^{3}	253.	7.208×10^{-5}	8.109×10^{-5}	1.29	273	62.7	34.9	.000	0	0	7.208×10^{-5}	253.
1.187×10^{3}	255.	6.928×10^{-5}	7.794×10^{-5}	1.29	273	64.7	35.2	.000	0	0	6.928×10^{-5}	255.
1.237×10^{3}	257.	6.667×10^{-5}	7.501×10^{-5}	1.29	273	66.6	35.5	.000	0	0	6.667×10^{-5}	257.
1.287×10^{3}	258.	6.424×10^{-5}	7.228×10^{-5}	1.29	273	68.5	35.8	.000	0	0	6.424×10^{-5}	258.
1.337×10^{3}	260.	6.197×10^{-5}	6.972×10^{-5}	1.29	273	70.5	36.1	.000	0	0	6.197×10^{-5}	260.
1.387×10^{3}	262.	5.984×10^{-5}	6.733×10^{-5}	1.29	273	72.4	36.3	.000	0	0	5.984×10^{-5}	262.

Table C-6 (cont)

								At z = 1.60 m				
Downwind Distance (m)	Elevation (m)	Mole Fraction	Concentration (kg/m^3)	Density (kg/m^3)	Temperature (K)	σ_y (m)	σ_z (m)	Mole Fraction	Width to mol%: 1.00×10^{-2} (m)	4.70×10^{-2} (m)	Maximum Mole Fraction	Elevation for Maximum Mole Fraction (m)
1.437×10^{3}	263.	5.785×10^{-5}	6.508×10^{-5}	1.29	273	74.3	36.6	.000	0	0	5.785×10^{-5}	263.
1.487×10^{3}	265.	5.597×10^{-5}	6.296×10^{-5}	1.29	273	76.3	36.9	.000	0	0	5.597×10^{-5}	265.
1.537×10^{3}	266.	5.420×10^{-5}	6.097×10^{-5}	1.29	273	78.2	37.1	.000	0	0	5.420×10^{-5}	266.
1.587×10^{3}	267.	5.253×10^{-5}	5.909×10^{-5}	1.29	273	80.2	37.4	.000	0	0	5.253×10^{-5}	267.
1.637×10^{3}	269.	5.095×10^{-5}	5.732×10^{-5}	1.29	273	82.1	37.6	.000	0	0	5.095×10^{-5}	269.
1.687×10^{3}	270.	4.945×10^{-5}	5.564×10^{-5}	1.29	273	84.0	37.9	.000	0	0	4.945×10^{-5}	270.
1.737×10^{3}	271.	4.804×10^{-5}	5.404×10^{-5}	1.29	273	85.9	38.1	.000	0	0	4.804×10^{-5}	271.
1.787×10^{3}	273.	4.669×10^{-5}	5.253×10^{-5}	1.29	273	87.9	38.3	.000	0	0	4.669×10^{-5}	273.
1.837×10^{3}	274.	4.542×10^{-5}	5.109×10^{-5}	1.29	273	89.8	38.6	.000	0	0	4.542×10^{-5}	274.
1.887×10^{3}	275.	4.420×10^{-5}	4.973×10^{-5}	1.29	273	91.7	38.8	.000	0	0	4.420×10^{-5}	275.
1.937×10^{3}	276.	4.304×10^{-5}	4.842×10^{-5}	1.29	273	93.7	39.0	.000	0	0	4.304×10^{-5}	276.
1.987×10^{3}	277.	4.194×10^{-5}	4.718×10^{-5}	1.29	273	95.6	39.2	.000	0	0	4.194×10^{-5}	277.
2.037×10^{3}	278.	4.089×10^{-5}	4.600×10^{-5}	1.29	273	97.5	39.5	.000	0	0	4.089×10^{-5}	278.
2.087×10^{3}	279.	3.988×10^{-5}	4.487×10^{-5}	1.29	273	99.4	39.7	.000	0	0	3.988×10^{-5}	279.
2.137×10^{3}	280.	3.892×10^{-5}	4.378×10^{-5}	1.29	273	101.	39.9	.000	0	0	3.892×10^{-5}	280.
2.187×10^{3}	281.	3.800×10^{-5}	4.275×10^{-5}	1.29	273	103.	40.1	.000	0	0	3.800×10^{-5}	281.
2.237×10^{3}	282.	3.711×10^{-5}	4.175×10^{-5}	1.29	273	105.	40.3	.000	0	0	3.711×10^{-5}	282.
2.287×10^{3}	283.	3.627×10^{-5}	4.080×10^{-5}	1.29	273	107.	40.5	.000	0	0	3.627×10^{-5}	283.
2.337×10^{3}	284.	3.546×10^{-5}	3.989×10^{-5}	1.29	273	109.	40.7	.000	0	0	3.546×10^{-5}	284.
2.387×10^{3}	285.	3.468×10^{-5}	3.901×10^{-5}	1.29	273	111.	40.9	.000	0	0	3.468×10^{-5}	285.
2.437×10^{3}	286.	3.393×10^{-5}	3.817×10^{-5}	1.29	273	113.	41.1	.000	0	0	3.393×10^{-5}	286.
2.487×10^{3}	286.	3.321×10^{-5}	3.736×10^{-5}	1.29	273	115.	41.2	.000	0	0	3.321×10^{-5}	286.
2.537×10^{3}	287.	3.252×10^{-5}	3.658×10^{-5}	1.29	273	117.	41.4	.000	0	0	3.252×10^{-5}	287.
2.587×10^{3}	288.	3.185×10^{-5}	3.583×10^{-5}	1.29	273	119.	41.6	.000	0	0	3.185×10^{-5}	288.
2.637×10^{3}	289.	3.121×10^{-5}	3.511×10^{-5}	1.29	273	120.	41.8	.000	0	0	3.121×10^{-5}	289.
2.687×10^{3}	290.	3.059×10^{-5}	3.441×10^{-5}	1.29	273	122.	42.0	.000	0	0	3.059×10^{-5}	290.
2.737×10^{3}	290.	2.999×10^{-5}	3.374×10^{-5}	1.29	273	124.	42.2	.000	0	0	2.999×10^{-5}	290.
2.787×10^{3}	291.	2.941×10^{-5}	3.309×10^{-5}	1.29	273	126.	42.3	.000	0	0	2.941×10^{-5}	291.
2.837×10^{3}	292.	2.885×10^{-5}	3.246×10^{-5}	1.29	273	128.	42.5	.000	0	0	2.885×10^{-5}	292.
2.887×10^{3}	293.	2.831×10^{-5}	3.185×10^{-5}	1.29	273	130.	42.7	.000	0	0	2.831×10^{-5}	293.
2.937×10^{3}	293.	2.779×10^{-5}	3.127×10^{-5}	1.29	273	132.	42.9	.000	0	0	2.779×10^{-5}	293.
2.987×10^{3}	294.	2.729×10^{-5}	3.070×10^{-5}	1.29	273	134.	43.0	.000	0	0	2.729×10^{-5}	294.
3.037×10^{3}	295.	2.680×10^{-5}	3.015×10^{-5}	1.29	273	136.	43.2	.000	0	0	2.680×10^{-5}	295.

Table C-6 (cont)

Downwind Distance (m)	Elevation (m)	Mole Fraction	Concentration (kg/m³)	Density (kg/m³)	Temperature (K)	σ y (m)	σ z (m)	At z = 1.60 m			Maximum Mole Fraction	Elevation for Maximum Mole Fraction (m)
								Mole Fraction	Width to mol%: 1.00×10^{-2} (m)	4.70×10^{-2} (m)		
3.087×10^{3}	295.	2.633×10^{-5}	2.962×10^{-5}	1.29	273	138.	43.4	.000	0	0	2.633×10^{-5}	295.
3.137×10^{3}	296.	2.588×10^{-5}	2.911×10^{-5}	1.29	273	139.	43.5	.000	0	0	2.588×10^{-5}	296.
3.187×10^{3}	297.	2.543×10^{-5}	2.861×10^{-5}	1.29	273	141.	43.7	.000	0	0	2.543×10^{-5}	297.
3.237×10^{3}	297.	2.500×10^{-5}	2.813×10^{-5}	1.29	273	143.	43.9	.000	0	0	2.500×10^{-5}	297.
3.262×10^{3}	297.	2.479×10^{-5}	2.789×10^{-5}	1.29	273	144.	43.9	.000	0	0	2.479×10^{-5}	297.

The entries on the "PROPERTIES" line are as follows: the ambient temperature is 273K at which temperature the density of air is 1.29 kg/m^3 and its specific heat at constant pressure is 990 J/kg/K. At a temperature of 273K, the density of the released gas is 1.141 kg/m^3 and the specific heat at constant pressure is 1,500 J/kg/K.

The entries on the "SOURCE" line are as follows: the rate of release is 7.69 kg/m^3 at a temperature of 273K. The amount of air initially entrained with the source is zero. The angle of release is zero radians (horizontal). The height of release is 5 m. The initial momentum flux is 2,540 kg m s^{-2} and is the product of the rate of release and the exit velocity (the speed of sound is approximately 330 m/s).

The "INTERVAL" line specifies that SAPLUME calculations start at a downwind distance x of 0.1 m and that calculations are performed at a uniform spacing of 0.15 in $\log_{10}(x)$.

On the "ROUG" line, the surface roughness length is 0.1 m and the windspeed is measured at a height of 10 m.

The "HAZARD" line specifies two levels of concern. As explained above in the discussion of the SLAB results, these are the LC$_{01}$ of 470 ppm (approximately 5.32x10^{-4} kg/m^3) and the ERPG-2 of 100 ppm (1.141x10^{-4} kg/m^3).

"VGRAD" informs SAPLUME that it should consider the velocity gradient and the temperature gradient in the atmosphere. SAPLUME uses standard textbook formulae for these gradients. If the first entry after VGRAD were zero, velocity would be constant as a function of height. Similarly, if the second entry after VGRAD were zero, the temperature of the atmosphere would remain constant as height increases.

A value of 3 after "NEUT" specifies one of three parametrizations for the standard deviations in the Gaussian model once the released material has evolved out of the jet phase. NEUT =3 corresponds to a parameterization that is appropriate for a rural site. "DUR" specifies that the duration of release is one hour.

Finally, the repetition of "END" terminates the run of SAPLUME.

SAPLUME Output

A partial SAPLUME output corresponding to the input in Table C-7 is given in Table C-8. This table indicates that, for hazard level 1 (i.e., the LC$_{01}$ of 470 ppm discussed above) the plume touches down at a downwind distance of approximately 63 m and extends to about 3 km, covering an area of about 10^5 m^2 (one tenth of a square kilometer). The table of pairs of values of downwind distance, x, and width can be coupled to a plotting routine to give contours of constant concentration. Similarly, hazard level 2 (the ERPG-2 of 100 ppm)

Table C-7. Input for SAPLUME Runs

****	EPA Hydrogen Sulfide Runs					
****	January 1993					
****	No Protective Measures					
****	Composition D - 30% H_2S at Wellhead					
****	2x10^{7} SCFD:					
****	Horizontal Release					
****	H_2S Release Rate - 3.073 kg/s					
****	Total Mixture Release Rate - 7.69 kg/s					
****	Hazard Level - ERPG-2 (100 ppm) and					
****	LC_{01} (470 ppm) Both Adjusted for Stream Composition					
****	Category F Weather, Windspeed 1.5 m/s					
SITE	1.000	1.000				
1.000x10^{4}						
1.000						
WEATHER	1.000					
1.500						
2.500x10^{-1}						
PROP	2.730x10^{2}	1.290	9.900x10^{2}	2.730x10^{2}	1.141	1.500x10^{3}
SOURCE	7.690	2.730x10^{2}	0.000	0.000	5.000	2.540x10^{3}
INTERVAL	1.000x10^{-1}	1.5000x10^{-1}				
ROUG	1.0000x10^{-1}	1.000x10^{1}				
HAZARD	2.000					
5.320x10^{-4}	1.141x10^{-4}					
VGRAD	1.000	1.000				
NEUT	3.000					
DUR	1.000					
END						
END						

Table C-8. Partial SAPLUME Output for Horizontal Plume

FOR HAZARD LEVEL 1, WINDSPEED 1.500 m/s AND CATEGORY 6

THE HAZARDOUS CLOUD EXTENDS FROM 6.327x10^{1} TO 3.126x10^{3} METERS DOWNWIND AND HAS AN AREA OF 1.129x10^{5} m^{2}

CLOUD BOUNDARIES

X^{a} (m)	WIDTH (m)	X (m)	WIDTH (m)	X (m)	WIDTH (m)	X (m)	WIDTH (m)	X (m)	WIDTH (m)
0.000	0.000	1.000x10^{-1}	0.000	1.162x10^{-1}	0.000	1.350x10^{-1}	0.000	1.568x10^{-1}	0.000
1.822x10^{-1}	0.000	2.117x10^{-1}	0.000	2.460x10^{-1}	0.000	2.858x10^{-1}	0.000	3.320x10^{-1}	0.000
3.857x10^{-1}	0.000	4.482x10^{-1}	0.000	5.207x10^{-1}	0.000	6.050x10^{-1}	0.000	7.029x10^{-1}	0.000
8.166x10^{-1}	0.000	9.488x10^{-1}	0.000	1.102	0.000	1.281	0.000	1.488	0.000
1.729	0.000	2.009	0.000	2.334	0.000	2.711	0.000	3.150	0.000
3.660	0.000	4.252	0.000	4.940	0.000	5.740	0.000	6.669	0.000
7.748	0.000	9.002	0.000	1.046x10^{1}	0.000	1.215x10^{1}	0.000	1.412x10^{1}	0.000
1.640x10^{1}	0.000	1.906x10^{1}	0.000	2.214x10^{1}	0.000	2.572x10^{1}	0.000	2.989x10^{1}	0.000
3.472x10^{1}	0.000	4.034x10^{1}	0.000	4.687x10^{1}	0.000	5.446x10^{1}	0.000	6.327x10^{1}	5.555
7.351x10^{1}	2.627	8.540x10^{1}	2.739	9.922x10^{1}	2.955	1.153x10^{2}	3.294	1.339x10^{2}	3.768
1.556x10^{2}	4.385	1.808x10^{2}	5.149	2.101x10^{2}	6.066	2.441x10^{2}	7.143	2.835x10^{2}	8.388
3.294x10^{2}	9.811	3.827x10^{2}	1.142x10^{1}	4.447x10^{2}	1.324x10^{1}	5.167x10^{2}	1.527x10^{1}	6.003x10^{2}	1.701x10^{1}
6.974x10^{2}	1.856x10^{1}	8.103x10^{2}	2.005x10^{1}	9.414x10^{2}	2.140x10^{1}	1.094x10^{3}	2.257x10^{1}	1.271x10^{3}	2.345x10^{1}
1.476x10^{3}	2.393x10^{1}	1.715x10^{3}	2.384x10^{1}	1.993x10^{3}	2.295x10^{1}	2.315x10^{3}	2.082x10^{1}	2.690x10^{3}	1.653x10^{1}
3.126x10^{3}	5.139								

[a] x = Downwind distance.

extends from about 60 m to about 12 km downwind, covering an area of approximately 10^6 m^2.

The above results are close to those predicted by SLAB. The higher result is about 50% larger than that predicted by SLAB. However, the difference is within the range of uncertainties expected for these dispersion models. As noted above, the neglect of dry deposition means that the predictions are likely to be conservative.

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16. ABSTRACT

Under section 112(n)(5) of the Clean Air Act Amendments of 1990, the EPA is required to submit this report which assesses the hazards to public health and the environment resulting from the emission of hydrogen sulfide associated with the extraction of oil and natual gas. This assessment is designed to build upon work done under section 8002(m) of the Solid Waste Disposal Act and to reflect consultation with the States. The report includes a review of existing State and industry control standards, techniques, and enforcement and includes recommendations for control of hydrogen sulfide emissions from these sources.

The Office of Air Quality Planning and Standards and the Office of Solid Waste and Emergency Response completed this report on a joint effort. This report provides the information currently available on each of the elements listed above.

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Hydrogen Sulfide, Oil and Gas, and People's Health

By

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Submitted in partial satisfaction of the requirements for the degree of

Master's of Science

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1. Introduction

This paper documents impacts on human health caused by exposure to hydrogen sulfide (H_2S) associated with oil and natural gas development. I begin with a brief background on hydrogen sulfide, its presence in oil and natural gas, and possible emission sources from various oil and gas operations. I then present a review of literature[1] from available public health, epidemiology, and industrial health publications, as well as of sources from regulatory and environmental agencies, that addresses human health impacts from exposure to H_2S. The Literature Review section first covers studies of health effects from acute exposure to relatively high concentrations of H_2S. I then review the literature documenting human health effects from chronic exposure to lower ambient H_2S levels. Both kinds of exposure – acute and chronic – can be expected to occur near oil and gas operations. From the available sources, I construct a table of human health effects associated with different levels of hydrogen sulfide and different lengths of exposure. Reviewing studies on the effects of H_2S exposure on laboratory animals is beyond the scope of this study.

Next, I present current federal and state regulations and recommendations pertaining to exposure to hydrogen sulfide. Many recommendations established to protect human health are based on crude exposure estimates or on extrapolation from animal studies. The federal government does not regulate ambient H_2S levels, but many states do. Three states conduct routine monitoring of ambient H_2S levels, and several others have monitored H_2S as part of specific projects. I present the available monitoring data, as well as anecdotal evidence about H_2S emissions and human health concerns that I obtained from conversations with staff at state environmental agencies.

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[1] I searched on-line catalogs including Web of Science and Environmental Sciences and Pollution Management, and tracked down relevant references listed within each article.

The final component of my research consists of informal interviews with people living near oil and gas operations who have been, or believe they have been, exposed to hydrogen sulfide and believe they are experiencing adverse heath effects due to exposure. Enough evidence emerges from literature searches and reviews, environmental health professionals, available monitoring data, and personal stories to warrant more research. Although the evidence is patchy, the potential for health risks is real and the stakes are high. More monitoring and regulation are required to adequately protect human health.

2. Hydrogen Sulfide in the Environment

Approximately 90 percent of the sources that emit hydrogen sulfide into the air are natural.[2] Hydrogen sulfide is released into the air as a product of the decomposition of dead plant and animal material,[3] especially when this occurs in wet conditions with limited oxygen, such as in swamps. Hot springs, volcanoes, and other geothermal sources also emit H_2S.

Anthropogenic releases of H_2S into the air result from industrial processes, primarily from the extraction and refining of oil and natural gas and from paper and pulp manufacturing,[4] but the gas is also present at sewage treatment plants, manure-handling plants, tanneries, and coke oven plants.[5]

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[2] EPA, "Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas." EPA-453/R-93-045, October 1993. " p.III-4.

[3] Decomposition of dead organic matter (DOM) by fungi, actinomycetes, and bacteria releases hydrogen sulfide from sulfur-containing proteins and from the direct reduction of sulfate (SO4+).

[4] New York State Department of Health: available at http://www.health.state.ny.us/nysdoh/environ/btsa/sulfide.htm

[5] "Public Health Statement for Hydrogen Sulfide," Agency for Toxic Substances and Disease, September 2004. Available at http://www.atsdr.cdc.gov/toxprofiles/tp114-c1.pdf

3. Hydrogen Sulfide and Oil and Gas

Hydrogen sulfide is a naturally occurring component of crude oil and natural gas. Petroleum oil and natural gas are the products of thermal conversion of decayed organic matter (called kerogen) that is trapped in sedimentary rocks. High-sulfur kerogens release hydrogen sulfide during decomposition, and this H_2S stays trapped in the oil and gas deposits.[6]

Methane (CH_4) is the predominant component of natural gas, comprising 70 to 90 percent, while other gaseous hydrocarbons, butane (C_4H_{10}), propane (C_3H_8), and ethane (C_2H_6), account for up to 20 percent. Contaminants present in natural gas, which have to be removed at natural gas processing facilities, include water vapor, sand, oxygen, carbon dioxide, nitrogen, rare gases such as helium and neon, and hydrogen sulfide.[7] In fact, hydrogen sulfide is the predominant impurity in natural gas.[8] The Environmental Protection Agency (EPA) classifies natural gas as *sour* when H_2S is present "in amounts greater than 5.7 milligrams per normal cubic meters (mg/Nm^3) (0.25 grains per 100 standard cubic feet)."[9]

Sour gas is routinely 'sweetened' at processing facilities called desulfurization plants. Ninety five percent of the gas sweetening process involves removing the H_2S by absorption in an amine solution, while other methods include carbonate processes, solid bed absorbents, and physical absorption.[10]

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[6] EPA "Report to Congress on Hydrogen Sulfide Emissions", p.II-1.

[7] *Oil and Gas at Your Door? A landowner's guide to oil and gas development*. OGAP 2005. p.I-2.

[8] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.II-i.

[9] Environmental Protection Agency, AP 42, Fifth Edition, Volume I, Chapter 5: The Petroleum Industry, available at http://www.epa.gov/ttn/chief/ap42/ch05/final/c05s03.pdf

[10] EPA, "Petroleum Industry." P.5.3-1. For details on these and other technologies for 'sweetening' sour gas, see "Crystasulf Process for Desulfurizing Ultra-deep Natural Gas Near the Wellhead," presented at *Natural Gas Technologies II Conference and Exhibition,* February 2004. Phoenix, AZ. Ref. No. T04135. pp.5-9.

Between 15 to 25 percent of natural gas in the U.S. may contain hydrogen sulfide,[11] while worldwide, the figure could be as high as 30 percent. The exact number of sour wells in the United States is not known, though natural gas deposits in Arkansas, southeastern New Mexico, western Texas, and north-central Wyoming have been identified as sour.[12] Hydrogen sulfide occurs naturally in the geologic formations in the Rockies, the Midcontinent, Permian Basin, and Michigan and Illinois Basins.[13] As more natural gas development occurs in these areas, it is likely that the number of sour wells will increase, because new drilling is increasingly focused on deep gas formations that tend to be sour.[14] Although exact statistics on sour wells are not available, the EPA concedes that "the potential for routine H_2S emissions [at oil and gas wells] is significant."[15]

The most comprehensive source on the distribution of sour gas is a report prepared by consultants for the Gas Technology Institute, formerly Gas Research Institute, a research, development, and training organization that serves the natural gas industry.[16] This report states that "Regions with the largest percentage of proven reserves with at least 4 ppm hydrogen sulfide are Eastern Gulf of Mexico (89 percent), Overthrust (77 percent), and Permian Basin (46

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[11] Dalrymple, D.A., Skinner, F.D. and Meserole, N.P. 1991. *Investigation of U.S. Natural Gas Reserve Demographics and Gas Treatment Processes.* Topical Report, GRI-91/0019, Section 3.0, pp. 3-1 to 3-13. Gas Research Institute. And Hugman, R.H., Springer, P.S. and Vidas, E.H. *Chemical Composition of Discovered and Undiscovered Natural Gas in the United States: 1993 update*. Topical Report, GRI-93/0456. p. 1-3. Gas Research Institute. As cited in McIntush, K.E., Dalrymple, D.A. and Rueter, C.O. 2001. "New process fills technology gap in removing H2S from gas," *World Oil*, July, 2001.

[12] EPA, "Report to Congress on Hydrogen Sulfide Emissions". p. I-3.

[13] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p. I-3.

[14] Quinlan, M., 1996. "Evaluation of selected emerging sulfur recovery technologies," *GRI Gas Tips*, 3(1):26-35. In McIntush, K.E., Dalrymple, D.A. and Rueter, C.O. 2001. "New process fills technology gap in removing H2S from gas," *World Oil*, July, 2001.

[15] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-35.

[16] Energy and Environmental Analysis, Inc. for Gas Research Institute, "Chemical Composition of Discovered and Undiscovered Natural Gas in the Lower-48 United States," GRI 90/0248. November 1990. (mailed to me by librarian for Gas Technology Institute).

percent)."[17] Figure 1 illustrates the major H_2S prone areas in the United States and identifies the basins.

Figure 1. ***Map of Major H_2S-prone Areas in the Continental United States***[18]

4. Hydrogen Sulfide Emissions from Oil and Gas Facilities

There has been some investigation of hydrogen sulfide emissions associated with oil and gas development.[19] In the Literature Review section, I summarize several studies that researched H_2S emissions near oil and gas facilities. Several states' environmental departments have monitored H_2S concentrations near oil and gas operations. My conversations with personnel at these agencies confirm that there are H_2S emissions associated with oil and gas activities. I present the evidence from the state studies and my conversations with staff in the State Regulations section. Finally, the interviews I conducted with people living near oil and gas

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[17] Energy and Environmental Analysis, Inc. for Gas Research Institute. pp.2-3.
[18] Energy and Environmental Analysis, Inc. for Gas Research Institute. p.1-13 and p.A-5.
[19] For example, Environmental Protection Agency, "Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas." EPA-453/R-93-045, October 1993. and Tarver, Gary A. and Purnendu K. Dasgupta. "Oil Field Hydrogen Sulfide in Texas: Emission Estimates and Fate." *Environmental Science and Technology*. **31**: (12) 3669-3676. 1997.

sites attest to the presence of H_2S in the ambient air. Detailed narratives of the interviews are in Appendix D.

Oil and gas operations may emit hydrogen sulfide, routinely or accidentally, during the extraction, storage, transport, or processing stage.[20] During of extraction, hydrogen sulfide may be released into the atmosphere at wellheads, pumps, piping, separation devices, oil storage tanks, water storage vessels, and during flaring operations.[21] Flares burn gases that cannot be sold as well as gases at points in the system where operating problems may occur, as a safety measure. Because it cannot be sold, hydrogen sulfide is routinely flared. Sulfur dioxide (SO_2) is the product of combusting hydrogen sulfide, but in the event of incomplete combustion, H_2S may be emitted into the atmosphere.

Based on reviewing the available literature and the records of agencies to which accidental releases of hydrogen sulfide might be reported,[22] the EPA states that well blowouts, line releases, extinguished flares, collection of sour gas in low-lying areas, line leakage, and leakage from idle or abandoned wells are sources of documented accidental releases that have impacted the public, not just workers at of oil and gas extraction sites.[23] Well blowouts are uncontrolled releases from wells, and can occur during drilling, servicing, or production, as a result of a failed 'blowout preventer' during drilling or a failed subsurface safety valve during

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[20] *Schlumberger Oilfield Glossary*, available at http://www.glossary.oilfield.slb.com/default.cfm

[21] EPA "Report on Hydrogen Sulfide Air Emissions," P.II-6. See Section II, pp.3 to 10 for details. A wellhead is the first piece of equipment where the oil leaves the ground. Pumps that extract the oil may leak at the seals. Piping connects the various machinery and storage units at an oil pad. Separation devices separate oil from gas and water, and pipes take the gas to a dehydrator, while other pipes direct water and oil to a heater-treater where the two are separated. The oil is then piped into an oil storage tank, and the water is piped into a produced water storage tank. Wellheads, pipes, and separation devices may leak hydrogen sulfide because of corrosion and embrittlement caused by the reaction of water with metal and H_2S, or due to poor maintenance and poor materials. The heater-treaters may release hydrogen sulfide due to high pressures or pressure changes above design specifications. Oil storage tanks may release hydrogen sulfide as a result of day-night temperature changes, volatilization, and filling operations. Produced water storage vessels may contain hydrogen sulfide dissolved in water that is brought up from the reservoir, or it may be produced by sulfate-reducing bacteria found in water and oil.

[22] State agencies, emergency response organizations, industry officials. EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-36.

[23] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-38.

production.[24] The release from a well blowout can last for an indefinite period.[25] After all economically recoverable oil and gas has been removed, the well needs to be plugged, or sealed. If a well is improperly sealed, hydrogen sulfide may routinely seep into the atmosphere. One study, discussed below, documented precisely this type of hydrogen sulfide emissions in Whaler's Cove, a community in Long Beach, California, where a townhouse development was built on a 1940s oil field. Additionally, hydrogen sulfide may be routinely or accidentally released into the atmosphere at oil refineries and natural gas processing facilities, including desulfurization plants.

Hydrogen sulfide emissions from oil and gas development may pose a significant human health risk, as the studies discussed below reveal. Workers in the oil and gas industry are trained to recognize and respond to high-concentration accidental releases of H_2S. The American Petroleum Institute (API), an oil and gas industry technical organization, publishes recommendations for practices that help prevent hazardous H_2S concentrations from occurring in the workplace.[26] People living near oil and gas development sites may be chronically exposed to much lower, but nonetheless dangerous ambient H_2S levels, as well as to accidental high-concentration releases. A 1993 EPA report on the emissions of hydrogen sulfide from oil and gas extraction acknowledges that because of the proximity of oil and gas wells to areas where people live, the affected population may be large.[27]

Additionally, the "Public Health Statement for Hydrogen Sulfide," a public health advisory summarizing the longer H_2S Toxicological Profile issued by the Centers for Disease Control and Prevention's Agency for Toxic Substances and Disease Registry (ATSDR),

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[24] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-45.

[25] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-49.

[26] API Recommended Practice (RP) 54, *Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations* and API RP 49, *Safe Drilling of Wells Containing Hydrogen Sulfide*.

[27] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-65.

acknowledges that "As a member of the general public, you might be exposed to higher-than-normal levels of hydrogen sulfide if you live near a waste water treatment plant, a gas and oil drilling operation, a farm with manure storage or livestock confinement facilities, or a landfill. Exposure from these sources is mainly from breathing air that contains hydrogen sulfide."[28] The ATSDR also reports that higher than normal ambient "levels [of hydrogen sulfide] (often exceeding 90 ppb) have been detected in communities living near natural sources of hydrogen sulfide or near industries releasing hydrogen sulfide."[29]

5. Human Health Effects from Exposure to Hydrogen Sulfide

Human health effects of exposure to hydrogen sulfide, an irritant and an asphyxiant, depend of the concentration of the gas and the length of exposure. Background ambient levels of H_2S in urban areas range from 0.11 to 0.33 ppb, while in undeveloped areas concentrations can be as low as 0.02 to 0.07 ppb.[30] A rotten egg odor characterizes H_2S at low concentrations, and some people can detect the gas by its odor at concentrations as low as 0.5 ppb.[31] About half of the population can smell H_2S at concentrations as low as 8 ppb, and more than 90% can smell it at levels of 50 ppb.[32] Hydrogen sulfide, however, is odorless at concentrations above 150 ppb, because it quickly impairs the olfactory senses.[33] Prolonged exposure to concentrations below

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[28] "Public Health Statement for Hydrogen Sulfide," Agency for Toxic Substances and Disease, September 2004. Available at http://www.atsdr.cdc.gov/toxprofiles/tp114-c1.pdf

[29] ATSRD, Ch2, p.1.

[30] Agency for Toxic Substances and Disease Registry (ATSDR). 2004. Toxicological profile for hydrogen sulfide (*Draft for Public Comment*). Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. Chapter 2, p.1.

[31] New York State Department of Health: available at http://www.health.state.ny.us/nysdoh/environ/btsa/sulfide.htm

[32] Collins, P. and Lewis, L. 2000. *Hydrogen Sulfide: Evaluation of Current California Air Quality Standard with Respect to Protection of Children.* Prepared for California Air Resources Board and California Office of Environmental Health Hazard Assessment. In: Summary of the toxicity assessment of hydrogen sulfide conducted by the Secretary's Scientific Advisory Board on Toxic Air Pollutants. http://daq.state.nc.us/toxics/studies/H2S

[33] Knight, Laura D., MD, and S. Erin Presnell, MD. 2005. "Death by Sewer Gas: Case Report of a Double Fatality and Review of the Literature." *The American Journal of Forensic Medicine and Pathology*. p.183.

150 ppb can also cause olfactory fatigue.[34] This effect of disabling the sense of smell at levels that pose serious health risks and possibly are life-threatening is one especially insidious aspect of hydrogen sulfide exposure. Odor is not necessarily a reliable warning signal of the presence of H_2S.

Most effects to humans occur from inhalation, though exposure generally also affects the eyes. Because most organ systems are susceptible to its effects, hydrogen sulfide is considered a broad spectrum toxicant.[35] The organs and tissues with exposed mucous membranes (eyes, nose) and with high oxygen demand (lungs, brain) are the main targets of hydrogen sulfide.[36] Hydrogen sulfide acts similarly to hydrogen cyanide, interfering with cytochrome oxidase and with aerobic metabolism.[37] Essentially, hydrogen sulfide blocks cellular respiration, resulting in cellular anoxia, a state in which the cells do not receive oxygen and die. The human body detoxifies hydrogen sulfide by oxidizing it into sulfate or thiosulfate by hemoglobin-bound oxygen in the blood or by liver enzymes.[38] Lethal toxicity occurs when H_2S is present in concentrations high enough to overwhelm the body's detoxification capacity.[39]

At levels up to 100 to 150 ppm, hydrogen sulfide is a tissue irritant, causing keratoconjunctivitis (combined inflammation of the cornea and conjunctiva), respiratory irritation with lacrimation (tears) and coughing.[40] Skin irritation is also a common symptom. Instantaneous loss of consciousness, rapid apnea (slowed or temporarily stopped breathing), and

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[34] Glass, D.C. "A Review of the Health Effects of Hydrogen Sulphide Exposure." *Annals of Occupational Hygiene*. 34:(3) p.323.

[35] Legator, Marvin S., et al.. "Health Effects from Chronic Low-Level Exposure to Hydrogen Sulfide." *Archives of Environmental Health*. **56:** (2) 123-131. March/April 2001. p.124.

[36] Legator, Marvin S., et al.. p.124.

[37] Knight, Laura D., MD, and S. Erin Presnell, MD. 2005. "Death by Sewer Gas: Case Report of a Double Fatality and Review of the Literature." *The American Journal of Forensic Medicine and Pathology*. p.183.

[38] Knight, 2005. p.184.

[39] Knight, 2005. p.184.

[40] Knight, 2005. p.183.

death may result from acute exposure to levels above 1,000 ppm.[41] At these higher levels, hydrogen sulfide is an asphyxiant.

The non-lethal effects can be summarized as *neurological* – consisting of symptoms such as dizziness, vertigo, agitation, confusion, headache, somnolence, tremulousness, nausea, vomiting, convulsions, dilated pupils, and unconsciousness, and *pulmonary* – with symptoms including cough, chest tightness, dyspnea (shortness of breath), cyanosis (turning blue from lack of oxygen), hemoptysis (spitting or coughing up blood), pulmonary edema (fluid in the lungs), and apnea with secondary cardiac effects.[42]

Table 1 lists the health effects associated with H_2S exposures of varying durations. The table reports health effects that toxicological and epidemiological studies have attributed to specific concentrations (or a range of concentrations) of hydrogen sulfide. Table 1 also includes health effects of exposure to known concentrations of H_2S that were self-reported by participants in the studies discussed below.

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[41] Knight, 2005. p.183.

[42] Snyder, Jack W., MD, PhD. et al.. "Occupational Fatality and Persistent Neurological Sequelae After Mass Exposure to Hydrogen Sulfide." *American Journal of Emergency Medicine*. **13**: (2) 199-203. 1995. p.201.

Table 1: Health Effects Associated with Hydrogen Sulfide[43]

Concentration (ppm)	Length of exposure	Effect	Source
0.0057	*Community/chronic*	*Eye and nasal symptoms, coughs, headaches and/or migraines*	*Partti-Pellinen, p.316.*
0.003 – 0.02	Immediate	Detectable odor	EPA Report 1993, p.III-5
0.01	*Community/chronic*	*Neurophysiological abnormalities*	*Legator, p.124.*
0.1 – 1	*Not reported (n.r.)*	*Abnormal balance with closed eyes, delayed verbal recall, impaired color discrimination, decreased grip strength*	*Kilburn, 1999, p.210.*
0.2	n.r.	Detectable odor	Fuller, p.940
0.250 – 0.300	Prolonged	Nuisance due to odor from prolonged exposure	Milby, p.194
1 – 5	*n.r.*	*Abnormal balance with open and closed eyes, delayed verbal recall, impaired color discrimination, decreased grip strength, abnormal simple and choice reaction time, abnormal digit symbol and trailmaking.*	*Kilburn, 1999, p.210*
2 – 8	*Community*	*Malaise, irritability, headaches, insomnia, nausea, throat irritation, shortness of breath, eye irritation, diarrhea, and weight loss*	*EPA Report 1993, p. III-32.*
10	10 minutes	Eye irritation, chemical changes in blood and muscle tissue after 10 minutes	New York State Department of rt
> 30	Prolonged	Fatigue, paralysis of olfaction from prolonged exposure	Snyder, p.200
50	n.r.	Eye and respiratory irritation	Fuller, p.940
50 – 100	Prolonged	Prolonged exposure leads to eye irritation; eye irritation (painful conjunctivitis, sensitivity to light, tearing, clouding of vision) and serious eye injury (permanent scarring of the cornea)	Milby p.194; EPA Report 1993,
150 – 200	n.r.	Olfactory nerve paralysis	EPA Report 1993, p.III-6
200	n.r.	Respiratory and other mucous membrane irritation	Snyder, p.200
250	n.r.	Damage to organs and nervous system; depression of cellular metabolism	EPA Report 1993, p.III-5
250	Prolonged	Possible pulmonary edema from prolonged exposure	Milby p.193
320 – 530	n.r.	Pulmonary edema with risk of death	Kilburn (1999), p.212
500	30 minutes	systemic symptoms after 30 minutes	Fuller, p.940
500 –1000	Immediate	Stimulation of respiratory system, leading to hyperpnoea (rapid breathing); followed by apnea (cessation of breathing)	EPA Report 1993, p.III-5
750	Immediate	Unconsciousness, death	Fuller, p.940
1000	Immediate	Collapse, respiratory paralysis, followed by death	Fuller, p.940, EPA Report 1993 p.
750 – 1000	Immediate	Abrupt physical collapse, with possibility of recovery if exposure is terminated; if not terminated, fatal respiratory paralysis	Milby, p.192
1000 – 2000	n.r.	Immediate collapse with paralysis of respiration	Kilburn (1999), p.212
5000	Immediate	Death	Fuller, p.940

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[43] Italics signify concentrations and health effects in studies that rely on self-reporting of symptoms, usually in questionnaires.

5.1 Literature Review - Acute Exposure

The following studies focused on short-term exposure to relatively high levels of hydrogen sulfide, the kind of scenario that can be expected from an accidental release. There are many documented instances and peer-reviewed studies of serious health effects and deaths from exposure to relatively high concentrations of hydrogen sulfide.

Fuller and Suruda (2000), who reviewed Occupational Safety and Health Administration (OSHA) investigation records from 1984 to 1994, reported 80 deaths in the United States from occupational exposure to hydrogen sulfide, out of a total 18559 occupational death during this period.[44] Twenty-two of the 80 deaths were in the oil and gas industry.[45] These deaths occurred as a result of workers' exposure to accidental releases of hydrogen sulfide in high concentrations. The authors concluded that portable H_2S meters or alarms could have prevented these deaths.[46]

In their 1997 study, Hessel et al. submitted a questionnaire about health effects from hydrogen sulfide exposure to 175 oil and gas workers in Alberta, Canada, a known region of sour gas. Of the 175 workers, one third reported having been exposed to H_2S, and 14 workers (8%) experienced knockdown,[47] a term for the loss of consciousness due to inhaling high concentrations of hydrogen sulfide. The workers who had experienced knockdown exhibited the respiratory symptoms of shortness of breath, wheezing while hurrying or walking up hill, and random wheezing attacks.[48] The investigators found no

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[44] Fuller, Douglas C., MD, MPH, and Anthony J. Suruda, MD, MPH. "Occupationally Related Hydrogen Sulfide Deaths in the United States From 1984 to 1994." *Journal of Occupational and Environmental Medicine*. **42**:(9) 939-942. September 2000. p.940.

[45] Fuller and Suruda, p.941.

[46] Fuller and Suruda, p.942.

[47] Hessel, Patrick A., PhD. et al.. "Lung Health in Relation to Hydrogen Sulfide Exposure in Oil and Gas Workers in Alberta, Canada." *American Journal of Industrial Medicine*. **31**:554-557. 1997., p.555

[48] Hessel, pp.555-556.

"measurable pulmonary health effects as a result of exposure to H_2S that were intense enough to cause symptoms but not intense enough to cause unconsciousness."[49] In other words, the workers who reported initially experiencing symptoms from H_2S exposure did not report exhibiting any lingering respiratory symptoms at the time of the study. However, other kinds of long term effects could exist; indeed, the study itself acknowledged that long term effects of acute short term exposure have not been studied enough, and finds this lack "noteworthy."[50]

Milby and Baselt (1999) relied on a review of literature about hydrogen sulfide poisoning, and state that "A phenomenon referred to as 'knockdown' has been reported in oil field workers and others to describe sudden, brief loss of consciousness followed by immediate full recovery after short-lived exposure to very high concentrations of hydrogen sulfide (e.g., 750-1000 ppm)."[51] However, other studies have contested this claim of full recovery following a knockdown.

Kaye Kilburn, a medical doctor and professor of medicine at the University of Southern California, has devoted a considerable part of his career to studying and reporting on the adverse health effects of hydrogen sulfide. Refuting Milby and Baselt's (1999) finding that full recovery followed unconsciousness, or 'knockdown,' Kilburn states, "In 1989, for the first time, sensitive testing showed that, although survivors who had been unconscious looked all right, brain functions were impaired. Similar impairments were measured in people exposed to amounts below 50 ppm that had not caused unconsciousness. Next, subtle impairments of brain function were measured from

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[49] Hessel, p..556.

[50] Hessel, p.555.

[51] Milby, Thomas H. MD, and Randall C. Baselt, PhD. "Hydrogen Sulfide Poisoning: Clarification of Some Controversial Issues." *American Journal of Industrial Medicine*. **35**: 192-195. 1999. p.192.

exposures to concentrations of less than 5 ppm in air."[52] Kilburn reported examining one oil field worker, Stan, who had experienced 'knockdown' on the job after exposure to 1 percent hydrogen sulfide concentration (or 9,999 ppm as Stan's meter recorded it.) Three years after the incident, while appearing physically healthy, Kilburn's tests of Stan revealed significant brain damage (IQ lowered to 77, though the previous IQ is not reported), severely impaired balance and motor function, and inability to recall stories and visual designs.[53]

Another study by Kilburn (2003)[54] reported long term effects of hydrogen sulfide exposure. Kilburn performed physiologic and psychological measurements on nineteen exposed and 202 unexposed subjects.[55] Ten of the nineteen subjects were exposed at work, including four at oil and gas sites, while the other nine were exposed in their residences, which were near various sources of H_2S.[56] The concentrations to which the subjects were exposed are not known. Exposure times ranged from twenty minutes to nine years, and Kilburn examined the subjects from 1.7 to 22 years after their exposures.[57] The study methods consisted of a questionnaire and a series of neurophysiological and neuropsychological tests. The neurophysiological tests measured simple reaction time, visual two-choice reaction time, balance, color recognition, and hearing, and the neuropsychological tests measured immediate memory recall, mood, and vocabulary.[58] Tension, depression, anger, fatigue, and confusion were all significantly elevated in the

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[52] Kaye H. Kilburn. "Killer Molecules in Natural Gas." Chapter 7 in *Endangered Brains: How Chemicals Threaten Our Future*. Birmingham, AL: Princeton Scientific Publishers Company, Inc. 2004. p.78.
[53] Kilburn, (2004) p.79.
[54] Kilburn, Kaye H. "Effects of Hydrogen Sulfide on Neurobehavioral Function." *Southern Medical Journal*. **96**: (7) 639-646. 2003.
[55] Kilburn, (2003), p.640.
[56] Kilburn, (2003), p.640, see Table 1, p.641.
[57] Kilburn, (2003), p.640.
[58] Kilburn, (2003), pp.640-641.

exposed subjects compared to the control group. In addition, respiratory symptoms were more prevalent among the exposed subjects.[59] Even subjects who did not experience unconsciousness at the time of their exposure exhibited permanent neurobehavioral damage.[60]

The studies mentioned thus far focused on occupational exposure. They document the dangerous properties of hydrogen sulfide, as well as highlight the fact that more research is needed on the long term effects of even short duration exposures. There have been some studies of non-occupational exposure to relatively high H_2S levels. The proximity of oil refineries, gas treatment and processing plants, and oil and gas wells to residences constitutes a likely source of H_2S emissions and potentially poses a risk to people in a non-occupational setting.

Kilburn has studied the health effects of a series of explosions at an oil refinery in Wilmington, California, which occurred in October 1992. The explosions released unknown amounts of hydrogen sulfide into the air, making people ill in Wilmington, Torrance, Carson, Long Beach, and South Los Angeles.[61] Some street monitors recorded H_2S concentrations as high as 24 ppm, and since no one died, Kilburn concluded that concentrations probably did not exceed 200 ppm. Seven thousand people who had been exposed and sickened filed a consolidated lawsuit against the refinery, and a random sample were examined three and a half years after the explosion for court proceedings.[62]

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[59] Kilburn, (2003), p.643.
[60] Kilburn, (2003), p.644.
[61] Kilburn, (2004) p.77.
[62] 400 people were selected to represent the 7000 filing suit, and 120 were selected at random to be examined by a general practitioner. Then, 68 of the 120 were examined using sensitive neurobehavioral tests. Kilburn, (2004) p.81.

Persistent symptoms included impaired balance, delayed recall memory, elevated depression and confusion scores, and abnormally slow reaction times.[63]

As background to their 1987 study, which focused on methods of improving the prediction and management of public health risks associated with the development of sour gas wells, Layton and Cederwall[64] summarized studies of two incidents during which people were exposed to hydrogen sulfide released from gas operations. One occurred in 1950 in Poza Rica, Mexico, where 320 people were hospitalized and 22 died as a result of a major hydrogen sulfide release from a gas purification plant.[65] The second incident, known as the Lodgepole blowout, was a sour gas blowout in Alberta, Canada, in 1982. In this case, the hydrogen sulfide releases lasted for 67 days, and the affected people reported headaches, eye irritation, and various respiratory and gastrointestinal symptoms.[66] In both instances, there were no reliable measurements of H_2S concentrations. In Alberta, maximum reported hourly concentrations were 15 ppm, and concentrations 100 kilometers away from the source were below 100 ppb, but residents there filed over a thousand complaints.[67] This study concluded that the hazard zone for sublethal effects around sour gas wells encompasses from less than 400 meters up to 6500 meters, while lethal exposure to hydrogen sulfide could occur as far as 2000 meters from the source.[68] Among the proposed recommendations for improving public safety is "preemptive land ownership,"[69] an issue which I revisit in the Concluding Remarks section. This study also stressed that

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[63] Kilburn, (2004) p.81.

[64] Layton, David W. and Richard T. Cederwall. 1987. "Predicting and Managing the Health Risks of Sour-Gas Wells." *Journal of the Air Pollution Control Association.* **37**: 1185-1190.

[65] Layton and Cederwall, 1987. pp.1185-1186.

[66] Layton and Cederwall, 1987. p 1186.

[67] Layton and Cederwall, 1987. p 1186.

[68] Layton and Cederwall, 1987. p 1188.

[69] Layton and Cederwall, 1987. p 1187.

sublethal effects of hydrogen sulfide are not well studied and that the dose-response relationship at lower levels is not well characterized.[70]

5.2 Literature Review - Chronic Exposure

Literature is also available on the human health impacts of chronic exposure to relatively low concentrations of hydrogen sulfide. Generally, chronic exposure to low-level concentrations of hydrogen sulfide is associated with neurological symptoms that include fatigue, loss of appetite, irritability, impaired memory, altered moods, headaches, and dizziness.[71] At persistent concentrations of 0.250 to 0.300 ppm (250 to 300 ppb), the rotten egg odor of H_2S creates a nuisance to communities, and exposure to such concentrations has been documented to affect quality of life by causing headaches, nausea, and sleep disturbances.[72]

Schiffman et al. (1995) evaluated the effect of odors emanating from swine operations on mood.[73] Although the source of odors were swine operations rather than oil and gas sites, the study is relevant because hydrogen sulfide caused the persistent odors, much as is the case near oil refineries and natural gas processing plants. This study concluded that continuously smelling odors is associated with "significantly more tension, more depression, less vigor, more fatigue, and more confusion."[74]

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[70] Layton and Cederwall, 1987. p 1185.

[71] McGavran, Pat. "Literature Review of the Health Effects Associated with the Inhalation of Hydrogen Sulfide." Idaho Department of Environmental Quality, Boise, Idaho. June 19, 2001. p.3.

[72] Milby, 1999, p.194.

[73] Schiffman, Susan S., Elizabeth A. Sattely, et al.. "The Effect of Environmental Odors Emanating From Commercial Swine Operations on the Mood of Nearby Residents." *Brain Research Bulletin*. 37:4 369-375. 1995

[74] Schiffman et al., p.371.

One frequently cited study, by Partti-Pellinen et al. (1996), examined the health effects of chronic, low-level exposure to sulfur compounds, including hydrogen sulfide, near a paper and pulp mill in Finland.[75] They found that the exposed people experienced eye and nasal symptoms, coughs, and headaches or migraines much more frequently than the people in the control group, while acute respiratory infections also occurred more frequently in the study group.[76] Once again, the study acknowledged the lack of data on long term effects of low-dose, chronic exposure, and concluded that, at the very least, the exposure and odor make "everyday life uncomfortable."[77]

Legator et al. (2001) investigated the effects of chronic, low levels of hydrogen sulfide by surveying two exposed communities, Odessa, Texas, and Puna, Hawaii, and comparing the health findings with several control communities.[78] Due to emissions from industrial wastewater, ambient concentrations of H_2S in Odessa, Texas, registered at 335 to 503 ppb over 8 hours, 101 to 201 ppb over 24 hours, with an annual average of 7 to 27 ppb.[79] Puna, Hawaii, is situated in a volcanically active area.[80] There were no reliable measurements of H_2S levels at Puna—they ranged from less than 1 ppb to periodic highs of 200 to 500 ppb. The study relied on a multi-symptom health survey and found various adverse health effects associated with hydrogen sulfide exposure in the study populations. The health symptoms included central nervous system impacts (fatigue, restlessness,

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[75] Partti-Pellinen, Kirsi, Marttila Olli, Vilkka Vesa, et al.. "The South Karelia Air Pollution Study: effects of low-level exposure to malodorous sulfur compounds on symptoms." *Archives of Environmental Health.* **51**. (4) 315-320 1996. The study looked at the main components of total reduced sulfur (TRS) compounds—hydrogen sulfide H_2S, methyl mercaptan, CH_3SH, dimethyl sulfide $[CH_3]_2S$, and dimethyl disulfide $[CH_3]_2S_2$.

[76] Partti-Pellinen et al.. Acute respiratory infections occurred 1.6 times per year in the study group as compared to 1.1 times per year in the control group.

[77] Partti-Pellinen, et al., p.320.

[78] Legator, Marvin S., et al.. "Health Effects from Chronic Low-Level Exposure to Hydrogen Sulfide." *Archives of Environmental Health*. **56:** (2) 123-131. March/April 2001.

[79] Legator, p.124.

[80] Since 1976, Puna is a site of geothermal energy production, and supplies about 30% of Hawaii's electricity. US Department of Energy.

depression, short term memory loss, balance, sleep problems, anxiety, lethargy, headaches, dizziness, tremors), respiratory system impacts (wheezing, shortness of breath, coughing), and various ear, nose, and throat symptoms.[81] This study also concluded with a call for more research:

> The findings in our study, taken together with previously reported data concerning adverse responses to H_2S, strongly mandate the need for continued research on the possible detrimental effects of chronic exposure to the toxic agent. This is of decided public health significance, given the relatively large segment of the population that is regularly exposed to low levels of H_2S.[82]

Kilburn has also studied health impacts from chronic exposure to lower concentrations of hydrogen sulfide. He examined a preacher and eighteen congregation members in Odessa, Texas, who lived downwind from an oil refinery and often smelled the characteristic rotten egg odor of H_2S, occasionally experiencing nausea and vomiting.[83] Kilburn observed impaired balance, delayed verbal recall for stories, and difficulty distinguishing colors among the people he studied in Odessa.[84] Workers and people living downwind of another oil refinery, in Nipoma Mesa near San Luis Obispo, California, also exhibited impaired reaction time, impaired balance, depression, and impaired recall memory.[85]

As a result of poorly plugged wells of an abandoned oil and gas field in Long Beach, California, people living in a community built on this location were exposed to hydrogen sulfide that collected under concrete foundations and crawl spaces of homes,

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[81] Legator, pp.126-129.

[82] Legator, p.130.

[83] Kilburn, (2004) p.79.

[84] Kilburn, (2004) p.80.

[85] Kilburn, (2004) p.80.

and in a low lying area around a communal swimming pool.[86] The H_2S measurements ranged from 0.1 ppm to 1 ppm, with several peaks up to 5 ppm.[87] Kilburn examined 24 people from this community, and recorded abnormal balance with closed eyes, delayed verbal recall, and impaired color discrimination and grip strength, as compared to a control group.[88]

As reported by the EPA,[89] two notable occasions of increased ambient concentrations of hydrogen sulfide occurred in Great Kanawha River Valley, West Virginia, in 1950, and in Terre Haute, Indiana, in 1964. In Terre Haute, ambient H_2S concentrations ranged from 2 to 8 ppm, emanating from a lagoon. In West Virginia, the highest concentration was 293 ppb, but there is no information on other levels. In both cases, symptoms included malaise, irritability, headaches, insomnia, and nausea, while the people exposed in Terre Haute also reported, among other effects, throat irritation, shortness of breath, eye irritation, diarrhea, and weight loss.[90] These incidents provide some evidence of health impacts from chronic exposure to ambient levels of hydrogen sulfide in the range that may be expected to occur near oil and gas sites.

Tarver and Dasgupta (1997) measured hydrogen sulfide concentrations near several oil fields in western Texas.[91] Although the researchers were studying the effects of increased anthropogenic sources of sulfur emissions on the sulfur cycle, the authors nevertheless gathered data that is pertinent to my research. The study found nighttime

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[86] Kilburn, Kaye H. "Evaluating health effects from exposure to hydrogen sulfide: central nervous system dysfunction." *Environmental Epidemiology and Toxicology*. **1**:207-216. 1999. p.208.
[87] Kilburn (1999), p.208.
[88] Kilburn, (1999), p.210.
[89] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-32. For the entire paragraph.
[90] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-32
[91] Tarver, Gary A. and Purnendu K. Dasgupta. "Oil Field Hydrogen Sulfide in Texas: Emission Estimates and Fate." *Environmental Science and Technology*. **31**: (12) 3669-3676. 1997.

maximum H_2S concentrations between 1 and 5 ppb.[92] While this concentration of hydrogen sulfide is only enough to produce an odor, a persistent odor can be a nuisance, and has been associated with increased tension, depression, fatigue, confusion, and decreased vigor.[93]

Some evidence exists on the effects of hydrogen sulfide on the reproductive system. Xu et al. (1998) conducted a retrospective epidemiological study to assess the association between spontaneous abortion and exposure to petrochemicals.[94] By reviewing the plant employment records, which also contain medical information, the researchers identified over 3000 women from the Beijing Yanshan Petrochemical Corporation who had been pregnant. Trained interviewers administered a questionnaire to gather information on the subjects' reproductive history, pregnancy outcomes, employment history, occupational exposure, smoking habits, alcohol consumption, indoor air pollution, diet, and demographic variables.[95] The study found that "exposure to petrochemicals, specifically benzene, gasoline, and hydrogen sulphide is significantly associated with increased frequency of spontaneous abortion."[96] Each chemical was individually found to have a statistically significant effect on the frequency of spontaneous abortion. Although the exposures mainly occurred in maintenance operations or due to accidental leaks and spillages,[97] rather than being chronic low level exposures,[98] this study is nevertheless important for the link it established between hydrogen sulfide

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[92] Tarver and Dasgupta, p.3673.

[93] Schiffman et al. Discussed above on p.18.

[94] Xu, Xiping, Sung-Il Cho, et al.. "Association of petrochemical exposure with spontaneous abortion." *Occupational and Environmental Medicine*. 55: 31-36. 1998.

[95] Xu et al., p.31.

[96] Xu et al., p.34.

[97] Xu et al., p.35.

[98] The study acknowledged that "at lower exposures, the reproductive effects of hydrogen sulphide have not been determined, although it has been shown to enhance the fetal toxicity of carbon disulphide." Xu et al., pp.34-35.

and effects on the reproductive system. According to one personal account recounted below, hydrogen sulfide exposure is associated with spontaneous abortions in cattle as well as other reproductive effects in animals.

Most studies acknowledge that there is a need for more research on the health impacts of chronic exposure to lower concentrations of H_2S. Although the health effects are not well documented,[99] many studies recognize the potential for harm. In 1993, the EPA prepared an in-depth report on hydrogen sulfide emissions associated with oil and gas extraction.[100] The report matched available routine emissions data from oil and gas sites with studies documenting health effects of these levels, and assessed the risk of accidental releases, to determine whether these warrant a national control strategy.[101] Although the report acknowledged that oil refineries and gas processing plants are a major possible source of H_2S, these were not included in the analysis because they fall outside the definition of the term 'extraction.'[102] The report also excluded exploration and well development activities. Each of these areas of oil and gas operations is a potential source of hydrogen sulfide emissions.

The report concluded that "the potential for human and environmental exposures from routine emissions of H_2S from oil and gas wells exists, but insufficient evidence exists to suggest that these exposures present any significant threat,"[103] and that "there appears to be no evidence that a significant threat to public health or the environment exists from routine H_2S emissions from oil and gas extraction."[104] The EPA reached this

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[99] New York State Department of Health, http://www.health.state.ny.us/nysdoh/environ/btsa/sulfide.htm
[100] EPA, "Report to Congress on Hydrogen Sulfide Emissions."
[101] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-1.
[102] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.I-4.
[103] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.iii.
[104] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.V-1.

conclusion “from the limited data available.”[105] However, because, as the report itself acknowledged, there is not enough information on ambient air quality around well sites,[106] the conclusion that there are no health risks is ill founded. A call for further research would have been more appropriate, but strikingly, the “Research and Further Studies” section of the last chapter does not recommend additional research of routine hydrogen sulfide emissions and health effects.

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[105] EPA, “Report to Congress on Hydrogen Sulfide Emissions,” p.V-1.
[106] EPA, “Report to Congress on Hydrogen Sulfide Emissions,” p.III-1.

Table 2: Summary of Studies

	Author(s) / Date	Discipline	Motivation for Study / Summary of Findings
Acute Exposure	Fuller and Suruda (2000)	Medicine	To determine the number of occupational deaths related to hydrogen sulfide; review of OSHA records; acute exposure
	Milby and Baselt (1999)	Medicine / Toxicology	Review of literature on hydrogen sulfide; focusing on neurotoxic effects of acute exposure, effects on the lungs, diagnosis of poisoning, and community exposure issues.
	Hessel et al. (1997)	Public Health	To assess pulmonary health effects of oil and gas workers in Alberta, Canada; administered questionnaire to 175 workers
	Snyder et al. (1995)	Medicine	To assess neurological problems from exposure to hydrogen sulfide; review of case reports from an incident of mass exposure to H2S in New Jersey; calls for annual neurological and neuropsychological testing of exposed subjects to enhance knowledge of long term effects
Chronic Exposure	Parti-Pellinen et al. (1996)	Medicine / Public Health	Examined health effects chronic, low-level exposure to sulfur compounds, including H2S, near a paper and pulp mill; administered cross-sectional questionnaire to 336 subjects and to a reference community; increased frequency of eye and nasal symptoms, coughs, and headaches or migraines, and acute respiratory infections.
	Legator et al. (2001)	Medicine / Toxicology / Public Health	Investigate effects of chronic exposure to low levels of hydrogen sulfide; multi-symptom health survey submitted to two exposed communities – Odessa, Texas and Puna, Hawaii, and to control communities; found central nervous system impacts: fatigue, restlessness, depression, short term memory loss, balance and sleep problems, anxiety, lethargy, headaches, dizziness, tremors; respiratory system impacts: wheezing, shortness of breath, coughing; and various ear, nose, and throat symptoms.
	Tarver and Dasgupta (1997)	Chemistry	To determine hydrogen sulfide concentrations near oil fields in Western Texas
	Xu et al. (1998)	Medicine / Epidemiology	To determine effects of exposure to hydrogen sulfide on the reproductive system; conducted a retrospective epidemiological study to assess the association between spontaneous abortion and exposure to petrochemicals in Beijing, China; found an association.
	Kilburn (1999)	Epidemiology	To determine long-term effects of exposure to hydrogen sulfide; examined and submitted a questionnaire to four groups of people that were exposed to hydrogen sulfide (from boreholes in the ground, downwind of a refinery, due to an oil refinery explosion, and a group of people exposed to odors); found abnormal balance, delayed verbal recall, impaired color discrimination and grip strength.
	Schiffman et al. (1995)	Psychiatry	To determine the effect of persistent environmental odors on the mood of people living near the source of odors; submitted a questionnaire to 44 subjects and 44 controls; found more tension, depression, fatigue, and confusion, and less vigor among the exposed subjects.
	Kilburn (2003)	Epidemiology	To measure long term effects of hydrogen sulfide exposure – various lengths of exposure and various concentrations; submitted a questionnaire, and performed neuropsychological and neurophysiological tests on 19 exposed subjects and 202 unexposed subjects; found elevated tensions, depression, anger, fatigue, and confusion, and more prevalent respiratory symptoms among exposed subjects.
Other	Layton and Cederwall (1987)	Engineering / Public Health	Methods for improving the prediction and management of public health risks associated with development of sour gas wells
	Knight and Presnell (2005)	Medicine / pathology	Review of literature on H2S toxicology; case study of two fatalities due to occupational exposure to H2S

6. Regulations and Recommendations for Exposure to Hydrogen Sulfide

6.1 Federal Recommendations and Regulations

At the federal level, some regulations and recommendations exist to protect humans from the health effects of exposure to hydrogen sulfide. Regulations are laws that can be enforced by agencies such as the Environmental Protection Agency (EPA), the Food and Drug Administration (FDA), and the Occupational Safety and Health Administration (OSHA). Recommendations, on the other hand, do not carry the force of law, and are determined by agencies such as the National Institute for Occupational Safety and Health (NIOSH) and the Agency for Toxic Substances and Disease Registry (ATSDR), both part of the federal Centers for Disease Control and Prevention (CDC).

The American Conference of Governmental Industrial Hygienists (ACGIH), a longstanding member-based organization committed to promoting worker health and safety, also recommends exposure limits for various substances. The current ACGIH hydrogen sulfide standards are 10 ppm for the Threshold-Limit Value-Time Weighted Average (TLV-TWA), and 15 ppm for the TLV short term exposure limit (TLV-STEL). The TVL-TWA is the time-weighted average concentration to which workers can be routinely and consistently exposed over an 8-hour workday and 40-hour workweek without adverse effect. The TVL-STEL is the concentration to which workers can be exposed for short periods of time without suffering adverse health effects. The ACGIH updates its standards annually, and can relatively quickly modify its standards in response to new research.[107]

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[107] EPA "Report to Congress on Hydrogen Sulfide Emissions," p.III-10.

OSHA began setting standards for workers' exposure to hazardous substances in the 1970s, and initially adopted the ACGIH values.[108] The current OSHA workplace standard for H_2S exposure is 10 parts per million (ppm), while the exposure times are longer than the ACGIH recommends. In more detail, according to OSHA, "Exposures shall not exceed 20 ppm (ceiling) with the following exception: if no other measurable exposure occurs during the 8-hour work shift, exposures may exceed 20 ppm, but not more than 50 ppm (peak), for a single time period up to 10 minutes."[109] The OSHA regulations do not specify an 8-hour time weighted average (TWA) for H_2S. Exposure to these concentrations even for the seemingly short duration of 10 minutes can nevertheless result in eye and respiratory irritation, according to several sources. The NIOSH recommended exposure limit to the OSHA 10 ppm standard is 10 minutes, and its Immediately Dangerous to Life or Health (IDLH) H_2S concentration is 100 ppm.[110] OSHA standards have the force of law, while ACGIH's and NIOSH's levels are only recommendations.

It is important to note that OSHA standards apply only to workplaces and not to domestic situations or residences. The human data on which the standards are based are from uncontrolled exposure incidents, so the levels of exposure are crudely estimated.[111] In general, the controlled exposure data is derived from animal studies and then extrapolated to humans. As one study discussed above summed up, "a precise ratio with which to predict human effects on the basis of the ratio of rat-to-human effects is

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[108] EPA "Report to Congress on Hydrogen Sulfide Emissions," p.III-10.

[109] Occupational Safety and Health Administration, 29 CFR 1910.1000, available at http://www.osha.gov/dts/chemicalsampling/data/CH_246800.html

[110] NIOSH is a department within the Centers for Disease Control and Prevention. See http://www.cdc.gov/niosh/npg/npgd0337.html for NIOSH's H_2S exposure recommendations.

[111] Guidotti, Tee L. 1994. "Occupational exposure to hydrogen sulfide in the sour gas industry: some unresolved issues." *International Archives of Occupational and Environmental Health*. p.157.

lacking."[112] Further, the standards are based on the expected effects of hydrogen sulfide on healthy adult males, so people who are young, old, or have compromised immune systems may be at risk at considerably lower concentrations of H_2S. Additionally, exposure to hydrogen sulfide may affect the human reproductive system, as determined in the study by Xu et al. and reported above, so standards based on males may not protect women's reproductive health.

In addition to general standards for workplace inhalation exposure, OSHA specifically sets standards for industries in which hydrogen sulfide occurs in quantities exceeding 1500 pounds, in their Process Safety Management of Highly Hazardous Chemicals Standard (1910-119). Significantly, the oil and gas industry is exempt from this standard.[113] According to the 1993 EPA report, the reason OSHA gave for this exemption is that OSHA "continues to believe that oil and gas well drilling and servicing operations should be covered in a standard designed to address the uniqueness of the industry."[114] OSHA also proposed a monitoring program for hydrogen sulfide for drilling and service operations that occur in areas where H_2S exposure is a potential risk.[115] Neither of these exists at the time of writing.

The 1990 Clean Air Act is the primary federal law that regulates air pollution. The EPA sets the levels of various air pollutants, including the National Ambient Air Quality Standards (NAAQS) for six criteria pollutants and the National Emissions Standards for Hazardous Air Pollutants (NESHAPs) for another 188 substances commonly referred to as

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[112] Kilburn, Kaye H. "Effects of Hydrogen Sulfide on Neurobehavioral Function." 2003. p.639.
[113] OSHA, http://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=STANDARDS&p_id=9760
[114] As quoted in EPA "Report to Congress on Hydrogen Sulfide Emissions," p.IV-28.
[115] EPA "Report to Congress on Hydrogen Sulfide Emissions," p.IV-30.

HAPs.[116] The EPA does not regulate hydrogen sulfide as one of its criteria pollutants nor as one of the HAPs under the 1990 Clean Air Act. When George Bush, Sr. signed the Clean Air Act in 1990, H_2S was not among the 188 chemicals on the final HAPs list to be regulated, despite the calls of public interest groups and government scientists, some even within the EPA, for its inclusion. Hydrogen sulfide had been on the proposed original list of hazardous substances,[117] and was removed from this list as a result of successful efforts by the oil and gas, chemical, and paper industries.[118] For instance, the American Petroleum Institute, representing the interests of the oil and gas industry, argued that H_2S emissions are an "accidental-release issue" rather than a routine one,[119] and that H_2S therefore should not be regulated as one of the Clean Air Act's Hazardous Air Pollutants. This lack of an EPA standard has prompted one newspaper to label hydrogen sulfide "the least regulated common poison."[120]

Hydrogen sulfide is on the EPA's list of Extremely Hazardous Substances,[121] another category under the Clean Air Act, which regulates substances "known or may be anticipated to cause death, injury, or serious adverse effects to human health or the

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[116] According to the EPA, "Hazardous air pollutants, also known as toxic air pollutants or air toxics, are those pollutants that cause or may cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental and ecological effects." http://www.epa.gov/ttn/atw/pollsour.html

[116] Interestingly, hydrogen sulfide remained on the list as a result of "administrative error" until it was removed by a Senate Joint Resolution on August 1, 1991. See http://www.epa.gov/ttn/atw/pollutants/atwsmod.html for details.

[117] Interestingly, hydrogen sulfide remained on the list as a result of "administrative error" until it was removed by a Senate Joint Resolution on August 1, 1991. See http://www.epa.gov/ttn/atw/pollutants/atwsmod.html for details.

[118] Jim Morris. "Lost Opportunity: EPA had its chance to regulate hydrogen sulfide." November 8, 1997. *The Houston Chronicle.*

[119] As quoted in *The Houston Chronicle.*

[120] Jim Morris, *The Houston Chronicle.*

[121] Environmental Protection Agency, Chemical Emergency Preparedness and Prevention. Look for H_2S on the list at http://yosemite.epa.gov/oswer/ceppoehs.nsf/Alphabetical_Results!OpenView&Start=146

environment upon accidental release."[122] This classification requires companies that produce the substance to develop plans to prevent and respond to accidental releases. Importantly, however, this classification does not require regular emission controls of the substance.[123] Additionally, H_2S is not on the list of toxic substances whose releases companies are required to report under the EPA's Toxic Release Inventory (TRI).[124] This exclusion is due to an administrative stay put in place on August 22, 1994, as a result of lobbying by a paper, forest, and wood products industry association.[125] The administrative stay will remain in effect until the EPA decides to lift it.

At the time of writing, the EPA is considering whether to re-evaluate including hydrogen sulfide on the HAPs list of the Clean Air Act.[126] The EPA is motivated by some concerns regarding chronic and acute exposure to hydrogen sulfide.[127] Further, if they proceed with research, the EPA's findings may inform action on the current administrative stay that is responsible for exempting H_2S from TRI reporting requirements.[128]

The EPA does, however, have an inhalation reference concentration (RfC) for hydrogen sulfide, which is "an estimate (with uncertainty spanning perhaps an order of magnitude) of a daily inhalation exposure of the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a

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[122] Section 112(r) of the Clean Air Act, as cited in EPA, "Report to Congress on Hydrogen Sulfide Air Emissions," p.i.

[123] Jim Morris, *The Houston Chronicle*.

[124] EPA's Toxic Release Inventory list of chemicals for Reporting Year 2004. Available at http://www.epa.gov/tri/chemical/RY2004ChemicalLists.pdf

[125] See http://www.epa.gov/tri/guide_docs/2001/brochure2000.pdf, footnote on p.18.

[126] Personal communication with Jim Hirtz, February 24, 2006. US EPA, Health and Environmental Impacts Division, Research Triangle, North Carolina. The EPA undertook this action in response to a request by an environmental organization from Texas.

[127] Personal communication with Jim Hirtz, February 24, 2006. US EPA, Health and Environmental Impacts Division, Research Triangle, North Carolina.

[128] Personal communication with Jim Hirtz, March 2, 2006. US EPA, Health and Environmental Impacts Division, Research Triangle, North Carolina.

lifetime."[129] The RfC is one important standard for chronic exposure. According to the EPA's on-line Integrated Risk Information System (IRIS) database, the current inhalation RfC for hydrogen sulfide is $2x10^{-3}$ mg/m^3 (1.4 ppb). Applying the RfC definition, this means that it is possible that inhaling more than this concentration on a daily basis over a lifetime poses "an appreciable risk of deleterious effects." The RfC is well below any occupational standards set by OSHA or recommended by NIOSH and the ACGIH

The EPA also recommends levels of hydrogen sulfide for their Acute Exposure Guideline Levels (AEGL) for various exposure periods. These threshold exposure limits apply to the general public for emergency exposures ranging from 10 minutes to 8 hours, and are "intended to describe the risk to humans resulting from once-in-a-lifetime, or rare, exposure to airborne chemicals."[130] Appendix A includes definitions of the AEGL categories, and the recommended H_2S levels for each exposure period and AEGL category.

Other guidelines also exist for exposure to hydrogen sulfide in emergency situations. To protect the health of the general public in the event of an emergency release, the American Industrial Hygiene Association (AIHA) establishes Emergency Response Planning Guidelines (ERPGs), which specify one-hour exposure limits. These limits are also included in the table in Appendix A.

The National Research Council's Committee on Toxicology recommended Emergency Exposure Guidance Level (EEGL) to the Department of Defense for

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[129] EPA Integrated Risk Information System, Hydrogen sulfide (CASRN 7783-06-4), http://www.epa.gov/iris/subst/0061.htm.

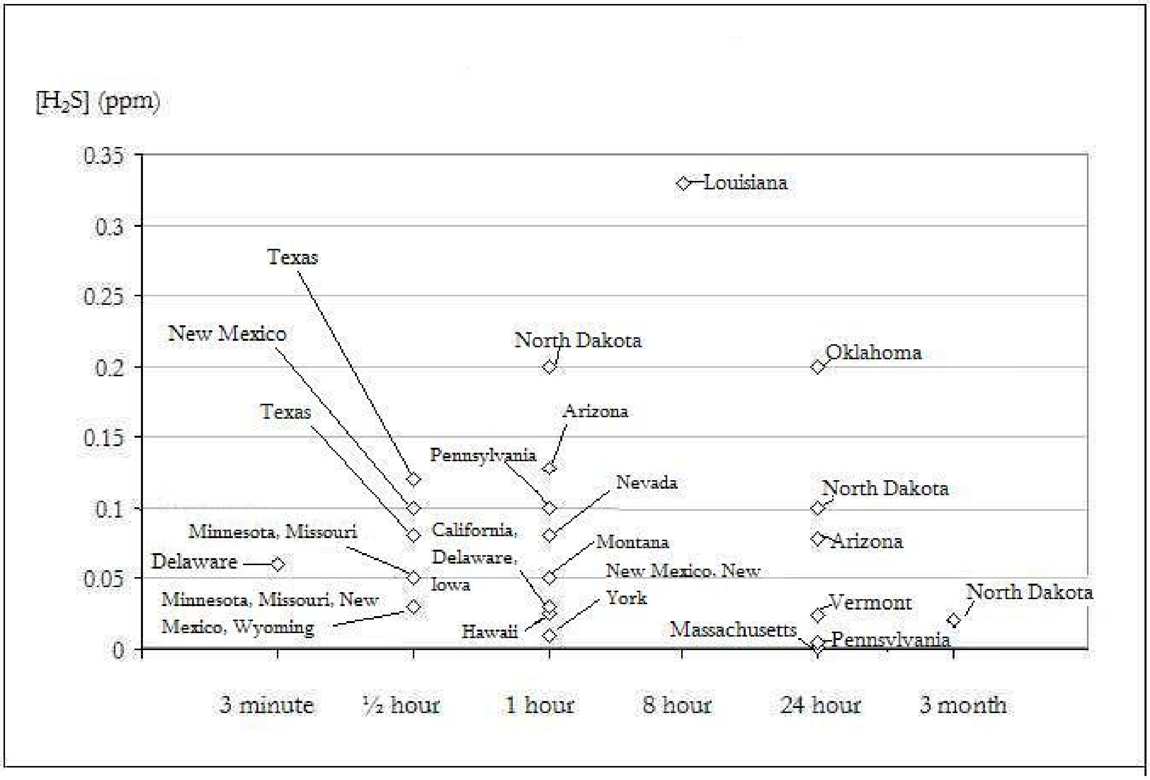
[130] EPA, The Development of Acute Exposure Guideline Levels (AEGLs), http://www.epa.gov/oppt/aegl/index.htm

maximum concentrations acceptable in rare situations such as spills and fires.[131] The EEGLs apply to young and healthy military personnel, and exist for 41 substances, of which hydrogen sulfide is one. The 10 minute EEGL for H_2S is 50 ppm, and the 24 hour H_2S EEGL is 10 ppm.[132]

6.2 State Regulations

In the absence of federal standards for ambient levels of hydrogen sulfide, twenty states have passed their own laws to regulate H_2S emissions. Figure 2 is a snapshot of state ambient hydrogen sulfide regulations. It illustrates the wide range of existing state standards.

Figure 2: State Ambient H_2S Regulations



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[131] National Oceanic and Atmospheric Administration, Office of Response and Restoration, "Public Exposure Guidelines" at http://archive.orr.noaa.gov/cameo/locs/expguide.html

[132] As cited in the EPA "Report to Congress on Hydrogen Sulfide Emissions," p.III-14.

A detailed table listing the states with ambient H_2S standards can be found in Appendix B. States set their standards based on a variety of justifications, and if available, these are also listed in Appendix B. I compiled this data by reviewing information available on each state environmental department's website, and by speaking with appropriate staff. Some states have based their ambient standard for hydrogen sulfide on odor thresholds, while others have based their standard on health considerations, either adopting the EPA's RfC inhalation guideline, modifying the OSHA safety standard to apply to continuous exposure, or basing their standard on other health studies. The fact that these states have taken the initiative to regulate ambient H_2S indicates that there is concern for human health even at these relatively low levels.

Many states' health/environmental departments routinely receive odor complaints about hydrogen sulfide. Specifically, staff at agencies in Colorado, Idaho, Iowa, Kansas, Michigan, Montana, Nevada, New Mexico, Ohio, Oregon, Texas, and Wyoming reported receiving many H_2S odor complaints. In Kansas and Ohio, people have also complained about health effects from hydrogen sulfide. In Colorado, there have been some cattle deaths attributed to exposure to hydrogen sulfide, which had collected in low-lying areas.

In addition to inquiring about ambient hydrogen sulfide standards, I collected information about any monitoring of H_2S – routine or otherwise – that the state agency conducts. The most frequently cited reason for the lack of routine monitoring, even in states with ambient H_2S standards, are budget constraints. A number of people said that monitoring and more information in general would be desirable. Some states have conducted periodic, project-based monitoring of hydrogen sulfide. Studies of hydrogen sulfide emissions from Arkansas, Colorado, Louisiana, New Mexico, and North Dakota are available. These studies are of varying quality and scope, but each sheds some light on the topic of hydrogen sulfide emissions and oil and gas operations.

6.2.1 Special H_2S Monitoring Studies

6.2.1.1 Arkansas

The Arkansas Department of Environmental Quality conducted two hydrogen sulfide monitoring studies in response to numerous health and welfare related concerns of Texarkana residents about emissions from gas processing plants in the area.[133] The first study, spanning 1995 to 1997, was a scoping study to determine whether hydrogen sulfide was indeed present in ambient air and to determine whether the facilities that were emitting H_2S were in compliance with their emissions permits. After this study established that H_2S was present in the air, a second, more rigorous study was conducted from March 1998 through March 1999. The state does not have an ambient hydrogen sulfide standard.

The monitoring data from the latter study has been reported to the EPA's Air Quality System (AQS) database. The AQS database contains measurements of air pollutants – criteria pollutants, hazardous air pollutants, and other monitored substances – and this data is publicly available.[134] The Arkansas Department of Environmental Quality itself did not provide any monitoring data or comments. Data from the AQS site[135] is available for two monitoring locations, which are classified as rural residential. At the first monitoring location, the mean concentrations for the monitoring periods from May to

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[133] Pleasant Hills H_2S Study, obtained February 2006 by mail from Jay Justice, Senior Epidemiologist with the Arkansas DEQ.

[134] http://www.epa.gov/air/data/aqsdb.html

[135] http://oaspub.epa.gov/aqspub1/aqs_query.psite The code for hydrogen sulfide is 42402.

July 1998, and October to December 1998, were 2.4 ppb and 3.4 ppb, respectively, and the maximum hydrogen sulfide concentrations were 35 ppb and 24 ppb, respectively. The levels of H_2S recorded at the second monitoring location for which data is available on the AQS site were slightly higher than at the first. The mean concentration in December 1998 was 4 ppb, and in January 1999, 5.5 ppb. The maximum concentration recorded in those months were 55 ppb and 127 ppb, respectively. These levels of hydrogen sulfide, while not very high, are nevertheless higher than normal urban background levels of up to 0.33 ppb.[136] The levels measured in this study may be expected to produce a persistent odor, which has been shown in one study (Schiffman et al., 1995) to have a negative effect on the mood of nearby residents. Based on the literature reviewed above, there is little evidence of more serious health effects attributable to these levels of H_2S.

6.2.1.2 Colorado

In 1997, the Colorado Department of Public Health and Environment (CDPHE), Air Pollution Control Division, conducted a monitoring study of H_2S concentrations near several known sources, and of urban and rural background ambient levels.[137] The CDPHE initially considered monitoring at oil and gas sites because of the information in the 1993 EPA report on emissions of H_2S at points of oil and gas extraction. Ultimately, the Colorado study excluded oil and gas operations, because of assurances from the Colorado Oil and Gas Conservation Commission (COGCC) that elevated H_2S levels are not

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[136] Agency for Toxic Substances and Disease Registry (ATSDR). 2004. Toxicological profile for hydrogen sulfide (*Draft for Public Comment*). Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. Chapter 2, p.1.

[137] “Hydrogen Sulfide Concentrations in Colorado; Results from a Screening Survey.” Prepared by The Technical Services Program, Air Pollution Control Division, Colorado Department of Public Health and the Environment, 1997. Obtained February 2006 by mail from Ray Mohr, CDPHE.

common in deposits in Colorado.[138] However, interviews with people living near oil and gas sites in Colorado, presented below, suggest that hydrogen sulfide is present near these facilities. The COGCC itself has not conducted any monitoring of H_2S at oil and gas sites. Thus, the question of what concentrations of hydrogen sulfide are present near oil and gas operations in the state is still unanswered. Colorado does not have an ambient hydrogen sulfide standard.

6.2.1.3 Louisiana

The Louisiana Department of Environmental Quality, motivated by numerous odor complaints from nearby residents, monitored hydrogen sulfide and sulfur dioxide concentrations downwind of the Calumet Refinery in Shreveport.[139] The hourly average concentration for hydrogen sulfide, for the monitoring period from October 2002 to April 2005, was 2.56 ppb, with a maximum of 50.15 ppb and a median of 1.92 ppb.[140] These measurements correspond to the range of the monitoring data from Arkansas, and the same analysis of potential health effects applies.

6.2.1.4 New Mexico

In February 2002, the Air Quality Bureau of the New Mexico Environment Department monitored hydrogen sulfide levels to determine if ambient concentrations near certain facilities are in compliance with the state's ambient standards.[141] Air samples

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[138] "Hydrogen Sulfide Concentrations in Colorado," p.2.

[139] James M. Hazlett, "Report for the Calumet Air Monitoring Project," Louisiana Department of Environmental Quality, Office of Environmental Assessment. June 8, 2005. (obtained from the author and used with permission.)

[140] Hazlett, p.4.

[141] New Mexico Environment Department (NMED), Air Quality Bureau. "Trip Report: H_2S Survey, March 18-22, 2002." By Steve Dubyk and Sufi Mustafa. Obtained from the author.

were collected near a sewage treatment plant, four dairy operations, a poultry operation, one liquid septage facility, one sewage sludge disposal facility, and several oil and gas facilities.[142] Table 3 presents the data from the monitors near the oil and gas facilities, and a discussion of the results follows.

Table 3: Summary of Monitoring Data from New Mexico Study

Facility type	**H_2S concentration measured at monitoring site (ppb)[143]**	
	Range	**Average**
Indian Basin Hilltop, no facility	5 – 8	7
Indian Basin Compressor Station	3 – 9	6
Indian Basin Active Well Drilling Site	7 – 190	114
Indian Basin Flaring, Production, and Tank Storage Site	4 – 1,200	203
Marathon Indian Basin Refining and Tank Storage Site	2 – 370	16
Carlsbad City Limits, near 8 to 10 wells and tank storage sites	5 –7	6
Carlsbad City Limits, Tracy-A	5 – 8	7
Compressor station, dehydrators – Location A	4 –5	4
Compressor station, dehydrators – Location B	2 – 15,000	1372
Huber Flare/Dehydrating Facility [a]	4 – 12	77
Snyder Oil Well Field	2 – 5	4
Empire Abo Gas Processing Plant	1 – 1,600	300
Navajo Oil Refinery	3 – 14	7 - 8

[a] Strong winds, flare not operating correctly at time of sampling may have caused lower readings than expected, according to study, p.8.

The New Mexico data indicates that ambient concentrations of hydrogen sulfide at the sampling locations, which included both oil and gas facilities and sites without oil and gas facilities, are at least an order of magnitude greater than 0.11 to 0.33 ppb, which are the ambient levels of H_2S that can normally be expected in urban areas.[144] The ambient levels recorded at the two sites without expected sources of H_2S – Indian Basin Hilltop, no facility and Carlsbad City Limits, Tracy-A – both averaged 7 ppb, indicating that usual

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[142] NMED Trip Report, p.1.

[143] The monitor that the NMED used recorded hydrogen sulfide concentrations every 30 seconds for 3 minutes. The averages reported in this table are averages of 3-minute mean concentrations.

[144] Agency for Toxic Substances and Disease Registry (ATSDR). 2004. Toxicological profile for hydrogen sulfide (*Draft for Public Comment*). Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. Chapter 2, p.1.

H_2S concentrations in this part of New Mexico are higher than normal urban background levels.

Hydrogen sulfide levels sampled at flaring, tank storage, and well drilling sites, averaging from approximately 100 to 200 ppb, are significantly elevated compared to normal background levels, and compared to usual background H_2S concentrations in this area of New Mexico. While these concentrations generally produce a nuisance due to odors which may translate into headaches, nausea and sleep disturbances if exposure is constant, one study discussed above (Legator et al., 2001) found central nervous system, respiratory system, and ear, nose and throat symptoms associated with annual average hydrogen sulfide levels ranging from 7 to 27 ppb. Overall, the data shows that concentrations of H_2S vary widely, even at similar facilities: at one compressor / dehydrator, the average concentration over the course of monitoring was 4 ppb, while at another, the average was 1372 ppb. The data further demonstrates that H_2S is present, often at quite elevated levels, at oil and gas facilities. A staff person at the NMED indicated that there is need for more monitoring and a better-designed study, but that budget constraints prevent them from routine monitoring. The department had rented a hydrogen sulfide monitor for this study.

6.2.1.5 North Dakota

The North Dakota State Department of Health and Consolidated Laboratories monitored hydrogen sulfide emissions from oil and gas wells at several locations, from 1980 until 1992. Each location was near at least one oil or gas well. At one location, the Lostwood Wildlife Refuge monitoring station, the highest one hour average concentration recorded was 88 ppb, in 1990.[145] At Lone Butte, 6 miles north of the Theodore Roosevelt National Park, one hour average hydrogen sulfide concentrations frequently exceeded 200 ppb.[146] At another site, in a valley with several wells within one mile from the monitor, recorded concentrations were as high as 250 ppb.[147] These findings highlight the fact that hydrogen sulfide is routinely emitted near oil and gas wells.

These monitoring studies reveal that hydrogen sulfide is present at oil and gas facilities, including oil refineries, gas processing plants, oil and gas wells, flares, and compressor stations. These types of facilities are commonly situated near residences, where people can be routinely exposed to hydrogen sulfide. The levels of H_2S range from relatively low concentrations of 2 ppb recorded in Louisiana to the much higher concentrations observed in New Mexico and North Dakota.

6.2.2 Routine Monitoring

Of the twenty states that have an ambient hydrogen sulfide standard, only three – California, Oklahoma, and Texas – conduct routine monitoring of ambient H_2S concentrations. The other eighteen states do not monitor ambient H_2S levels. Rather, the standard is generally used in permitting facilities that emit hydrogen sulfide. Typically, the health/environmental departments model emissions and permit a facility if the model reports that the emissions would not raise ambient levels above the standard.

6.2.2.1 California

The California Air Resources Board (CARB), which manages air quality and pollution in the state, has authority to enforce the state ambient hydrogen sulfide standard

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[145] EPA, “Report to Congress on Hydrogen Sulfide Emissions,” p.III-22.
[146] EPA, “Report to Congress on Hydrogen Sulfide Emissions,” p.III-26.
[147] EPA, “Report to Congress on Hydrogen Sulfide Emissions,” p.III-30.

of 30 ppb, averaged over one hour. CARB also delegates management to the state's 35 Air Pollution Control Districts (APCDs) or Air Quality Management Districts (AQMDs), each with authority to adopt its own rules and regulations to control and monitor emissions of hydrogen sulfide. A map of the state air districts is in Appendix C. The local districts defer to the state ambient standard, but they are in charge of conducting monitoring of ambient H_2S.

The twelve sites in California where hydrogen sulfide is routinely monitored were chosen because of nearby emission sources. Table 4 summarizes the monitoring sites and the sources of H_2S. I discuss the data for 2005 from Contra Costa and Santa Barbara Counties, where the H_2S sources are due to oil and gas facilities. Daily averages of hourly hydrogen sulfide readings at the three monitoring sites in Contra Costa County range from 0.000 to 0.003 ppm, with one reading of 0.007 ppm at one monitoring site. Similarly, the daily averages of hourly H_2S concentrations recorded during 2005 at all three sites in Santa Barbara range from 0.000 to 0.001 ppm.[148] These levels are most likely of no health concern.

Table 4: California H_2S Monitoring Sites

District	**County**	**Sites**	**Source(s)**
Great Basin Unified APCD	Inyo	2	Geothermal Power Plant
Lake County AQMD	Lake	3	Geothermal Power Plants
Mojave Desert AQMD	San Bernardino	1	Chemical Processing Facility
San Francisco Bay Area AQMD	Contra Costa	3	Chevron Oil Refinery
Santa Barbara County APCD	Santa Barbara	3	Oil and Gas Processing Facilities

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[148] Data is available at http://www.arb.ca.gov/adam/cgi-bin/db2www/adamweeklyc.d2w/start. In Step 3, select desired county, and on the next page, in Step 1, select "Daily Average of Hourly Measurements." Use arrows on the right to select different time periods.

6.2.2.2 Oklahoma

The Air Quality Monitoring division of the Oklahoma Department of Environmental Quality (DEQ) continuously monitors ambient levels of hydrogen sulfide at sites downwind of two large oil refineries in Tulsa. The DEQ initiated the monitoring because complaints about foul odors numbered as many as 5 or 6 per day.[149] According to staff at the Oklahoma DEQ, the DEQ installed three monitors in Tulsa, and continuous hourly average data for two of the three monitors is available on-line.

Figure 3 summarizes the data on ambient H_2S levels recorded at these two sites in Tulsa. Monitor 235 is in a park right next to residences an eighth to a quarter of a mile downwind and across the river from a refinery. Monitor 501 is on a hill, two to three miles downwind of another refinery. The hill elevation approximately lines up with the height of the refinery stacks. The majority of the odor complaints mentioned above came from residents of this neighborhood. Now, the DEQ receives about 3 or 4 complaints a week. The levels of hydrogen sulfide in both neighborhoods, although not very high, are nevertheless above the EPA's RfC of 1.4 ppb, and are well elevated above normal background levels of 0.11 to 0.33 ppb. It is possible that continuous exposure to these levels poses health risks. While the Oklahoma DEQ is monitoring hydrogen sulfide levels, there is no concurrent community health or exposure study investigating the health effects of chronic exposure to these levels of H_2S.

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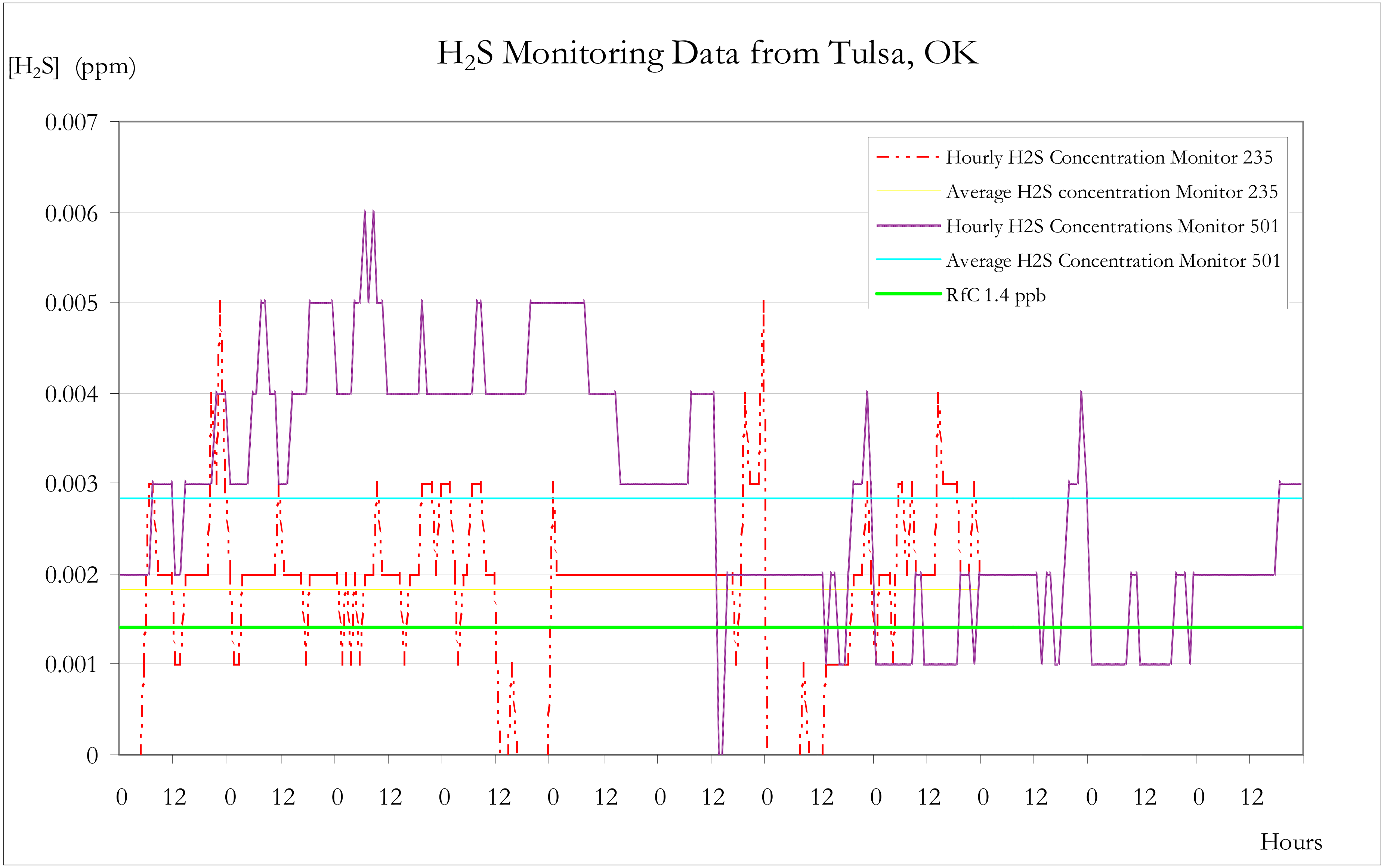
[149] Personal communication, Rhonda Jeffries, Oklahoma Department of Environmental Quality. February 10, 2006.

Figure 3: Tulsa H_2S Monitoring Data[150]



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[150] Data from http://www.deq.state.ok.us/aqdnew/monitoring/cpdata.htm#

6.2.2.3 Texas

The Texas Commission on Environmental Quality (TCEQ) coordinates a network of monitors across the state to insure compliance with its ambient air quality standards. Hydrogen sulfide is among the pollutants that are routinely monitored. There are twelve active H_2S monitors in Texas, some in residential and some in industrial areas, each near an oil or gas facility, including a refinery, a tank battery, and a compressor station.[151] The majority of the monitors register relatively low H_2S levels, ranging from 0.1 ppb to 5 ppb. However, one monitor at compressor station near a residence, consistently records elevated levels of H_2S. In December 2005, the last month for which the data has been validated by the TCEQ, 20 percent of the hourly readings exceeded the state standard of 0.8 ppm.[152] Chronic exposure to such levels, generally considered a nuisance due to odor, has also been shown to adversely affect human health, as discussed in the Literature Review – Chronic Exposure section.

7. Evidence From People Living Near Oil and Gas Operations

I conducted semi-structured, informal telephone interviews with people who believe that their health has been compromised as a result of exposure to hydrogen sulfide from oil and gas operations. Appendix D contains narratives of each interview, and provides details about each interviewee's experience. Some interviewees had previously contacted the Oil and Gas Accountability Project (OGAP), a non-profit organization working to reduce the impacts of oil and gas development on communities and the

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[151] Data and photos are available at http://www.tceq.state.tx.us/compliance/monitoring/air/monops/sites/monitors_map.html

[152] 65 out of 332 readings were above 80 ppb. (40 data points did not include readings due to equipment maintenance).

environment, about their concerns. These interviewees identified other potential interview participants. I spoke with eleven people, and obtained information about the experiences of two additional people who lived with the interviewees. Thus, the information I present here is based on the experience of thirteen people. The ages of the interview participants range from 25 to 76. To protect the privacy of the interviewees, their names and other identifying characteristics have been withheld.

Table 4 summarizes the information on the sources of H_2S, lengths of exposure, and symptoms reported by each interviewee. Hydrogen sulfide exposure was due to emissions from a variety of sources. As identified in the interviews, these consisted of a natural gas sweetening facility, natural gas and oil well sites, flaring operations at both oil and gas facilities, venting, wastewater pits, and an oil refinery. The duration of exposure also varied, from one year to as long as eleven years, and these exposure periods in several cases include instances of acute exposure to accidental high-concentration H_2S releases. Some interviewees had information on the concentrations of H_2S to which they were exposed, while others did not.

The reported health effects are consistent with exposure to hydrogen sulfide, and include both physical and neurological symptoms. The most commonly reported symptoms were pressure headaches or dull headaches (ten people), fatigue or loss of energy (seven people), and memory impairments (seven people). Dizziness, throat irritation, eye irritation, heart palpitations, and insomnia were each reported by four people, and nosebleeds by five people. Other symptoms that the interviewees are experiencing are balance problems, trouble walking, vomiting, coughing, concentration problems, skin irritations (in some cases severe), and shortness of breath.

Eight people are experiencing chemical hypersensitivity and attribute it to hydrogen sulfide exposure. Two people I interviewed have had their gall bladders removed, which may or may not have been related to hydrogen sulfide exposure, and four have been diagnosed with chemical encephalopathy (swelling of the brain). Three interviewees are on permanent Social Security disability as a result of their health problems, which they attribute to hydrogen sulfide exposure. Five separate interviewees also stated that animals in their area were experiencing health problems. Every interviewee reported that the characteristic rotten egg odor of hydrogen sulfide was commonplace at their residences. Four families that I interviewed chose to move from their previous residences because of the health problems they associate with hydrogen sulfide.

While some of the interviewees have been diagnosed by medical professionals who attributed their symptoms to exposure to hydrogen sulfide, others have not. Oil and gas operations emit a host of other pollutants in addition to hydrogen sulfide, many of which are hazardous to human health, confounding the process of ascribing health effects to just one chemical. Additional confounders are individual health factors and the potential presence of other sources of hydrogen sulfide. This difficulty of disaggregating pollutants and symptoms provides an opportunity for critics to undermine the conclusion that the health problems reported by the people I interviewed are due to hydrogen sulfide. Nevertheless, the symptoms that the interviewees experienced match the health effects associated with hydrogen sulfide exposure as reported in the toxicological studies I present above.

The interviews provide evidence, which, although it is anecdotal, attests to the fact that hydrogen sulfide is emitted at a host of oil and gas facilities, and that its continual presence in ambient air compromises human health and well being. Although the concentrations of H_2S to which the interviewees were exposed are, for the most part, not known, they likely are not very high. Except for the three cases of knockdown, the interviews show that chronic exposure to relatively low levels of hydrogen sulfide can nevertheless take a considerable toll on people's health. The health problems that the people I interviewed are experiencing are serious enough to warrant monitoring of ambient air near oil and gas facilities in residential areas to ensure that H_2S levels are not above those considered safe. Clearly, the very issue of what levels of hydrogen sulfide are "safe" is contentious, judging in part by the wide range of values that characterize states' ambient H_2S standards. More research is certainly needed, both to determine the effects of chronic exposure to low levels of H_2S and to establish a sound standard for safe exposure to H_2S.

Table 4: Summary of Interviews

	Age and Sex	Source of Emissions	Exposure Time and Concentrations	Symptoms	Diagnosis
Story 1	Male 76	Venting from tank battery	3 years ongoing, 2 acute exposures	*Ongoing*: Staggering, dizziness, pressure headaches, dry cough, shortness of breath, throat irritation, fatigue, lightheadedness, insomnia, lack of concentration, memory loss; *Acute exposure*: stiff neck, dizziness and dry heaving	chemical encephalopathy chemical hypersensitivity due to H_2S
	Male 25	Sour gas well, tank battery	Ongoing; one acute exposure-knockdown, 200 ppm	*Knockdown*: severe headache *Persistent symptoms*: very bad memory, some balance problems	
Story 2	Female 44	Oil refinery, waste water treatment plant, oil pads	Ongoing, unknown concentrations	Headaches, balance problems, concentrations problems, eye irritation, problems sleeping, general pain, low muscle strength, trouble walking, problems with memory retention and reading comprehension, hypersensitivity of the skin	chemical encephalopathy
Story 3	Male and Female, mid-40s	Natural gas well flaring	Ongoing, unknown concentrations	*Wife*: pains similar to severe rheumatoid arthritis, blistering of the skin when showering, severe burns on the bottoms of her feet, skin covered in welts, fatigue, vomiting, rectal bleeding, severe sinus headaches; gall bladder removed *Husband*: rectal bleeding	None specific to H2S
Story 4	Male and Female, mid-60s	Amine plant, sour gas wells	Ongoing for 1 year; unknown concentrations	*Both*: chronic sore throat, congestion, coughing, headaches, swollen eyes, insomnia, occasional nosebleeds, and a general lack of energy. *Husband*: face burns, burning on hands and eyes. *Wife*: heart palpitations	None
Story 5	Male and female, mid-40s	Oil refinery, waste water treatment	Husband: occupational; ongoing residential Wife: ongoing; Concentrations 3 ppm; 3 or 4 times per week 10 ppm	*Husband*: bloody nose, headaches, colon polyps, burning eyes, throat itching, and itching all over, severe headaches, severe rashes, burning skin, teeth damage, nerve damage, slurred speech; on disability, unable to work *Wife*: rapidly deteriorating eyesight, ringing in her ears, memory problems, trouble with balance, tremors, trouble walking up and down stairs, and severe migraine headaches; gall bladder removed	chemical encephalopathy
Story 6	Female 50s	Sour natural gas wells flaring, tank battery	Ongoing; one acute exposure	*Acute exposure*: headache, extremely sick; *Later*: extreme fatigue, confusion, anxiety, heart symptoms, shaking and tremors when exposed to certain chemicals, dizziness, headaches, nosebleeds, memory and cognitive impairments, especially upon exposure to H2S or other chemicals, bronchial asthma symptoms *Son knocked down*: arrhythmia, balance problems, and pneumonia; *Currently:* nosebleeds, walks with a cane, experiences extreme headaches, confusion, brain fog, ongoing heart problems, burning lungs when he’s in an area with chemicals, scaling of the skin, psoriasis, and chloro-acne	chemical encephalopathy, non-recoverable

Story 7	Male 27	Gas processing plant, wells	Ongoing, one acute exposure	Acute exposure: extreme shortness of breath, close to unconsciousness Ongoing: blurred vision, brain fog, memory impairment, excessive sleepiness, lack of energy and strength, occasional diarrhea, blood in his urine, loss of libido, abnormal heart rhythm, and anxiety-like attacks, severe and protracted involuntary muscle movements in his arms and legs.	Chemical encephalopathy, optical nerve damage
Story 8	Female 50s	Gas wells, flares, condensate pits	Ongoing occupational, one acute exposure	Acute exposure: knockdown, blinding headache, fading of consciousness Ongoing: nasal irritation, balance and memory impairment, nosebleeds, nerve inflammation	Chemical sensitivity

8. Concluding Remarks

The literature on human health and hydrogen sulfide reveals serious and lasting physiological and neurological effects associated with acute exposure. The health effects of chronic exposure to lower levels of H_2S, as documented in several studies, also include persistent physiological and neurological disturbances. Oil and gas facilities can be expected to accidentally and routinely emit hydrogen sulfide in concentrations that span a wide range and are associated with a variety of health effects. Academic studies, my conversations with health department staff, and available data from monitoring projects help establish that hydrogen sulfide is indeed present near oil and gas facilities.

Because people live near oil and gas sites, emissions of H_2S may be routinely compromising human health. The interviews I conducted with people who live close to oil and gas facilities, as well as some research reported in the Literature Review section, provide evidence of health impacts from exposure to H_2S emitted by oil and gas development. Although the anecdotal evidence from my interviews is vulnerable to criticism that other pollutants or individual health factors may be responsible for the symptoms, the reported health effects are consistent with hydrogen sulfide exposure. The fact that concentrations of H_2S to which people are exposed are often not known does not imply that hydrogen sulfide is not the cause of the observed health effects. The lack of precise exposure data is, however, one area that future research should address.

In the meanwhile, people's health needs to be protected. The proximity of oil and gas wells to people's residences is one route of exposure to hydrogen sulfide, and to other pollutants associated with oil and gas extraction. The persistence of the land ownership pattern known as 'split estate,' under which one entity owns the rights to the surface of the property and another to the minerals under the surface, is partly responsible for the proximity of oil and gas facilities to residences. Another factor are low setbacks, the minimum distance required between an energy facility and a specific type of development.[153] For example, in Colorado, where some of the interviewees live, the residential setback requirement for oil and gas wells is 150 feet.[154] In Texas, the setback is also 150 feet,[155] while the New Mexico residential setback is just 100 feet.[156] In Alberta, Canada, the residential setback requirement for sour gas wells areas is 100 m (approximately 330 feet).[157] While greater than Colorado's and Texas's required setback, this distance may not be sufficient, as some of the interviewees were exposed to hydrogen sulfide in Alberta. To truly provide a margin of safety and protection to people who live in areas of oil and gas development, whether the facilities are on their surface property or not, greater setback distances need to be established. The siting of oil refineries and gas processing plants near residences, and conversely, building homes near existing refineries and gas plants, exposes people to a host of pollutants, including hydrogen sulfide. This is often an issue with the dimension of social and environmental justice added to questions of protecting public health.

Some technological options exist that may help mitigate the effects of hydrogen sulfide on the health of people who live near emission sources. One advanced technology for odor control, consisting of a dry scrubbing system with multiple beds of engineered media (made by soaking, or on a rotating agglomeration disk), removed hydrogen sulfide at a wastewater

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[153] http://www.eub.ca/portal/server.pt/gateway/PTARGS_0_0_257_229_0_43/http%3B/extContent/publishedcontent/publish/eub_home/public_zone/eub_process/enerfaqs/EnerFAQs5.aspx#1

[154] Colorado Oil and Gas Conservation Commission, Rule 603. Available at http://oil-gas.state.co.us/RR_Asps/600Series.pdf

[155] Texas Administrative Code, Title 16, Part I, Chapter 3, Rule 3.21 (a) and (i). Available at http://info.sos.state.tx.us/pls/pub/readtac$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y

[156] Personal communication, Denny Foust, New Mexico Environment Department, April 12, 2006.

[157] Alberta Energy and Utilities Board, Directive 056, Energy Development Applications and Schedules. Available at http://www.eub.ca/docs/documents/directives/directive056.pdf, pp.54-55.

treatment facility with an efficiency of 99.94 percent.[158] This odor control technology reduced the peak inlet hydrogen sulfide concentration of 108.0 ppm to 0.061 ppm.[159] Such odor abatement technologies could be required at all facilities that emit hydrogen sulfide, including oil refineries and gas processing plants. At points of oil and gas extraction and processing, requiring high efficiency flares would ensure that less hydrogen sulfide (and other pollutants) escape into ambient air unburned.

As I show in the Regulations and Recommendations section, at the federal level, the oil and gas industry and the paper and pulp industry have exerted their influence to prevent H_2S from being included on the Clean Air Act's Hazardous Air Pollutants (HAPs) list, and to exempt it from reporting under the EPA's Toxic Release Inventory (TRI). At the time of writing, the EPA is reviewing both decisions, which at the very least indicates that some concern exists over the lack of stricter regulation of hydrogen sulfide at the federal level. The level of regulation of hydrogen sulfide varies widely across the states that have established an ambient standard in the absence of a federal one, but again, the very existence of ambient standards suggests that hydrogen sulfide is a concern.

Monitoring of ambient H_2S is necessary to determine exactly how much is being emitted and to clarify the link between exposure and health effects. Enough evidence of routine H_2S emissions at oil and gas facilities emerges from my conversations with health department personnel, interviews with people living near oil and gas sites, several studies summarized in the Literature Review section, and state monitoring projects to merit more comprehensive monitoring. The lack of federal standards for ambient H_2S levels or for emissions of H_2S is one reason for sparse monitoring even at state level, since state health / environmental departments

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[158] Gailey, Karen. 2004. "Goodbye Odors, Hello Happy Neighbors." *Pollution Engineering*. p.30.
[159] Gailey, Karen. 2004. "Goodbye Odors, Hello Happy Neighbors." *Pollution Engineering*. p.30.

largely depend on federal funding for their projects. More routine and special project monitoring would facilitate conducting community health studies, by providing accurate exposure data that could be matched with observed health effects.

In light of the information presented here on the health effects associated with exposure to hydrogen sulfide, even though rigorous data on the dose-response relationship is lacking, it is irresponsible and callous to delay making some public policy decisions that would help protect human health.

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Appendix A: Guidelines for Occupational Exposure to Hydrogen Sulfide

$[H_2S]$ (ppm)	Agency	Duration	Comments
0.1	AIHA [a]	ERPG- 1 1 hour	Maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing other than mild, transient adverse health effects or perceiving a clearly defined objectionable odor; based on human odor detection.
0.33	EPA [b]	AEGL 1 8 hours	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could experience notable discomfort, irritation, or certain asymptomatic nonsensory effects. However, the effects are not disabling and are transient and reversible upon cessation of exposure.
0.36	EPA [b]	AEGL 1 4 hours	
0.51	EPA [b]	AEGL 1 1 hour	
0.6	EPA [b]	AEGL 1 30 minutes	
0.75	EPA [b]	AEGL 1 10 minutes	
10	ACGIH [c]	TLV-TWA 8hr/day, 40hr/week	Occupational exposure
10	OSHA [d]	8hr/day, 40hr/week	Occupational exposure
10	NIOSH [e]	10 minutes	Recommended exposure time to 10 ppm in the workplace
15	ACGIH [c]	TVL-STEL Short periods of time	Occupational exposure for short periods of time
17	EPA [b]	AEGL 2 8 hours	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape.
20	EPA [b]	AEGL 2 4 hours	
20	OSHA [d]	Ceiling	Ceiling, if no other exceedence of 10 ppm standard
27	EPA [b]	AEGL 2 1 hour	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape.
30	AIHA [a]	ERPG-2 1 hour	Maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms which could impair an individual's ability to take productive action; based on animal studies
31	EPA [b]	AEGL 3 8 hours	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could experience life-threatening health effects or death.
32	EPA [b]	AEGL 2 30 minutes	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape.
37	EPA [b]	AEGL 3 4 hours	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could experience life-threatening health effects or death.
41	EPA [b]	AEGL 2 10 minutes	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape.
50	OSHA [d]	10 minute ceiling	If no other measurable exposure during 8 hr shift
50	EPA [b]	AEGL 3 1 hour	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could

59	EPA [b]	AEGL 3 30 minutes	experience life-threatening health effects or death.
76	EPA [b]	AEGL 3 10 minutes	
100	NIOSH [d]	IDLH	Immediately Dangerous to Life and Health
100	AIHA [a]	ERPG-3 1 hour	Maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing life-threatening health effects; based on human studies

[a] Source: EPA, http://www.epa.gov/oppt/aegl/define.htm and http://www.epa.gov/oppt/aegl/results57.htm

[b] Source: AIHA, 2005 American Industrial Hygiene Association, available at http://www.aiha.org/1documents/Committees/ERP-erpglevels.pdf, and EPA Report, 1993 p.III-11, 13.

[c] EPA "Report to Congress on Hydrogen Sulfide Emissions," p.III-10.

[d] Occupational Safety and Health Administration, 29 CFR 1910.1000, available at http://www.osha.gov/dts/chemicalsampling/data/CH_246800.html

[e] Source: NIOSH is a department within the Centers for Disease Control and Prevention. See http://www.cdc.gov/niosh/npg/npgd0337.html for NIOSH's H_2S exposure recommendations.

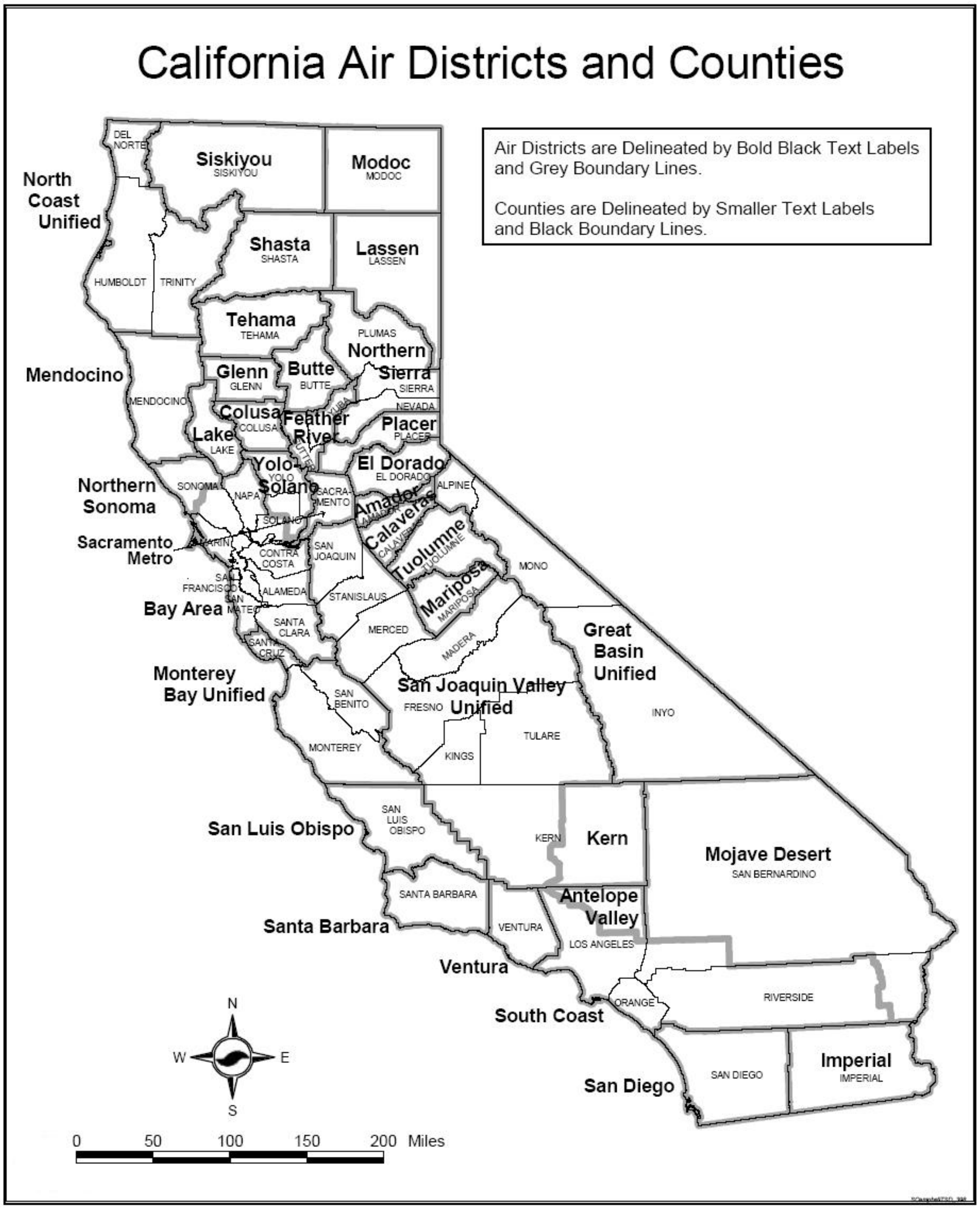
Appendix B: State Ambient Hydrogen Sulfide Standards

State	Standard	Duration	Justification	Source
Arizona	180 µg/m3 (0.128 ppm)	1 hr	AAAQG, health based, on OSHA guidelines	www.azdeq.gov/environ/air/permits/download/ambient.pdf
	110 µg /m3 (0.078ppm)	24 hr		
California	0.03 ppm	1 hr		California Air Resources Board, Nov 2005: http://www.arb.ca.gov/aqs/aaqs2.pdf
Delaware	0.06 ppm	average concentration not to be exceeded taken over any consecutive 3 minutes		Regulation 3, Delaware Ambient Air Quality Standards, www.dnrec.state.de.us/air/aqm_page/docs/pdf/reg_3.pdf
	0.03 ppm	average concentration not to be exceeded taken over any consecutive 60 minutes		
Hawaii	25 ppb	1 hr	Combination of health and nuisance	Hawaii State Ambient Air Quality Standards, www.hawaii.gov/health/environmental/air/chart.pdf
Iowa	30 ppb	1-hr daily maximum	"health effects standard"	www.legis.state.ia.us/Rules/2004/Bulletin/IAB040818.pdf
Louisiana	330 ppb	8-hr average	NIOSH/OSHA safety standard, took 1/42 of their level	Personal Communication, Jim Hazlett, Air Quality Assessment, Louisiana Department of Environmental Quality
Massachusetts	0.65 ppb	24-hr and annual limit	Based on EPA RfC, Threshold Effects Exposure Limit and Allowable Ambient Limit	Massachusetts Rule 310: Ambient Air Exposure Limits for Chemicals www.mass.gov/dep/air/aallist.pdf
Minnesota	0.05 ppm (70 µg /m3)	1/2 hr average not to be exceeded over 2 times per year		Minnesota Pollution Control Agency, State Ambient Air Quality Standards, Chapter 7009.0080 www.revisor.leg.state.mn.us/arule/7009/0080.html
	0.03 ppm (42 µg /m3)	1/2 hr average not to be exceeded over 2 times in any 5 consecutive days		
Missouri	0.05 ppm (70 µg /m3)	1/2 hr average not to be exceeded over 2 times per year		Missouri Ambient Air Quality Standards CSR 10-6.010, www.sos.mo.gov/adrules/csr/current/10csr/10c10-6a.pdf
	0.03 ppm (42 µg /m3)	1/2 hr average not to be exceeded over 2 times in any 5 consecutive days		
Montana	0.05 ppm	hourly average, not to be exceeded more than once per year	health based	Montana Rule 17-8-214 http://deq.mt.gov/dir/legal/Chapters/CH08-02.pdf
Nevada	0.08 ppm	1-hr average	health based	Nevada Chapter 445B – Air Controls, section 22097, www.leg.state.nv.us/NAC/NAC-445B.html#NAC445BSec22097
New Mexico	0.010 ppm	1-hr average not to be exceeded more than once per year		New Mexico Ambient Air Quality Standards, Title 20, Chapter 2, Part 3 www.nmenv.state.nm.us/aqb/regs/20_2_03nmac_103102.pdf
	0.100 ppm	1/2 hour average	special for the Pecos-Permian Basin Intrastate Air Quality Control Region	
	0.030 ppm	1/2 hour average	for within five miles of municipalities in Pecos-Permian Basin that are populated areas (more than 20,000 people)	

New York	0.01 ppm	1-hr average	odor and aesthetic	New York Rules and Regulations, Chapter III, Subpart 257-10; www.dec.state.ny.us/website/regs/subpart257_10.html
North Dakota	10 ppm	ceiling, maximum instantaneous concentration not to be exceeded	health based	North Dakota Ambient Air Quality Standards, Chapter 33-15-2 www.legis.nd.gov/information/acdata/html/..%5Cpdf%5C33-15-02.pdf
	0.20 ppm	maximum 1-hr average concentration not to be exceeded more than once per month		
	0.10 ppm	maximum 24-hr average concentration not to be exceeded more than once per year		
	0.02 ppm	maximum arithmetic mean concentration averaged over three consecutive months		
Oklahoma	200 ppb	24-hr average concentration		Oklahoma Air Pollution Control Rules, Title 252, Chapter 100-31-7 www.deq.state.ok.us/rules/100.pdf
Oregon	2 µg /m3 (0.3 ppb)*	annual average concentration	based on EPA's RfC, proposed benchmark	Personal Communication, Bruce Hope, Senior Environmental Toxicologist, Oregon Department of Environmental Quality, Air Quality Division. Feb. 10, 2006.
Pennsylvania	0.005 ppm	24-hr average		Pennsylvania Article III, Chapter 131, www.pacode.com/secure/data/025/chapter131/025_0131.pdf
	0.1 ppm	1-hr average		
Texas	0.08 ppm	30-min average	if the downwind concentration of hydrogen sulfide affects a property used for residential, business, or commercial purposes	Texas Administrative Code, Title 30 Part 1, Chapter 112, subchapter B; http://info.sos.state.tx.us/pls/pub/readtac$ext.ViewTAC?tac_view=5&ti=30&pt=1&ch=112&sch=B&rl=Y
	0.12 ppm	30-min average	if the downwind concentration of hydrogen sulfide affects only property used for other than residential, recreational, business, or commercial purposes, such as industrial property and vacant tracts and range lands not normally occupied by people.	
Vermont	33.3 µg /m3 (0.024 ppm)	24-hr	health based	proposing 1 µg /m3 annual average, to be determined in April; current standard available at http://www.anr.state.vt.us/air/docs/apcregs.pdf
Wyoming	70 µg /m3 (0.05 ppm)	1/2 hour average not to be exceeded more than 2 times per year		Wyoming Department of Environmental Quality, Air Quality Division, Ambient Air Quality Standards, Chapter 2: http://deq.state.wy.us/aqd/stnd/Chapter2_2-3-05FINAL_CLEAN.pdf
	40 µg /m3 (0.03 ppm)	1/2 hour average not to be exceeded more than 2 times in any 5 consecutive days		

* Proposed, to be reviewed April 2, 2006

Appendix C: California Air Districts



Appendix D: Interview Narratives

Story 1

One participant, a 76-year-old rancher, used to own and live on a ranch on flat prairie land in Alberta, Canada. His property was three quarters of a mile straight east and downwind of an oil facility, which included a tank battery where impurities such as sand and salt water were removed from the oil to prepare it for the pipeline. According to government figures which he claims to have obtained, the oil initially contained 8% hydrogen sulfide. This figure increased to 13% after a few years of production. The interviewee believes that H_2S emissions affected people within a radius of up to three miles from the facility.

Venting to the atmosphere from several big tanks in the battery released hydrogen sulfide, as oil added to the tanks stirred up the settled oil, emitting H_2S. For the first three years of the facility's operation, there was no flare, and the hydrogen sulfide would accumulate and then be vented.

This interviewee was exposed to hydrogen sulfide many times before he realized what was taking place. He often woke up dizzy, and reports staggering for a half hour before regaining his balance for the rest of the day. Initially, he thought the dizziness was due to high blood pressure, but tests revealed that his blood pressure was normal. During and after every exposure, he experienced angina pains (pain due to lack of oxygen to the heart muscle) while walking even short distances. After moving away, the angina improved and he is able to control it with medication. Nevertheless, he has undergone six by-pass surgeries. Additionally, he experienced pressure inside his head and short term memory loss.

This interviewee experienced health problems as a result of several specific hydrogen sulfide releases from the tank battery. He believes he was exposed to a very high, but unknown, concentration of hydrogen sulfide on one occasion, when he was harvesting crops approximately 500 feet from the oil facility's fence line. He recalls briefly smelling the rotten egg odor, and then not noticing it further. At that time, he experienced a stiffening of the neck and shoulders, and his head 'froze' in the position he had turned it. Now, if he is exposed to hydrogen sulfide, he experiences similar but not as severe symptoms of the head, neck, and shoulders.

On another occasion, when the rotten egg odor characteristic of hydrogen sulfide was especially strong outside the house, he was sick for three days. During this episode, which he attributes to many small exposures over the three days, his balance was disrupted so that he could not stand when he stood up, and he experienced dry heaving. After this episode, he started to be observant and to study the effects of hydrogen sulfide on human health. He used the Internet and visited other people who had problems due to H_2S, and found that his symptoms matched hydrogen sulfide exposure.

The interviewee eventually purchased a hydrogen sulfide monitor, and he reports that there were short periods of time when H_2S concentrations were very high. On one occasion, his 17-year-old grandson experienced knockdown while monitoring for hydrogen sulfide on the property. The monitor recorded 200 ppm at that time. His grandson had been exposed at other times while working on the ranch, and had difficulty in school after the knockdown.

I also spoke with the grandson about his knockdown. He experienced dull headaches in the front of his head whenever he was exposed to H_2S. He remembers having a very intense headache right before the incident. His head and neck stiffened, and he lost consciousness. Since this exposure, he has difficulty remembering details and notices his memory getting progressively worse. His balance is not as good as it used to be, and he experiences hot flashes several times per week.

The older interviewee sought medical help on many occasions because of his health problems. Eight hours of testing by an H_2S specialist ruled out Alzheimer's, Parkinson's, and Lou Gehrig's diseases, as well as progressive blindness and deafness. According to this professional's letter, which the interviewee read to me, the diagnosis was of a "75-year-old man who had extensive exposure" and now suffers from chemical encephalopathy (swelling of the brain) due to H_2S, small airways obstruction beyond that due to cigarette smoking and attributable to H_2S, $SO_{2,}$ and diesel exhaust, and chemical hypersensitivity due to H_2S exposure. His symptoms are a dry cough, shortness of breath, throat irritation, fatigue, lightheadedness, dizziness, insomnia, lack of concentration, and memory loss. The symptoms that improved after moving are throat and eye irritation and balance, but the others persist.

There have also been problems with cattle in the area, including spontaneous abortions and animals' hooves falling off and not healing.

Story 2

A 44-year-old woman has suffered many health impacts from exposure to hydrogen sulfide and from an oil refinery, and there are many pump jacks, collection ponds, and tank batteries close to her residence.

The oil refinery transfers its wastewater and production water to the municipal wastewater treatment facility, which also received wastewater from a dairy facility until 2001.[160] Her husband, who was employed at the wastewater treatment facility and had previously worked for an oil company, is now on permanent Social Security Disability Leave because repeated exposure rendered him physically and psychologically unfit to work. According to a safety company monitoring data that she has seen, she reported that concentrations of 10 ppm are commonplace in the street in front of the wastewater treatment plant. A park where children play is across the street from the plant.

She believes that she is exposed to hydrogen sulfide daily or almost daily. The smell of rotten eggs is regularly present in town and at her residence. Sometimes, the odor is very strong for a short time, "a minute or so," and then she no longer detects it. She thinks this is due to concentrations above the odor threshold, which occurs between 50 and 100 ppm.[161] At other times, visitors new to the area could detect an odor while she could not. She thinks her nose is no longer as sensitive to the odor of H_2S due to chronic exposure.

As a result of her and others' complaints, the Center for Disease Control's ATSDR sent personnel to her property to monitor for H_2S. Based on the levels they found in the ambient air, ATSDR has plans to follow up with water and soil sampling on the property. Although the monitors registered H_2S, the ATSDR took no action because of a lack of health studies attributing adverse health effects to the measured levels. She does not know the exact levels of H_2S on her property.

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[160] Since then, the diary has secured a discharge permit from the state Department of Environmental Quality to treat its waters on site. The treatment amounts to holding ponds on adjacent farmland that the dairy purchased, and then discharging the water over their property.

[161] Refer to Health Effects Chart.

She also experiences headaches, balance problems, concentrations problems, eye irritation, problems sleeping, and general pain. The headaches are a daily occurrence, but the severity changes. If she leaves town for several days, the headaches stop. Other problems are low muscle strength, trouble walking, problems with memory retention and reading comprehension, and hypersensitivity of the skin. She believes some of her problems are due to sexual contact with her husband, who had been routinely exposed to much higher levels at the workplace, as high as 200 ppm on one occasion, according to a police report of the accident. Specialists have diagnosed her husband with brain damage and physical damage to the neurological and muscular system from exposure to hydrogen sulfide.

Her symptoms prompted her to seek medical help on many occasions. Because of her low muscle strength, one doctor initially diagnosed her with multiple sclerosis. He later changed the diagnosis to chemical encephalopathy along with peripheral neuropathy. Another doctor has diagnosed her with cystic fibrosis, and she is awaiting results from a breast tissue biopsy. She has experienced immune system disorders and her blood tests show abnormalities that no one can explain. Other people in the area have similar blood problems.

Story 3

A couple in their mid-40s lived for eleven years in a rural Colorado area of farmland, orchards, trees, and country roads. They have since moved from that location because of the myriad health problems they were experiencing. A natural gas well was situated directly across the street, less than a thousand feet from their residence. There were other gas wells close to their property, including several on the mountainside nearby, where they could see many being flared. On that mountainside, there was also a big pit containing wastewater.

The property was situated amidst hills and mountains, and it was often very windy. They continually smelled a rotten egg odor from the well across the street, which caused them to complain to the company that was doing the drilling. At first, the company was responsive, shutting the well off for a few days, draining the tanks, and then turning the rig back on. Soon, however, the couple would notice the smell again, complain, and the company would again shut off the well, drain the tanks, then eventually turn them back on. After a year and a half, the company was no longer as responsive to their complaints or as prompt to take action.

There was flaring for many weeks at both gas wells. According to the husband, the company received several citations for illegal flaring. As a result of the their complaints, the company eventually removed one of the tanks. The company told them that they were smelling sour gas and that they had nothing to worry about. In addition to the smell, they were disturbed by the noise from the well. On many occasions, they would leave for the weekend to escape the noise and the odors.

The couple believe that they were continually exposed to hydrogen sulfide for eleven years from the gas well directly across the street and from a well on an adjacent plot. They did not know what they were exposed to until 2005, but based on information they have since gathered and on professional medical assessments, they believe it was hydrogen sulfide all along. They do not know to what concentrations they were exposed.

The couple experienced health problems, which they now attribute to ongoing exposure to hydrogen sulfide. The wife, who spent more time at home, experienced and continues to experience more and worse symptoms than her husband, who would leave the house during the week for work. Specifically, the wife, who had always been healthy before the gas wells started operating near their residence, experienced pains similar to severe rheumatoid arthritis, though tests did not reveal its presence in her body. She nevertheless took medication for nine years, which did not help with her pain. She also experienced blistering of the skin when showering, severe burns on the bottoms of her feet, and her skin was covered in welts. Her entire body was swollen and her throat burned. She spent months sleeping and vomiting. She also suffered from severe sinus headaches, and both husband and wife experienced rectal bleeding, as did some of their neighbors.

After moving, the wife's arthritis symptoms relaxed, but she still sleeps a lot, and undergoes spells of vomiting. Her body experienced symptoms of detoxification after moving. Eventually, her gall bladder was removed, and showed symptoms of poisoning. By this time, she had lost over 50 pounds and was malnourished. Her gall bladder was enlarged to the size of a small pineapple, and had excessive scar tissue, which the doctor attributed to toxicity. She has been experiencing one especially disturbing, and puzzling, behavior, which started after the couple moved away from their old residence near the gas wells. Although she was born and raised in Southern California and English is her native language, she now speaks with a strange, heavy accent, which at times resembles Russian, German, or Swedish. Because of the many persistent heath problems, she is no longer considered ‘insurable’ by medical insurance companies, nor is she able to work. She is now on permanent Social Security disability.

In addition to their health problems, the couple believe hydrogen sulfide in the air around their former residence is responsible for causing the metal siding on their house to peel just two years after installation, although it was supposed to last for 50 years. Further, animals on their property experienced health problems. Two baby llamas died from a pneumonia-type illness, and an older llama had severe sinus problems. They put their dogs to sleep because of tumors. They tried to breed miniature poodles, but all the dogs were sterile.

Story 4

In October 2004, a couple in their mid-60s retired to a poor rural county in Texas, a known region of sour gas. There are several sour gas wells near their residence. Since March 2005, their property has been surrounded by several wells, all within one mile of their house, with one well across the street and less than a quarter of a mile away. Additionally, an amine gas treating plant where sour gas is sweetened, which also began operating in March 2005, is a half mile from their residence. According to a public record document that the wife received from the state environmental department in response to one of her complaints, “The facility receives sour natural gas and treats the gas with an amine treater to remove CO_2 and H_2S.”[162]

The couple believe they are exposed to hydrogen sulfide from the amine plant and the sour wells that surround their property and that their exposure is ongoing. They have noticed that odors are worse at night. They are convinced that there are hydrogen sulfide

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[162] Personal communication, February 27, 2006.

emissions because of the fact that the region is know for sour gas, because the amine plant's purpose is to sweeten sour gas, and because they have read a permit from the state allowing the amine plant to emit up to four pounds of H_2S per hour into the air. They often notice a strong rotten egg odor, as well as other chemical smells, including a sweet smell. (The latter may be due to benzene, or to high levels of H_2S, which has been reported to produce a sickening, sweet smell in concentrations above 30 ppm.[163]) The couple acknowledge that there are other pollutants emitted into the air that they do not know about. There has been no monitoring done on their property, and they do not know to what concentrations they are exposed.

Both husband and wife have experienced a host of adverse health effects since the gas wells and the amine plant began operating. Though neither smokes, nor ever has, they are both experiencing a chronic sore throat. Their other symptoms include congestion, coughing, headaches, swollen eyes, insomnia, occasional nosebleeds, and a general lack of energy. The husband's face burns, as do his hands and eyes. The wife has experienced heart palpitations and is now on heart medication, though she was entirely healthy before moving. They have both seen doctors many times because of their problems, including several visits to the emergency room, but neither has been officially diagnosed with hydrogen sulfide exposure. However, they think this is due to the general lack of knowledge about the subject.

On many occasions, they have been awakened by rotten egg fumes that choked, and burned their eyes, nose, and throat, and made them feel dizzy. At these times, they

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[163] Snyder, Jack W., MD, PhD. et al. 1995. "Occupational Fatality and Persistent Neurological Sequelae After Mass Exposure to Hydrogen Sulfide." *American Journal of Emergency Medicine*. p. 200.

leave the house and stay in a hotel, and now have a packed suitcase ready in case they need to evacuate in a hurry.

Story 5

A New Mexico couple in their late 40s live a quarter to a half mile from a municipal wastewater treatment facility, which has been receiving wastewater from an oil refinery since 1992. The oil refinery itself is four miles from the couple's residence, and there are several oil fields in the vicinity. The refinery has been there since the 1970s, but until 1992, it injected its wastewater into the ground. The wastewater facility used to receive water from a dairy operation as well.

At their residence, the couple are routinely exposed to hydrogen sulfide, which emanates from the water at the treatment facility. The husband used to work at the wastewater treatment facility, so he was exposed to H_2S more frequently, and to higher concentrations than his wife. Accordingly, his symptoms are much more severe. The couple own an H2S monitor, which sounds an alarm at 10 ppm, a daily occurrence inside and outside the house, and while driving in town. A monitor within the gates of the wastewater facility in the past registered 375 ppm, prompting the facility to be temporarily shut down. Additionally, staff from the Centers for Disease Control (CDC) were in the area for six weeks, studying hydrogen sulfide. They placed two monitors on the couple's property, and although the official results are not yet ready, the CDC staff acknowledged that conditions are bad.

The husband's blood tests showed abnormally high levels of H2S, levels so high that the examining physician thought the sample was from a deceased man. Doctors have also confirmed that the wife has been exposed to hydrogen sulfide. The husband's health has been deteriorating since 1992, when the refinery started discharging wastewater into the municipal wastewater treatment facility. His symptoms include nosebleeds, headaches, burning eyes, throat itching, itching all over his body, severe headaches, and severe rashes. His skin burns when he sweats. His teeth have been damaged, and he has suffered nerve damage and slurred speech. The wife has experienced rapidly deteriorating eyesight, ringing in her ears, memory problems, has had her gall bladder removed, and, since 1995, has trouble with balance, tremors, trouble walking up and down stairs, and severe migraine headaches.

Both have been examined by several H_2S specialists, and both have been diagnosed with chemical encephalopathy. Each time they are tested, the results are worse. The husband is permanently and totally disabled, and is on Social Security disability.

Story 6

This interviewee lived on a 640 acre farm in a relatively flat prairie areas with some undulating hills in Alberta, Canada. A natural gas well said to contain one percent hydrogen sulfide was situated about a third of a mile from the residence. There were other gas wells in the vicinity of her property, and gas was piped from these wells to a site about a mile away, where it was flared. Within three miles from the residence, there were at least a dozen natural gas wells, all with hydrogen sulfide content of one percent. There was also a battery three miles away.

Her first serious exposure occurred as a result of flaring during an initial test soon after the closest well to her house was drilled. The flaring created a jet plane-like sound, shaking the house. At this time, she experienced a headache and felt extremely sick. Her

20-year-old son, who was out walking in the field when the incident occurred, experienced knockdown. He staggered into the house, lost his balance, and collapsed. His skin was a greenish gray color when he collapsed. She contacted a regulatory body, which asked the company to stop operations. However, next day the wells were operating again. This flaring continued for a week, continually exposing her and her family to H2S. She smelled the rotten egg odor of hydrogen sulfide, and the company told her that 1 ppm of H2S was blowing to the residence. They continued to smell H2S several times per week. There has been no monitoring to determine the exact concentrations of H2S at her residence.

Within a month of the acute exposure, she was experiencing extreme fatigue, confusion, anxiety, heart symptoms, shaking and tremors, dizziness, headaches, nosebleeds, memory and cognitive impairments. Exposure to H2S or other chemicals would aggravate many of her symptoms. She also has bronchial asthma symptoms though she has never smoked. Her son developed heart arrhythmia, balance problems, and pneumonia three months after the knockdown. He now walks with a cane, experiences extreme headaches, confusion, ongoing heart problems, skin conditions including psoriasis, and burning in his lungs when exposed to chemicals. Both the interviewee and her son have multiple chemical sensitivities. An H2S specialist has diagnosed them with non-recoverable chemical encephalopathy.

Other people in the area have experienced respiratory problems, and there have been many effects on animals, including abortions and cattle's hooves falling off.

Story 7

A 27 year-old interviewee lived half a mile from a gas plant, and a little over half a mile from several oil wells with flares. He has since moved to another residence in the same Alabama county, where over 500 oil and gas are active, and he is still exposed to hydrogen sulfide.

He is convinced that he is continually exposed to hydrogen sulfide because of the presence of the rotten egg odor. The results of a monitoring project at his residence confirm the presence of H2S in concentrations of 10 ppb.[164] In addition to his ongoing exposure, the interviewee recalls nearly experiencing knockdown on one occasion while driving by a sour gas plant about five miles from his former residence. The source of that exposure was a flare at the plant, but the concentration of hydrogen sulfide is not known. At that time, he experienced shortness of breath and felt very near unconsciousness.

When he first moved to his previous residence, he started experiencing blurred vision and a loss of energy. His current health problems consist of brain fog, memory impairment, excessive sleepiness, and a lack of energy and strength. He has also experienced diarrhea, blood in his urine, loss of libido, abnormal heart rhythm, and anxiety-like attacks. Sometimes, he experiences severe and protracted involuntary muscle movements in his arms and legs that last up to a day. Exposure to hydrogen sulfide aggravates his existing symptoms. Since moving to the new residence, his heart symptoms have lessened.

He has seen several doctors about his health problems. One doctor diagnosed him with optic nerve damage, and another with chemical encephalopathy. He has tested

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[164] Monitoring done by Lisa Sumi, Research Director, Oil and Gas Accountability Project. August 2005, using Jerome 631 H2S monitor. Data used with permission.

negative for a host of diseases, including Parkinson's. Though he is 27, he said he feels 67, and that not a day goes by when he feels normal.

Cats at his old residence were also affected. They experienced vomiting and weight loss, and exhibited sexually confused behavior.

Story 8:

This interviewee, a woman in her 50s, is in the process of moving to eastern Texas from her western Colorado home, where she has lived for ten years and worked as an irrigator. There are two natural gas wells about a mile downwind of her residence, and a shut in well across the street. Flaring and open condensate pits were common at these wells.

Although this interviewee experienced symptoms at her residence, her primary exposure to hydrogen sulfide was while she was working in the area, because many wells dot the fields she was irrigating. She started working near the gas wells in March 2005. One well pad was very close to the inlet for the irrigation water. Within a month, she began experiencing burning and swelling in her nasal passages. Several treatments with antibiotics did not clear her symptoms, and her doctor conceded that he did not know what was causing her problems. After this experience, she began wearing a charcoal filter mask.

Her single major exposure, which resulted in a knockdown, occurred one evening when she was getting out of her truck to turn off the irrigation water. She was approximately 50 feet from the well, when she experienced a blinding headache that made her feel like her head would burst. She then started to collapse and black out. She caught the door of her truck and was dangling there for about five minutes. Her headache then abated and she started to smell the rotten egg odor of hydrogen sulfide, though she did not smell it when the headache started.

Since the knockdown, this interviewee has developed chemical sensitivities, and her doctor has advised her to move. She requires a respirator to be outside, and even with the respirator, she can only be outside for about an hour. She has installed three air scrubbers to purify the air in her house.

She experiences burning around her eyes and on the exposed skin on her face. Her sinuses burn and itch, and she frequently gets nosebleeds. If she is outside for more than an hour, even with the respirator, she develops ulcers on her tongue and in her mouth, and eventually the glands in her neck and armpits swell. If she ignores these symptoms, she gets nauseated and experiences vomiting and explosive diarrhea. She also has nerve inflammation in her legs, and her balance and short term memory are impaired.

The source of hydrogen sulfide, she believes, are fugitive emissions from the wells, and especially from open condensate tanks. A stack flare was also operating within a mile of her house. No tests have been done to confirm the presence of hydrogen sulfide.

Other people in her area have also been affected. One neighbor has been feeling nauseated, while many people smell the odors from the wells and have upper respiratory infections. The interviewee's new mule, which grazes on land near the wells, has experienced hair falling out. A horse also had his mane thin out and experienced diarrhea during flaring. The horse's hooves fell apart and would not heal, so the interviewee had him put down.

HYDROGEN SULFIDE:
EVALUATION OF CURRENT CALIFORNIA AIR QUALITY STANDARDS WITH RESPECT TO PROTECTION OF CHILDREN

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A. Extended abstract

The current California Ambient Air Quality Standard (CAAQS) for hydrogen sulfide is 0.03 ppm (30 ppb, 42 µg/m^3) for one hour. The standard was adopted in 1969 and was based on the geometric mean odor threshold measured in adults. The purpose of the standard was to decrease odor annoyance. The standard was reviewed in 1980 and 1984 (CARB, 1984), and was not changed since no new relevant information had emerged. The U.S. EPA presently does not classify hydrogen sulfide as either a criteria air pollutant or a Hazardous Air Pollutant. However, several countries have short-term (usually 30 minute) standards for hydrogen sulfide, as well as long-term (24 hour) standards.

This report focuses on key studies in humans and animals bearing on the health-protectiveness of the CAAQS for hydrogen sulfide. It also includes a discussion of whether significant adverse health effects would reasonably be expected to occur, especially among infants and children, at exposure concentrations below the CAAQS of 30 ppb, based on the findings of published studies. Additional research on odor sensitivity in infants, children, and adults would be useful in evaluating the standard. This would include: (1) testing of the odor threshold for H_2S using the most current methodology among groups of healthy persons of both sexes in different age ranges; (2) odor testing of hydrogen sulfide in adolescents or younger children to determine their odor threshold for H_2S; (3) the identification of children hypersensitive to the odor of hydrogen sulfide; and (4) physiologic testing of anosmic (either specifically anosmic to H_2S or totally anosmic) children at the CAAQS to determine if adverse physiological symptoms occur in the absence of odor detection.

B. Background

The Mulford-Carrell Air Resources Act of 1967 directed the Air Resources Board to divide California into Air Basins and to adopt ambient air quality standards for each basin (Health and Safety Code (H&SC) Section 39606). The existing California state-wide ambient air quality standard (CAAQS) for hydrogen sulfide of 0.03 ppm (30 ppb, 42 $\mu g/m^3$), averaged over a period of 1 hour and not to be equaled or exceeded, protects against nuisance odor ("rotten egg smell") for the general public. The standard was adopted in 1969 and was based on rounding of the geometric mean odor threshold of 0.029 ppm (range = 0.012 – 0.069 ppm; geometric SD = 0.005 ppm) measured in adults (California State Department of Public Health, 1969). The standard was reviewed by the Department of Health Services in 1980 and 1984, and was not changed since no new relevant information had emerged. OEHHA (1999) formally adopted 30 ppb as the acute Reference Exposure Level (REL) for use in evaluating peak off-site concentrations from industrial facilities subject to requirements in H&SC Section 44300 *et seq*. OEHHA (2000) adopted a level of 8 ppb (10 $\mu g/m^3$) as the chronic Reference Exposure Level (cREL) for use in evaluating long term emissions from Hot Spots facilities. The cREL was based on a study demonstrating nasal histological changes in mice.

At the federal level, U.S. EPA does not currently classify hydrogen sulfide as either a criteria air pollutant or a Hazardous Air Pollutant (HAP). U.S. EPA has developed a (chronic) Reference Concentration (RfC) of 0.001 mg/m^3 (1 $\mu g/m^3$) for hydrogen sulfide (USEPA, 1999). The RfC is an estimate (with uncertainty spanning perhaps an order of magnitude) of a daily inhalation exposure of the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime.

There are no international standards for H_2S. Many countries have "short-term" (usually 30 minute) standards, which range from 6 to 210 ppb (WHO, 1981). The World Health Organization (WHO) recommends that, in order to avoid substantial complaints about odor annoyance among the exposed population, hydrogen sulfide concentrations should not be allowed to exceed 0.005 ppm (5 ppb; 7 $\mu g/m^3$), with a 30-minute averaging time (WHO, 1981; National Research Council, 1979; Lindvall, 1970). A very short-lived, peak concentration could also be annoying. Rule 2 of Regulation 9 of the Bay Area Air Quality Management District (BAAQMD) specifies that ambient ground level H_2S concentrations may not exceed 60 ppb averaged over 3 consecutive minutes. Regulating at averaging times less than 30 – 60 minutes may be difficult. Many countries have “long-term” (24 hour) standards (WHO, 1981).

NRC (1979), WHO (1981), Beauchamp *et al*. (1984), Reiffenstein *et al*. (1992), and ATSDR (1999) have published reviews of the health effects of hydrogen sulfide.

C. Principal sources/Exposure assessment

Hydrogen sulfide (H_2S) is used as a reagent and as an intermediate in the preparation of other reduced sulfur compounds (HSDB, 1999). It is also a by-product of desulfurization processes in the oil and gas industries and rayon production, sewage treatment, and leather tanning (Ammann, 1986). Geothermal power plants, petroleum production and refining, and sewer gas are specific sources of hydrogen sulfide in California. The annual statewide industrial emissions from facilities reporting under the Air Toxics Hot Spots Information and Assessment Act in California (H&SC Sec. 44300 *et seq*.), based on the most recent inventory, were estimated to be 5,688,172 pounds of hydrogen sulfide (CARB, 1999).

A specific concern in California has been schools located near workplaces emitting toxic substances. For example, the Hillcrest Elementary School in Rodeo (Contra Costa County; part of the BAAQMD) is adjacent to an oil refinery which, on occasion, has emitted enough malodorous sulfur compounds (including H_2S) for the school to close its doors and for the teachers and children to “shelter-in-place.” Thus the school district has planned to relocate the school (West County Times, November 23, 1999). These compounds have also affected other schools in the area.

Hydrogen sulfide is produced endogenously in mammalian tissues from L-cysteine, mainly by two pyridoxal-5'-phosphate-dependent enzymes, cystathionine beta-synthetase and cystathionine gamma-lyase (Hosoki *et al*., 1997). Abe and Kimura (1996) suggested that hydrogen sulfide may be an endogenous neuromodulator in the hippocampus based on the high level of cystathionine beta-synthetase in the hippocampus and on experimental effects of activators and inhibitors of the enzyme.

D. Key studies of acute and chronic health impacts

D.1. Toxicity to Humans

D.1.1. Adults. Hydrogen sulfide is an extremely hazardous gas (ACGIH, 1991). Exposure to high concentrations of hydrogen sulfide is reported to be the most common cause of sudden death in the workplace (NIOSH, 1977). Estimates of the mortality resulting from acute hydrogen sulfide intoxication include 2.8% (Arnold *et al*., 1985) and 6% (WHO, 1981). While severe intoxication is especially of concern when exposure occurs in confined spaces, an accidental release of hydrogen sulfide into the ambient air surrounding industrial facilities can cause very serious effects. As a result of an accidental release of hydrogen sulfide due to a malfunctioning flare at an oilfield at Poza Rica, Mexico in 1950, 320 people were hospitalized and 22 died (WHO, 1981).

Most information on H_2S toxicity comes from studies that used levels of H_2S orders of magnitude above the standard of 0.03 ppm. Hazardtext (1994) reported an inhalation LC_{Lo} of 600 and 800 ppm (840 and 1,120 mg/m^3) for 30 and 5 minutes, respectively. A lethal exposure was documented for a worker exposed to approximately 600 ppm H_2S for 5 to 15 minutes (Simson and Simpson, 1971). Inhalation of 1,000 ppm (1,400 mg/m^3) is reported to cause immediate respiratory arrest (ACGIH, 1991). Concentrations greater than 200 ppm (280 mg/m^3) H_2S are reported to cause direct irritant effects on exposed surfaces and can cause pulmonary edema following longer exposures (Spiers and Finnegan, 1986). The mechanism of H_2S

toxicity, cellular hypoxia caused by inhibition of cytochrome oxidase, is similar to that for cyanide. Toxicity can be treated by induction of methemoglobin or by therapy with hyperbaric oxygen (Elovaara *et al*., 1978; Hsu *et al*., 1987).

At concentrations exceeding 50 ppm (70 mg/m³) H_2S, olfactory fatigue prevents detection of H_2S odor. Exposure to 100-150 ppm (140-210 mg/m³) for several hours causes local irritation (Haggard, 1925). Exposure to 50 ppm for 1 hour causes conjunctivitis with ocular pain, lacrimation, and photophobia; this can progress to keratoconjunctivitis and vesiculation of the corneal epithelium (ACGIH, 1991).

Bhambhani and Singh (1985) reported that exposure of 42 individuals to 2.5 to 5 ppm (3.5 to 7 mg/m³) H_2S caused coughing and throat irritation after 15 minutes. Bhambhani and Singh (1991) showed that 16 healthy adult male subjects (25.2±5.5 years old) exposed to 5 ppm (7 mg/m³) H_2S under conditions of moderate exercise exhibited impaired lactate and oxygen uptake in the blood. Subsequently Bhambani *et al*. (1994) compared the effects of inhaling 5 ppm H_2S on physiological and hematological responses during exercise. Subjects were 13 men (mean±SD for age, height, and weight = 24.7±4.6 y, 173±6.6 cm, and 73.1±8.1 kg, respectively) and 12 women (mean±SD = 22.0±2.1 y, 165±8.2 cm, and 63.4±8.6 kg, respectively). Subjects completed two 30-minute exercise tests on a cycle ergometer at 50% of their predetermined maximal aerobic power, while breathing either air or 5 ppm H_2S. There were no significant differences between the two exposures for metabolic (oxygen uptake, carbon dioxide production, respiratory exchange ratio), cardiovascular (heart rate, blood pressure, rate pressure product), arterial blood (oxygen and carbon dioxide tensions, pH), and perceptual (rating of perceived exertion) responses. No one reported adverse health effects following H_2S exposure. The authors believe that healthy adults can safely perform moderate intensity work in environments containing 5 ppm H_2S.

Bhambhani *et al*. (1996) examined the acute effects of “oral” inhalation of 10-ppm H_2S, the occupational exposure limit, on lung physiology as measured by pulmonary function in nine men and ten women. The volunteers inhaled medical air or 10 ppm H_2S through the mouth for 15 minutes each during cycle exercise at 50% of their maximal aerobic power. Routine pulmonary function tests (FVC, FEV_1, FEV_1/FVC, PEFR, maximal ventilation volume, and DL_{CO}) were administered at rest and immediately after the two exposure conditions. There were no significant changes in any of the variables derived from the flow volume loop, maximum ventilation volume, and diffusion capacity of the lung for carbon monoxide (DL_{CO}) in both genders. No subject experienced any sign or symptom as a result of H_2S. The authors concluded that inhalation of 10 ppm H_2S through the mouth at an elevated metabolic and ventilation rate does not significantly alter pulmonary function in healthy people.

Jappinen *et al*. (1990) exposed ten adult asthmatic volunteers to 2 ppm H_2S for 30 minutes and tested pulmonary function. All subjects reported detecting “very unpleasant” odor but “rapidly became accustomed to it.” Three subjects reported headache following exposure. No significant changes in mean FVC or FEV_1 were reported. Although individual values for specific airway resistance (SR_{aw}) were not reported, the difference following exposure ranged from –5.95% to +137.78%. The decrease in specific airway conductance, SG_{aw}, ranged from –57.7% to +28.9%. The increase in mean SR_{aw} and the decrease in mean SG_{aw} were not statistically significant for the entire group. However, markedly (>30%) increased airway resistance and decreased airway conductance were noted in two of the ten asthmatic subjects at 2 ppm, which indicated bronchial obstruction and may be clinically important. Two ppm is 67 times the CAAQS of 0.03 ppm.

Hydrogen sulfide is noted for its strong and offensive odor. The existing CAAQS of 0.03 ppm (30 ppb, 42 $\mu g/m^3$) for 1 hour is based on rounding the geometric mean odor detection threshold of 0.029 ppm (range = 0.012 – 0.069 ppm; GSD = 0.005 ppm). The threshold was determined for a panel of 16 presumably healthy adults (California State Department of Public Health, 1969). No information on the sex or age of the panel members has been located. Amoore (1985) reviewed 26 studies, published between 1848 and 1979, all of which reported average odor detection thresholds for H_2S. The 26 studies seem to be mainly controlled exposures and used various measurement methods. They included (1) at least two studies using only one subject, (2) a study of a panel of 35 people testing odors in natural gas in Southern California, and (3) another study of 852 untrained young adults (age range = 17.5 – 22.4 years) tested at county and state fairs in the Northwest. The average odor detection threshold in the 26 studies ranged from 0.00007 to 1.4 ppm H_2S. The geometric mean of the 26 studies was 0.008 ppm (8 ppb), approximately one-fourth the value determined by the Department of Public Health and lower than the lowest individual threshold of 12 ppb measured in the California panel. Surprisingly the Department of Public Health panel study was <u>not</u> one of the 26 studies used by Amoore and was not even mentioned in his 1985 report to the ARB.

Venstrom and Amoore (1968) reported that, in general, olfactory sensitivities decrease by a factor of 2 for each 22 years of age above age 20. The conclusion was based on a study of 18 odorants in 97 government laboratory workers, ages 20 through 70. Hydrogen sulfide was not tested. The geometric mean odor threshold of 8 ppb for H_2S from the 26 studies is based on an average age of 40 (possibly assumed to be the age of an average adult). Amoore (1985) estimated that an 18-year-old person would have a threshold of 4 ppb H_2S, while a 62-year-old person was predicted to have a threshold of 16 ppb. Amoore also stated that there was no noticeable trend of odor sensitivity between young adults and children down to 5 years but did not present specific data to support the statement.

Concentrations, which substantially exceed the odor threshold for, result in the annoying and discomforting physiological symptoms of headache or nausea (Amoore, 1985; Reynolds and Kauper 1984). The perceived intensity of the odor of H_2S depends on the longevity of the concentration, and the intensity increases 20% for each doubling of the concentration (Amoore, 1985). Several studies have been conducted to establish the ratio of discomforting annoyance threshold to detection threshold for unpleasant odors (Winkler, 1975; Winneke and Kastka, 1977; Hellman and Small, 1974; Adams *et al.,* 1968; and NCASI, 1971). The geometric mean for these studies is 5; therefore an unpleasant odor should result in annoying discomfort when it reaches an average concentration of 5 times its detection threshold. (Two studies that tested only H_2S had a geometric mean of 4.) Applying the 5-fold multiplier to the mean detectable level of 8 ppb results in a mean annoyance threshold of 40 ppb. Amoore (1985) estimates that at 30 ppb, the CAAQS, H_2S would be detectable by 83% of the population and would be discomforting to 40% of the population (Table 1). These “theoretical” estimates have been substantiated by odor complaints and reports of nausea and headache (Reynolds and Kauper 1984) at 30 ppb H_2S exposures from geyser emissions.

In order to avoid substantial complaints about odor annoyance among the exposed population, the World Health Organization (WHO) recommends that hydrogen sulfide concentrations should not exceed 0.005 ppm (5 ppb; 7 $\mu g/m^3$), with a 30-minute averaging time (WHO, 1981; National Research Council, 1979; Lindvall, 1970). The WHO task group believed that 5 ppb averaged over 30 minutes “should not produce odour nuisance in most situations.”

Table 1. Predicted effects of exposure to ambient H_2S. (Adapted from Amoore, 1985)

H_2S (ppb)	% able to detect odor[a]	Perceived odor intensity[b] (ratio)	Median odor units[c]	% annoyed by odor[d]
200	99	2.31	25	88
100	96	1.93	12	75
50	91	1.61	6.2	56
40	88	1.52	5.0	50
35	87	1.47	4.4	47
30 (CAAQS)	83	1.41	3.7	40
25	80	1.34	3.1	37
20	74	1.27	2.5	31
15	69	1.18	1.9	22
10	56	1.06	1.2	17
8	50	1.00	1.00	11
6	42	0.93	0.75	8
4	30	0.83	0.50	5
2	14	0.70	0.25	2
1	6	0.58	0.12	1
0.5	2	0.49	0.06	0

[a] Based on mean odor detection threshold of 8.0 ppb and SD±2.0 binary steps

[b] Based on intensity exponent of 0.26 (Lindvall, 1974).

[c] H_2S concentration divided by mean odor detection threshold of 8 ppb.

[d] Based on assumption that mean annoyance threshold is 5x the mean odor detection threshold, and SD±2.0 binary steps.

Kilburn and Warshaw (1995) investigated whether people exposed to sulfide gases, including H_2S, as a result of working at or living downwind from the processing of "sour" crude oil demonstrated persistent neurobehavioral dysfunction. They studied 13 former workers and 22 neighbors of a California coastal oil refinery who complained of headaches, nausea, vomiting, depression, personality changes, nosebleeds, and breathing difficulties. Neurobehavioral functions and a profile of mood states were compared to 32 controls matched for age and educational level. The exposed subjects' mean values were statistically significantly different (abnormal) compared to controls for several tests (two-choice reaction time; balance (as speed of sway); color discrimination; digit symbol; trail-making A and B; immediate recall of a story). Their profile of mood states (POMS) scores were much higher than those of controls. Test scores for anger, confusion, depression, tension-anxiety, and fatigue were significantly elevated and nearly identical in both exposed residents and former workers, while the scores for controls equaled normal values from other published studies. Visual recall was significantly impaired in neighbors, but not in the former workers. Limited off-site air monitoring (one week) in the neighborhood found average levels of 10 ppb H_2S (with peaks of 100 ppb), 4 ppb dimethylsulfide, and 2 ppb mercaptans. On-site levels were much higher. The authors concluded that neurophysiological abnormalities were associated with exposure to reduced sulfur gases, including H_2S from crude oil desulfurization.

D.1.2. Children. In a case report Gaitonde *et al*. (1987) described subacute encephalopathy, ataxia, and choreoathetoid (jerky, involuntary) responses in a 20-month-old child with long term (approximately one year) exposure to hydrogen sulfide from a coal mine. Levels of up to at least 0.6 ppm (600 ppb) were measured and levels were possibly higher before measurements started. The abnormalities resolved after the emission source ceased operation.

As part of the South Karelia Air Pollution Study in Finland (Jaakkola *et al*., 1990), Marttila *et al*. (1994) assessed the role of long-term exposure to ambient air malodorous sulfur compounds released from pulp mills as a determinant of eye and respiratory symptoms and headache in children. The parents of 134 children living in severely polluted (n = 42), moderately polluted (n = 62), and rural, non-polluted (n = 30) communities responded to a cross-sectional questionnaire (response rate = 83%). In the severely polluted area, the annual mean concentrations of hydrogen sulfide and methyl mercaptan (H_3CSH) were estimated to be 8 $\mu g/m^3$ (6 ppb) and 2 - 5 $\mu g/m^3$ (1.4 – 3.6 ppb), respectively. The highest daily average concentrations were 100 $\mu g/m^3$ (71 ppb) and 50 $\mu g/m^3$ (36 ppb), respectively. The adjusted odds ratios (OR) for symptoms experienced during the previous 4 weeks and 12 months in the severely versus the non-polluted community were estimated in logistic regression analysis controlling for age and gender. The risks of nasal symptoms, cough, eye symptoms, and headache were increased in the severely polluted community, but did not reach statistical significance (Table 2). In addition, OEHHA staff noted that the highest percentages of children with symptoms were in the moderately polluted community, not in the severely polluted community. The authors concluded that exposure to malodorous sulfur compounds may affect the health of children. The odor threshold for methyl mercaptan of 1.6 ppb (Amoore and Hautala, 1983) indicates that it also likely contributed to the odor and probably the symptoms.

Table 2. Symptoms Reported in Marttila *et al*. (1994)

Symptom	*Time*	*Odds Ratio*	*95% CI*	*Time*	*Odds ratio*	*95%CI*
nasal symptoms	4 weeks	1.40	0.59-3.31	12 months	2.47	0.93-6.53
cough	4 weeks	1.83	0.75-4.45	12 months	2.28	0.95-5.47
eye symptoms	NR	NR	NR	12 months	1.15	0.43-3.05
headache	NR	1.02	0.36-2.94	12 months	1.77	0.69-4.54

NR = not reported

Studies of controlled exposures in children to study H_2S odor detection have not been located. A recent report studying children concluded that children aged 8 to 14 years have equivalent odor sensitivity to young adults (Cain *et al*., 1995), although children lack knowledge to identify specific odors by name. Koelega (1994) found that prepubescent children (58 nine-year-olds) were inferior in their detection of 4 of 5 odors compared to 15-year-olds (n = 58) and 20-year-olds (n = 112). Schmidt and Beauchamp (1988) have even tested 3-year-olds (n = 16) for sensitivity to noxious chemicals, such as butyric acid and pyridine.

In March-April 1983, 949 cases (including 727 in adolescent females) of acute non-fatal illness consisting of headache, dizziness, blurred vision, abdominal pain, myalgia, and fainting occurred at schools on the West Bank. However, physical examinations and biochemical tests were normal. There was no common exposure to food, drink, or agricultural chemicals among those affected. No toxins were consistently present in patients' blood or urine. The only environmental toxicant detected was H_2S gas in low concentrations (40 ppb) in a schoolroom at the site of the first outbreak (from a faulty latrine in the schoolyard). The illness was deemed to be psychogenic and possibly triggered by the smell of H_2S (Landrigan and Miller , 1983; Modan *et al*., 1983).

D.1.3. Development. Xu *et al*. (1998) conducted a retrospective epidemiological study in a large petrochemical complex in Beijing, China in order to assess the possible association between petrochemical exposure and spontaneous abortion. The facility consisted of 17 major production plants divided into separate workshops, which allowed for the assessment of exposure to specific chemicals. Married women (n = 2,853), who were 20-44 years of age, had never smoked, and who reported at least one pregnancy during employment at the plant, participated in the study. According to their employment record, about 57% of these workers reported occupational exposure to petrochemicals during the first trimester of their pregnancy. There was a significantly increased risk of spontaneous abortion for women working in all of the production plants with frequent exposure to petrochemicals compared with those working in non-chemical plants. Also, when a comparison was made between exposed and non-exposed groups within each plant, exposure to petrochemicals was consistently associated with an increased risk of spontaneous abortion (overall odds ratio (OR) = 2.7 (95% confidence interval (CI) = 1.8 to 3.9) after adjusting for potential confounding factors). Using exposure information obtained from interview responses for (self-reported) exposures, the estimated OR for spontaneous abortions was 2.9 (95% CI = 2.0 to 4.0). When the analysis was repeated by excluding 452 women who provided inconsistent reports between recalled exposure and work history, a comparable risk of spontaneous abortion (OR 2.9; 95% CI = 2.0 to 4.4) was found. In analyses for exposure to specific chemicals, an increased risk of spontaneous abortion was found with exposure to most chemicals. There were 106 women (3.7% of the study population) exposed only to hydrogen sulfide; the results for H_2S (OR 2.3; 95% CI = 1.2 to 4.4) were statistically significant. Unfortunately H_2S exposure concentrations were not reported.

D.2. Effects of Animal Exposure

D.2.1. Adult/mature animals. A median lethal concentration (LC_{50}) in rats exposed to H_2S for 4 hours was estimated as 440 ppm (616 mg/m³) (Tansy *et al*., 1981). An inhalation LC_{Lo} of 444 ppm for an unspecified duration is reported in rats, and a lethal concentration of 673 ppm (942 mg/m³) for 1 hour is reported in mice (RTECS, 1994). In another study, mortality was significantly higher for male rats (30%), compared to females (20%), over a range of exposure times and concentrations (Prior *et al*., 1988). A concentration of 1,000 ppm (1,400 mg/m³) caused respiratory arrest and death in dogs after 15-20 minutes (Haggard and Henderson, 1922). Inhalation of 100 ppm (140 mg/m³) for 2 hours resulted in altered leucine incorporation into brain proteins in mice (Elovaara *et al*., 1978). Kosmider *et al*. (1967) reported abnormal electrocardiograms in rabbits exposed to 100 mg/m³ (71 ppm) H_2S for 1.5 hours.

Khan *et al*. (1990) exposed groups of 12 male Fischer 344 rats to 0, 10, 50, 200, 400, or 500-700 ppm hydrogen sulfide for 4 hours. Four rats from each group were euthanized at 1, 24, or 48 hours post-exposure. The activity of cytochrome c oxidase in lung mitochondria, a primary molecular target of H_2S, was significantly ($p<0.05$) decreased at 50 ppm (15%), 200 ppm (43%), and 400 ppm (68%) at 1-hour post-exposure compared to controls. A NOAEL of 10 ppm for inhibition of cytochrome c oxidase was identified in this study.

Fischer and Sprague-Dawley rats (15 per group) were exposed to 0, 10.1, 30.5, or 80 ppm (0, 14.1, 42.7, or 112 mg/m³, respectively) H_2S for 6 hours/day, 5 days/week for 90 days (CIIT, 1983a,b). Measurements of neurological and hematological function revealed no abnormalities due to H_2S exposure. Histological examination of the nasal turbinates also revealed no significant exposure-related changes. A significant decrease in body weight was observed in both strains of rats exposed to 80 ppm (112 mg/m³).

In a companion study, the CIIT conducted a 90-day inhalation study in mice (10 or 12 mice per group) exposed to 0, 10.1, 30.5, or 80 ppm (0, 14.1, 42.7, or 112 mg/m³, respectively) H_2S for 6 hours/day, 5 days/week (CIIT, 1983c). Neurological function was measured by tests for posture, gait, facial muscle tone, and reflexes. Ophthalmologic and hematologic examinations were also performed, and a detailed necropsy was included at the end of the experiment. The only exposure-related histological lesion was inflammation of the nasal mucosa of the anterior segment of the noses of mice exposed to 80 ppm (112 mg/m^3) H_2S. Weight loss was also observed in the mice exposed to 80 ppm. Neurological and hematological tests revealed no abnormalities. The 30.5 ppm (42.5 mg/m^3) level was considered to be a NOAEL for histological changes in the nasal mucosa. (Different adjustments were made to this NOAEL by U. S. EPA to calculate the RfC of 1 μg/m^3 and by OEHHA to calculate the chronic REL of 10 μg/m^3 (8 ppb).)

Hydrogen sulfide (0, 10, 30, or 80 ppm) was administered via inhalation (6 h/d, 7 d/wk) to 10-week-old male CD rats (n = 12/group) for 10 weeks (Brenneman *et al*., 2000). Histological evaluation revealed that rats exposed to 30 or 80 ppm had significant increases in lesions of the olfactory mucosa but not other tissues. Multifocal, rostrocaudally-distributed olfactory neuron loss and basal cell hyperplasia were seen. The dorsal medial meatus and the dorsal and medial portions of the ethmoid recess were affected. The lowest dose (10 ppm) was considered a no observed adverse effect level for olfactory lesions.

Fischer F344 rats inhaled 0, 1, 10, or 100 ppm hydrogen sulfide for 8 hours/day for 5 weeks (Hulbert *et al*, 1989). No effects were noted on baseline measurements of airway resistance, dynamic compliance, tidal volume, minute volume, or heart rate. Two findings were noted more frequently in exposed rats: (1) proliferation of ciliated cells in the tracheal and bronchiolar epithelium, and (2) lymphocyte infiltration of the bronchial submucosa. Some exposed animals responded similarly to controls to aerosol methacholine challenge, whereas a subgroup of exposed rats were hyperreactive to concentrations as low as 1 ppm H_2S.

Male rats were exposed to 0, 10, 200, or 400 ppm H_2S for 4 hours (Lopez *et al.*, 1987). Samples of bronchoalveolar and nasal lavage fluid contained increased inflammatory cells, protein, and lactate dehydrogenase in rats treated with 400 ppm. Later Lopez and associates (1988) showed that exposure to 83 ppm (116 mg/m^3) for 4 hours resulted in mild perivascular edema.

D.2.2. Developing animals. Saillenfait *et al.* (1989) investigated the developmental toxicity of H_2S in rats. Rats were exposed 6 hours/day on days 6 through 20 of gestation to 100 ppm hydrogen sulfide. No maternal toxicity or developmental defects were observed.

Hayden *et al*. (1990) exposed gravid Sprague-Dawley rat dams continuously to 0, 20, 50, and 75 ppm H_2S from day 6 of gestation until day 21 postpartum. The animals demonstrated normal reproductive parameters until parturition, when delivery time was extended in a dose-dependent manner (with a maximum increase of 42% at 75 ppm). Pups exposed in utero and neonatally to day 21 postpartum developed with a subtle decrease in time of ear detachment and hair development, but with no other observed change in growth and development through day 21 postpartum.

Hannah and Roth (1991) analyzed the dendritic fields of developing Purkinje cells in rat cerebellum to determine the effects of chronic exposure to low concentrations of H_2S during perinatal development. Treatment of timed-pregnant female Sprague Dawley rats with 20 and 50 ppm H_2S for 7 hours per day from day 5 after mating until day 21 after birth produced severe alterations in the architecture and growth characteristics of the dendritic fields of the Purkinje cells. The architectural modifications included longer branches, an increase in the vertex path length, and variations in the number of branches in particular areas of the dendritic field. The treated cells also exhibited a nonsymmetrical growth pattern at a time when random terminal branching is normally occurring. Thus, developing neurons exposed to H_2S may be at risk of severe deficits. However, the lower level of 20 ppm for 7 hours is nearly 2 orders of magnitude above the present one-hour standard.

Dorman *et al*. (2000) examined the effect of perinatal exposure of H_2S on pregnancy outcomes, offspring development, and offspring behavior in rats. Male and female Sprague-

Dawley rats (12 rats/sex/concentration) were exposed to 0, 10, 30, or 80 ppm H_2S 6 h/day, 7 days/week for 2 weeks prior to breeding. Exposures continued during a 2-week mating period and then from Gestation Day (GD) 0 through GD 19. Exposure of rat dams and their pups (eight rats/litter after culling) resumed between postnatal day (PND) 5 and 18. Adult males were exposed for 70 consecutive days. Offspring were evaluated using motor activity (assessed on PND 13, 17, 21, and 60±2), passive avoidance (PND 22±1 and 62±3), functional observation battery (FOB) (PND 60±2), acoustic startle response (PND 21 and 62±3), and neuropathology (PND 23±2 and 61±2). No deaths occurred and no adverse physical signs were seen in F_0 males or females. There were no statistically significant effects on the reproductive performance of the F_0 rats as assessed by the number of females with live pups, litter size, average length of gestation, and the average number of implants per pregnant female. Exposure to H_2S did not affect pup growth, development, or performance on any behavioral test. The authors conclude that H_2S is neither a reproductive toxicant nor a behavioral developmental neurotoxicant in the rat at occupationally relevant exposure concentrations (i.e., at 10 ppm, the current occupational daily average exposure limits - TLV and PEL; however, the ACGIH is considering lowering the TLV to 5 ppm). The lowest level tested (10 ppm) is more than 300-fold higher than the CAAQS of 0.030 ppm.

E. Interactions between hydrogen sulfide and other pollutants

Ethanol can potentiate the effects of H_2S by shortening the mean time-to-unconsciousness in mice exposed to 800 ppm (1,120 mg/m^3) H_2S (Beck *et al*., 1979).

Endogenous hydrogen sulfide may regulate smooth muscle tone in synergy with nitric oxide (Hosoki *et al*., 1997).

Hydrogen sulfide is often accompanied by other malodorous sulfur compounds, such as methyl mercaptan, dimethyl sulfide, and dimethyl disulfide. Some of these have odor thresholds lower than that of hydrogen sulfide. The complex mixture is often referred to as TRS (total reduced sulfur).

Lindvall (1977) reported that the perceived odor strength of H_2S is increased by the simultaneous presence of 600 ppb nitric oxide (600 ppb nitric acid is imperceptible by itself).

F. Conclusions

The current standard of 0.03 ppm (30 ppb) hydrogen sulfide for one hour based on odor is well below NOAEL levels from animal experiments where exposure lasted weeks to months, including the period of intrauterine development. However, it is greater than OEHHA's chronic Reference Exposure Level (REL) of 8 ppb, which is based on histological changes in the nasal area of mice. (The chronic REL is compared to the annual average H_2S concentration.) Ideally neither of these two benchmark levels should be exceeded by the properly averaged concentration.

Additional research might help reduce uncertainties regarding the impacts of hydrogen sulfide on the health of infants and children. This would include:

a. Odor testing of hydrogen sulfide in adolescents or younger children, if ethically permissible, to determine their odor threshold. Current data on odor detection in children are not consistent. Data on H_2S odor detection in children under controlled exposure are lacking.

b. The identification of children hypersensitive to the odor of hydrogen sulfide. While the odor from very low level H_2S would not itself threaten their physical health, the odor might be alarming to hypersensitive children. Psychosomatic complaints might be more confusing to children than to adults.

c. Physiologic testing of anosmic (either specifically anosmic to H_2S or totally anosmic) children at the CAAQS would be useful in determining whether if adverse physiological symptoms occur in the absence of odor detection.

d. Testing of the odor threshold for H_2S using the most current methodology among groups of healthy persons of both sexes in different age ranges. Data from such testing would likely be an improvement over the use of either the mean of 16 people (California Department of Public Health, 1969) or the mean from 26 studies, conducted over a period of 130 years, which found thresholds spanning a 20,000 fold range, from 0.07 ppb to 1400 ppb (Amoore, 1985). (If the highest and lowest values of the range in Amoore (1985) are dropped as outliers - Amoore (1985) stated that these two studies seemed to involve only one subject - the range would be 0.43 ppb to 190 ppb, a 440-fold range).

e. Further research is needed on the topic of when odor is an adverse health effect and how much consideration should be given to psychosomatic complaints accompanying odor annoyance (Dalton *et al*., 1997; ATS, 2000). A recent American Thoracic Society position paper titled "What Constitutes an Adverse Health Effect of Air Pollution?" (ATS, 2000) indicates that air pollution exposures, which interfere with the quality of life, can be considered adverse. This suggests that, for the purpose of setting a standard, odor-related annoyance should be considered adverse, even if nausea or headache or other symptoms are not present.

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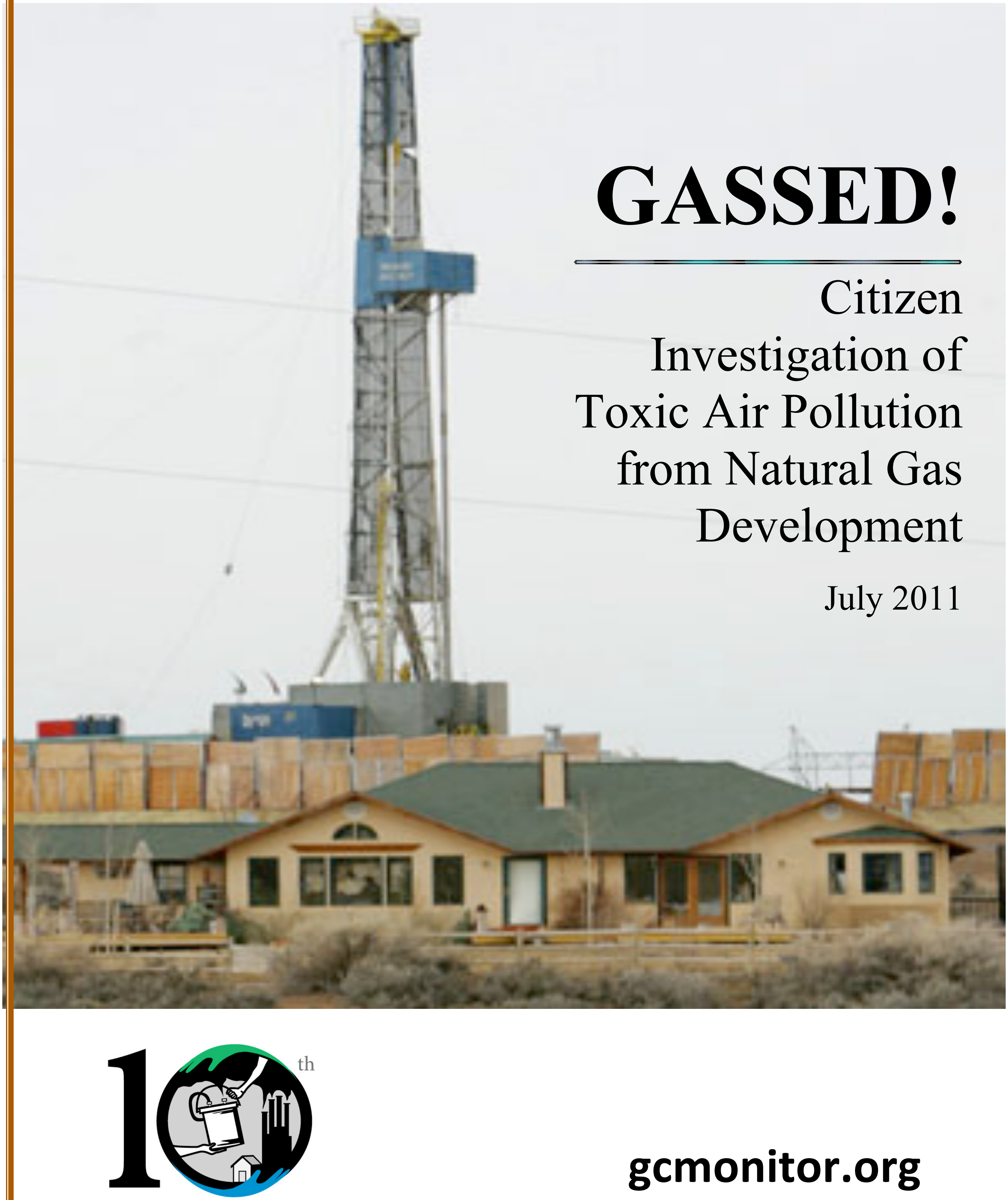

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Citizen Investigation of Toxic Air Pollution from Natural Gas Development

July 2011

10th ANNIVERSARY
Global Community Monitor
Breathing New Life into Communities

gcmonitor.org

Background on Global Community Monitor

Global Community Monitor, founded in 2001, trains and supports communities internationally in the use of environmental monitoring tools to understand and address industrial toxic pollution threats to their health and the environment.

GCM, best known as the innovator of the "Bucket Brigade", incubates community-based groups to develop the skills, expertise, and experience to win demands around environmental health and justice. Since GCM's approach is extremely replicable and effective, we have been invited to work with more than 40 communities in 27 countries. GCM collaborates with an established network of environmental health experts in the US and internationally to leverage resources for the communities.

Addition Information including News and Media available at:
http://gcmonitor.org/section.php?id=179
http://gcmonitor.org/section.php?id=29
http://gcmonitor.org/section.php?id=224

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Citizen Investigation of Toxic Air Pollution from Natural Gas Development

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Executive Summary

Over the past decade, oil and natural gas exploration and production have grown at an unprecedented rate in the United States. Since necessary environmental and health regulations are not in place for this industry, residents living near oil and natural gas sites may be exposed to highly toxic chemicals on a regular basis, with their health at risk.

During 2010-11, Global Community Monitor (GCM), responding to citizen odor and health complaints, launched a community-based pilot environmental monitoring program in northwest New Mexico, southwest Colorado and western Colorado to document and measure air pollution from natural gas facilities. Through the course of this pilot study, residents, armed with their own air monitors, documented a potent mix of chemicals in nine air samples from different locations. The sites in this program are all natural gas production and processing sites, although production of oil presents similar risks. Air sampling for this project targeted many aspects of natural gas development.

Through the course of this study, several serious issues emerged:

Citizen samples exposed alarming levels of toxins in the air.

A total of *22 toxic chemicals* were detected in the nine air samples, including *four known carcinogens,* toxins known to damage the nervous system, and respiratory irritants. The levels detected were in many cases significantly higher than what is considered safe by state and federal agencies. The levels of chemicals, including benzene and acrylonitrile, ranged from three to 3,000 times higher than levels established to estimate increased risk of serious health effects and cancer based on long-term exposure.

These air samples confirm the observations, experiences and first-hand complaints of residents. Odors and health effects that have been reported for years were consistent with exposure to the chemicals found in the samples. These results underscore the need of regulatory agencies to take such complaints seriously, given the close proximity between the industry and its residential neighbors.

At least two cancer-causing chemicals, acrylonitrile and methylene chloride, were detected at high levels near natural gas operations. Neither chemical is associated with natural gas or oil deposits, but both seem to be associated with the use of hydraulic fracturing (fracking) products. Resins acrylonitrile, 1, 3 butadiene and styrene (ABS) are suspected to be present in fracking additives.

Air emissions from natural gas production are largely unregulated and unmonitored, despite being a significant source of air pollution. State and Federal air monitoring devices are located several miles from production sites, and test for criteria air pollutants rather than specific volatile organic compounds associated with natural gas exploration and production.

Oil and gas exploration and production operations are exempt from two key provisions of the Clean Air Act's National Emissions Standards for Hazardous Air Pollutants, designed to protect public health. Because of these exemptions, the industry avoids complying with standards that are applied to other industries.

Based on the data gathered in this pilot study, highly toxic chemicals are permeating the air near homes, farms, schools, playgrounds, and town centers. Due to the lack of regulation and standards, key information about chemicals being used in the production process, including hydraulic fracturing is widely unavailable. Combined with the lack of appropriate air monitoring near production sites, **citizen right-to-know is virtually non-existent.**

Without registration of the chemicals by industry, neighbors of gas wells have no way of knowing what chemicals are stored on site, used during the industrial processes, vented to the air, water or land, or disposed nearby.

Recommendations

1. Given the proximity of residential and public property, any new sites –whether drilling, fracking, refining, or disposal – should be located at least one-quarter mile from homes, farms, schools, playgrounds, and businesses. This space would provide a **buffer zone** for industry to continue its operations while reducing community exposure to chemical contaminants.

2. The U.S. Environmental Protection Agency (EPA) should update air quality standards for oil and gas development, including the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants, based on the principles of comprehensiveness, effectiveness, full health protection, forward looking, and enforceability.

3. Until strong new rules are in place, the oil and natural gas industry can and should **voluntarily invest in equipment that reduces pollution escaping to the air**. Such equipment is readily available and financially profitable for companies. These investments would increase efficiency and production and reduce cancer-causing chemicals from being emitted into the air in communities near production facilities – saving lives and protecting the health of neighboring families.

4. Current natural gas production and processing sites should **have air monitors near all operations and equipment. All data should be made available to the public**.

5. **EPA and state agencies must enforce the current laws** on the books vigorously and impose the maximum penalties available to create a culture that prioritizes public health. Regulators should be accessible and fully funded to ensure their ability to protect public health and the environment.

As the natural gas industry continues to grow, so will the number of families neighboring and affected by the emissions. Industry and government leaders have a unique opportunity to address public health and environmental issues by implementing all of these recommendations. For coexistence between communities and industry to be possible, chemical exposure has to be immediately addressed.

Oil and Natural Gas Development and Air Pollution

There are a variety of chemicals used and released during the drilling, fracking, and production phases of oil and gas development. In addition, different types of wastes are produced throughout the development process. Air pollution is generated at all stages of oil and gas development including wellpad construction and drilling, workovers, fracking and completion, gas compression, evaporation of chemicals from produced water and frack flowback, dehydration, separation, waste treatment and disposal, transmission and processing.

The following is a brief glossary of the life cycle of natural gas development:

Construction activity

Even prior to producing natural gas, air pollution is generated by heavy construction activity including trucks and other equipment that emit air pollutants at well pads, pipelines, roads and compressor stations.

Drilling

During the drilling of a well, air pollution is generated by diesel engines powering the drill rig, as well as by any natural gas emissions being vented from the hole in the ground. These emissions could include various toxic gases, including volatile organic compounds.

Hydraulic fracturing (fracking) and completion[1]

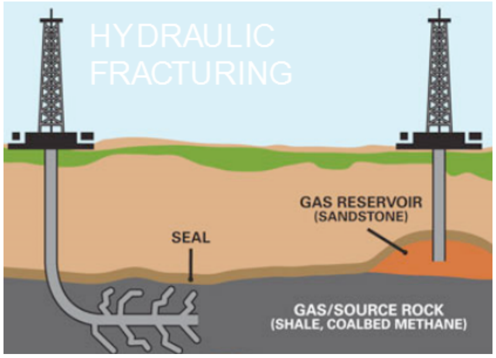

Image from Stark Political Report

While oil and gas have always been extractable from the natural fissures in certain rock formations, some of these deposits are too diffuse to be economically feasible to exploit using traditional drilling methods. Increasing demand, however, has spurred the evolving development of fracturing technology. Pioneered in west Texas, fracking is being used to increase the productivity of drill sites in shale, coalbed methane, and tight sands formations that previously were too expensive to drill.

Fracking is dependent on fracturing fluid, typically comprised of water-based concoctions riddled with assortments of chemicals and proppants like sand. The chemical makeup of the fluid varies from company to company and site to site. The process of fracking involves perforating oil and gas wells and then pumping chemical fluid into the earth. By pumping fracturing fluid deep into the rock formation fissures under the earth at very high pressure, the cracks are expanded and then propped open with the proppant. These expanded cracks allow a single well to tap into multiple diffuse deposits.

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[1] "Hydraulic Fracturing Research Study," US EPA. Office of Research and Development. 24 May 2011. http://www.epa.gov/safewater/uic/pdfs/hfresearchstudyfs.pdf

Though fracking enables cost effective production of natural gas for the gas companies, it also comes with risks to public health and the environment. One of the least documented risks has been from air pollution caused by fracking compounds during their use, storage, or waste disposal.

Pits

Waste from drilling, fracking, or production may be dumped into open air pits to allow some of the toxic material to evaporate into the air. This can result in significant air pollution.

Land application (including land farming)

Waste from drilling, fracking, or production may be spread on the ground or otherwise applied to the land. This can result in significant air pollution.

Compressor station

Gas from wells is collected at central locations and compressed into smaller volumes at stations. Another type of compressor is located on the well site. Both types of compressors can leak and release a variety of toxic gases.

Condensate tanks

Some well sites produce semi-liquid gases along with natural gas that are stored in tanks, which can leak various toxic gases into the air.

Dehydrators

These systems are needed to remove water from natural gas and can release toxic gases in the process.

Flaring

Unwanted gases in the production process may be burned off in the open air through flares, which can produce other toxic gases as a result.

Fugitive emissions

Leaks in equipment such as pumps, valves, compressors, pipes and tanks can result in significant air pollution releases because of the number of components in gas processing.

Venting

During various stages of gas exploration, production and maintenance, gases are vented directly into the air rather than contained or flared. Venting can release large volumes of toxic gases.

Gas processing plant

The last stage of gas production involves the refining of the raw gas into the final product. This occurs at large gas processing plants, which have many sources of air emissions.

Additional waste disposal sites[2]

Wastes from various stages of gas production and processing may be sent to treatment sources including landfills, injection sites and wastewater treatment sites, which can also release air pollution.

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[2] "Public Health and Toxics." EARTHWORKS. 20 March 2011, http://www.earthworksaction.org/Health%20and%20Toxics.cfm

Air Pollution and Human Health Impacts of Natural Gas Development

Air pollution can affect our health in many ways, with both *short-term* and *long-term* effects. Different groups of individuals are affected by air pollution in different ways. Some individuals are much more sensitive to pollutants than others. Sensitive populations, including young children and elderly people, often suffer more from the effects of air pollution. People with health problems such as asthma, heart and lung disease may also suffer more when the air is polluted. The extent to which an individual is harmed by air pollution usually depends on the **total exposure** to the damaging chemicals, i.e., the *duration of exposure* and the *concentration of the chemicals.* Total exposure must be taken into account when assessing air pollution risks.

Examples of **short-term effects** include irritation to the eyes, nose, and throat, and upper respiratory infections such as bronchitis and pneumonia. Other symptoms can include headaches, nausea, and allergic reactions. Short-term air pollution can aggravate the medical conditions of individuals with asthma and emphysema.

Long-term health effects can include chronic respiratory disease, lung cancer, heart disease, and even damage to the brain, nerves, liver, or kidneys. Continual exposure to air pollution affects the lungs of growing children and may aggravate or complicate medical conditions in the elderly.[3]

Chemicals such as benzene, toluene, ethylbenzene and xylene (BTEX) are known to be present around natural gas development sites, both from the gas deposits as well as chemical additives. Our independent testing found significantly high amounts of these toxic gases downwind of various sites. Health effects from BTEX include dizziness and confusion, eye, nose and throat irritation, birth defects, kidney, liver, and neurological damage, and cancer. For example, benzene is known to cause leukemia.[4]

Hydrogen sulfide was also found in the Bucket tests, warning signs for the gas are often visible near well pads. Long-term exposure to hydrogen sulfide is associated with an elevated incidence of respiratory infections, irritation of the eye, nose and throat, coughing, breathlessness, nausea, headache, and mental health impacts, including depression.[5] It is recommended, that workers handling hydrogen sulfide be equipped with hydrogen sulfide monitors, respirators, and rescue packs for protection in the event of elevated exposure; the public has no such protection.[6]

Additional toxic substances were detected at high levels in the air samples, including toxic gases not previously associated with natural gas development, suggesting that substances possibly associated with fracking additives may have been released into the air.

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[3] "How Can Air Pollution Hurt My Health." Health Effects of Air Pollution, Lawrence Berkeley National Laboratory, March 2011, http://www.lbl.gov/Education/ELSI/Frames/pollution-health-effects-f.html

[4] NRDC, Drilling Down, October, 2007, table on page vi

[5] Chernaik, Mark. Data Interpretation Synthesis Letter. Science for Citizens. 16 Feb. 2011

[6] Air Products, Material Data Sheet, http://avogadro.chem.iastate.edu/MSDS/hydrogen_sulfide.pdf

Overall, air samples gathered for this project showed that neighbors of the natural gas operations in the target communities are breathing multiple chemicals that can cause an increased risk of cancer and other serious health effects. There are no health-based standards for exposure to multiple chemicals, although the negative health impacts are considered to be increased.

Natural Gas Development in Colorado and New Mexico

Growth in Project Areas

GCM worked with two communities in the San Juan Basin—one in southwest Colorado and a second in northwest New Mexico. In addition, GCM worked with a third community in Garfield County in western Colorado.

- ***Colorado's natural gas production has risen 450% since 1990 with over 27,000 active wells statewide.*** [7]

- ***Currently there are approximately 3,400 wells in La Plata County, CO.*** [8]

Image from BP.com

- ***There are approximately 21,000 wells in San Juan County, NM***

- ***The approximate total of wells in the entire San Juan Basin is 35,000 wells*** [9]

Image from Realtor.com

- ***In western Colorado, Garfield County has an estimated 8,249 active wells with 2,037 new permits approved in 2010*** [10]

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[7] "Background." Western Colorado Congress, 20 March 2011, http://www.wccongress.org/gvca.htm#background

[8] "Natural Resources- Oil and Gas." La Plata County Planning Department, 25 March 2011, http://www.co.laplata.co.us/departments_and_elected_officials/planning/natural_resources_oil_gas

[9] United States Department of Interior, Bureau of Land Management, **Farmington Resource Management Plan** (December 2003) Final **RMP**/Record of Decision

[10] May 2011 Colorado Oil & Gas Conservation Commission Staff Report

Target Communities

GCM worked with communities in northwest New Mexico and southwest Colorado in partnership with the San Juan Citizens Alliance. The project also included communities in western Colorado in partnership with the Western Colorado Congress. The communities were trained in air monitoring and bucket sampling around natural gas development sites.

Northwest New Mexico: Aztec and Farmington Area

Of the three communities involved in this pilot project, northwest New Mexico has the longest history of complaints about natural gas drilling. Natural gas has been drilled for, and produced, in northwest New Mexico for over 60 years with natural gas facilities interspersed among residential areas. Community residents in northwest New Mexico have noticed strong odors since the late 1980s, reported as smelling like rotten eggs, petroleum and sewage, around the ever-expanding oil and gas industry. Residents have experienced nose, throat and eye irritation that occasionally would last for hours after smelling the odors. When the odors increased in frequency, so did the associated acute health effects.

Energy companies in the area, including BP, Energen, XTO, Devon, Conoco Phillips, Enterprise, Williams and Questar, are associated with drilling for and transporting natural gas, where operations at sites can include fracking by numerous companies. San Juan County in Northwest New Mexico consists of more than 100,000 residents potentially affected by natural gas production, either by living near a gas well or near the plants that process the natural gas.

There are many gas wells near schools, churches, private residences and community centers. Natural gas odor incidents are frequent, along with adverse health effects in the community. For example, in December 2009, one of the members of the San Juan Citizens Alliance and long-term area resident Shirley McNall went out to get her mail. She was immediately struck with an extremely potent rotten egg odor and overcome with dizziness and nausea. According to McNall, she fell to the ground and was forced to crawl back into the house. While the symptoms began to slowly subside, she reported numbness in her lips that lasted for three days after the incident.

During less severe odor incidents, residents commonly reported headaches, nausea and dizziness in addition to nose, throat and eye irritation.

Shirley McNall- Aztec, NM

The health effects and reported odors could be associated with chemical exposure. McNall and other residents have documented odors most frequently during the late evening through the early morning hours. This could be related to the industrial process and/or weather patterns that concentrate or bring the toxic fumes near homes.

Community members call the New Mexico Oil and Gas Conservation Division frequently, often multiple times a week, to report these odors. However, no satisfactory permanent solutions have been reached. On occasion, a representative of the New Mexico Oil and Gas Conservation Division will conduct an on-site investigation. During one of these investigations, the representative informed the residents that the most likely cause of the odors is “treated” hydrogen sulfide. This is a major concern because hydrogen sulfide is highly toxic and, while its presence requires formal signage by law, no signage was present at the well under investigation.

Homeowners are not generally informed of the toxic risk when their property is in proximity to natural gas facilities. Split estate situations where mineral ownership is separate from private surface ownership creates confusion and uncertainty surrounding where wells can be drilled in relation to homes. Numerous contractors and subcontractors may be involved with natural gas facilities, further complicating responsibilities and actions. The New Mexico Environmental Department and the U.S. Environmental Protection Agency’s (EPA) efforts to monitor and evaluate air impacts from natural gas resources in northwest New Mexico have been limited.

Southwest Colorado: Durango

This troubling trend is not unique to the northwest corner of New Mexico. The expanding oil and gas industry has spread into communities in Colorado.

La Plata County, located in southwest Colorado where the southern Rockies meet the high desert country of northern New Mexico, is home to three municipalities, four river drainages, and a sovereign Indian nation. It is known for its outdoor activities including hiking, rock climbing, backpacking and white water rafting along the Animas River, and for the incredibly lucrative coalbed methane field that underlies it.

Coalbed methane development has been going on here since in the mid-1980s. The environmental degradation associated with development has been documented to include coal seam fires and hydrogen sulfide and methane seeps at the Fruitland formation outcrop. The full impacts of development on air quality and public health, however, remain largely unexamined.

Due to split estate status, energy companies can lease the mineral rights underneath the property of a homeowner. Insufficient setbacks and surface owner protections allow the oil and gas industry to place facilities directly next to homes and schools. Near Sunnyside Elementary School, air monitoring on January 7, 2011 showed elevated levels of four known carcinogens. Two of the carcinogens were recorded at levels that are considered to be an unacceptable long-term exposure risk.

Josh Joswick- Durango, CO

LaPlata County has an estimated 3,400 wells. Many county residents therefore live in or adjacent to the ‘gas patch,’ often times in close proximity to gas wells, compressor stations, dehydrators, and processing plants. This incompatible mix of industrial activity in rural residential areas has had an impact on people's lives. Gas patch residents in La Plata County report odors similar to their neighbors in New Mexico. These odors, smelling like burning oil, car exhaust, and burning rubber, are most frequently noticed around well sites.

Aaron Mallet, a La Plata County resident active with the Bucket Brigade, stated on September 28, 2010: "On a regular basis there is an acrid smell in the air that emanates from that well pad."[11] Residents have also documented headaches, sore throats and burning nasal passages during these odor incidents.

Western Colorado: Battlement and Silt Mesas

Lastly, GCM worked with the communities of Battlement and Silt Mesas in Garfield County, Colorado. Battlement and Silt Mesas are two rural communities experiencing impacts from nearby development of natural gas.

Battlement Mesa is an unincorporated retirement community of 5,500 residents in western Garfield County. Originally constructed by Exxon in the 1970s for workers in the oil shale industry,[12] it was later marketed as a destination for retirees seeking a peaceful place to spend their golden years. Exxon eventually sold the surface properties but retained the mineral rights to extract the fossil fuels beneath Battlement Mesa at any time in the future.

Community members watched as natural gas wells incrementally came closer to Battlement Mesa, and the residents began to wonder if drilling would be allowed within their retirement neighborhood.

Dave Devanney- Battlement Mesa, CO

In 2009, Battlement Mesa learned of a proposal to drill 200 natural gas wells within its borders, including sites near homes, along the Colorado River, on the golf course, and near a school. Battlement Mesa residents called for thorough scientific research of the potential public health impacts of natural gas development before any permitting decision. After hundreds of residents signed a petition, a groundbreaking Health Impact Assessment was commissioned for drilling within Battlement Mesa and county officials delayed any new drilling inside of the retirement community until this process was completed. Drilling, however, began just outside the border of the community and community members began complaining of noxious fumes being emitted.

Battlement Mesa residents documented strong petroleum-like odors in the middle of the night and early mornings. Residents believed that these strong petroleum, diesel and chemical smells were caused by nearby fracking operations. Nearby residents began experiencing health effects such as throat and nose irritation, headaches, itching skin, burning eyes, and dizziness. Residents

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[11] Mallet, Aaron. Pollution Log 28 Sept. 2011

[12] Oil Shale is a different formation than the source of shale gas.

called the Colorado Oil and Gas Conservation Commission to formally report the odor events; they started documenting odor occurrences, and they contacted local authorities.

The Colorado Oil and Gas Conservation Commission cited the operator for failing to capture nuisance odors derived from its operations. The company was encouraged to use additional vapor recovery techniques during flowback operations to reduce odors (but never received a monetary penalty). Residents noticed a marked diminishment of the odors, but around the same time, in November of 2010, a local news channel highlighted nearby Silt Mesa residents' problems with natural gas development. Silt Mesa residents reported odors they thought were caused by natural gas activity, and Dave Devanney of the Battlement Concerned Citizens contacted them.

Silt Mesa is a network of irrigation canals and small ranches, sitting along the Colorado River between Rifle and Silt, Colorado. Drilling for natural gas is taking place near homes and water supplies, presenting many of the same challenges as on Battlement Mesa.

One Silt Mesa family with two young sons had three natural gas drill rigs surrounding its property, each with ongoing flaring. The nearest flare stack was less than one-half a mile from their home. Family members reported pungent odors of rotten eggs followed by severe headaches, nosebleeds and rashes. The nosebleeds were persistent and heavy, much different than the average nose bleed. The mother described it as "almost like hemorrhaging." The youngest son developed a full body rash, which prompted a doctor visit. Upon examination, the doctor immediately told the Silt Mesa family to evacuate their home.

Although the family was forced to vacate their home because of nearby industrial activity, the state did not issue any violations. According to Colorado rules, Silt Mesa is not a High Density area, therefore, drilling for natural gas in the area does not warrant additional safety precautions.[13]

Today, the Silt Mesa family has left their home and put it up for sale. An air sample taken on January 15, 2011, on their property, contained levels of hydrogen sulfide more than 185 times above the long term level set by the U.S. EPA (2 $\mu g/m^3$) to estimate increased risk of serious health effects.

This Silt Mesa family, as well as the Battlement Mesa residents, call frequently to report odor complaints and other incidents of non-compliance. They call the Colorado Oil and Gas Conservation Commission, the Garfield County Oil and Gas Department, the Colorado Department of Public Health and Environment, and occasionally, the Environmental Protection Agency. The communities have seen worse local air quality since natural gas development markedly increased in Garfield County, although limited air monitoring is conducted by local and state authorities.

Collectively, nine air samples were taken by the Bucket Brigades. The members of San Juan Citizens Alliance and Battlement Concerned Citizens have taken the results to local officials and

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[13] Colorado Oil and Gas Conservation Commission. "Series Safety Regulations" 2 June 2011. http://cogcc.state.co.us/

the U.S. EPA, but, to date, the agencies have not taken any action. Most of the residents feel their concerns have fallen on deaf ears.

A press release was issued in Aztec, New Mexico and Durango, Colorado announcing the air sample results. The residents still have not received an adequate response from the regulatory agencies. On Monday, April 4, 2011, Katee McClure sent an e-mail to the New Mexico Environment Department inquiring about who is responsible for enforcing air regulations. Although, the agency did respond in a timely manner, it provided incorrect information regarding standards for hydrogen sulfide pollution while failing to take responsibility or provide information for the responsible agency.[14]

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[14] McClure, Katee. 4 April 2011

Citizen Air Sampling: Bucket Brigade Projects

Community-Based Air Monitoring: A Crucial Piece of the Puzzle

Building a trail of evidence

Regulatory and environmental agency personnel are not available at all hours to come out during a pollution incident. In the case of Colorado and New Mexico, a proper citizen complaint system is not established. A proper citizen complaint system would include a telephone hotline followed by rapid response from regulatory agencies and timely air sampling during odor incidents. Community-based monitoring provides an opportunity for residents to respond immediately to the pollution incident with sampling equipment and to contact agency personnel.

GCM trained members of the Western Colorado Congress, the San Juan Citizens Alliance, and other community members to keep a record of pollution incidents. These records include: the location, nature, and duration of the incident; the wind direction, health effects or property damage; and how the incident was addressed – by a call to the regulatory agency or the company suspected or known to be the source of the pollution, or informative calls to other neighbors.

Pollution incident records are referred to as “pollution logs.” Pollution logs filled out by community members ensure that a record is maintained beyond regular agency business hours. Community members are also encouraged to take pictures and/or use a video camcorder to catch a visual image of the pollution.

Bucket Brigades provide evidence and hard science to support the anecdotal stories of health impacts that all affected communities know too well: strange odors causing nausea, stinging eyes, burning noses, sore throats, coughs, and other distressing health symptoms. Community-based monitoring engages community members in record maintenance, site identification, operation of monitoring equipment, documentation, and custody and shipping of the sample.

The information gathered by Bucket Brigades, combining science with community experience and reports, helps bridge the gap between communities, regulators and industry. Air sampling and monitoring can provide key evidence exposing chemical exposure, can be a tangible way to show that the air pollution has decreased in a community, and can help build relationships where community members coexist with their industrial neighbors.

Bucket Brigade Training & Methods

To begin a project, GCM conducts a research assessment of toxic hazards in a target community and identifies the appropriate environmental monitoring tools that will assist community members in investigating their health concerns and exposures. We review the data on pollution sources and toxins and prioritize the most serious for early action. Due to the lack of publicly available data regarding the air emissions from natural gas drilling and refining sites, we had little research available for reference in this project.

All Bucket Brigade trainings are conducted on site, in the local community. For this project, GCM was given a local tour by community members in areas near Durango, Colorado; Battlement/Silt Mesas, Colorado; and Aztec, New Mexico in late July, 2010. During the training, GCM provided a day-long classroom training, including background on pollution and environmental health, how to document pollution incidents, hands on training and how to use monitoring equipment. We worked with the local community members to co-design an environmental sampling plan.

The training and plans emphasize standard scientific methods. Community members learn how the monitoring equipment works, the best time to use it, and the appropriate paperwork to fill out before shipping a sample to the lab. The Bucket Brigade's work is strengthened by following stringent Quality Assurance/Quality Control (QA/QC) protocols and the use of EPA approved labs.

The Bucket Monitoring Equipment

Due to the nature of the uncertainty of the emissions associated with natural gas drilling, hydraulic fracturing and refining, this project chose to use the Bucket as the monitoring equipment. The Bucket is modeled after the Summa Canister,[15] but has some advantages in its use.

The Bucket is portable, requiring only a tedlar bag and vacuum to take the grab sample. Air is "grabbed" out of the air for two to three minutes and captured in the bag. Once the sample is taken, the tedlar bag is sealed, removed from the bucket and sent to the lab for analysis.

The air sampling Bucket, gcmonitor.org

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[15] State of Nevada, Division of Environmental Protection. "Summa Canister Sampling". http://ndep.nv.gov/fallon/summa.pdf

The lab analysis is conducted by Columbia Analytical Services in Simi Valley, California. The lab utilizes EPA method TO-15 and ASTM D 5504-08 method for sample analysis. The TO-15 analysis includes a spectrum of more than 70 volatile organic compounds and the ASTM D 5504-08 method is used to test for 20 sulfur compounds.

Once the community members are trained on the equipment, the buckets are kept at various locations in the community – selected based on the location of odors and health symptoms that have been experienced and reported. When an odor incident occurs, Bucket Brigade members join together to bring a bucket to the site of the odor incident and take a sample of the air at the time of the odor.

Results & Discussion of Results

Individual sample results and overall trends:

For this project, communities in New Mexico and Colorado took a total of nine air samples between September 2010 and January 2011. This report documents serious toxic air pollution generated at various points of the life cycle of natural gas development. Targeted sampling sites included well pad, compressor station, gas separation plant, dehydrator and waste disposal site. Serious cancer-causing chemicals were detected at elevated levels, including chemicals associated with the fracking process used increasingly by energy companies.

While bucket samples are short-term grab samples of the air breathed by community members living near natural gas development facilities, letters and pollution logs reveal that the odors are persistent and occur on an ongoing basis. We therefore consider the data to be indicative of long-term exposures, and the expert interpretation used in this report compares the data to pollutant levels linked to long-term health effects.

A total of 22 toxic chemicals were detected in the nine air samples, including four known carcinogens, toxins known to damage the nervous system, and respiratory irritants. The levels of chemicals detected were in many cases significantly higher than is considered safe by state and federal agencies. The levels were between three to 3,000 times higher than levels established by public health agencies to estimate increased risk of serious health effects and cancer based on long-term exposure.[16]

The most significant results:

- ***Benzene***, a known carcinogen, was found at high concentrations in four air samples at levels between 6.3 and 47 $\mu g/m^3$. These levels are 48.5 to 800 times higher than the level set by the US EPA of 0.13 $\mu g/m^3$ to estimate increased cancer risk from long-term exposure.[17]

  Benzene can also cause serious non-cancer health effects which can damage the blood and nervous system Levels of benzene in one of the nine samples, collected on January 7, 2011 near the Sunnyside Elementary School, Durango, Colorado, exceeded the level set by the U.S. EPA for benzene (30 $\mu g/m^3$) to estimate increased risk of non-cancer health effects.

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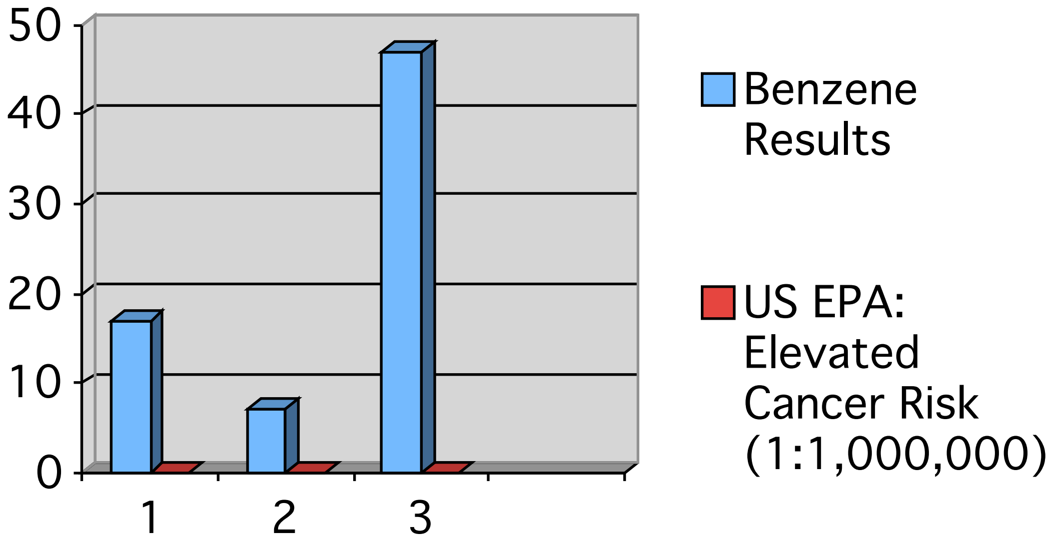
[16] This report defines an elevated cancer risk as 1:1,000,000

[17] http://www.epa.gov/ttn/atw/toxsource/table1.pdf

Sample 1: 200 Montana St Bloomfield NM
Sample 2: Bondad 33-10 #26 Williams Well, Durango, CO
Sample 3: Intersection of US 550 & CR 218 Durango, CO, near Sunnyside Elementary



- ***Acrylonitrile***, a human carcinogen, was found in five samples at levels between 7.9 and 30 µg/m^3. These levels are 790 to 3000 times above the U.S. EPA level of 0.01 µg/m^3, set to estimate an increased risk of cancer from long term exposure. All of these levels correspond to what EPA would consider an "unacceptable cancer risk" in that long-term exposure is associated with a cancer risk of greater than 100 in a million.[18]

  Acrylonitrile is also a respiratory irritant, causing degeneration and inflammation of nasal epithelium. Levels of acrylonitrile in the five samples exceeded the level set by U.S. EPA for risk of increased non-cancer health effects from long term exposure (2 µg/m^3) by 3 to 15 times.[19]

- ***Methylene chloride***, a human carcinogen, was found in five samples at levels between 7.9 and 17 µg/m^3. These levels are 3 to 8 times higher than the level set by the U.S. EPA (2.0 µg/m^3.) to estimate an increased risk of cancer from long-term exposure.

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[18] Communication from Miriam Rotkin-Ellman, Natural Resources Defense Council. 7 June 2011

[19] The USEPA Reference Concentration (RfC) is an estimate of a continuous inhalation exposure concentration to people (including sensitive subgroups) that is likely to be without risk of deleterious effects during a lifetime.

- ***Ethylbenzene***, a human carcinogen, was found in five samples at levels between 5.1 to 22 μg/m^3. These levels are 12 to 55 times higher than the level set by the US EPA (0.4μg/m^3) to estimate increased cancer risk cancer from long-term exposure.

- ***Xylene***, were found at a level of 100 and 154 μg/m^3. These levels exceed the U.S. EPA's level for estimating increased non-cancer health risks of 100 μg/m^3.

- ***Hydrogen sulfide*** was found in one sample at 370 μg/m^3 which is more than 185 times above the long term level set by the U.S. EPA (2 μg/m^3) to estimate increased risk of serious health effects.

  Long-term exposure to hydrogen sulfide is associated with an elevated incidence of respiratory infections, irritation of the eye and nose, cough, breathlessness, nausea, headache, and mental symptoms, including depression. The World Health Organization's Guideline Value for exposure to hydrogen sulfide is 7 μg/m^3 over a 30-minute period.

For the first time, at least two cancer-causing chemicals found at high levels, acrylonitrile and methylene chloride,[20] were detected by the air samples at a variety of natural gas development sites. Neither is associated with natural gas and oil deposits, but both have been shown to be associated with chemicals used in the fracking process to increase yields from oil and gas deposits.

The air samples found high levels of chemicals that can cause symptoms that match the odors and health effects reported by nearby residents for years. This confirms the need for agencies to take such complaints seriously and to better monitor and require pollution controls at all points of natural gas production and processing.

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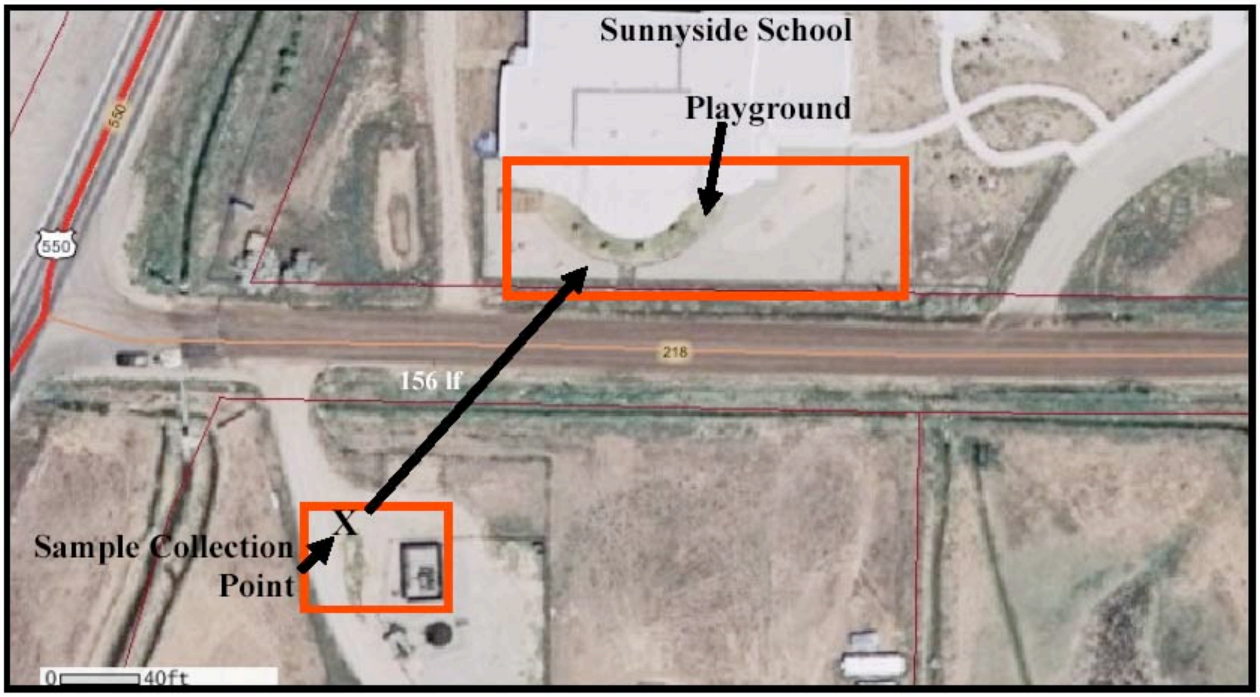
[20] Cherniak, Mark. Data Interpretation Synthesis Letter. 16 Feb 2011

Image from San Juan Basin Health Department



Bucket Brigade Sample Collection Event
January 7, 2011
Dehydrator Facility Located
156 lf from Sunnyside Kindergarten Playground

Results near the Sunnyside School in La Plata County, Colorado

On January 7, 2011, two members of the Bucket Brigade team in La Plata County, Colorado, took an air sample less than 50 feet from a dehydrator that is less than 200 feet from the Sunnyside Elementary School playground near Durango. This natural gas dehydrator is a frequently suspected source of unknown chemical odors. The sampling team on site experienced odors. Subsequent analysis of the air sample revealed a number of toxic chemicals, including four known carcinogens.

A significant level of acrylonitrile, a human carcinogen, was detected in this sample (as it was in four other samples in this report) at a level above which is considered by the US EPA to be an unacceptable long-term exposure risk.[21] Methylene chloride, a human carcinogen, was also detected in this sample (as it was in four other samples) at a level above which is considered to be an unacceptable long-term exposure risk.

Two more carcinogenic substances, benzene and ethylbenzene, were also detected in this sample at levels above that which is considered to be an unacceptable long-term exposure risk. The

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[21] http://www.epa.gov/ttn/atw/toxsource/table1.pdf

level of benzene in this sample, 47 ug/m^3, is notable in that it is the highest level of benzene detected so far in this area by the Bucket Brigade. Besides acting as a carcinogen, benzene can also adversely impact the human immune system by decreasing circulating levels of lymphocytes. To prevent reduced lymphocyte counts, the U.S. EPA has an established a reference (long-term) concentration for benzene of only 30 ug/m^3.

Mark Chernaik, PhD, interpreted the test results for this project. According to Dr. Chernaik, "The level of benzene in this sample is more than 50% above the U.S. Reference concentration for benzene. If this detected level of benzene in this sample represents ambient air quality that generally prevails at this location, then persons living or attending school at this location would be at risk to adverse impacts to the immune system."[22]

The levels of other aromatics in the sample, – 4-ethyltoluene, 1,3,5-trimethylbenzene, 1,2,4-trimethylbenzene, – although not above health reference levels are strikingly similar to the levels of these aromatics in four other samples and seem to be a fingerprint for volatile organic compounds near an oil and gas facility in this area. The high levels of the tentatively identified compounds propane and butane also strongly suggest that the source of the volatile organic compounds is related to gas field activities.

Matching odors and health effects to sample results

Residents of natural gas production facilities involved in the Bucket Brigade air-testing project recorded their observations and health effects during testing. Once sample results were available, the observed odors and health effects noted in pollution logs were compared to the known health effects of the toxic chemicals found in the samples. Here are several examples:

> *"On Wednesday, Jan 19th air sample was taken at the Blanco, NM Enterprise Buena Vista Compressor Station in Pump Canyon north of several homes. Chris Velasquez and his family live "down wind" of this site. Chris was my guide and companion on the testing trip.*
>
> *I smelled the heavy smell of oily burning plastic. My eyes burned and my nose, throat and mouth became irritated instantly. The soft tissue in my nose, throat and mouth are still sore today as I write this. I have been coughing and my nose is still runny. My eyes are still very red and irritated."*[23]

The sample results confirmed the presence of several noxious benzene compounds, including chlorobenzene, 1, 2, 4-trimethylbenzene and xylene compounds. They are significant irritants to the respiratory system and combined exposure to these could have resulted in the health effects experienced by the sampler.

> *"Warren & I noted additional sharp natural gas/petroleum odors coming from the direction of the BP/CP wells when we did the air sample on January 18th. Warren noted that his eyes were burning. My throat was very irritated and my eyes burned. The musty*

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[22] Chernaik, Mark. 25 Jan. 2011

[23] McNall, Shirley. 20 Jan. 2011

> *sewage/feed lot odor is nauseating and causes throat irritation and burning eyes for me.*
>
> *The wells are on BLM land that was granted to the City of Aztec in 1963 for Recreation & Public Use Purposes (R&PP). Some of that land has been granted to Aztec Schools for the new athletic fields and sports complex located about 800 ft. from the wells."*[24]

Sample results from the January 18th sample confirmed the presence of 22 different toxic gases, including cancer-causing benzene. Many of the gases present in the sample irritate the respiratory system and the eyes. Again, the observations recorded by Bucket Brigade air samplers match the sample results.

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[24] McNall, Shirley. 20 Jan. 2011

Recommendations

Given the close proximity of residential and public property, any new sites – whether drilling, fracking, refining, or disposal – should be located at least one-quarter mile from homes, farms, schools, playgrounds, and businesses. This space would provide a **buffer zone** for industry to continue its operations while reducing community exposure to chemical contaminants.

U.S. EPA should update air quality standards for oil and gas development, including the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP), based on the following principles:

Comprehensiveness: All sources of air pollution in the oil and gas sector, including exploration, production, processing, transmission, distribution, and storage, and all pollutants released by these sources should be included in any updated air quality regulations, regardless of the level of emissions or major or area source status.

Air monitoring and transparency: Natural gas development sites including well pads, compressors, gas plants, and waste sites should be required to continuously monitor for volatile organic compounds and hydrogen sulfide in order to ensure compliance with regulations, emission limits and public health protections. All data should be publicly available via the web to provide full transparency to the public.

Effectiveness: The EPA should require the best available control technology and require practices and technologies that both reduce air pollution and promote more efficient oil and gas operations.

Full Health Protection: The EPA should consider prohibiting hazardous air pollutant emissions in certain circumstances, and ensure that any residual risk standards reduce lifetime cancer risk from oil and gas operations to below one in one million.

Forward Looking: EPA should develop mechanisms to ensure that any new equipment, facilities, technologies or practices will be subject to air pollution control requirements that may be required under any updated NSPS and NESHAP.

Enforceability: Any standards should be practicably enforceable by including monitoring, record keeping, and reporting requirements necessary to ensure continuous compliance with the standards and to allow the public, States, and the EPA to easily determine deviations and enforce any noncompliance.

CONGRESS should close the gaping loophole in the Clean Air Act’s National Emission Standards for Hazardous Air Pollutants (NESHAPs). Oil and gas exploration and production operations are exempt from two key provisions of the NESHAPs, designed to protect public health, allowing the industry to avoid complying with standards that are applied to other industries.

STATES:

In 2009, EPA Administrator Lisa Jackson issued a ruling on a Title V petition holding that states must assess whether oil and natural gas operations should be aggregated in accordance with longstanding EPA policies governing New Source Review and Title V permitting.[25] States should follow the EPA's recent guidance and ensure that emissions from oil and gas operations are appropriately aggregated to ensure compliance with New Source Review and Title V. Aggregation provides an important opportunity to more accurately recognize integrated source operations under the Clean Air Act and ensure that oil and gas operations are regulated on a cumulative basis under New Source Review and Title V.

Until strong new rules are in place, the oil and natural gas industry can and should **voluntarily invest in equipment that reduces pollution escaping to the air**. Such equipment is readily available and financially profitable for companies. These investments would increase efficiency and production and reduce cancer causing chemicals from being emitted into the air in communities near production facilities –saving lives and protecting the health of neighboring families.

As the natural gas industry continues to grow, so will the number of families neighboring and affected by the emissions. Industry and government leaders have a unique opportunity to address public health and environmental issues by implementing these recommendations. For coexistence between communities and industry to be possible, chemical exposure has to be immediately addressed.

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[25] http://www.epa.gov/region7/air/title5/t5memos/oilgaswithdrawal.pdf

Greater focus needed on methane leakage from natural gas infrastructure

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Contributed by Stephen W. Pacala, February 13, 2012 (sent for review December 21, 2011)

Natural gas is seen by many as the future of American energy: a fuel that can provide energy independence and reduce greenhouse gas emissions in the process. However, there has also been confusion about the climate implications of increased use of natural gas for electric power and transportation. We propose and illustrate the use of technology warming potentials as a robust and transparent way to compare the cumulative radiative forcing created by alternative technologies fueled by natural gas and oil or coal by using the best available estimates of greenhouse gas emissions from each fuel cycle (i.e., production, transportation and use). We find that a shift to compressed natural gas vehicles from gasoline or diesel vehicles leads to greater radiative forcing of the climate for 80 or 280 yr, respectively, before beginning to produce benefits. Compressed natural gas vehicles could produce climate benefits on all time frames if the well-to-wheels CH_4 leakage were capped at a level 45–70% below current estimates. By contrast, using natural gas instead of coal for electric power plants can reduce radiative forcing immediately, and reducing CH_4 losses from the production and transportation of natural gas would produce even greater benefits. There is a need for the natural gas industry and science community to help obtain better emissions data and for increased efforts to reduce methane leakage in order to minimize the climate footprint of natural gas.

With growing pressure to produce more domestic energy and to reduce greenhouse gas (GHG) emissions, natural gas is increasingly seen as the fossil fuel of choice for the United States as it transitions to renewable sources. Recent reports in the scientific literature and popular press have produced confusion about the climate implications of natural gas (1–5). On the one hand, a shift to natural gas is promoted as climate mitigation because it has lower carbon per unit energy than coal or oil (6). On the other hand, methane (CH_4), the prime constituent of natural gas, is itself a more potent GHG than carbon dioxide (CO_2); CH_4 leakage from the production, transportation and use of natural gas can offset benefits from fuel-switching.

The climatic effect of replacing other fossil fuels with natural gas varies widely by sector (e.g., electricity generation or transportation) and by the fuel being replaced (e.g., coal, gasoline, or diesel fuel), distinctions that have been largely lacking in the policy debate. Estimates of the net climate implications of fuel-switching strategies should be based on complete fuel cycles (e.g., "well-to-wheels") and account for changes in emissions of relevant radiative forcing agents. Unfortunately, such analyses are weakened by the paucity of empirical data addressing CH_4 emissions through the natural gas supply network, hereafter referred to as CH_4 leakage.* The U.S. Environmental Protection Agency (EPA) recently doubled its previous estimate of CH_4 leakage from natural gas systems (6).

In this paper, we illustrate the importance of accounting for fuel-cycle CH_4 leakage when considering the climate impacts of fuel-technology combinations. Using EPA's estimated CH_4 emissions from the natural gas supply, we evaluated the radiative forcing implications of three U.S.-specific fuel-switching scenarios: from gasoline, diesel fuel, and coal to natural gas.

A shift to natural gas and away from other fossil fuels is increasingly plausible because advances in horizontal drilling and hydraulic fracturing technologies have greatly expanded the country's extractable natural gas resources particularly by accessing gas stored in shale deep underground (7). Contrary to previous estimates of CH_4 losses from the "upstream" portions of the natural gas fuel cycle (8, 9), a recent paper by Howarth et al. calculated upstream leakage rates for shale gas to be so large as to imply higher lifecycle GHG emissions from natural gas than from coal (1). (*SI Text*, discusses differences between our paper and Howarth et al.) Howarth et al. estimated CH_4 emissions as a percentage of CH_4 produced over the lifecycle of a well to be 3.6–7.9% for shale gas and 1.7–6.0% for conventional gas. The EPA's latest estimate of the amount of CH_4 released because of leaks and venting in the natural gas network between production wells and the local distribution network is about 570 billion cubic feet for 2009, which corresponds to 2.4% of gross U.S. natural gas production (1.9–3.1% at a 95% confidence level) (6).† EPA's reported uncertainty appears small considering that its current value is double the prior estimate, which was itself twice as high as the previously accepted amount (9).

Comparing the climate implications of CH_4 and CO_2 emissions is complicated because of the much shorter atmospheric lifetime of CH_4 relative to CO_2. On a molar basis, CH_4 produces 37 times more radiative forcing than CO_2.‡ However, because CH_4 is oxidized to CO_2 with an effective lifetime of 12 yr, the integrated, or cumulative, radiative forcings from equi-molar releases of CO_2 and CH_4 eventually converge toward the same value. Determining whether a unit emission of CH_4 is worse for the climate than a unit of CO_2 depends on the time frame considered. Because accelerated rates of warming mean ecosystems and humans have less time to adapt, increased CH_4 emissions due to substitution of natural gas for coal and oil may produce undesirable climate outcomes in the near-term.

The concept of global warming potential (GWP) is commonly used to compare the radiative forcing of different gases relative

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Author contributions: R.A.A., S.W.P., and S.P.H. designed research; R.A.A. performed research; R.A.A., S.W.P., and S.P.H. analyzed data; and R.A.A., S.W.P., J.J.W., W.L.C., and S.P.H. wrote the paper.

The authors declare no conflict of interest.

*Challenges also exist in the quantification of CH_4 emissions from the extraction of coal. We use the term "leakage" for simplicity and define it broadly to include all CH_4 emissions in the natural gas supply, both fugitive leaks as well as vented emissions.

†This represents an uncertainty range between −19% and +30% of natural gas system emissions. For CH_4 from petroleum systems (35% of which we assign to the natural gas supply) the uncertainty is −24% to +149%; however, this is only a minor effect because the portion of natural gas supply that comes from oil wells is less than 20%.

‡One-hundred-two times on a mass basis. This value accounts for methane's direct radiative forcing and a 40% enhancement because of the indirect forcing by ozone and stratospheric water vapor (10).

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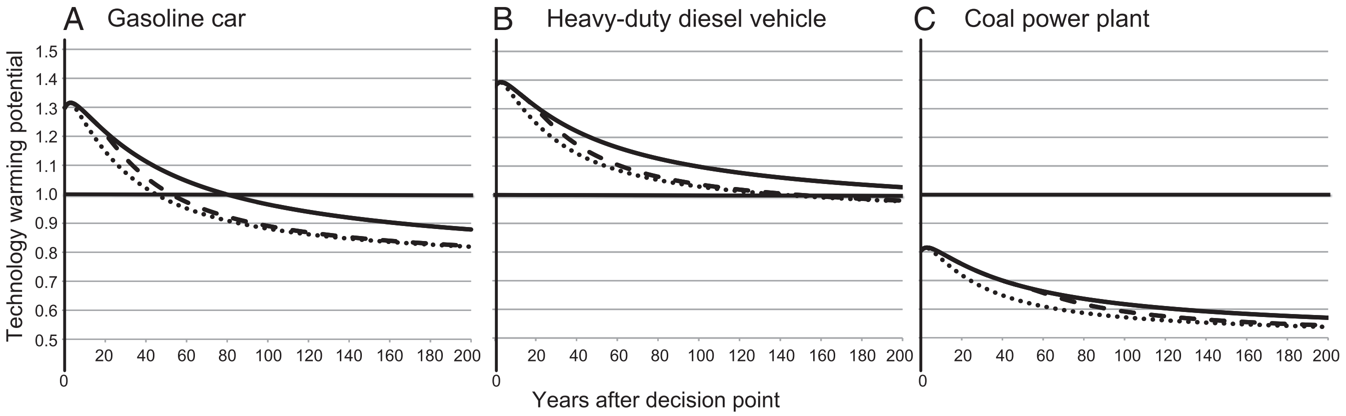

Fig. 1. Technology warming potential (TWP) for three sets of natural gas fuel-switching scenarios. (*A*) CNG light-duty cars vs. gasoline cars; (*B*) CNG heavy-duty vehicles vs. diesel vehicles; and (*C*) combined-cycle natural gas plants vs. supercritical coal plants using low-CH_4 coal. The three curves within each frame simulate real-world choices, including a single emissions pulse (dotted lines); emissions for the full service life of a vehicle or power plant (15 and 50 years, respectively, dashed lines); and emissions from a converted fleet continuing indefinitely (solid lines). For the pulse and service life analyses, our scenarios assume that the natural gas choice reverts back to the incumbent choice before the switch took place; for the fleet conversion analysis we assume that a natural gas vehicle or power plant is replaced by an identical unit at the end of its service life.

to CO_2 and represents the ratio of the cumulative radiative forcing *t* years after emission of a GHG to the cumulative radiative forcing from emission of an equivalent quantity of CO_2 (10). The Intergovernmental Panel on Climate Change (IPCC) typically uses 100 yr for the calculation of GWP. Howarth et al. (1) emphasized the 20-year GWP, which accentuates the large forcing in early years from CH_4 emissions, whereas Venkatesh et al. (2) adopted a 100-yr GWP and Burnham et al. (4) utilized both 20- and 100-yr GWPs.

GWPs were established to allow for comparisons among GHGs at one point in time after emission but only add confusion when evaluating environmental benefits or policy tradeoffs over time. Policy tradeoffs like the ones examined here often involve two or more GHGs with distinct atmospheric lifetimes. A second limitation of GWP-based comparisons is that they only consider the radiative forcing of single emission pulses, which do not capture the climatic consequences of real-world investment and policy decisions that are better simulated as emission streams.

To avoid confusion and enable straightforward comparisons of fuel-technology options, we suggest that plotting as a function of time the relative radiative forcing of the options being considered would be more useful for policy deliberations than GWPs. These technology warming potentials (TWP) require exactly the same inputs and radiative forcing formulas used for GWP but reveal time-dependent tradeoffs inherent in a choice between alternative technologies. We illustrate the value of our approach by applying it to emissions of CO_2 and CH_4 from vehicles fueled with CNG compared with gasoline or diesel vehicles and from power plants fueled with natural gas instead of coal.

Wigley also analyzed changes in the relative benefits over time of switching from coal to natural gas, but that was done in the context of additional complexities including specific assumptions about the global pace of technological substitution, emissions of sulfur dioxide and black carbon, and a specific model of global warming due to radiative forcing (5). We compare our results with Wigley's in the next section.

Results and Discussion

We focus on the TWPs of real-world choices faced by individuals, corporations, and policymakers about fuel-switching in the transport and power sectors. Each of the three curves within the panels of Fig. 1 represents a distinct choice and its associated emission duration: for example, whether to rent a CNG or a gasoline car for a day (Pulse TWP); whether to purchase and operate a CNG or gasoline car for a 15-yr service life (Service-Life TWP); and whether a nation should adopt a policy to convert the gasoline fleet of cars to CNG (Fleet Conversion TWP). In each of these cases, a TWP greater than 1 means that the cumulative radiative forcing from choosing natural gas today is higher than a current fuel option after *t* yr. Our results for pulse TWP at 20 and 100 yr are identical to fuel-cycle analyses using 20-year or 100-year GWPs for CH_4.

Given EPA's current estimates of CH_4 leakage from natural gas production and delivery infrastructure, in addition to a modest CH_4 contribution from the vehicle itself (for which few empirical data are available), CNG-fueled vehicles are not a viable mitigation strategy for climate change.[§] Converting a fleet of gasoline cars to CNG increases radiative forcing for 80 yr before any net climate benefits are achieved; the comparable cross-over point for heavy-duty diesel vehicles is nearly 300 yr.

Stated differently, converting a fleet of cars from gasoline to CNG would result in numerous decades of more rapid climate change because of greater radiative forcing in the early years after the conversion. This is eventually offset by a modest benefit. After 150 yr, a CNG fleet would have produced about 10% less cumulative radiative forcing than a gasoline fleet—a benefit equivalent to a fuel economy improvement of 3 mpg in a 30 mpg fleet. CNG vehicles fare even less favorably in comparison to heavy-duty diesel vehicles.

In contrast to the transportation cases, a fleet of new, combined-cycle natural gas power plants reduces radiative forcing on all time frames, relative to new coal plants burning low-CH_4 coal—assuming current estimates of leakage rates (Fig. 1*C*). The conclusions differ primarily because of coal's higher carbon content relative to petroleum fuels; however, fuel-cycle CH_4 leakage can also affect results. (As discussed elsewhere in this paper, our analysis considered only the emissions of CH_4 and CO_2. In *SI Text*, we examine the effect of different CH_4 leak rates in the coal and natural gas fuel cycles for the electric power scenario.)

To provide guidance to industry and policymakers, we also determined the maximum well-to-wheels or well-to-burner-tip leakage rate needed to ensure net climate benefits on all time frames after fuel-switching to natural gas (see Fig. 2). For example, if the well-to-wheels leakage was reduced to an effective leak rate of 1.6% of natural gas produced (approximately 45% below our estimate of current leakage of 3.0%), CNG cars would result

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[§] The CH_4 from operation of a CNG automobile was estimated to be 20 times the value for gasoline vehicles (11), which is approximately 20% of the well-to-pump CH_4 leakage on a kg/mmBtu basis. This assumption deserves much further scrutiny.

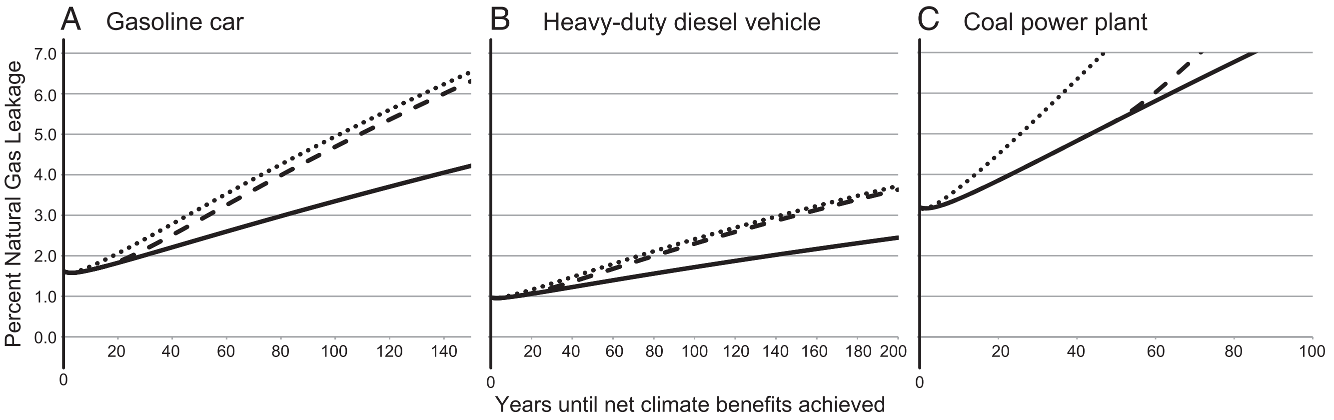

Fig. 2. Maximum "well-to-wheels" natural gas leak rate as a function of the number of years needed to achieve net climate benefits after choosing a CNG option in lieu of (*A*) gasoline cars; (*B*) heavy-duty diesel vehicles; and (*C*) coal power plants. For *A* and *B*, the maximum leakage is the sum of losses from the well through the distribution system plus losses from the CNG vehicle itself (well-to-wheels); for *C*, the maximum leakage is from the well through the transmission system where most power plants receive their fuel. When leak rates are less than the y-intercept, a fuel switch scenario would result in net climate benefits beginning immediately. The three curves within each frame follow the conventions outlined in Fig. 1 and represent: single emissions pulses (dotted lines); the service life of a vehicle or a power plant, 15 or 50 years, respectively (dashed lines); and a permanent fleet conversion (solid lines).

in climate benefits immediately and improve over time.[¶] For CNG to immediately reduce climate impacts from heavy-duty vehicles, well-to-wheels leakage must be reduced below 1%. Fig. 2*C* shows that new natural gas power plants produce net climate benefits relative to efficient, new coal plants using low-gassy coal on all time frames as long as leakage in the natural gas system is less than 3.2% from well through delivery at a power plant. Fig. 2 also shows, for a range of leakage rates, the number of years needed to reach the "cross-over point" when net climate benefits begin to occur after a fuel-technology choice is made.

We emphasize that our calculations assume an average leakage rate for the entire U.S. natural gas supply (as well for coal mining). Much work needs to be done to determine actual emissions with certainty and to accurately characterize the site-to-site variability in emissions. However, given limited current evidence, it is likely that leakage at individual natural gas well sites is high enough, when combined with leakage from downstream operations, to make the total leakage exceed the 3.2% threshold beyond which gas becomes worse for the climate than coal for at least some period of time.[||] Our analysis of reported routine emissions for over 250 well sites with no compressor engines in Barnett Shale gas well sites in Fort Worth, Texas, in 2010 revealed a highly skewed distribution of emissions, with 10% of well sites accounting for nearly 70% of emissions (see *SI Text*).[**] Natural gas leak rates calculated based on operator-reported, daily gas production data at these well sites ranged from 0% to 5%, with six sites out of 203 showing leak rates of 2.6% or greater due to routine emissions alone.[††]

Our analysis of coal-to-natural gas fuel-switching does not consider potential changes in sulfate aerosols and black carbon, short-lived climate forcers previously shown to affect the climate implications of such fuel-switching scenarios (5, 13). Recently, Wigley concluded that coal-to-gas switching on a global scale would result in increased warming on a global scale in the short term, based on examining a set of scenarios with a climate model that included both the increased warming produced by CH_4 losses from the natural gas fuel cycle and the additional cooling that occurs due to SO_2 emissions and the sulfate aerosols they form as a result of burning coal (5). The applicability of Wigley's global conclusion to the United States or any other individual country is limited due to the reliance on global emissions scenarios. Analyses such as Wigley's, which model the climate impacts of all climate forcing emissions, are useful to evaluate specific fuel-switching scenarios; however, their ultimate relevance to policymakers and fleet owners will be determined by the fidelity with which they reflect actual emissions from all phases of each fuel cycle at the relevant geographic scale (e.g., national, continental, or global). The SO_2 emissions that Wigley assumed are much higher than those of the current fleet of coal electrical generation plants in the United States, where SO_2 emissions declined by more than 50% between 2000 and 2010.[‡‡] Moreover, due to state and federal pollution abatement requirements, U.S. SO_2 emissions are projected to continue declining, to roughly 30% of 2000 levels by 2014 (see *SI Text*). This means that by 2014 the projected sulfur emissions from the U.S. coal electrical generation plant fleet, 3 TgS/GtC, will approach the emission factor that Wigley assumed the global fleet would reach in 2060 (2 TgS/GtC), when he projected the climate benefits of fuel-switching might begin, and significantly lower than Wigley's estimated 2010 value of 12 TgS/GtC. Accounting for the lower SO_2 from U.S. coal plants in an integrated way will result in greater net climate impacts of using coal than reported by Wigley and in turn the net benefits of fuel-switching will occur much sooner than he projected.

Increasingly, this will also be the case globally. The production of sulfur aerosols as a result of coal combustion causes such negative impacts on human and ecosystem health that it is prudent to assume that policies will continue to be rapidly implemented in many, if not most, countries to reduce such emissions at a much faster pace than assumed by Wigley. Indeed, it has been reported that China has already installed SO_2 scrubbers on power plants accounting for over 70% of the nation's installed coal power capacity (14), such that SO_2 emissions from power plants in 2010 were 58% below 2004 levels (15). The SO_2 emissions factor from

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[¶] Our estimate that current well-to-wheels leakage is 3.0% of gas produced assumes that 2.4% of gas produced is lost between the well and the local distribution system (based on EPA's 2011 GHG emission inventory) and that 0.6% is due to emissions during refueling and from the vehicle itself. For further discussion of the climatic implication of natural gas vehicles see (12).

[||] EPA's GHG inventory suggests leakage from natural gas processing and transmission is 0.6% of gas produced, meaning production leakage must be greater than 2.6% for the total fuel cycle leakage of a power plant receiving fuel from a transmission pipeline to exceed 3.2%.

[**] Sites with compressor engines were excluded due to the contractor's assumption that all engines in the City were uncontrolled, which leads to erroneous emission estimates.

[††] Routine emissions do not include such occasional events as well completions and blowdowns. Only 203 of the 254 sites had data for gas production. An Excel spreadsheet containing the Fort Worth data and our calculations is provided in Dataset S1.

[‡‡] Emissions query performed on December 5, 2011, using the Data and Maps feature of the U.S. Environmental Protection Agency's Clean Air Markets Web page (http://camddataandmaps.epa.gov/gdm/).

Chinese coal plants in 2010 has been estimated to be 204 g/GJ, comparable to the 2010 value of 229 g/GJ (4.7 TgS/GtC) for U.S. coal plants (*SI Text*).

Little work appears to have been done to evaluate fuel-switching in on-road transportation with methods that consider the implications of all climate forcing emissions, including sulfur aerosols and black carbon, although the effect of short-lived climate forcers on individual transport sectors has been studied (16, 17). One study reports that the influence of negative radiative forcing due to emissions from on-road transport is much lower than for the power generation sector in both the United States and globally (18). This implies that our approach, which considers CO_2 and CH_4 emissions alone, provides a reasonable first-order estimate of changes in radiative forcing from fuel-switching scenarios for the on-road transport sector.

Conclusions

The TWP Approach Proposed Here Offers Policymakers Greater Insights than Conventional GWP Analyses. GWPs are a valuable tool to compare the radiative forcing of different gases but are not sufficient when thinking about fuel-switching scenarios. TWPs provide a transparent, policy-relevant analytical approach to examine the time-dependent climate influence of different fuel-technology choices.

Improved Science and Data Are Needed. Despite recent changes to EPA's methodology for estimating CH_4 leakage from natural gas systems, the actual magnitude remains uncertain and estimates could change as methods are refined. Ensuring a high degree of confidence in the climate benefits of natural gas fuel-switching pathways will require better data than are available today. EPA's rule requiring natural gas industry disclosure of GHG emissions should begin to produce data in 2012, though it is unlikely that most uncertainties will be resolved and possible systematic biases eliminated. Specific challenges include confirming the primary sources of emissions and determining drivers of variance in leakage rates. Greater direct involvement of the scientific community could help improve estimates of CH_4 leakage and identify approaches that enable independent validation of industry-reported emissions.

Reductions in CH_4 Leakage Are Needed to Maximize the Climate Benefits of Natural Gas. While CH_4 leakage from natural gas infrastructure and use remains uncertain, it appears that current leakage rates are higher than previously thought. Because CH_4 initially has a much higher effect on radiative forcing than CO_2, maintaining low rates of CH_4 leakage is critical to maximizing the climate benefits of natural gas fuel-technology pathways. Significant progress appears possible given the economic benefits of capturing and selling lost natural gas and the availability of proven technologies. (EPA's Natural Gas STAR program shows many examples: www.epa.gov/gasstar/tools/recommended.html.)

Table 2. Radiative efficiency (RE) values used in this paper

	Direct RE ($W\ m^{-2}\ ppb^{-1}$)	Relative direct + indirect RE (per ppb or molar basis)	Relative direct + indirect RE (per kg basis)*
CO_2	1.4×10^{-5}	1	1
CH_4	3.7×10^{-4}	37	102

*Obtained by multiplying the molar radiative efficiency by the ratio of molecular weights of CH_4 and CO_2.

Methods

Our approach of using TWPs to compare the cumulative radiative forcing of fuel-technology combinations is a straightforward extension of the calculation of GWP, which is given by Eq. **1** over a time horizon, TH, for a pulse emission of 1 kg of a generic GHG producing time-dependent radiative forcing given by $RF_{GHG}(t)$:

$$\mathrm{GWP} = \frac{\int_0^{TH} RF_{GHG}(t)dt}{\int_0^{TH} RF_{CO_2}(t)dt}. \quad [1]$$

SI Text shows the analytical solution of Eq. **1** (i.e., GWP as a function of time horizon). Plotting the entire curve enables one to see the GWP values for all time horizons.

Our TWP approach extends the standard GWP calculation in two ways: by combining the effects of CH_4 and CO_2 emissions from technology-fuel combinations and by considering streams of emissions in addition to single pulses. Considering streams of emissions is more reflective of real-world scenarios that involve activities that occur over multiyear time frames.

Eq. **2** is our extension of the GWP formula Eq. **1** to calculate TWPs, with the following definitions. We label as Technology-1 the alternative that combusts natural gas and has CO_2 emissions E_{1,CO_2} and CH_4 emissions from the production, processing, storage, delivery, and use of the fuel: E_{1,CH_4}. If L_{REF} is the percent of gross natural gas produced that is currently emitted to the atmosphere over the relevant fuel cycle (e.g., electric power or transportation), then Technology-1's CH_4 emissions at leakage rate L would be: $(L/L_{REF})E_{1,CH_4}$. The calculations of TWP in this paper assume that the leakage rate L is at the national average value L_{REF} (and thus $L/L_{REF} = 1$). The scaling factor L/L_{REF} is included to allow calculations about changes in the national leakage rate or about individual wells and distribution networks that deviate from the national average. The values we used for L_{REF} are derived in *SI Text* using EPA's estimated emissions with one exception and are equal to 2.1% for a natural gas power plant and 3.0% for CNG vehicles. The exception to the last statement is that we estimated CH_4 from the operation of a CNG automobile to be 20 times that from a gasoline vehicle (11), which is approximately 20% of the well-to-pump CH_4 leakage on a kg/mmBtu basis. This assumption deserves much further scrutiny. Technology-2 combusts gasoline, diesel fuel, or coal and produces CO_2 emissions E_{2,CO_2} and methane emissions E_{2,CH_4}. Estimates of the Es for each of the technologies considered are reported in Table 1 and are explained in *SI Text*. The TWPs at each point in time can be obtained by substituting the total radiative forcing values, $TRF_{CH_4}(t)$ and $TRF_{CO_2}(t)$ for CH_4 and CO_2, respectively, and emission factors, $E_{n,GHG}$ from Table 1 into Eq. **2**:

Table 1. Emission factors used for TWP calculations in this paper

	Power Plants		Vehicles			
	Natural gas combined cycle* (kg/MW*h*)	Supercritical pulverized coal† (kg/MW*h*)	Light-duty CNG car (kg/mmBtuHHV)‡	Light-duty gasoline car (kg/mmBtuHHV)	Heavy-duty CNG truck (mg/ton-mile)	Heavy-duty diesel truck (mg/ton-mile)
Upstream CH_4	3.1	0.65	0.51	0.1	590	100
Upstream CO_2	36	7	9.4	15.9	10,000	15,000
In-Use CH_4	0	0	0.11	0.0056	15	0
In-Use CO_2	361	807	53.1	70.3	80,000	85,000
Fuel cycle CH_4	3.1	0.65	0.62	0.11	605	100
Fuel cycle CO_2	397	814	62.5	86.2	90,000	100,000

*Heat rate = 6,798 Btu/kWh.

†Heat rate = 8,687 Btu/kWh.

‡1 mmBtu = 10^6 Btu = 1.055 GJ.

Table 3. Total radiative forcing (TRF) functions for CH_4 and CO_2 used in calculation of TWP in Eq. 2 for three distinct emissions profiles

Case	$\mathrm{TRF}_{CH_4}(t)$	$\mathrm{TRF}_{CO_2}(t)$
Pulse TWP	$\mathrm{RE}\{\tau_M(1-e^{-t/\tau_M})\}$	$a_0 t + \sum_{i=1}^{3} a_i\tau_i(1-e^{-t/\tau_i})$
Service Life TWP for $t \leq \mathrm{AMAX}$	$\mathrm{RE}\{\tau_M t - \tau_M^2(1-e^{-t/\tau_M})\}$	$a_0\frac{t^2}{2} + \sum_{i=1}^{3} a_i(\tau_i t - \tau_i^2(1-e^{-t/\tau_i}))$
Service Life TWP for $t > \mathrm{AMAX}$	$\mathrm{RE}\{\tau_M \mathrm{AMAX} - \tau_M^2 e^{-t/\tau_M}(e^{\mathrm{AMAX}/\tau_M}-1)\}$	$a_0[\mathrm{AMAX}\,t - \frac{\mathrm{AMAX}^2}{2}] + \sum_{i=1}^{3} a_i(\tau_i \mathrm{AMAX} - \tau_i^2 e^{-t/\tau_i}(e^{\mathrm{AMAX}/\tau_i}-1))$
Fleet Conversion TWP	$\mathrm{RE}\{\tau_M t - \tau_M^2(1-e^{-t/\tau_M})\}$	$a_0\frac{t^2}{2} + \sum_{i=1}^{3} a_i(\tau_i t - \tau_i^2(1-e^{-t/\tau_i}))$

RE in these formulas is the radiative efficiency of CH_4 relative to CO_2 and equals 102.

$$\mathrm{TWP}(t) = \frac{\frac{L}{L_{\mathrm{REF}}} E_{1,\mathrm{CH_4}}\mathrm{TRF}_{\mathrm{CH_4}}(t) + E_{1,\mathrm{CO_2}}\mathrm{TRF}_{\mathrm{CO_2}}(t)}{E_{2,\mathrm{CH_4}}\mathrm{TRF}_{\mathrm{CH_4}}(t) + E_{2,\mathrm{CO_2}}\mathrm{TRF}_{\mathrm{CO_2}}(t)}. \qquad [2]$$

The TRF values needed for Eq. **2** are derived as follows. Let $f(t, t_E)$ be the mass of a gas left in the atmosphere at time t if 1 kg of the gas was emitted at time t_E. The cumulative radiative forcing function, $\mathrm{CRF}(t)$ (in units of J m^{-2} kg^{-1}), at a later time t, due to emission of 1 kg of the gas at time t_E, is then:

$$\mathrm{CRF}(t) \equiv \int_{t_E}^{t} \mathrm{RE}\, f(x, t_E)dx, \qquad [3]$$

where RE is the radiative efficiency of the gas. The integral in Eq. **3** sums radiative forcing for the $t - t_E$ years from the year in which the gas was emitted, $x = t_E$, to year $x = t$. For simplicity, we adopt units which make the RE of CO_2 equal to one, and so the RE of CH_4 is expressed as a multiple of the RE of CO_2. In these units, the RE of CH_4 is determined to be 102, using the values in Table 2 taken from the IPCC (10) and following the IPCC convention that methane's direct radiative efficiency be enhanced by 25% and 15% to account for indirect forcing due to ozone and stratospheric water, respectively.

Now suppose that instead of a single pulse, the gas is emitted continuously at a rate of 1 kg/yr from $t = 0$ until some maximum time $t_{\max}$, as would occur, for example, if emissions were to continue over the service life of a vehicle, power plant, or fleet. For such cases we define the total radiative forcing (TRF) in year t to be:

$$\mathrm{TRF}(t) \equiv \int_{0}^{t_{\max}} \int_{t_E}^{t} \mathrm{RE}\, f(x, t_E)dx\, dt_E. \qquad [4]$$

In the special case of a single emission pulse, $\mathrm{TRF}(t) = \mathrm{CRF}(t)$. Our use of Eq. **4** assumes a constant, unit emission rate; a more general formulation could be employed to reflect potential technology improvements over time.

For CH_4, $f(t, t_E)$ is an exponential decay:

$$f(t, t_E) = e^{-\frac{t - t_E}{\tau_M}}, \qquad [5]$$

where τ_M is 12 yr. For CO_2, we follow the IPCC and use the Bern carbon cycle model (10):

$$f(t, t_E) = a_0 + \sum_{i=1}^{3} a_i e^{-\frac{t - t_E}{\tau_i}} \qquad [6]$$

where $\tau_1 = 172.9$, $\tau_2 = 18.51$, $\tau_3 = 1.186$, $a_0 = 0.217$, $a_1 = 0.259$, $a_2 = 0.338$, and $a_3 = 0.186$. Our calculations do not consider the CO_2 produced from the oxidation of CH_4, an approximation which introduces a small underestimation of the radiative forcing from a fuel cycle's CH_4 leakage.

If calculating the TWP for a single pulse of emissions (pulse TWP), then $t_E = 0$; $\mathrm{TRF}_{CH_4}(t)$ is given by Eq. **3** with $f(t, t_E)$ given by Eq. **5**; and $\mathrm{TRF}_{CO_2}(t)$ is given by Eq. **3** with $f(t, t_E)$ given by Eq. **6**. If calculating the TWP for a permanent fuel conversion of a fleet (fleet conversion TWP) then $\mathrm{TRF}_{CH_4}(t)$ is given by Eq. **4** with $t_{\max} = t$ and $f(t, t_E)$ given by Eq. **5**. Similarly, $\mathrm{TRF}_{CO_2}(t)$ is given by Eq. **4** with $t_{\max} = t$ and $f(t, t_E)$ given by Eq. **6**. If calculating the TWP for emissions over the service life of a vehicle or power plant (service life TWP) and $t \leq \mathrm{AMAX}$, where AMAX is the average age at which the asset ceases to emit, then $TRF_{CH_4}(t)$ and $\mathrm{TRF}_{CO_2}(t)$ are the same as in the fleet conversion TWP calculations. However, if $t > \mathrm{AMAX}$, then $\mathrm{TRF}_{CH_4}(t)$ is given by Eq. **4** with $t_{\max} = \mathrm{AMAX}$ and $f(t, t_E)$ given by Eq. **5**. Similarly, $\mathrm{TRF}_{CO_2}(t)$ is given by Eq. **4** with $t_{\max} = \mathrm{AMAX}$ and $f(t, t_E)$ given by Eq. **6**. The solutions for all of these cases are in Table 3. We use $\mathrm{AMAX} = 15$ yr for vehicles and $\mathrm{AMAX} = 50$ yr for power plants.

By rearranging terms in Eq. **2** when $\mathrm{TWP} = 1$ to bring L to the left hand side, we obtain an equation for the relationship between the cross-over time (t^*—the time at which the two technologies have equal cumulative radiative forcing) and the percent leakage that makes this happen (L^*):

$$L^* = L_{\mathrm{REF}}\left\{\frac{E_{2,\mathrm{CH_4}}}{E_{1,\mathrm{CH_4}}} + \frac{E_{2,\mathrm{CO_2}} - E_{1,\mathrm{CO_2}}}{E_{1,\mathrm{CH_4}}}\,\frac{\mathrm{TRF}_{\mathrm{CO_2}}(t^*)}{\mathrm{TRF}_{\mathrm{CH_4}}(t^*)}\right\}. \qquad [7]$$

Taking the limit of L^* as the cross-over time t^* goes to zero, we obtain an expression for the critical leakage rate L_0, which serves as an approximation of the leakage rate below which the natural gas-burning technology causes less radiative forcing on all time frames.

$$L_0 = L_{\mathrm{REF}}\left\{\frac{E_{2,\mathrm{CH_4}}}{E_{1,\mathrm{CH_4}}} + \frac{E_{2,\mathrm{CO_2}} - E_{1,\mathrm{CO_2}}}{\mathrm{RE}\ \mathrm{E}_{1,\mathrm{CH_4}}}\right\} \qquad [8]$$

where $\mathrm{RE} = 102$. Eq. **8** must be viewed as an approximation because L^* is a nonmonotonic function of t^* for small values of t^* (see Fig. 2, which plots L^* as a function of cross-over time t^*). The small decrease in L^* for small t^* is caused by the fact that 18.6% of the emitted CO_2 decays faster than CH_4 in the Bern carbon cycle model (time scales of 1.186 vs. 12 yr). The large increase in L^* for $t_* > 3$ years is caused by the rapid decay of CH_4 relative to the remaining 81.4% of the CO_2. The decay curves for CO_2 and CH_4 are shown in *SI Text*. Calculated values of L_o using Eq. **8** are within 2–3% of the absolute minima for L^*. Calculations of TWP and L^* using Eq. **2** and Eq. **8** were performed with an Excel spreadsheet and are available in Dataset S1.

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EPA United States Environmental Protection Agency

Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

Background Technical Support Document for Proposed Standards

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Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

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DISCLAIMER

FOREWORD

This background technical support document (TSD) provides information relevant to the proposal of New Source Performance Standards (NSPS) for limiting VOC emissions from the Oil and Natural Gas Sector. The proposed standards were developed according to section 111(b)(1)(B) under the Clean Air Act, which requires EPA to review and revise, is appropriate, NSPS standards. The NSPS review allows EPA to identify processes in the oil and natural sector that are not regulated under the existing NSPS but may be appropriate to regulate under NSPS based on new information. This would include processes that emit the current regulated pollutants, VOC and SO_2, as well as any additional pollutants that are identified. This document is the result of that review process. Chapter 1 provides introduction on NSPS regulatory authority. Chapter 2 presents an overview of the oil and natural gas sector. Chapter 3 discusses the entire NSPS review process undertaken for this review. Finally, Chapters 4-8 provide information on previously unregulated emissions sources. Each chapter describes the emission source, the estimated emissions (on average) from these sources, potential control options identified to reduce these emissions and the cost of each control option identified. In addition, secondary impacts are estimated and the rationale for the proposed NSPS for each emission source is provided.

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APPENDIX A

1.0 NEW SOURCE PERFORMANCE STANDARD BACKGROUND

Standards of performance for new stationary sources are established under section 111 of the Clean Air Act (42 U.S.C. 7411), as amended in 1977. Section 111 directs the Administrator to establish standards of performance for any category of new stationary sources of air pollution which "…causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare." This technical support document (TSD) supports the proposed standards, which would control volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from the oil and natural gas sector.

1.1 Statutory Authority

Section 111 of the Clean Air Act (CAA) requires the Environmental Protection Agency Administrator to list categories of stationary sources, if such sources cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for such source categories. A performance standard reflects the degree of emission limitation achievable through the application of the "best system of emission reduction" (BSER) which the EPA determines has been adequately demonstrated. The EPA may consider certain costs and nonair quality health and environmental impact and energy requirements when establishing performance standards. Whereas CAA section 112 standards are issued for existing and new stationary sources, standards of performance are issued for new and modified stationary sources. These standards are referred to as new source performance standards (NSPS). The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to "at least every 8 years review and, if appropriate, revise" performance standards unless the "Administrator determines that such review is not appropriate in light of readily available information on the efficacy" of the standard. When conducting a review of an existing performance standard, the EPA has discretion to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to "reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." This level of control is referred to as the best system of emission reduction (BSER). In determining BSER, a technology review is conducted that identifies what emission reduction systems exist and how much the identified systems reduce air pollution in practice. For each control system identified, the costs and secondary air benefits (or disbenefits) resulting from energy requirements and non-air quality impacts such as solid waste generation are also evaluated. This analysis determines BSER. The resultant standard is usually a numerical emissions limit, expressed as a performance level (i.e., a rate-based standard or percent control), that reflects the BSER. Although such standards are based on the BSER, the EPA may not prescribe a particular technology that must be used to comply with a performance standard, except in instances where the Administrator determines it is not feasible to prescribe or enforce a standard of performance. Typically, sources remain free to elect whatever control measures that they choose to meet the emission limits. Upon promulgation, a NSPS becomes a national standard to which all new, modified or reconstructed sources must comply.

1.2 History of Oil and Natural Gas Source Category

In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). On June 24, 1985 (50 FR 26122), the EPA promulgated a NSPS for the source category that addressed volatile organic compound (VOC) emissions from leaking components at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for the source category that regulates sulfur dioxide (SO_2) emissions from natural gas processing plants (40 CFR part 60, subpart LLL). Other than natural gas processing plants, EPA has not previously set NSPS for a variety of oil and natural gas operations. These NSPS are relatively narrow in scope as they address emissions only at natural gas processing plants. Specifically, subpart KKK addresses VOC emissions from leaking equipment at onshore natural gas processing plants, and subpart LLL addresses SO_2 emissions from natural gas processing plants.

1.3 NSPS Review Process Overview

CAA section 111(b)(1)(B) requires EPA to review and revise, if appropriate, NSPS standards. First, the existing NSPS were evaluated to determine whether it reflects BSER for the emission affected sources. This review was conducted by examining control technologies currently in use and assessing whether these technologies represent advances in emission reduction techniques compared to the technologies upon which the existing NSPS are based. For each new control technology identified, the potential emission reductions, costs, secondary air benefits (or disbenefits) resulting from energy requirements and non-air quality impacts such as solid waste generation are evaluated. The second step is evaluating whether there are additional pollutants emitted by facilities in the oil and natural gas sector that contribute significantly to air pollution and may reasonably be anticipated to endanger public health or welfare. The final review step is to identify additional processes in the oil and natural gas sector that are not covered under the existing NSPS but may be appropriate to develop NSPS based on new information. This would include processes that emit the current regulated pollutants, VOC and SO_2, as well as any additional pollutants that are identified. The entire review process is described in Chapter 3.

2.0 OIL AND NATURAL GAS SECTOR OVERVIEW

The oil and natural gas sector includes operations involved in the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas. Specifically for oil, the sector includes all operations from the well to the point of custody transfer at a petroleum refinery. For natural gas, the sector includes all operations from the well to the customer. The oil and natural gas operations can generally be separated into four segments: (1) oil and natural gas production, (2) natural gas processing, (3) natural gas transmission and (4) natural gas distribution. Each of these segments is briefly discussed below.

Oil and natural gas production includes both onshore and offshore operations. Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation or treating of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head and "Christmas tree" piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices and dehydrators. Production operations also include well drilling, completion and recompletion processes; which includes all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the "pads" where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production sector also includes the low pressure, small diameter, gathering pipelines and related components that collect and transport the oil, gas and other materials and wastes from the wells to the refineries or natural gas processing plants. None of the operations upstream of the natural gas processing plant (i.e. from the well to the natural gas processing plant) are covered by the existing NSPS. Offshore oil and natural gas production occurs on platform structures that house equipment to extract oil and gas from the ocean or lake floor and that process and/or transfer the oil and gas to storage, transport vessels or onshore. Offshore production can also include secondary platform structures connected to the platform structure, storage tanks associated with the platform structure and floating production and offloading equipment.

There are three basic types of wells: Oil wells, gas wells and associated gas wells. Oil wells can have "associated" natural gas that is separated and processed or the crude oil can be the only product processed. Once the crude oil is separated from the water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar or pipeline. The oil refinery sector is considered separately from the oil and natural gas sector. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

Natural gas is primarily made up of methane. However, whether natural gas is associated gas from oil wells or non-associated gas from gas or condensate wells, it commonly exists in mixtures with other hydrocarbons. These hydrocarbons are often referred to as natural gas liquids (NGL). They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produced "pipeline quality" dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover natural gas liquids or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: Oil and condensate separation, water removal, separation of natural gas liquids, sulfur and CO_2 removal, fractionation of natural gas liquid and other processes, such as the capture of CO_2 separated from natural gas streams for delivery outside the facility. Natural gas processing plants are the only operations covered by the existing NSPS.

The pipeline quality natural gas leaves the processing segment and enters the transmission segment. Pipelines in the natural gas transmission segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

In addition to the pipelines and compressor stations, the natural gas transmission segment includes underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration and flow measurement.

The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines to business and household customers. The delivery point where the natural gas leaves the transmission segment and enters the distribution segment is often called the "citygate." Typically, utilities take ownership of the gas at the citygate. Natural gas distribution systems consist of thousands of miles of piping, including mains and service pipelines to the customers. Distribution systems sometimes have compressor stations, although they are considerably smaller than transmission compressor stations. Distribution systems include metering stations, which allow distribution companies to monitor the natural gas in the system. Essentially, these metering stations measure the flow of gas and allow distribution companies to track natural gas as it flows through the system.

Emissions can occur from a variety of processes and points throughout the oil and natural gas sector. Primarily, these emissions are organic compounds such as methane, ethane, VOC and organic hazardous air pollutants (HAP). The most common organic HAP are n-hexane and BTEX compounds (benzene, toluene, ethylbenzene and xylenes). Hydrogen sulfide and SO_2 are emitted from production and processing operations that handle and treat sour gas[i]

In addition, there are significant emissions associated with the reciprocating internal combustion engines and combustion turbines that power compressors throughout the oil and natural gas sector. However, emissions from internal combustion engines and combustion turbines are covered by regulations specific to engines and turbines and, thus, are not addressed in this action.

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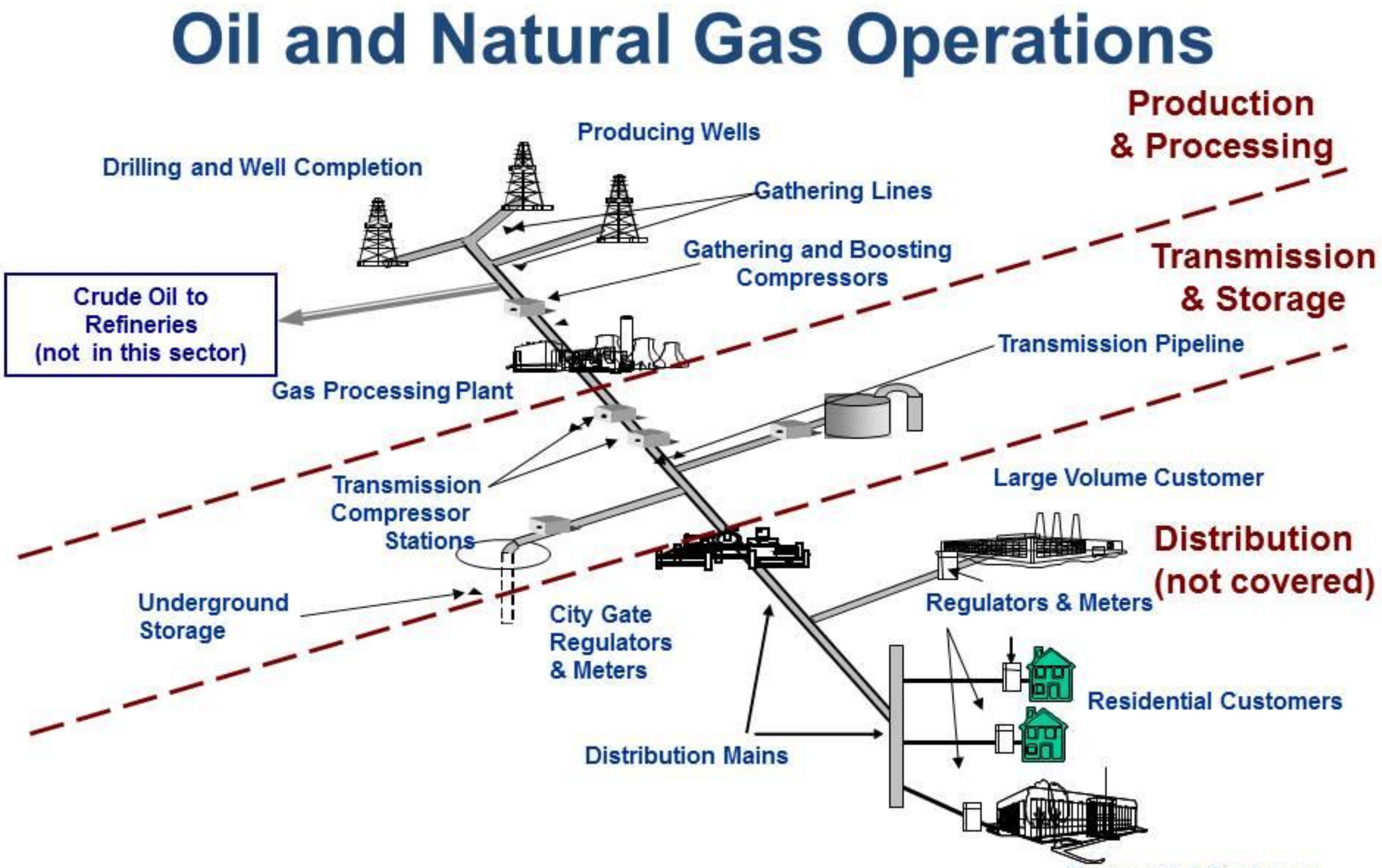
[i] Sour gas is defined as natural gas with a maximum H_2S content of 0.25 gr/100 scf (4ppmv) along with the presence of CO_2



Source: Adapted from American Gas Association and EPA Natural Gas STAR Program

Figure 2-1. Oil and Natural Gas Operations

3.0 NEW SOURCE PERFORMANCE STANDARD REVIEW

As discussed in section 1.2, there are two NSPS that impact the oil and natural gas sector: (1) the NSPS for equipment leaks of VOC at natural gas processing plants (subpart KKK) and (2) the NSPS for SO_2 emissions from sweetening units located at natural gas processing plants (subpart LLL). Because they only address emissions from natural gas processing plants, these NSPS are relatively narrow in scope.

Section 111(b)(1) of the CAA requires the EPA to review and revise, if appropriate, NSPS standards. This review process consisted of the following steps:

1. Evaluation of the existing NSPS to determine whether they continue to reflect the BSER for the emission sources that they address;
2. Evaluation of whether there were additional pollutants emitted by facilities in the oil and natural gas sector that warrant regulation and for which there is adequate information to promulgate standards of performance; and
3. Identification of additional processes in the oil and natural gas sector for which it would be appropriate to develop performance standards, including processes that emit the currently regulated pollutants as well as any additional pollutants identified in step two.

The following sections detail each of these steps.

3.1 Evaluation of BSER for Existing NSPS

Consistent with the obligations under CAA section 111(b), control options reflected in the current NSPS for the Oil and Natural Gas source category were evaluated in order to distinguish if these options still represent BSER. To evaluate the BSER options for equipment leaks the following was reviewed: EPA's current leak detection and repair (LDAR) programs, the Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database, and emerging technologies that have been identified by partners in the Natural Gas STAR program.[1]

3.1.1 BSER for VOC Emissions from Equipment Leaks at Natural Gas Processing Plants

The current NSPS for equipment leaks of VOC at natural gas processing plants (40 CFR part 60, subpart KKK) requires compliance with specific provisions of 40 CFR part 60, subpart VV, which is a LDAR program, based on the use of EPA Method 21 to identify equipment leaks. In addition to the subpart VV requirements, the LDAR requirements in 40 CFR part 60, subpart VVa were also reviewed. This LDAR program is considered to be more stringent than the subpart VV requirements, because it has lower component leak threshold definitions and more frequent monitoring, in comparison to the subpart VV program. Furthermore, subpart VVa requires monitoring of connectors, while subpart VV does not. Options based on optical gas imaging were also reviewed.

The currently required LDAR program for natural gas processing plants (40 CFR part 60, subpart KKK) is based on EPA Method 21, which requires the use of an organic vapor analyzer to monitor components and to measure the concentration of the emissions in identifying leaks. Although there have been advancements in the use of optical gas imaging to detect leaks from these same types of components, these instruments do not yet provide a direct measure of leak concentrations. The instruments instead provide a measure of a leak relative to an instrument specific calibration point. Since the promulgation of 40 CFR part 60, subpart KKK (which requires Method 21 leak measurement monthly), the EPA has updated the 40 CFR part 60 General Provisions to allow the use of advanced leak detection tools, such as optical gas imaging and ultrasound equipment as an alternative to the LDAR protocol based on Method 21 leak measurements (see 40 CFR 60.18(g)). The alternative work practice allowing use of these advanced technologies includes a provision for conducting a Method 21-based LDAR check of the regulated equipment annually to verify good performance.

In considering BSER for VOC equipment leaks at natural gas processing plants, four options were evaluated. One option evaluated consists of changing from a 40 CFR part 60, subpart VV-level program, which is what 40 CFR part 60, subpart KKK currently requires, to a 40 CFR part 60, subpart VVa program, which applies to new synthetic organic chemical plants after 2006. Subpart VVa lowers the leak definition for valves from 10,000 parts per million (ppm) to 500 ppm, and requires the monitoring of connectors. In our analysis of these impacts, it was estimated that, for a typical natural gas processing plant, the incremental cost effectiveness of changing from the current subpart VV-level program to a subpart VVa-level program using Method 21 is $3,352 per ton of VOC reduction.

In evaluating 40 CFR part 60, subpart VVa-level LDAR at processing plants, the individual types of components (valves, connectors, pressure relief devices and open-ended lines) were also analyzed separately to determine cost effectiveness for individual components. Detailed discussions of these component-by-component analyses are provided in Chapter 8. Cost effectiveness ranged from $144 per ton of VOC (for valves) to $4,360 per ton of VOC (for connectors), with no change in requirements for pressure relief devices and open-ended lines.

Another option evaluated for gas processing plants was the use of optical gas imaging combined with an annual EPA Method 21 check (i.e., the alternative work practice for monitoring equipment for leaks at 40 CFR 60.18(g)). It was previously determined that the VOC reduction achieved by this combination of optical gas imaging and Method 21 would be equivalent to reductions achieved by the 40 CFR part 60, subpart VVa-level program. Based on the emission reduction level, the cost effectiveness of this option was estimated to be $6,462 per ton of VOC reduction. This analysis was based on the facility purchasing an optical gas imaging system costing $85,000. However, at least one manufacturer was identified that rents the optical gas imaging systems. That manufacturer rents the optical gas imaging system for $3,950 per week. Using this rental cost in place of the purchase cost, the VOC cost effectiveness of the monthly optical gas imaging combined with annual Method 21 inspection visits is $4,638 per ton of VOC reduction.[i]

A third option evaluated consisted of monthly optical gas imaging without an annual Method 21 check. The annual cost of the monthly optical gas imaging LDAR program was estimated to be $76,581 based on camera purchase, or $51,999 based on camera rental. However, it is not possible to quantify the VOC emission reductions achieved by an optical imaging program alone, therefore the cost effectiveness of this option could not be determined. Finally, a fourth option was evaluated that was similar to the third option, except that the optical gas imaging would be performed annually rather than monthly. For this option, the annual cost was estimated to be $43,851, based on camera purchase, or $18,479, based on camera rental.

Because the cost effectiveness of options 3 and 4 could not be estimated, these options could not be identified as BSER for reducing VOC leaks at gas processing plants. Because options 1 and 2 achieve equivalent VOC reduction and are both cost effective, both options 1 and 2 reflect BSER for LDAR for natural gas processing plants. As mentioned above, option 1 is the LDAR in 40 CFR part 60, subpart VVa and option 2 is the alternative work practice at 40 CFR 60.18(g) and is already available to use as an alternative to subpart VVa LDAR.

3.1.2 BSER for SO_2 Emissions from Sweetening Units at Natural Gas Processing Plants

For 40 CFR part 60, subpart LLL, control systems for SO_2 emissions from sweetening units located at natural gas processing plants were evaluated, including those followed by a sulfur recovery unit. Subpart

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[i] Because optical gas imaging is used to view multiple pieces of equipment at a facility during one leak survey, options involving imaging are not amenable to a component by component analysis.

LLL provides specific standards for SO_2 emission reduction efficiency, on the basis of sulfur feed rate and the sulfur content of the natural gas.

According to available literature, the most widely used process for converting H_2S in acid gases (i.e., H_2S and CO_2) separated from natural gas by a sweetening process (such as amine treating) into elemental sulfur is the Claus process. Sulfur recovery efficiencies are higher with higher concentrations of H_2S in the feed stream due to the thermodynamic equilibrium limitation of the Claus process. The Claus sulfur recovery unit produces elemental sulfur from H_2S in a series of catalytic stages, recovering up to 97-percent recovery of the sulfur from the acid gas from the sweetening process. Further, sulfur recovery is accomplished by making process modifications or by employing a tail gas treatment process to convert the unconverted sulfur compounds from the Claus unit.

In addition, process modifications and tail gas treatment options were also evaluated at the time 40 CFR part 60, subpart LLL was proposed.[ii] As explained in the preamble to the proposed subpart LLL, control through sulfur recovery with tail gas treatment may not always be cost effective, depending on sulfur feed rate and inlet H_2S concentrations. Therefore, other methods of increasing sulfur recovery via process modifications were evaluated.

As shown in the original evaluation for the proposed subpart LLL, the performance capabilities and costs of each of these technologies are highly dependent on the ratio of H_2S and CO_2 in the gas stream and the total quantity of sulfur in the gas stream being treated. The most effective means of control was selected as BSER for the different stream characteristics. As a result, separate emissions limitations were developed in the form of equations that calculate the required initial and continuous emission reduction efficiency for each plant. The equations were based on the design performance capabilities of the technologies selected as BSER relative to the gas stream characteristics.[iii] The emission limit for sulfur feed rates at or below 5 long tons per day, regardless of H_2S content, was 79 percent. For facilities with sulfur feed rates above 5 long tons per day, the emission limits ranged from 79 percent at an H_2S content below 10 percent to 99.8 percent for H_2S contents at or above 50 percent.

To review these emission limitations, a search was performed of the RBLC database[1] and state regulations. No State regulations were identified that included emission limitations more stringent than 40 CFR part 60, subpart LLL. However, two entries in the RBLC database were identified having SO_2

[ii] 49 FR 2656, 2659-2660 (1984).

[iii] 49 FR 2656, 2663-2664 (1984).

emission reductions of 99.9 percent. One entry is for a facility in Bakersfield, California, with a 90 long ton per day sulfur recovery unit followed by an amine-based tailgas treating unit. The second entry is for a facility in Coden, Alabama, with a sulfur recovery unit with a feed rate of 280 long tons of sulfur per day, followed by selective catalytic reduction and a tail gas incinerator. However, neither of these entries contained information regarding the H_2S contents of the feed stream. Because the sulfur recovery efficiency of these large sized plants was greater than 99.8 percent, the original data was reevaluated. Based on the available cost information, a 99.9 percent efficiency is cost effective for facilities with a sulfur feed rate greater than 5 long tons per day and H_2S content equal to or greater than 50 percent. Based on this review, the maximum initial and continuous efficiency for facilities with a sulfur feed rate greater than 5 long tons per day and a H_2S content equal to or greater than 50 percent is raised to 99.9 percent.

The search of the RBLC database did not uncover information regarding costs and achievable emission reductions to suggest that the emission limitations for facilities with a sulfur feed rate less than 5 long tons per day or H_2S content less than 50 percent should be modified. Therefore, there were not any identifiable changes to the emissions limitations for facilities with sulfur feed rate and H_2S content less than 5 long tons per day and 50 percent, respectively.[1]

3.2 Additional Pollutants

The two current NSPS for the Oil and Natural Gas source category address emissions of VOC and SO_2. In addition to these pollutants, sources in this source category also emit a variety of other pollutants, most notably, air toxics. However, there are NESHAP that address air toxics from the oil and natural gas sector, specifically 40 CFR subpart HH and 40 CFR subpart HHH.

In addition, processes in the Oil and Natural Gas source category emit significant amounts of methane. The 1990 - 2009 U.S. GHG Inventory estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries) to be 251.55 MMtCO2e (million metric tons of CO2-equivalents (CO2e)).[iv] The emissions estimated from well completions and recompletions exclude a significant number of wells completed in tight sand plays, such as the Marcellus, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays (being considered as a planned improvement in development of the 2010 Inventory).

[iv] U.S. EPA. Inventory of U.S. Greenhouse Gas Inventory and Sinks. 1990 - 2009. http://www.epa.gov/climatechange/emissions/downloads10/US-GHGInventory2010_ExecutiveSummary.pdf

This adjustment would increase the 2009 Inventory estimate by 76.74 MMtCO2e. The total methane emissions from Petroleum and Natural Gas Systems, based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus, is 328.29 MMtCO2e.

Although this proposed rule does not include standards for regulating the GHG emissions discussed above, EPA continues to assess these significant emissions and evaluate appropriate actions for addressing these concerns. Because many of the proposed requirements for control of VOC emissions also control methane emissions as a co-benefit, the proposed VOC standards would also achieve significant reduction of methane emissions.

Significant emissions of oxides of nitrogen (NO_x) also occur at oil and natural gas sites due to the combustion of natural gas in reciprocating engines and combustion turbines used to drive the compressors that move natural gas through the system, and from combustion of natural gas in heaters and boilers. While these engines, turbines, heaters and boilers are co-located with processes in the oil and natural gas sector, they are not in the Oil and Natural Gas source category and are not being addressed in this action. The NO_x emissions from engines and turbines are covered by the Standards of Performance for Stationary Spark Internal Combustion Engines (40 CFR part 60, subpart JJJJ) and Standards of Performance for Stationary Combustion Turbines (40 CFR part 60, subpart KKKK), respectively.

An additional source of NO_x emissions would be pit flaring of VOC emissions from well completions. As discussed in Chapter 4 Well completions, pit flaring is one option identified for controlling VOC emissions. Because there is no way of directly measuring the NO_x produced, nor is there any way of applying controls other than minimizing flaring, flaring would only be required for limited conditions.

3.3 Additional Processes

The current NSPS only cover emissions of VOC and SO_2 from one type of facility in the oil and natural gas sector, which is the natural gas processing plant. This is the only type of facility in the Oil and Natural Gas source category where SO_2 is expected to be emitted directly; although H_2S contained in sour gas[v] forms SO_2 as a product of oxidation when oxidized in the atmosphere or combusted in boilers and heaters in the field. These field boilers and heaters are not part of the Oil and Natural Gas source category and are generally too small to be regulated by the NSPS covering boilers (i.e., they have a heat

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[v] Sour gas is defined as natural gas with a maximum H_2S content of 0.25 gr/100 scf (4ppmv) along with the presence of CO_2.

input of less than 10 million British Thermal Units per hour). They may, however, be included in future rulemakings.

In addition to VOC emissions from gas processing plants, there are numerous sources of VOC throughout the oil and natural gas sector that are not addressed by the current NSPS. Pursuant to CAA section 111(b), a modification of the listed category will now include all segments of the oil and natural gas industry for regulation. In addition, VOC standards will now cover additional processes at oil and natural gas operations. These include NSPS for VOC from gas well completions and recompletions, pneumatic controllers, compressors and storage vessels. In addition, produced water ponds may also be a potentially significant source of emissions, but there is very limited information available regarding these emissions. Therefore, no options could be evaluated at this time. The remainder of this document presents the evaluation for each of the new processes to be included in the NSPS.

3.4 References

1 Memorandum to Bruce Moore from Brad Nelson and Phil Norwood. Crude Oil and Natural Gas Production NSPS Technology Reviews. EC/R Incorporated. July 28, 2011.

4.0 WELL COMPLETIONS AND RECOMPLETIONS

In the oil and natural gas sector, well completions and recompletions contain multi-phase processes with various sources of emissions. One specific emission source during completion and recompletion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during recompletion activities that involve re-drilling or re-fracturing an existing well. This chapter describes completions and recompletions, and provides estimates for representative wells in addition to nationwide emissions. Control techniques employed to reduce emissions from flowback gas venting during completions and recompletions are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for reducing flowback emissions during completions and recompletions.

4.1 Process Description

4.1.1 Oil and Gas Well Completions

All oil and natural gas wells must be "completed" after initial drilling in preparation for production. Oil and natural gas completion activities not only will vary across formations, but can vary between wells in the same formation. Over time, completion and recompletion activities may change due to the evolution of well characteristics and technology advancement. Conventional gas reservoirs have well defined formations with high resource allocation in permeable and porous formations, and wells in conventional gas reservoirs have generally not required stimulation during production. Unconventional gas reservoirs are more dispersed and found in lower concentrations and may require stimulation (such as hydraulic fracturing) to extract gas.[1]

Well completion activities include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production. Surface components, including wellheads, pumps, dehydrators, separators, tanks, and gathering lines are installed as necessary for production to begin. The flowback stage of a well completion is highly variable but typically lasts between 3 and 10 days for the average well.[2]

Developmental wells are drilled within known boundaries of a proven oil or gas field, and are located near existing well sites where well parameters are already recorded and necessary surface equipment is in place. When drilling occurs in areas of new or unknown potential, well parameters such as gas composition, flow rate, and temperature from the formation need to be ascertained before surface facilities required for production can be adequately sized and brought on site. In this instance, exploratory (also referred to as "wildcat") wells and field boundary delineation wells typically either vent or combust the flowback gas.

One completion step for improving gas production is to fracture the reservoir rock with very high pressure fluid, typically a water emulsion with a proppant (generally sand) that "props open" the fractures after fluid pressure is reduced. Natural gas emissions are a result of the backflow of the fracture fluids and reservoir gas at high pressure and velocity necessary to clean and lift excess proppant to the surface. Natural gas from the completion backflow escapes to the atmosphere during the reclamation of water, sand, and hydrocarbon liquids during the collection of the multi-phase mixture directed to a surface impoundment. As the fracture fluids are depleted, the backflow eventually contains a higher volume of natural gas from the formation. Due to the additional equipment and resources involved and the nature of the backflow of the fracture fluids, completions involving hydraulic fracturing have higher costs and vent substantially more natural gas than completions not involving hydraulic fracturing.

Hydraulic fracturing can and does occur in some conventional reservoirs, but it is much more common in "tight" formations. Therefore, this analysis assumes hydraulic fracturing is performed in tight sand, shale, and coalbed methane formations. This analysis defines tight sand as sandstones or carbonates with an in situ permeability (flow rate capability) to gas of less than 0.1 millidarcy.[i]

"Energized fractures" are a relatively new type of completion method that injects an inert gas, such as carbon dioxide or nitrogen, before the fracture fluid and proppant. Thus, during initial flowback, the gas stream will first contain a high proportion of the injected gas, which will gradually decrease overtime.

4.1.2 Oil and Gas Well Recompletions

Many times wells will need supplementary maintenance, referred to as recompletions (these are also referred to as workovers). Recompletions are remedial operations required to maintain production or minimize the decline in production. Examples of the variety of recompletion activities include

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[i] A darcy (or darcy unit) and millidarcies (mD) are units of permeability Converted to SI units, 1 darcy is equivalent to 9.869233×10^{-13} m² or 0.9869233 (µm)². This conversion is usually approximated as 1 (µm)².

completion of a new producing zone, re-fracture of a previously fractured zone, removal of paraffin buildup, replacing rod breaks or tubing tears in the wellbore, and addressing a malfunctioning downhole pump. During a recompletion, portable equipment is conveyed back to the well site temporarily and some recompletions require the use of a service rig. As with well completions, recompletions are highly specialized activities, requiring special equipment, and are usually performed by well service contractors specializing in well maintenance. Any flowback event during a recompletion, such as after a hydraulic fracture, will result in emissions to the atmosphere unless the flowback gas is captured.

When hydraulic re-fracturing is performed, the emissions are essentially the same as new well completions involving hydraulic fracture, except that surface gas collection equipment will already be present at the wellhead after the initial fracture. The backflow velocity during re-fracturing will typically be too high for the normal wellhead equipment (separator, dehydrator, lease meter), while the production separator is not typically designed for separating sand.

Backflow emissions are not a direct result of produced water. Backflow emissions are a result of free gas being produced by the well during well cleanup event, when the well also happens to be producing liquids (mostly water) and sand. The high rate backflow, with intermittent slugs of water and sand along with free gas, is typically directed to an impoundment or vessels until the well is fully cleaned up, where the free gas vents to the atmosphere while the water and sand remain in the impoundment or vessels. Therefore, nearly all of the backflow emissions originate from the recompletion process but are vented as the backflow enters the impoundment or vessels. Minimal amounts of emissions are caused by the fluid (mostly water) held in the impoundment or vessels since very little gas is dissolved in the fluid when it enters the impoundment or vessels.

4.2. Emission Data and Emissions Factors

4.2.1 Summary of Major Studies and Emission Factors

Given the potential for significant emissions from completions and recompletions, there have been numerous recent studies conducted to estimate these emissions. In the evaluation of the emissions and emission reduction options for completions and recompletions, many of these studies were consulted. Table 4-1 presents a list of the studies consulted along with an indication of the type of information contained in the study.

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Documents [3]	EPA	2010	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008 [4,5]	EPA	2010	Nationwide	X	
Methane Emissions from the Natural Gas Industry [6, 7, 8, 9]	Gas Research Institute /US Environmental Protection Agency	1996	Nationwide	X	X
Methane Emissions from the US Petroleum Industry (Draft) [10]	EPA	1996	Nationwide	X	
Methane Emissions from the US Petroleum Industry [11]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States [12]	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories [13]	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State[14]	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements [15]	Environmental Defense Fund	2009	Regional	X	X
Emissions from Oil and Natural Gas Production Facilities [16]	Texas Commission for Environmental Quality	2007	Regional	X	X
Availability, Economics and Production of North American Unconventional Natural Gas Supplies 1	Interstate Natural Gas Association of America	2008	Nationwide		

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Petroleum and Natural Gas Statistical Data[17]	U.S. Energy Information Administration	2007-2009	Nationwide		
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations [18]	EPA	1999		X	
Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program [19]	New York State Department of Environmental Conservation	2009	Regional	X	X
Natural Gas STAR Program [20, 21, 22, 23, 24, 25]	EPA	2000-2010	Nationwide/ Regional	X	X

4.2.2 Representative Completion and Recompletion Emissions

As previously mentioned, one specific emission source during completion and recompletion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during the completion of a new well or during recompletion activities that involve re-drilling or re-fracturing of an existing well. For this analysis, well completion and recompletion emissions are estimated as the venting of emissions from the well during the initial phases of well preparation or during recompletion maintenance and/or re-fracturing of an existing well.

As previously stated, this analysis assumes wells completed/recompleted with hydraulic fracturing are found in tight sand, shale, or coal bed methane formations. A majority of the available emissions data for recompletions is for vertically drilled wells. It is projected that in the future, a majority of completions and recompletions will predominantly be performed on horizontal wells. However, there is not enough history of horizontally drilled wells to make a reasonable estimation of the difference in emissions from recompletions of horizontal versus vertical wells. Therefore, for this analysis, no distinction was made between vertical and horizontal wells.

As shown in Table 4-1, methane emissions from oil and natural gas operations have been measured, analyzed and reported in studies spanning the past few decades. The basic approach for this analysis was to approximate methane emissions from representative oil and gas completions and recompletions and then estimate volatile organic compounds (VOC) and hazardous air pollutants (HAP) using a representative gas composition.[26] The specific gas composition ratios used for gas wells were 0.1459 pounds (lb) VOC per lb methane (lb VOC/lb methane) and 0.0106 lb HAP/lb methane. The specific gas composition ratios used for oil wells were 0.8374 pounds lb VOC/lb methane and 0.0001 lb HAP/lb methane.

The EPA's analysis to estimate methane emissions conducted in support of the Greenhouse Gas Mandatory Reporting Rule (Subpart W), which was published in the *Federal Register* on November 30, 2010 (75 FR 74458), was the foundation for methane emission estimates from natural gas completions with hydraulic fracturing and recompletions with hydraulic fracturing. Methane emissions from oil well completions, oil well recompletions, natural gas completions without hydraulic fracturing, and natural gas recompletions without hydraulic fracturing were derived directly from the EPA's Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008 (Inventory).[4] A summary of emissions for a representative model well completion or recompletion is found in Table 4-2.

Table 4-2. Uncontrolled Emissions Estimates from Oil and Natural Gas Well Completions and Recompletions

Well Completion Category	Emissions (Mcf/event)	Emissions (tons/event)		
	Methane	Methane[a]	VOC[b]	HAP[c]
Natural Gas Well Completion without Hydraulic Fracturing	38.6	0.8038	0.12	0.009
Natural Gas Well Completion with Hydraulic Fracturing	7,623	158.55	23.13	1.68
Oil Well Completions	0.34	0.0076	0.00071	0.0000006
Natural Gas Well Recompletion without Hydraulic Fracturing	2.59	0.0538	0.0079	0.0006
Natural Gas Well Recompletion with Hydraulic Fracturing	7,623	158.55	23.13	1.68
Oil Well Recompletions	0.057	0.00126	0.001	0.0000001

Minor discrepancies may exist due to rounding.

a. Reference 4, Appendix B., pgs 84-89. The conversion used to convert methane from volume to weight is 0.0208 tons methane is equal to 1 Mcf of methane. It is assumed methane comprises 83.081 percent by volume of natural gas from gas wells and 46.732 percent by volume of methane from oil wells.

b. Assumes 0.1459 lb VOC /lb methane for natural gas wells and 0.8374 lb VOC/lb methane for oil wells.

c. Assumes 0.0106 lb HAP/lb methane for natural gas wells and 0.0001 lb HAP/lb methane for oil wells.

4.3 Nationwide Emissions from New Sources

4.3.1 Overview of Approach

The first step in this analysis is to estimate nationwide emissions in absence of the proposed rulemaking, referred to as the baseline emissions estimate. In order to develop the baseline emissions estimate, the number of completions and recompletions performed in a typical year was estimated and then multiplied by the expected uncontrolled emissions per well completion listed in Table 4-2. In addition, to ensure no emission reduction credit was attributed to sources already controlled under State regulations, it was necessary to account for the number of completions/recompletions already subject to State regulations as detailed below. In order to estimate the number of wells that are already controlled under State regulations, existing well data was analyzed to estimate the percentage of currently controlled wells. This percentage was assumed to also represent the wells that would have been controlled in absence of a federal regulation and applied to the number of well completions estimated for future years.

4.3.2 Number of Completions and Recompletions

The number of new well completions was estimated using the National Energy Modeling System (NEMS). NEMS is a model of U.S. energy economy developed and maintained by the Energy Information Administration (EIA). NEMS is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy economy from the current year to 2035. EIA is legally required to make the NEMS source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of NEMS, numerous agencies, national laboratories, research institutes, and academic and private-sector researchers have used NEMS to analyze a variety of issues. NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions.

New well completion estimates are based on predictions from the NEMS Oil and Gas Supply Model, drawing upon the same assumptions and model used in the Annual Energy Outlook 2011 Reference Case. New well completions estimates were based on total successful wells drilled in 2015 (the year of analysis for regulatory impacts) for the following well categories: natural gas completions without hydraulic fracturing, natural gas completions with hydraulic fracturing, and oil well completions.

Successful wells are assumed to be equivalent to completed wells. Meanwhile, it was assumed that new dry wells would be abandoned and shut in and would not be completed. Therefore estimates of the number of dry wells were not included in the activity projections or impacts discussion for exploratory and developmental wells. Completion estimates are based on successful developmental and exploratory wells for each category defined in NEMS that includes oil completions, conventional gas completions and unconventional gas completions. The NEMS database defines unconventional reservoirs as those in shale, tight sand, and coalbed methane formations and distinguishes those from wells drilled in conventional reservoirs. Since hydraulic fracturing is most common in unconventional formations, this analysis assumes new successful natural gas wells in shale, tight sand, and coalbed methane formations are completed with hydraulic fracturing. New successful natural gas wells in conventional formations are assumed to be completed without hydraulic fracturing.

The number of natural gas recompletions with hydraulic fracturing (also referred to as a re-fracture), natural gas recompletions without hydraulic fracturing and oil well recompletions was based on well count data found in the HPDI® database.[ii, iii] The HPDI database consists of oil and natural gas well information maintained by a private organization that provides parameters describing the location, operator, and production characteristics. HPDI® collects information on a well basis such as the operator, state, basin, field, annual gas production, annual oil production, well depth, and shut-in pressure, all of which is aggregated from operator reports to state governments. HPDI was used to estimate the number of recompleted wells because the historical well data from HPDI is a comprehensive resource describing existing wells. Well data from 2008 was used as a base year since it was the most recent available data at the time of this analysis and is assumed to represent the number of recompletions that would occur in a representative year. The number of hydraulically fractured natural gas recompletions was estimated by estimating each operator and field combination found in the HPDI database and multiplying by 0.1 to represent 10 percent of the wells being re-fractured annually (as assumed in Subpart W's Technical Supporting Document3). This results in 14,177 total natural gas recompletions with hydraulic fracturing in the U.S. for the year 2008; which is assumed to depict a representative year. Non-fractured

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[ii] HPDI, LLC is a private organization specializing in oil and gas data and statistical analysis. The HPDI database is focused on historical oil and gas production data and drilling permit data.

[iii] For the State of Pennsylvania, the most recent drilling information available from HPDI was for 2003. Due to the growth of oil and gas operations occurring in the Marcellus region in Pennsylvania, this information would not accurately represent the size of the industry in Pennsylvania for 2006 through 2008. Therefore, information from the Pennsylvania's Department of Environmental Protection was used to estimate well completion activities for this region. Well data from remaining states were based on available information from HPDI. From <http://www.marcellusreporting.state.pa.us/OGREReports/Modules/DataExports/DataExports.aspx

recompletions were based on well data for 2008 in HPDI. The number of estimated well completions and recompletions for each well source category is listed in Table 4-3.

4.3.3 Level of Controlled Sources in Absence of Federal Regulation

As stated previously, to determine the impact of a regulation, it is first necessary to determine the current level of emissions from the sources being evaluated, or baseline emissions. To more accurately estimate baseline emissions for this analysis, and to ensure no emission reduction credit was attributed for sources already being controlled, it was necessary to evaluate the number of completions and recompletions already subject to regulation. Therefore, the number of completions and recompletions already being controlled in the absence of federal regulation was estimated based on the existing State regulations that require control measures for completions and recompletions. Although there may be regulations issued by other local ordinances for cities and counties throughout the U.S., wells impacted by these regulations were not included in this analysis because well count data are not available on a county or local ordinance level. Therefore, the percentage calculated based on the identified State regulations should be considered a conservative estimate.

In order to determine the number of completions and recompletions that are already controlled under State regulations, EIA historical well count data was analyzed to determine the percentage of new wells currently undergoing completion and recompletion in the States identified as having existing controls.[iv] Colorado (CO) and Wyoming (WY) were the only States identified as requiring controls on completions prior to NSPS review. The State of Wyoming's Air Quality Division (WAQD) requires operators to complete wells without flaring or venting where the following criteria are met: (1) the flowback gas meets sales line specifications and (2) the pressure of the reservoir is high enough to enable REC. If the above criteria are not met, then the produced gas is to be flared. [27] The WAQD requires that, "emissions of VOC and HAP associated with the flaring and venting of hydrocarbon fluids (liquids and gas) associated with well completion and recompletion activities shall be eliminated to the extent practicable by routing the recovered liquids into storage tanks and routing the recovered gas into a gas sales line or collection system." Similar to WY, the Colorado Oil and Gas Conservation Commission (COOGCC) requires REC for both oil and natural gas wells.[28] It was assumed for this analysis that the ratio of natural wells in CO and WY to the total number of wells in the U.S. represents the percentage of controlled wells for well completions. The ratio of wells in WY to the number of total nationwide wells

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[iv] See EIA's The Number of Producing Wells, http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm

Table 4-3: Estimated Number of Total Oil and Natural Gas Completions and Recompletions for a Typical Year

Well Completion Category	**Estimated Number of Total Completions and Recompletions**[a]	**Estimated Number of Controlled Completions and Recompletions**	**Estimated Number of Uncontrolled Completions and Recompletions**[b]
Natural Gas Well Completions without Hydraulic Fracturing*	7,694		7,694
Exploratory Natural Gas Well Completions with Hydraulic Fracturing**	446		446
Developmental Natural Gas Well Completions with Hydraulic Fracturing[c]	10,957	1,644	9,313
Oil Well Completions[d]	12,193		12,193
Natural Gas Well Recompletions without Hydraulic Fracturing	42,342		42,342
Natural Gas Well Recompletions with Hydraulic Fracturing‡‡	14,177	2,127	12,050
Oil Well Recompletions‡	39,375		39,375

a. Natural gas completions and recompletions without hydraulic fracturing are assumed to be uncontrolled at baseline.

b. Fifteen percent of natural gas well completions with hydraulic fracturing are assumed as controlled at baseline.

c. Oil well completions and recompletions are assumed to be uncontrolled at baseline.

d. Fifteen percent of natural gas well recompletions with hydraulic fracturing are assumed to be controlled at baseline.

was assumed to represent the percentage of controlled well recompletions as it was the only State identified as having regulations directly regulated to recompletions.

From this review it was estimated that 15 percent of completions and 15 percent of recompletions are controlled in absence of federal regulation. It is also assumed for this analysis that only natural gas wells undergoing completion or recompletion with hydraulic fracturing are controlled in these States. Completions and recompletions that are performed without hydraulic fracturing, in addition to oil well completions and recompletions were assumed to not be subject to State regulations and therefore, were assumed to not be regulated at baseline. Baseline emissions for the controlled completions and recompletions covered by regulations are assumed to be reduced by 95 percent from the use of both REC and combustion devices that may be used separately or in tandem, depending on the individual State regulation.[v] The final activity factors for uncontrolled completions and uncontrolled recompletions are also listed in Table 4-3.

4.3.4 Emission Estimates

Using the estimated emissions, number of uncontrolled and controlled wells at baseline, described above, nationwide emission estimates for oil and gas well completions and recompletions in a typical year were calculated and are summarized in Table 4-4. All values have been independently rounded to the nearest ton for estimation purposes. As the table indicates, hydraulic fracturing significantly increases the magnitude of emissions. Completions and recompletions without hydraulic fracturing have lower emissions, while oil completions and recompletions have even lower emissions in comparison.

4.4 Control Techniques

4.4.1 Potential Control Techniques

Two techniques were considered that have been proven to reduce emissions from well completions and recompletions: REC and completion combustion. One of these techniques, REC, is an approach that not only reduces emissions but delivers natural gas product to the sales meter that would typically be vented. The second technique, completion combustion, destroys the organic compounds. Both of these techniques are discussed in the following sections, along with estimates of the impacts of their application for a representative well. Nationwide impacts of chosen regulatory options are discussed in

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[v] Percentage of controls by flares versus REC were not determined, so therefore, the count of controlled wells with REC versus controlled wells with flares was not determined and no secondary baseline emission impacts were calculated.

Table 4-4. Nationwide Baseline Emissions from Uncontrolled Oil and Gas Well Completions and Recompletions

Well Completion Category	Uncontrolled Methane Emissions per event (tpy)	Number of Uncontrolled Wells[a]	Baseline Nationwide Emissions (tons/year)[a]		
			Methane[b]	VOC[c]	HAP[d]
Natural Gas Well Completions without Hydraulic Fracturing	0.8038	7,694	6,185	902	66
Exploratory Natural Gas Well Completions with Hydraulic Fracturing	158.55	446	70,714	10,317	750
Developmental Natural Gas Well Completions with Hydraulic Fracturing	158.55	9,313	1,476,664	215,445	15,653
Oil Well Completions	0.0076	12,193	93	87	.008
Natural Gas Well Recompletions without Hydraulic Fracturing	0.0538	42,342	2,279	332	24
Natural Gas Well Recompletions with Hydraulic Fracturing	158.55	12,050	1,910,549	278,749	20,252
Oil Well Recompletions	0.00126	39,375	50	47	.004

Minor discrepancies may be due to rounding.

a. Baseline emissions include emissions from uncontrolled wells plus five percent of emissions from controlled sources. The Baseline emission reductions listed in the Regulatory Impacts (Table 4-9) represents only emission reductions from uncontrolled sources.
b. The number of controlled and uncontrolled wells estimated based on State regulations.
c. Based on the assumption that VOC content is 0.1459 pounds VOC per pound methane for natural gas wells and 0.8374 pounds VOC per pound methane for oil wells This estimate accounts for 5 percent of emissions assumed as vented even when controlled. Does not account for secondary emissions from portion of gas that is directed to a combustion device.
d. Based on the assumption that HAP content is 0.0106 pounds HAP per pound methane for natural gas wells and 0.0001 pounds HAP per pound methane for oil wells. This estimate accounts for 5 percent of emissions assumed as vented even when controlled. Does not account for secondary emissions from portion of gas that is directed to a combustion device.

section 4.5.

4.4.2 Reduced Emission Completions and Recompletions

4.4.2.1 Description

Reduced emission completions, also referred to as "green" or "flareless" completions, use specially designed equipment at the well site to capture and treat gas so it can be directed to the sales line. This process prevents some natural gas from venting and results in additional economic benefit from the sale of captured gas and, if present, gas condensate. Additional equipment required to conduct a REC may include additional tankage, special gas-liquid-sand separator traps, and a gas dehydrator.[29] In many cases, portable equipment used for RECs operate in tandem with the permanent equipment that will remain after well drilling is completed. In other instances, permanent equipment is designed (e.g. oversized) to specifically accommodate initial flowback. Some limitations exist for performing RECs since technical barriers fluctuate from well to well. Three main limitations include the following for RECs:

- Proximity of pipelines. For exploratory wells, no nearby sales line may exist. The lack of a nearby sales line incurs higher capital outlay risk for exploration and production companies and/or pipeline companies constructing lines in exploratory fields. The State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area that has never had oil and gas well production prior to that drilling instance (i.e., a wildcat well).[30] In instances where formations are stacked vertically and horizontal drilling could take place, it may be possible that existing surface REC equipment may be located near an exploratory well, which would allow for a REC.

- Pressure of produced gas. During each stage of the completion/recompletion process, the pressure of flowback fluids may not be sufficient to overcome the sales line backpressure. This pressure is dependent on the specific sales line pressure and can be highly variable. In this case, combustion of flowback gas is one option, either for the duration of the flowback or until a point during flowback when the pressure increases to flow to the sales line. Another control option is compressor applications. One application is gas lift which is accomplished by withdrawing gas from the sales line, boosting its pressure, and routing it down the well casing to push the fracture fluids up the tubing. The increased pressure facilitates flow into the separator and then the sales line where the lift gas becomes part of the normal flowback that can be recovered during a REC. Another potential compressor application is to boost pressure of the flowback gas after it exits the separator. This technique is experimental because of the difficulty operating a compressor on widely fluctuating flowback rate.

- Inert gas concentration. If the concentration of inert gas, such as nitrogen or carbon dioxide, in the flowback gas exceeds sales line concentration limits, venting or combustion of the flowback may be necessary for the duration of flowback or until the gas energy content increases to allow flow to the sales line. Further, since the energy content of the flowback gas may not be high enough to sustain a flame due to the presence of the inert gases, combustion of the flowback stream would require a continuous ignition source with its own separate fuel supply.

4.4.2.2. Effectiveness

RECs are an effective emissions reduction method for only natural gas completions and recompletions performed with hydraulic fracturing based on the estimated flowback emissions described in Section 4.2. The emissions reductions vary according to reservoir characteristics and other parameters including length of completion, number of fractured zones, pressure, gas composition, and fracturing technology/technique. Based on several experiences presented at Natural Gas STAR technology transfer workshops, this analysis assumes 90 percent of flowback gas can be recovered during a REC.[31] Any amount of gas that cannot be recovered can be directed to a completion combustion device in order to achieve a minimum 95 percent reduction in emissions.

4.4.2.3 Cost Impacts

All completions incur some costs to a company. Performing a REC will add to these costs. Equipment costs associated with RECs vary from well to well. High production rates may require larger equipment to perform the REC and will increase costs. If permanent equipment, such as a glycol dehydrator, is already installed or is planned to be in place at the well site as normal operations, costs may be reduced as this equipment can be used or resized rather than installing a portable dehydrator for temporary use during the completion. Some operators normally install equipment used in RECs, such as sand traps and three-phase separators, further reducing incremental REC costs.

Costs of performing a REC are projected to be between $700 and $6,500 per day, with representative well completion flowback lasting 3 to 10 days.2 This cost range is the incremental cost of performing a REC over a traditional completion, where typically the gas is vented or combusted because there is an absence of REC equipment. Since RECs involve techniques and technologies that are new and continually evolving, and these cost estimates are based on the state of the industry in 2006 (adjusted to 2008 US dollars). [vi] Cost data used in this analysis are qualified below:

- $700 per day (equivalent to $806 per day in 2008 dollars) represents completion and recompletion costs where key pieces of equipment, such as a dehydrator or three phase separator, are already found on site and are of suitable design and capacity for use during flowback.

- $6,500 per day (equivalent to $7,486 in 2008 dollars) represents situations where key pieces of equipment, such as a dehydrator or three-phase separator, are temporarily brought on site and then relocated after the completion.

Costs were assessed based on an average of the above data (for costs and number of days per completion), resulting in an average incremental cost for a REC of $4,146 per day (2008 dollars) for an average of 7 days per completion. This results in an overall incremental cost of $29,022 for a REC versus an uncontrolled completion. An additional $691 (2008 dollars) was included to account for transportation and placement of equipment, bringing total incremental costs estimated at $29,713. Reduced emission completions are considered one-time events per well; therefore annual costs were conservatively assumed to be the same as capital costs. Dividing by the expected emission reductions, cost-effectiveness for VOC is $1,429 per ton, with a methane co-benefit of $208 per ton. Table 4-5 provides a summary of REC cost-effectiveness.

Monetary savings associated with additional gas captured to the sales line was also estimated based on a natural gas price of $4.00[vii] per thousand cubic feet (Mcf).[32] It was assumed that all gas captured would be included as sales gas. Therefore, assuming that 90 percent of the gas is captured and sold, this equates

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[vi] The Chemical Engineering Cost Index was used to convert dollar years. For REC, the 2008 value equals 575.4 and the 2006 value equals 499.6.

[vii] The average market price for natural gas in 2010 was approximately $4.16 per Mcf. This is much less compared to the average price in 2008 of $7.96 per Mcf. Due to the volatility in the price, a conservative savings of $4.00 per Mcf estimate was projected for the analysis in order to not overstate savings. The value of natural gas condensate recovered during the REC would also be significant depending on the gas composition. This value was not incorporated into the monetary savings in order to not overstate savings.

Table 4-5. Reduced Emission Completion and Recompletion Emission Reductions and Cost Impacts Summary

Well Completion Category	Emission Reduction Per Completion/Recompletion (tons/year)[a]			Total Cost Per Completion/ Recompletion[b] ($/event)	VOC Cost Effectiveness ($/ton)[c]		Methane Cost Effectiveness ($/ton)	
	VOC	Methane	HAP		without savings	with savings	without savings	with savings
Natural Gas Completions and Recompletions with Hydraulic Fracturing	20.8	142.7	1.5	29,713	1,429	net savings	208	net savings

Minor discrepancies may be due to rounding.

a. This represents a ninety percent reduction from baseline for the average well.

b. Total cost for reduced emission completion is expressed in terms of incremental cost versus a completion that vents emissions. This is based on an average incremental cost of $4,146 per day for an average length of completion flowback lasting 7 days and an additional $691 for transportation and set up.

c. Cost effectiveness has been rounded to the nearest dollar.

to a total recovery of 8,258 Mcf of natural gas per completion or recompletion with hydraulic fracturing. The estimated value of the recovered natural gas for a representative natural gas well with hydraulic fracturing is approximately $33,030. In addition we estimate an average of 34 barrels of condensate is recovered per completion or recompletion. Assuming a condensate value of $70 per barrel (bbl), this result is an income due to condensate sales around $2,380.[33] When considering these savings from REC, for a completion or recompletion with hydraulic fracturing, there is a net savings on the order of $5,697 per completion.

4.4.2.4 Secondary Impacts

A REC is a pollution prevention technique that is used to recover natural gas that would otherwise be emitted. No secondary emissions (e.g., nitrogen oxides, particulate matter, etc.) would be generated, no wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to REC.

4.4.3 Completion Combustion Devices

4.4.3.1 Description

Completion combustion is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.[34] Completion combustion devices are used to control VOC in many industrial settings, since the completion combustion device can normally handle fluctuations in concentration, flow rate, heating value, and inert species content.[35] Completion combustion devices commonly found on drilling sites are rather crude and portable, often installed horizontally due to the liquids that accompany the flowback gas. These flares can be as simple as a pipe with a basic ignition mechanism and discharge over a pit near the wellhead. However, the flow directed to a completion combustion device may or may not be combustible depending on the inert gas composition of flowback gas, which would require a continuous ignition source. Sometimes referred to as pit flares, these types of combustion devices do not employ an actual control device, and are not capable of being tested or monitored for efficiency. They do provide a means of minimizing vented gas and is preferable to venting. For the purpose of this analysis, the term completion combustion device represents all types of combustion devices including pit flares.

4.4.3.2 Effectiveness

The efficiency of completion combustion devices, or exploration and production flares, can be expected to achieve 95 percent, on average, over the duration of the completion or recompletion. If the energy content of natural gas is low, then the combustion mechanism can be extinguished by the flowback gas. Therefore, it is more reliable to install an igniter fueled by a consistent and continuous ignition source. This scenario would be especially true for energized fractures where the initial flowback concentration will be extremely high in inert gases. This analysis assumes use of a continuous ignition source with an independent external fuel supply is assumed to achieve an average of 95 percent control over the entire flowback period. Additionally, because of the nature of the flowback (i.e., with periods of water, condensate, and gas in slug flow), conveying the entire portion of this stream to a flare or other control device is not always feasible. Because of the exposed flame, open pit flaring can present a fire hazard or other undesirable impacts in some situations (e.g., dry, windy conditions, proximity to residences, etc.). As a result, we are aware that owners and operators may not be able to flare unrecoverable gas safely in every case.

Federal regulations require industrial flares meet a combustion efficiency of 98 percent or higher as outlined in 40 CFR 60.18. This statute does not apply to completion combustion devices. Concerns have been raised on applicability of 40 CFR 60.18 within the oil and gas industry including for the production segment.[30, 36, 37] The design and nature of completion combustion devices must handle multiphase flow and stream compositions that vary during the flowback period. Thus, the applicability criterion that specifies conditions for flares used in highly industrial settings may not be appropriate for flares typically used to control emissions from well completions and recompletions.

4.4.3.3 Cost Impacts

An analysis depicting the cost for wells including completion combustion devices was conducted for the Petroleum Services Association of Canada (PSAC) [38] in 2009 by N.L. Fisher Supervision and Engineering, Ltd.[viii] The data corresponds to 34 gas wells for various types of formations, including coal bed methane and shale. Multiple completion methods were also examined in the study including hydraulic and energized fracturing. Using the cost data points from these natural gas well completions,

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[viii] It is important to note that outliers were excluded from the average cost calculation. Some outliers estimated the cost of production flares to be as low as $0 and as high as $56,000. It is expected that these values are not representative of typical flare costs and were removed from the data set. All cost data found in the PSAC study were aggregated values of the cost of production flares and other equipment such as tanks. It is possible the inclusion of the other equipment is not only responsible for the outliers, but also provides a conservatively high estimate for completion flares.

an average completion combustion device cost is approximately \$3,523 (2008 dollars).[ix] As with the REC, because completion combustion devices are purchased for these one-time events, annual costs were conservatively assumed to be equal to the capital costs.

It is assumed that the cost of a continuous ignition source is included in the combustion completion device cost estimations. It is understood that multiple completions and recompletions can be controlled with the same completion combustion device, not only for the lifetime of the combustion device but within the same yearly time period. However, to be conservative, costs were estimated as the total cost of the completion combustion device itself, which corresponds to the assumption that only one device will control one completion per year. The cost impacts of using a completion combustion device to reduce emissions from representative completions/recompletions are provided in Table 4-6. Completion combustion devices have a cost-effectiveness of \$161 per ton VOC and a co-benefit of \$23 per ton methane for completions and recompletions with hydraulic fracturing.

4.4.3.4 Secondary Impacts

Noise and heat are the two primary undesirable outcomes of completion combustion device operation. In addition, combustion and partial combustion of many pollutants also create secondary pollutants including nitrogen oxides (NO_x), carbon monoxide (CO), sulfur oxides (SO_x, carbon dioxide (CO_2), and smoke/particulates (PM). The degree of combustion depends on the rate and extent of fuel mixing with air and the temperature maintained by the flame. Most hydrocarbons with carbon-to-hydrogen ratios greater than 0.33 are likely to smoke.[34] Due to the high methane content of the gas stream routed to the completion combustion device, it suggests that there should not be smoke except in specific circumstances (e.g., energized fractures). The stream to be combusted may also contain liquids and solids that will also affect the potential for smoke. Soot can typically be eliminated by adding steam. Based on current industry trends in the design of completion combustion devices and in the decentralized nature of completions, virtually no completion combustion devices include steam assistance.[34]

Reliable data for emission factors from flare operations during natural gas well completions are limited. Guidelines published in AP-42 for flare operations are based on tests from a mixture containing

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[ix] The Chemical Engineering Cost Index was used to convert dollar years. For the combustion device the 2009 value equals 521.9. The 2009 average value for the combustion device is \$3,195.

Table 4-6. Emission Reduction and Cost-effectiveness Summary for Completion Combustion Devices

Well Completion Category	**Emission Reduction Per Completion/Workover (tons/year)**[a]			**Total Capital Cost Per Completion Event ($)***	**VOC Cost Effectiveness**	**Methane Cost Effectiveness**
	VOC	**Methane**	**HAP**		**($/ton)**[b]	**($/ton)**
Natural Gas Well Completions without Hydraulic Fracturing	0.11	0.76	0.0081	3,523	31,619	4,613
Natural Gas Well Completions with Hydraulic Fracturing	21.9	150.6	1.597		160	23
Oil Well Completions	0.01	0.007	0.0000007		520,580	488,557
Natural Gas Well Recompletions without Hydraulic Fracturing	0.007	0.051	0.0005		472,227	68,889
Natural Gas Well Recompletions with Hydraulic Fracturing	21.9	150.6	1.597		160	23
Oil Well Recompletions	0.00	0.001	0.0000001		3,134,431	2,941,615

Minor discrepancies may be due to rounding.

a. This assumes one combustion device will control one completion event per year. This should be considered a conservative estimate, since it is likely multiple completion events will be controlled with the same combustion unit in any given year. Costs are stated in 2008 dollars.

80 percent propylene and 20 percent propane.[34] These emissions factors, however, are the best indication for secondary pollutants from flare operations currently available. These secondary emission factors are provided are provided in Table 4-7.

Since this analysis assumed pit flares achieve 95 percent efficiency over the duration of flowback, it is likely the secondary emission estimations are lower than actuality (i.e. AP-42 assumes 98 percent efficiency). In addition due, to the potential for the incomplete combustion of natural gas across the pit flare plume, the likelihood of additional NO_x formulating is also likely. The degree of combustion is variable and depends on the on the rate and extent of fuel mixing with air and on the flame temperature. Moreover, the actual NO_x (and CO) emissions may be greatly affected when the raw gas contains hydrocarbon liquids and water. For these reasons, the nationwide impacts of combustion devices discussed in Section 4.5 should be considered minimum estimates of secondary emissions from combustion devices.

4.5 Regulatory Options

The REC pollution prevention approach would not result in emissions of CO, NO_x, and PM from the combustion of the completion gases in the flare, and would therefore be the preferred option. As discussed above, REC is only an option for reducing emissions from gas well completions/workovers with hydraulic fracturing. Taking this into consideration, the following regulatory alternatives were evaluated:

- Regulatory Option 1: Require completion combustion devices for conventional natural gas well completions and recompletions;
- Regulatory Option 2: Require completion combustion devices for oil well completions and recompletions;
- Regulatory Option 3: Require combustion devices for all completions and recompletions;
- Regulatory Option 4: Require REC for all completions and recompletions of hydraulically fractured wells;
- Regulatory Option 5: Require REC and combustion operational standards for natural gas well completions with hydraulic fracturing, with the exception of exploratory, and delineation wells;
- Regulatory Option 6: Require combustion operational standards for exploratory and delineation wells; and

Table 4-7. Emission Factors from Flare Operations from AP-42 Guidelines Table 13.4-1[a]

Pollutant	Emission Factor ($lb/10^6$ Btu)
Total Hydrocarbon[b]	0.14
Carbon Monoxide	0.37
Nitrogen Oxides	0.068
Particular Matter[c]	0-274
Carbon Dioxide[d]	60

a. Based on combustion efficiency of 98 percent.
b. Measured as methane equivalent.
c. Soot in concentration values: nonsmoking flares, 0 micrograms per liter (µg/L); lightly smoking flares, 40 µg/L; average smoking flares, 177 µg/L; and heavily smoking flares, 274 µg/L.
d. Carbon dioxide is measured in kg CO2/MMBtu and is derived from the carbon dioxide emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

- Regulatory Option 7: Require REC and combustion operational standards for all natural gas well recompletions with hydraulic fracturing.

The following sections discuss these regulatory options.

4.5.1 Evaluation of Regulatory Options

The first two regulatory options (completion combustion devices for conventional natural gas well completions and recompletions and completion combustion devices for oil well completions and recompletions) were evaluated first. As shown in Table 4-6, the cost effectiveness associated with controlling conventional natural gas and oil well completions and recompletions ranges from $31,600 per ton VOC to over $3.7 million per ton VOC. Therefore, Regulatory Options 1 and 2 were rejected due to the high cost effectiveness.

The next regulatory option, to require completion combustion devices for all completions and recompletions, was considered. Under Regulatory Option 3, all of the natural gas emitted from the well during flowback would be destroyed by sending flowback gas through a combustion unit. Not only would this regulatory option result in the destruction of a natural resource with no recovery of salable gas, it also would result in an increase in emissions of secondary pollutants (e.g., nitrogen oxides, carbon monoxide, etc.). Therefore, Regulatory Option 3 was also rejected.

The fourth regulatory option would require RECs for all completions and recompletions of hydraulically fractured wells. As stated previously, RECs are not feasible for all well completions, such as exploratory wells, due to their distance from sales lines, etc. Further, RECs are also not technically feasible for each well at all times during completion and recompletion activities due to the variability of the pressure of produced gas and/or inert gas concentrations. Therefore, Regulatory Option 4 was rejected.

The fifth regulatory option was to require an operational standard consisting of a combination of REC and combustion for natural gas well completions with hydraulic fracturing. As discussed for Regulatory Option 4, RECs are not feasible for every well at all times during completion or recompletion activities due to variability of produced gas pressure and/or inert gas concentrations. In order to allow for wellhead owners and operators to continue to reduce emissions when RECs are not feasible due to well characteristics (e.g, wellhead pressure or inert gas concentrations), Regulatory Option 5 also allows for the use of a completion combustion device in combination with RECs.

Under Regulatory Option 5, a numerical limit was considered, but was rejected in favor of an operational standard. Under section 111(h)(2) of the CAA, EPA can set an operational standard which represents the best system of continuous emission reduction, provided the following criteria are met:

> "(A) a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or
>
> (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations."

As discussed in section 4.4.3, emissions from a completion combustion device cannot be measured or monitored to determine efficiency making an operational standard appropriate. Therefore, an operational standard under this regulatory option consists of a combination of REC and a completion combustion device to minimize the venting of natural gas and condensate vapors to the atmosphere, but allows venting in lieu of combustion for situations in which combustion would present safety hazards, other concerns, or for periods when the flowback gas is noncombustible due to high concentrations of inert gases. Sources would also be required, under this regulatory option, to maintain documentation of the overall duration of the completion event, duration of recovery using REC, duration of combustion, duration of venting, and specific reasons for venting in lieu of combustion. It was also evaluated whether Regulatory Option 5 should apply to all well completions, including exploratory and delineation wells.

As discussed previously, one of the technical limitations of RECs is that they are not feasible for use at some wells due to their proximity to pipelines. Section 111(b)(2) of the CAA allows EPA to "…distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing…." performance standards. Due to their distance from sales lines, and the relatively unknown characteristics of the formation, completion activities occurring at exploratory or delineation wells were considered to be a different "type" of activity than the types of completion activities occurring at all other gas wells. Therefore, two subcategories of completions were identified: *Subcategory 1* wells are all natural gas wells completed with hydraulic fracturing that do not fit the definition of exploratory or delineation wells. *Subcategory 2* wells are natural gas wells that meet the following definitions of exploratory or delineation wells:

- Exploratory wells are wells outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists or

- Delineation wells means a well drilled in order to determine the boundary of a field or producing reservoir.

Based on this subcategorization, Regulatory Option 5 would apply to the Subcategory 1 wells and a sixth regulatory option was developed for Subcategory 2 wells.

Regulatory Option 6 requires an operational standard for combustion for the Subcategory 2 wells. As described above, REC is not an option for exploratory and delineation wells due to their distance from sales lines. As with the Regulatory Option 5, a numerical limitation is not feasible. Therefore, this regulatory option requires an operational standard where emissions are minimized using a completion combustion device during completion activities at Subcategory 2 wells, with an allowance for venting in situations where combustion presents safety hazards or other concerns or for periods when the flowback gas is noncombustible due to high concentrations of inert gases. Consistent with Regulatory Option 5, records would be required to document the overall duration of the completion event, the duration of combustion, the duration of venting, and specific reasons for venting in lieu of combustion.

The final regulatory option was considered for recompletions. Regulatory Option 7 requires an operational standard for a combination of REC and a completion combustion device for all recompletions with hydraulic fracturing performed on new and existing natural gas wells. Regulatory Option 7 has the same requirements as Regulatory Option 5. Subcategorization similar to Regulatory Option 5 was not necessary for recompletions because it was assumed that RECs would be technically feasible for recompletions at all types of wells since they occur at wells that are producing and thus proximity to a sales line is not an issue. While evaluating this regulatory option, it was considered whether or not recompletions at existing wells should be considered modifications and subject to standards.

The affected facility under the New Source Performance Standards (NSPS) is considered to be the wellhead. Therefore, a new well drilled after the proposal date of the NSPS would be subject to emission control requirements. Likewise, wells drilled prior to the proposal date of the NSPS would not be subject to emission control requirements unless they underwent a modification after the proposal date. Under section 111(a) of the Clean Air Act, the term “modification” means:

> "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted."

The wellhead is defined as the piping, casing, tubing, and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. In order to fracture an existing well during recompletion, the well would be re-perforated, causing physical change to the wellbore and casing and therefore a physical change to the wellhead, the affected facility. Additionally, much of the emissions data on which this analysis is based demonstrates that hydraulic fracturing results in an increase in emissions. Thus, recompletions using hydraulic fracturing result in an increase in emissions from the existing well producing operations. Based on this understanding of the work performed in order to recomplete the well, it was determined that a recompletion would be considered a modification under CAA section 111(a) and thus, would constitute a new wellhead affected facility subject to NSPS. Therefore, Regulatory Option 7 applies to recompletions using hydraulic fracturing at new and existing wells.

In summary, Regulatory Options 1, 2, 3, and 4 were determined to be unreasonable due to cost considerations, other impacts or technical feasibility and thereby rejected. Regulatory Options 5, 6, and 7 were determined to be applicable to natural gas wells and were evaluated further.

4.5.2 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to Regulatory Options 5, 6, and 7 which were selected as viable options for setting standards for completions and recompletions.

4.5.2.1 Primary Environmental Impacts of Regulatory Options

Regulatory Options 5, 6, and 7 were selected as options for setting standards for completions and regulatory options as follows:

- Regulatory Option 5: Operational standard for completions with hydraulic fracturing for Subcategory 1 wells (i.e., wells which do not meet the definition of exploratory or delineation wells), which requires a combination of REC with combustion, but allows for venting during specified situations.

- Regulatory Option 6: An operational standard for completions with hydraulic fracturing for exploratory and delineation wells (i.e., Subcategory 2 wells) which requires completion combustion devices with an allowance for venting during specified situations.

- Regulatory Option 7: An operational standard equivalent to Regulatory Option 5 which applies to recompletions with hydraulic fracturing at new and existing wells.

The number of completions and recompletions that would be subject to the regulatory options listed above was presented in Table 4-3. It was estimated that there would be 9,313 uncontrolled developmental natural gas well completions with hydraulic fracturing subject to Regulatory Option 5. Regulatory Option 6 would apply to 446 uncontrolled exploratory natural gas well completions with hydraulic fracturing, and 12,050 uncontrolled recompletions at existing wells would be subject to Regulatory Option 7.[x]

Table 4-8 presents the nationwide emission reduction estimates for each regulatory option. It was estimated that RECs in combination with the combustion of gas unsuitable for entering the gathering line, can achieve an overall 95 percent VOC reduction over the duration of the completion operation. The 95 percent recovery was estimated based on 90 percent of flowback being captured to the sales line and assuming an additional 5 percent of the remaining flowback would be sent to the combustion device. Nationwide emission reductions were estimated by applying this 95 percent VOC reduction to the uncontrolled baseline emissions presented in Table 4-4.

4.5.2.2 Cost Impacts

Cost impacts of the individual control techniques (RECs and completion combustion devices) were presented in section 4.4. For Regulatory Option 6, the costs for completion combustion devices presented in Table 4-6 for would apply to Subcategory 2 completions. The cost per completion event was estimated to be $3,523. Applied to the 446 estimated Subcategory 2 completions, the nationwide costs were estimated to be $1.57 million. Completion combustion devices are assumed to achieve an overall 95 percent combustion efficiency. Since the operational standards for Regulatory Options 5 and 7 include both REC and completion combustion devices, an additional cost impact analysis was

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[x] The number of uncontrolled recompletions at new wells is not included in this analysis. Based on the assumption that wells are recompleted once every 10 years, any new wells that are drilled after the date of proposal of the standard would not likely be recompleted until after the year 2015, which is the date of this analysis. Therefore, impacts were not estimated for recompletion of new wells, which will be subject to the standards.

Table 4-8. Nationwide Emission and Cost Analysis of Regulatory Option

Well Completion Category	Number of Sources subject to NSPS[a]	Annual Cost Per Completion Event ($)[b]	Nationwide Emission Reductions (tpy)[c]			VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
			VOC	Methane	HAP	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 5 (operational standard for REC and combustion)												
Subcategory 1: Natural gas Completions with Hydraulic Fracturing	9,313	33,237	204,134	1,399,139	14,831	1,516	net savings	221	net savings	309.5	309.5	(20.24)
Regulatory Option 6 (operational standard for combustion)												
Subcategory 2: Natural gas Completions with Hydraulic Fracturing	446	3,523	9,801	67,178	712	160	160	23	23	1.57	1.57	1.57
Regulatory Option 7 (operational standard for REC and combustion)												
Natural Gas Well Recompletions with Hydraulic Fracturing	12,050	33,237	264,115	1,810,245	19,189	1,516	net savings	221	net savings	400.5	400.5	(26.18)

Minor discrepancies may be due to rounding.

a. Number of sources in each well completion category that are uncontrolled at baseline as presented in Table 4-3.
b. Costs per event for Regulatory Options 5 and 7 are calculated by adding the costs for REC and completion combustion device presented in Tables 4-5 and 4-6, respectively. Cost per event for Regulatory Option 6 is presented for completion combustion devices in Table 4-6.
c. Nationwide emission reductions calculated by applying the 95 percent emission reduction efficiency to the uncontrolled nationwide baseline emissions in Table 4-4.

performed to analyze the nationwide cost impacts of these regulatory options. The total incremental cost of the operational standard for Subcategory 1 completions and for recompletions is estimated at around $33,237, which includes the costs in Table 4-5 for the REC equipment and transportation in addition to the costs in Table 4-6 for the completion combustion device. Applying the cost for the combined REC and completion combustion device to the estimated 9,313 Subcategory 1 completions, the total nationwide cost was estimated to be $309.5 million, with a net annual savings estimated around $20 million when natural gas savings are considered. A cost of $400.5 million was estimated for recompletions, with an overall savings of around $26 million when natural gas savings are considered. The VOC cost effectiveness for Regulatory Options 5 and 7 was estimated at around $1,516 per ton, with a methane co-benefit of $221 per ton.

4.5.2.3 Secondary Impacts

Regulatory Options 5, 6 and 7 all require some amount of combustion; therefore the estimated nationwide secondary impacts are a direct result of combusting all or partial flowback emissions. Although, it is understood the volume of gas captured, combusted and vented may vary significantly depending on well characteristics and flowback composition, for the purpose of estimating secondary impacts for Regulatory Options 5 and 7, it was assumed that ninety percent of flowback is captured and an additional five percent of the remaining gas is combusted. For both Subcategory 1 natural gas well completions with hydraulic fracturing and for natural gas well recompletions with hydraulic fracturing, it is assumed around 459 Mcf of natural gas is combusted on a per well basis. For Regulatory Option 6, Subcategory 2 natural gas completions with hydraulic fracturing, it is assumed that 95 percent (8,716 Mcf) of flowback emissions are consumed by the combustion device. Tons of pollutant per completion event was estimated assuming 1,089.3 Btu/scf saturated gross heating value of the "raw" natural gas and applying the AP-42 emissions factors listed in Table 4-7.

From category 1 well completions and from recompletions, it is estimated 0.02 tons of NO_x are produced per event. This is based on assumptions that 5 percent of the flowback gas is combusted by the combustion device. From category 2 well completions, it is estimated 0.32 tons of NO_x are produced in secondary emissions per event. This is based on the assumption 95 percent of flowback gas is combusted by the combustion device. Based on the estimated number of completions and recompletions, the proposed regulatory options are estimated to produce around 507 tons of NO_x in secondary emissions nationwide from controlling all or partial flowback by combustion. Table 4-9 summarizes the estimated secondary emissions of the selected regulatory options.

Table 4-9 Nationwide Secondary Impacts of Selected Regulatory Options[a]

Pollutant	Regulatory Options 5[b] Subcategory 1 Natural Gas Well Completions with Hydraulic Fracturing		Regulatory Option 6[c] Subcategory 2 Natural Gas Well Completions with Hydraulic Fracturing		Regulatory Options 7[b] Natural Gas Well Recompletions with Hydraulic Fracturing	
	tons per event[d]	Nationwide Annual Secondary Emissions (tons/year)	tons per event[d]	Nationwide Annual Secondary Emissions (tons/year)	tons per event[d]	Nationwide Annual Secondary Emissions (tons/year)
Total Hydrocarbons	0.03	326	0.66	296	0.03	422
Carbon Monoxide	0.09	861	1.76	783	0.09	1,114
Nitrogen Oxides	0.02	158	0.32	144	0.02	205
Particulate Matter	0.00000002	0.0002	0.011	5	0.00000002	0.0003
Carbon Dioxide	33.06	307,863	628	280,128	33.06	398,341

a. Nationwide impacts are based on AP-42 Emission Guidelines for Industrial Flares as outlined in Table 4-7. As such, these emissions should be considered the minimum level of secondary emissions expected.

b. The operational standard (Regulatory Options 5 and 7) combines REC and combustion is assumed to capture 90 percent of flowback gas. Five percent of the remaining flowback is assumed to be consumed in the combustion device. Therefore, it is estimated 459 Mcf is sent to the combustion device per completion event. This analysis assumes there are 9,313 Subcategory 1 wells and 12,050 recompletions.

c. Assumes 8,716 Mcf of natural gas is sent to the combustion unit per completion. This analysis assumes 446 exploratory wells fall into this category.

d. Based on 1,089.3 Btu/scf saturated gross heating value of the "raw" natural gas.

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5.0 PNEUMATIC CONTROLLERS

The natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature, and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic; (2) electrical; or (3) mechanical. Of these, only pneumatic devices are direct sources of air emissions. Pneumatic controllers are used throughout the oil and natural gas sector as part of the instrumentation to control the position of valves. This chapter describes pneumatic devices including their function and associated emissions. Options available to reduce emissions from pneumatic devices are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for pneumatic devices.

5.1 Process Description

For the purpose of this document, a pneumatic controller is a device that uses natural gas to transmit a process signal or condition pneumatically and that may also adjust a valve position based on that signal, with the same bleed gas and/or a supplemental supply of power gas. In the vast majority of applications, the natural gas industry uses pneumatic controllers that make use of readily available high-pressure natural gas to provide the required energy and control signals. In the production segment, an estimated 400,000 pneumatic devices control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. There are around 13,000 gas pneumatic controllers located in the gathering, boosting and processing segment that control and monitor temperature, liquid, and pressure levels. In the transmission segment, an estimated 85,000 pneumatic controllers actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities.[1]

Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations across all segments of the oil and gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate control of a valve. In these “gas-driven” pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady-state rates when operated under similar conditions. There are three basic designs: (1) continuous bleed devices are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time; (2) snap-acting devices release gas only when they open or close a valve or as they throttle the gas flow; and (3) self-contained devices release gas to a downstream pipeline instead of to the atmosphere. This analysis assumes self-contained devices that release natural gas to a downstream pipeline instead of to the atmosphere have no emissions. Furthermore, it is recognized "closed loop" systems are applicable only in instances with very low pressure[2] and may not be suitable to replace many applications of bleeding pneumatic devices. Therefore, these devices are not further discussed in this analysis.

Snap-acting controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. The actual amount of emissions from snap-acting devices is dependent on the amount of natural gas vented per actuation and how often it is actuated. Bleed devices also vent an additional volume of gas during actuation, in addition to the device's bleed stream. Since actuation emissions serve the device's functional purpose and can be highly variable, the emissions characterized for high-bleed and low-bleed devices in this analysis (as described in section 5.2.2) account for only the continuous flow of emissions (i.e. the bleed rate) and do not include emissions directly resulting from actuation. Snap-acting controllers are assumed to have zero bleed emissions. Most applications (but not all), snap-acting devices serve functionally different purposes than bleed devices. Therefore, snap-acting controllers are not further discussed in this analysis.

In addition, not all pneumatic controllers are gas driven. At sites without electrical service sufficient to power an instrument air compressor, mechanical or electrically powered pneumatic devices can be used. These "non-gas driven" pneumatic controllers can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed "instrument air." Because these devices are not gas driven, they do not directly release natural gas or VOC emissions. However, electrically powered systems have energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. Instrument air systems are feasible only at oil and natural gas locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient to power an air compressor. This analysis assumes that natural gas processing plants are the only facilities in the oil and natural gas sector highly likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of gas driven devices.[9] The application of electrical controls is further elaborated in Section 5.3.

5.2 Emissions Data and Information

5.2.1 Summary of Major Studies and Emissions

In the evaluation of the emissions from pneumatic devices and the potential options available to reduce these emissions, numerous studies were consulted. Table 5-1 lists these references with an indication of the type of relevant information contained in each study.

5.2.2 Representative Pneumatic Device Emissions

Bleeding pneumatic controllers can be classified into two types based on their emissions rates: (1) high-bleed controllers and (2) low-bleed controllers. A controller is considered to be high-bleed when the continuous bleed emissions are in excess of 6 standard cubic feet per hour (scfh), while low-bleed devices bleed at a rate less than or equal to 6 scfh.[i]

For this analysis, EPA consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices, Subpart W of the Greenhouse Gas Reporting rule, as well as obtained updated data from major vendors of pneumatic devices. The data obtained from vendors included emission rates, costs, and any other pertinent information for each pneumatic device model (or model family). All pneumatic devices that a vendor offered were itemized and inquiries were made into the specifications of each device and whether it was applicable to oil and natural gas operations. High-bleed and low-bleed devices were differentiated using the 6 scfh threshold.

Although by definition, a low-bleed device can emit up to 6 scfh, through this vendor research, it was determined that the typical low-bleed device available currently on the market emits lower than the maximum rate allocated for the device type. Specifically, low-bleed devices on the market today have emissions from 0.2 scfh up to 5 scfh. Similarly, the available bleed rates for a high bleed device vary significantly from venting as low as 7 scfh to as high as 100 scfh.[3,ii] While the vendor data provides useful information on specific makes and models, it did not yield sufficient information about the

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[i] The classification of high-bleed and low-bleed devices originated from a report by Pacific Gas & Electric (PG&E) and the Gas Research Institute (GRI) in 1990 titled “Unaccounted for Gas Project Summary Volume.” This classification was adopted for the October 1993 Report to Congress titled “Opportunities to Reduce Anthropogenic Methane Emissions in the United States”. As described on page 2-16 of the report, “devices with emissions or ‘bleed’ rates of 0.1 to 0.5 cubic feet per minute are considered to be ‘high-bleed’ types (PG&E 1990).” This range of bleed rates is equivalent to 6 to 30 cubic feet per hour.

[ii] All rates are listed at an assumed supply gas pressure of 20 psig.

Table 5-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Number of Devices	Emissions Information	Control Information
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Document [3]	EPA	2010	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2009 [4, 5]	EPA	2011	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry [6, 7, 8, 9]	Gas Research Institute / EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry (draft) [10]	EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry [11]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States [12]	Western Regional Air Partnership	2005	Regional	X	
Natural Gas STAR Program[1]	EPA	2000-2010		X	X

prevalence of each model type in the population of devices; which is an important factor in developing a representative emission factor. Therefore, for this analysis, EPA determined that best available emissions estimates for pneumatic devices are presented in Table W-1A and W-1B of the Greenhouse Gas Mandatory Reporting Rule for the Oil and Natural Gas Industry (Subpart W). However, for the natural gas processing segment, a more conservative approach was assumed since it has been determined that natural gas processing plants would have sufficient electrical service to upgrade to non-gas driven controls. Therefore, to quantify representative emissions from a bleed-device in the natural gas processing segment, information from Volume 12 of the EPA/GRI report[iii] was used to estimate the methane emissions from a single pneumatic device by type.

The basic approach used for this analysis was to first approximate methane emissions from the average pneumatic device type in each industry segment and then estimate VOC and hazardous air pollutants (HAP) using a representative gas composition.[13] The specific ratios from the gas composition were 0.278 pounds VOC per pound methane and 0.0105 pounds HAP per pound methane in the production and processing segments, and 0.0277 pounds VOC per pound methane and 0.0008 pounds HAP per pound methane in the transmission segment. Table 5-2 summarizes the estimated bleed emissions for a representative pneumatic controller by industry segment and device type.

5.3 Nationwide Emissions from New Sources

5.3.1 Approach

Nationwide emissions from newly installed natural gas pneumatic devices for a typical year were calculated by estimating the number of pneumatic devices installed in a typical year and multiplying by the estimated annual emissions per device listed in Table 5-2. The number of new pneumatic devices installed for a typical year was determined for each segment of the industry including natural gas production, natural gas processing, natural gas transmission and storage, and oil production. The methodologies that determined the estimated number of new devices installed in a typical year is provided in section 5.3.2 of this chapter.

5.3.2 Population of Devices Installed Annually

In order to estimate the average number of pneumatic devices installed in a typical year, each industry

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[iii] Table 4-11. page 56. epa.gov/gasstar/tools/related.html

Table 5-2. Average Bleed Emission Estimates per Pneumatic Device in the Oil and Natural Gas Sector (tons/year)[a]

Industry Segment	High-Bleed			Low-Bleed		
	Methane	**VOC**	**HAP**	**Methane**	**VOC**	**HAP**
Natural Gas Production[b]	6.91	1.92	0.073	0.26	0.072	0.003
Natural Gas Transmission and Storage[c]	3.20	0.089	0.003	0.24	0.007	0.0002
Oil Production[d]	6.91	1.92	0.073	0.26	0.072	0.003
Natural Gas Processing[e]	1.00	0.28	0.01	1.00	0.28	0.01

Minor discrepancies may be due to rounding.

a. The conversion factor used in this analysis is 1 thousand cubic feet of methane (Mcf) is equal to 0.0208 tons methane. Minor discrepancies may be due to rounding.
b. Natural Gas Production methane emissions are derived from Table W-1A and W-1B of Subpart W.
c. Natural gas transmission and storage methane emissions are derived from Table W-3 of Subpart W.
d. Oil production methane emissions are derived from Table W-1A and W-1B of Subpart W. It is assumed only continuous bleed devices are used in oil production.
e. Natural gas processing sector methane emissions are derived from Volume 12 of the 1996 GRI report.[9] Emissions from devices in the processing sector were determined based on data available for snap-acting and bleed devices, further distinction between high and low bleed could not be determined based on available data.

segment was analyzed separately using the best data available for each segment. The number of facilities estimated in absence of regulation was undeterminable due to the magnitude of new sources estimated and the lack of sufficient data that could indicate the number of controllers that would be installed in states that may have regulations requiring low bleed controllers, such as in Wyoming and Colorado.

For the natural gas production and oil production segments, the number of new pneumatics installed in a typical year was derived using a multiphase analysis. First, data from the US Greenhouse Gas Inventory: Emission and Sinks 1990-2009 was used to establish the ratio of pneumatic controllers installed per well site on a regional basis. These ratios were then applied to the number of well completions estimated in Chapter 4 for natural gas well completions with hydraulic fracturing, natural gas well completions without hydraulic fracturing and for oil well completions. On average, one pneumatic device was assumed to be installed per well completion for a total of 33,411 pneumatic devices. By applying the estimated 51 percent of bleed devices (versus snap acting controllers), it is estimated that an average of 17,040 bleed-devices would be installed in the production segment in a typical year.

The number of pneumatic controllers installed in the transmission segment was approximated using the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009. The number of new devices installed in a given year was estimated by subtracting the prior year (e.g. 2007) from the given year’s total (e.g. 2008). This difference was assumed to be the number of new devices installed in the latter year (e.g. Number of new devices installed during 2008 = Pneumatics in 2008 – Pneumatics in 2007). A 3-year average was calculated based on the number of new devices installed in 2006 through 2008 in order to determine the average number of new devices installed in a typical year.

Once the population counts for the number of pneumatics in each segment were established, this population count was further refined to account for the number of snap-acting devices that would be installed versus a bleed device. This estimate of the percent of snap-acting and bleed devices was based on raw data found in the GRI study, where 51 percent of the pneumatic controllers are bleed devices in the production segment, and 32 percent of the pneumatic controllers are bleed devices in the transmission segment.9 The distinction between the number of high-bleed and low-bleed devices was not estimated because this analysis assumes it is not possible to predict or ensure where low bleeds will be used in the future. Table 5-3 summarizes the estimated number of new devices installed per year.

Table 5-3. Estimated Number of Pneumatic Devices Installed in an Typical Year

Industry Segment	Number of New Devices Estimated for a Typical Year[a]		
	Snap-Acting	**Bleed-Devices**	**Total**
Natural Gas and Oil Production[b]	16,371	17,040	33,411
Natural Gas Transmission and Storage[c]	178	84	262

a. National averages of population counts from the Inventory were refined to include the difference in snap-acting and bleed devices based on raw data found in the GRI/EPA study. This is based on the assumption that 51 percent of the pneumatic controllers are bleed devices in the production segment, while 32 percent are bleed devices in the transmission segment.

b. The number of pneumatics was derived from a multiphase analysis. Data from the US Greenhouse Gas Inventory: Emission and Sinks 1990-2009 was used to establish the number of pneumatics per well on a regional basis. These ratios were applied to the number of well completions estimated in Chapter 4 for natural gas wells with hydraulic fracturing, natural gas wells without hydraulic fracturing and for oil wells.

c. The number of pneumatics estimated for the transmission segment was approximated from comparing a 3 year average of new devices installed in 2006 through 2008 in order to establish an average number of pneumatics being installed in this industry segment in a typical year. This analysis was performed using the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009.

For the natural gas processing segment, this analysis assumes that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e. an instrument air system) and any high-bleed devices that remain are safety related. As a result, the number of new pneumatic bleed devices installed at existing natural gas processing plants was estimated as negligible. A new greenfield natural gas processing plant would require multiple control loops. In Chapter 8 of this document, it is estimated that 29 new and existing processing facilities would be subject to the NSPS for equipment leak detection. In order to quantify the impacts of the regulatory options represented in section 5.5 of this Chapter, it is assumed that half of these facilities are new sites that will install an instrument air system in place of multiple control valves. This indicates about 15 instrument air systems will be installed in a representative year.

5.3.3 Emission Estimates

Nationwide baseline emission estimates for pneumatic devices for new sources in a typical year are summarized in Table 5-4 by industry segment and device type. This analysis assumed for the nationwide emission estimate that all bleed-devices have the high-bleed emission rates estimated in Table 5-2 per industry segment since it cannot be predicted which sources would install a low bleed versus a high bleed controller.

5.4 Control Techniques

Although pneumatic devices have relatively small emissions individually, due to the large population of these devices installed on an annual basis, the cumulative VOC emissions for the industry are significant. As a result, several options to reduce emissions have been developed over the years. Table 5-5 provides a summary of these options for reducing emissions from pneumatic devices including: instrument air, non-gas driven controls, and enhanced maintenance.

Given the various control options and applicability issues, the replacement of a high-bleed with a low-bleed device is the most likely scenario for reducing emissions from pneumatic device emissions. This is also supported by States such as Colorado and Wyoming that require the use of low-bleed controllers in place of high-bleed controllers. Therefore, low-bleed devices are further described in the following section, along with estimates of the impacts of their application for a representative device and nationwide basis. Although snap-acting devices have zero bleed emissions, this analysis assumes the

Table 5-4. Nationwide Baseline Emissions from Representative Pneumatic Device Installed in a Typical Year for the Oil and Natural Gas Industry (tons/year)[a]

Industry Segment	Baseline Emissions from Representative New Unit (tpy)			Number of New Bleed Devices Expected Per Year	Nationwide Baseline Emissions from Bleeding Pneumatic (tpy)[b]		
	VOC	Methane	HAP		VOC	Methane	HAP
Oil and Gas Production	1.9213	6.9112	0.0725	17,040	32,739	117,766	1,237
Natural Gas Transmission and Storage	0.09523	3.423	0.003	84	8	288	0.2

Minor discrepancies may be due to rounding.

a. Emissions have been based on the bleed rates for a high-bleed device by industry segment. Minor discrepancies may be due to rounding.

b. To estimate VOC and HAP, weight ratios were developed based on methane emissions per device. The specific ratios used were 0.278 pounds VOC per pound methane and 0.0105 pounds HAP per pound methane in the production and processing segments, and 0.0277 pounds VOC per pound methane and 0.0008 pounds HAP per pound methane in the transmission segment.

Table 5-5. Alternative Control Options for Pneumatic Devices

Option	Description	Applicability/Effectiveness	Estimated Cost Range
Install Low Bleed Device in Place of High Bleed Device	Low-bleed devices provide the same functional control as a high-bleed device, while emitting less continuous bleed emissions.	Applicability may depend on the function of instrumentation for an individual device on whether the device is a level, pressure, or temperature controller.	Low-bleed devices are, on average, around $165 more than high bleed versions.
Convert to Instrument Air[14]	Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. In this type of system, atmospheric air is compressed, stored in a tank, filtered and then dried for instrument use. For utility purposes such as small pneumatic pumps, gas compressor motor starters, pneumatic tools and sand blasting, air would not need to be dried. Instrument air conversion requires additional equipment to properly compress and control the pressured air. This equipment includes a compressor, power source, air dehydrator and air storage vessel.	Replacing natural gas with instrument air in pneumatic controls eliminates VOC emissions from bleeding pneumatics. It is most effective at facilities where there are a high concentration of pneumatic control valves and an operator present. Since the systems are powered by electric compressors, they require a constant source of electrical power or a back-up natural gas pneumatic device. These systems can achieve 100 percent reduction in emissions.	A complete cost analysis is provided in Section 5.4.2. System costs are dependent on size of compressor, power supply needs, labor and other equipment.
Mechanical and Solar Powered Systems in place of Bleed device[15]	Mechanical controls operate using a simple design comprised of levers, hand wheels, springs and flow channels. The most common mechanical control device is the liquid-level float to the drain valve position with mechanical linkages. Electricity or small electrical motors (including solar powered) have been used to operate valves. Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of back-up power or storage to ensure reliability.	Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations. Electric powered valves are only reliable with a constant supply of electricity. Overall, these options are applicable in niche areas but can achieve 100 percent reduction in emissions where applicable.	Depending on supply of power, costs can range from below $1,000 to $10,000 for entire systems.
Enhanced Maintenance[16]	Instrumentation in poor condition typically bleeds 5 to 10 scf per hour more than representative conditions due to worn seals, gaskets, diaphragms; nozzle corrosion or wear, or loose control tube fittings. This may not impact the operations but does increase emissions.	Enhanced maintenance to repair and maintain pneumatic devices periodically can reduce emissions. Proper methods of maintaining a device are highly variable and could incur significant costs.	Variable based on labor, time, and fuel required to travel to many remote locations.

devices are not always used in the same functional application as bleed devices and are, therefore, not an appropriate form of control for all bleed devices. It is assumed snap-acting, or no-bleed, devices meet the definition of a low-bleed. This concept is further detailed in Section 5.5 of this chapter. Since this analysis has assumed areas with electrical power have already converted applicable pneumatic devices to instrument air systems, instrument air systems are also described for natural gas processing plants only. Given applicability, efficiency and the expected costs of the other options identified in Table 5-5 (i.e. mechanical controls and enhanced maintenance), were not further conducted for this analysis.

5.4.1 Low-Bleed Controllers

5.4.1.1 Emission Reduction Potential

As discussed in the above sections, low-bleed devices provide the same functional control as a high-bleed device, but have lower continuous bleed emissions. As summarized in Table 5-6, it is estimated on average that 6.6 tons of methane and 1.8 tons of VOC will be reduced annually in the production segment from installing a low-bleed device in place of a high-bleed device. In the transmission segment, the average achievable reductions per device are estimated around 3.7 tons and 0.08 tons for methane and VOC, respectively. As noted in section 5.2, a low-bleed controller can emit up to 6 scfh, which is higher than the expected emissions from the typical low-bleed device available on the current market.

5.4.1.1 Effectiveness

There are certain situations in which replacing and retrofitting are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high bleed rate to actuate, or a safety isolation valve is involved. Based on criteria provided by the Natural Gas STAR Program, it is assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices throughout the production and transmission and storage industry segments.[1] This corresponds to 13,632 new high-bleed devices in the production segment (out of 17,040) and 67 new high-bleed devices in the transmission and storage segment (out of 84) that can be replaced with a new low-bleed alternative. For high-bleed devices in natural gas processing, this analysis assumed that the replaceable devices have already been replaced with instrument air and the remaining high-bleed devices are safety related for about half of the existing processing plants.

Table 5-6. Estimated Annual Bleed Emission Reductions from Replacing a Representative High-Bleed Pneumatic Device with a Representative Low-Bleed Pneumatic Device

Segment/Device Type	Emissions (tons/year)[a]		
	Methane	**VOC**	**HAP**
Oil and Natural Gas Production	6.65	1.85	0.07
Natural Gas Transmission and Storage	2.96	0.082	0.002

Minor discrepancies may be due to rounding.

a. Average emission reductions for each industry segment based on the typical emission flow rates from high-bleed and low-bleed devices as listed in Table 5-2 by industry segment.

Applicability may depend on the function of instrumentation for an individual device on whether the device is a level, pressure, or temperature controller. High-bleed pneumatic devices may not be applicable for replacement with low-bleed devices because a process condition may require a fast or precise control response so that it does not stray too far from the desired set point. A slower-acting controller could potentially result in damage to equipment and/or become a safety issue. An example of this is on a compressor where pneumatic devices may monitor the suction and discharge pressure and actuate a re-cycle when one or the other is out of the specified target range. Other scenarios for fast and precise control include transient (non-steady) situations where a gas flow rate may fluctuate widely or unpredictably. This situation requires a responsive high-bleed device to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes can accommodate control from a low-bleed device, which is slower-acting and less precise.

Safety concerns may be a limitation issue, but only in specific situations because emergency valves are not bleeding controllers since safety is the pre-eminent consideration. Thus, the connection between the bleed rate of a pneumatic device and safety is not a direct one. Pneumatic devices are designed for process control during normal operations and to keep the process in a normal operating state. If an Emergency Shut Down (ESD) or Pressure Relief Valve (PRV) actuation occurs,[iv] the equipment in place for such an event is spring loaded, or otherwise not pneumatically powered. During a safety issue or emergency, it is possible that the pneumatic gas supply will be lost. For this reason, control valves are deliberately selected to either fail open or fail closed, depending on which option is the failsafe.

5.4.1.2 Cost Impacts

As described in Section 5.2.2, costs were based on the vendor research described in Section 5.2 as a result of updating and expanding upon the information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices.[1] As Table 5-7 indicates, the average cost for a low bleed pneumatic is \$2,553, while the average cost for a high bleed is \$2,338.[v] Thus, the incremental cost of installing a low-bleed device instead of a high-bleed device is on the order of \$165 per device. In order to analyze cost impacts, the incremental cost to install a low-bleed instead of a high-bleed was

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[iv] ESD valves either close or open in an emergency depending on the fail safe configuration. PRVs always open in an emergency.

[v] Costs are estimated in 2008 U.S. Dollars.

Table 5-7. Cost Projections for the Representative Pneumatic Devices[a]

Device	**Minimum cost ($)**	**Maximum cost ($)**	**Average cost ($)**	**Low-Bleed Incremental Cost ($)**
High-bleed controller	366	7,000	2,388	$165
Low-bleed controller	524	8,852	2,553	

a. Major pneumatic devices vendors were surveyed for costs, emission rates, and any other pertinent information that would give an accurate picture of the present industry.

annualized for a 10 year period using a 7 percent interest rate. This equated to an annualized cost of around $23 per device for both the production and transmission segments.

Monetary savings associated with additional gas captured to the sales line was estimated based on a natural gas value of $4.00 per Mcf.[vi,17] The representative low-bleed device is estimated to emit 6.65 tons, or 319 Mcf, (using the conversion factor of 0.0208 tons methane per 1 Mcf) of methane less than the average high-bleed device per year. Assuming production quality gas is 82.8 percent methane by volume, this equals 385.5 Mcf natural gas recovered per year. Therefore, the value of recovered natural gas from one pneumatic device in the production segment equates to approximately $1,500. Savings were not estimated for the transmission segment because it is assumed the owner of the pneumatic controller generally is not the owner of the natural gas. Table 5-8 provides a summary of low-bleed pneumatic cost effectiveness.

5.4.1.3 Secondary Impacts

Low-bleed pneumatic devices are a replacement option for high-bleed devices that simply bleed less natural gas that would otherwise be emitted in the actuation of pneumatic valves. No wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the use of low-bleed pneumatic devices.

5.4.2 Instrument Air Systems

5.4.2.1 Process Description

The major components of an instrument air conversion project include the compressor, power source, dehydrator, and volume tank. The following is a description of each component as described in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air:*

- Compressors used for instrument air delivery are available in various types and sizes, from centrifugal (rotary screw) compressors to reciprocating piston (positive displacement) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank.

[vi] The average market price for natural gas in 2010 was approximately $4.16 per Mcf. This is much less compared to the average price in 2008 of $7.96 per Mcf. Due to the volatility in the value, a conservative savings of $4.00 per Mcf estimate was projected for the analysis in order to not overstate savings.

Table 5-8. Cost-effectiveness for Low-Bleed Pneumatic Devices versus High Bleed Pneumatics

Segment	**Incremental Capital Cost Per Unit ($)**[a]	**Total Annual Cost Per Unit ($/yr)**[b]		**VOC Cost Effectiveness ($/ton)**		**Methane Cost Effectiveness ($/ton)**	
		without savings	**with savings**	**without savings**	**with savings**	**without savings**	**with savings**
Oil and Natural Gas Production	165	23.50	-1,519	13	net savings	4	net savings
Natural Gas Transmission and Storage	165	23.50	23.50	286	286	8	8

a. Incremental cost of a low bleed device versus a high bleed device as summarized in Table 5-7.
b. Annualized cost assumes a 7 percent interest rate over a 10 year equipment lifetime.

For reliability, a full spare compressor is normally installed. A minimum amount of electrical service is required to power the compressors.

- A critical component of the instrument air control system is the power source required to operate the compressor. Since high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and in remote locations, however, a reliable source of electric power can be difficult to assure. In some instances, solar-powered battery-operated air compressors can be cost effective for remote locations, which reduce both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.

- Dehydrators, or air dryers, are also an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.

- The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. The use of instrument air eliminates natural gas emissions from natural gas powered pneumatic controllers. All other parts of a gas pneumatic system will operate the same way with instrument air as they do with natural gas. The conversion of natural gas pneumatic controllers to instrument air systems is applicable to all natural gas facilities with electrical service available.[14]

5.4.2.2 Effectiveness

The use of instrument air eliminates natural gas emissions from the natural gas driven pneumatic devices; however, the system is only applicable in locations with access to a sufficient and consistent supply of electrical power. Instrument air systems are also usually installed at facilities where there is a high concentration of pneumatic control valves and the presence of an operator that can ensure the system is properly functioning.[14]

5.4.2.3 Cost Impacts

Instrument air conversion requires additional equipment to properly compress and control the pressured air. The size of the compressor will depend on the number of control loops present at a location. A control loop consists of one pneumatic controller and one control valve. The volume of compressed air supply for the pneumatic system is equivalent to the volume of gas used to run the existing instrumentation – adjusted for air losses during the drying process. The current volume of gas usage can be determined by direct metering if a meter is installed. Otherwise, an alternative rule of thumb for sizing instrument air systems is one cubic foot per minute (cfm) of instrument air for each control loop.[14] As the system is powered by electric compressors, the system requires a constant source of electrical power or a back-up pneumatic device. Table 5-9 outlines three different sized instrument air systems including the compressor power requirements, the flow rate provided from the compressor, and the associated number of control loops.

The primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and related equipment and the operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator and a storage vessel. It is assumed that in either an instrument air solution or a natural gas pneumatic solution, gas supply piping, control instruments, and valve actuators of the gas pneumatic system are required. The total cost, including installation and labor, of three representative sizes of compressors were evaluated based on assumptions found in the Natural Gas STAR document, "Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air"[14] and summarized in Table 5-10.[vii]

For natural gas processing, the cost-effectiveness of the three representative instrument air system sizes was evaluated based on the emissions mitigated from the number of control loops the system can provide and not on a per device basis. This approach was chosen because we assume new processing plants will need to provide instrumentation of multiple control loops and size the instrument air system accordingly. We also assume that existing processing plants have already upgraded to instrument air

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[vii] Costs have been converted to 2008 US dollars using the Chemical Engineering Cost Index.

Table 5-9. Compressor Power Requirements and Costs for Various Sized Instrument Air Systems[a]

Compressor Power Requirements[b]			**Flow Rate**	**Control Loops**
Size of Unit	hp	kW	(cfm)	Loops/Compressor
small	10	13.3	30	15
medium	30	40	125	63
large	75	100	350	175

a. Based on rules of thumb stated in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*[14]

b. Power is based on the operation of two compressors operating in parallel (each assumed to be operating at full capacity 50 percent of the year).

Table 5-10 Estimated Capital and Annual Costs of Various Sized Representative Instrument Air Systems

Instrument Air System Size	Compressor	Tank	Air Dryer	Total Capital[a]	Annualized Capital[b]	Labor Cost	Total Annual Costs[c]	Annualized Cost of Instrument Air System
Small	$3,772	$754	$2,262	$16,972	$2,416	$1,334	$8,674	$11,090
Medium	$18,855	$2,262	$6,787	$73,531	$10,469	$4,333	$26,408	$36,877
Large	$33,183	$4,525	$15,083	$135,750	$19,328	$5,999	$61,187	$80,515

a. Total Capital includes the cost for two compressors, tank, an air dryer and installation. Installation costs are assumed to be equal to 1.5 times the cost of capital. Equipment costs were derived from the Natural Gas Star Lessons Learned document and converted to 2008 dollars from 2006 dollars using the Chemical Engineering Cost Index.

b. The annualized cost was estimated using a 7 percent interest rate and 10 year equipment life.

c. Annual Costs include the cost of electrical power as listed in Table 5-9 and labor.

unless the function has a specific need for a bleeding device, which would most likely be safety related.[9] Table 5-11 summarizes the cost-effectiveness of the three sizes of representative instrument air systems.

5.4.2.4 Secondary Impacts

The secondary impacts from instrument air systems are indirect, variable and dependent on the electrical supply used to power the compressor. No other secondary impacts are expected.

5.5 Regulatory Options

The affected facility definition for pneumatic controllers is defined as a single natural gas pneumatic controller. Therefore, pneumatic controllers would be subject to a New Source Performance Standard (NSPS) at the time of installation. The following Regulatory alternatives were evaluated:

- Regulatory Option 1: Establish an emissions limit equal to 0 scfh.
- Regulatory Option 2: Establish an emissions limit equal to 6 scfh.

5.5.1 Evaluation of Regulatory Options

By establishing an emission limit of 0 scfh, facilities would most likely install instrument air systems to meet the threshold limit. This option is considered cost effective for natural gas processing plants as summarized in Table 5-11. A major assumption of this analysis, however, is that processing plants are constructed at a location with sufficient electrical service to power the instrument air compression system. It is assumed that facilities located outside of the processing plant would not have sufficient electrical service to install an instrument air system. This would significantly increase the cost of the system at these locations, making it not cost effective for these facilities to meet this regulatory option. Therefore, Regulatory Option 1 was accepted for natural gas processing plants and rejected for all other types of facilities.

Regulatory Option 2 would establish an emission limit equal to the maximum emissions allowed for a low-bleed device in the production and transmissions and storage industry segments. This would most likely be met by the use of low-bleed controllers in place of a high-bleed controller, but allows flexibility in the chosen method of meeting the requirement. In the key instances related to pressure control that would disallow the use of a low-bleed device, specific monitoring and recordkeeping criteria

Table 5-11 Cost-effectiveness of Representative Instrument Air Systems in the Natural Gas Processing Segment

System Size	Number of Control Loops	Annual Emissions Reduction[a] (tons/year)			Value of Product Recovered ($/year)[b]	Annualized Cost of System		VOC Cost-effectiveness ($/ton)		Methane Cost-effectiveness ($/ton)	
		VOC	CH_4	HAP		without savings	with savings	without savings	with savings	without savings	with savings
Small	15	4.18	15	0.16	3,484	11,090	7,606	2,656	1,822	738	506
Medium	63	17.5	63	0.66	14,632	36,877	22,245	2,103	1,269	585	353
Large	175	48.7	175	1.84	40,644	80,515	39,871	1,653	819	460	228

Minor discrepancies may be due to rounding.

a. Based on the emissions mitigated from the entire system, which includes multiple control loops.

b. Value of recovered product assumes natural gas processing is 82.8 percent methane by volume. A natural gas price of $4 per Mcf was assumed.

would be required to ensure the device function dictates the precision of a high bleed device. Therefore, Regulatory Option 2 was accepted for locations outside of natural gas processing plants.

5.5.2 Nationwide Impacts of Regulatory Options

Table 5-12 summarizes the costs impacts of the selected regulatory options by industry segment. Regulatory Option 1 for the natural gas processing segment is estimated to affect 15 new processing plants with nationwide annual costs discounting savings of $166,000. When savings are realized the net annual cost is reduced to around $114,000. Regulatory Option 2 has nationwide annual costs of $320,000 for the production segment and around $1,500 in the natural gas transmission and storage segment. When annual savings are realized in the production segment there is a net savings of $20.7 million in nationwide annual costs.

Table 5-12 Nationwide Cost and Emission Reduction Impacts for Selected Regulatory Options by Industry Segment

Industry Segment	Number of Sources subject to NSPS*	Capital Cost Per Device/IAS ($)**	Annual Costs ($/year)		Nationwide Emission Reductions (tpy)†			VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs ($/year)		
			without savings	**with savings**	**VOC**	**Methane**	**HAP**	**without savings**	**with savings**	**without savings**	**with savings**	**Capital Cost**	**Annual without savings**	**Annual with savings**
Regulatory Option 1 (emission threshold equal to 0 scfh)														
Natural Gas Processing	15	16,972	11,090	7,606	63	225	2	2,656	1,822	738	506	254,576	166,351	114,094
Regulatory Option 2 (emission threshold equal to 6 scfh)														
Oil and Natural Gas Production	13,632	165	23	(1,519)	25,210	90,685	952	13	net savings	4	net savings	2,249,221	320,071	(20,699,918)
Natural Gas Transmission and Storage	67	165	23	23	6	212	0.2	262	262	7	7	11,039	1,539	1,539

Minor discrepancies may be due to rounding.

a. The number of sources subject to NSPS for the natural gas processing and the natural gas transmission and storage segments represent the number of new devices expected per year reduced by 20 percent. This is consistent with the assumption that 80 percent of high bleed devices can be replaced with a low bleed device. It is assumed all new sources would be installed as a high bleed for these segments. For the natural gas processing segment the number of new sources represents the number of Instrument Air Systems (IAS) that is expected to be installed, with each IAS expected to power 15 control loops (or replace 15 pneumatic devices).

b. The capital cost for regulatory option 2 is equal to the incremental cost of a low bleed device versus a new high bleed device. The capital cost of the IAS is based on the small IAS as summarized in Table 5-10.

c. Nationwide emission reductions vary based on average expected emission rates of bleed devices typically used in each segment industry segment as summarized in Tables 5-2.

5.6 References

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17 U.S. Energy Information Administration. Annual U.S. Natural Gas Wellhead Price. Energy Information Administration. Natural Gas Navigator. Retrieved online on 12 Dec 2010 at <http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm>

6.0 COMPRESSORS

Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and gas industry as prime movers are reciprocating and centrifugal compressors. This chapter discusses the air pollutant emissions from these compressors and provides emission estimates for reducing emission from these types of compressors. In addition, nationwide emissions estimates from new sources are estimated. Options for controlling pollutant emissions from these compressors are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for both reciprocating and centrifugal compressors.

6.1 Process Description

6.1.1 Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time,during operation of the compressor, the rings become worn and the packing system will need to be replaced to prevent excessive leaking from the compression cylinder.

6.1.2 Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Many centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and absorbs some compressed natural gas which is released to the atmosphere during the seal oil recirculation process. Alternatively, dry seals can be used to replace the wet seals in centrifugal compressors. Dry seals prevent leakage by using the opposing force created by hydrodynamic groves and springs. The opposing forcescreate a thin gap of high pressure gas between the rings through which little gas can leak. The rings do not wear or need lubrication because they are not in contact with each other. Therefore, operation and maintenance costs are lower for dry seals in comparison to wet seals.

6.2 Emissions Data and Emission Factors

6.2.1 Summary of Major Studies and Emissions Factors

There are a few studies that have been conducted that provide leak estimates from reciprocating and centrifugal compressors. These studies are provided in Table 6-1, along with the type of information contained in the study.

6.2.2 Representative Reciprocating and Centrifugal Compressor Emissions

The methodology for estimating emission from reciprocating compressor rod packing was to use the methane emission factors referenced in the EPA/GRI study[1] and use the methane to pollutant ratios developed in the gas composition memorandum.[2] The emission factors in the EPA/GRI document were expressed in thousand standard cubic feet per cylinder (Mscf/cyl), and were multiplied by the average number of cylinder per reciprocating compressor at each oil and gas industry segment. The volumetric methane emission rate was converted to a mass emission rate using a density of 41.63 pounds of methane per thousand cubic feet. This conversion factor was developed assuming that methane is an ideal gas and using the ideal gas law to calculate the density. A summary of the methane emission factors is presented in Table 6-2. Once the methane emissions were calculated, ratios were used to estimate volatile organic compounds (VOC) and hazardous air pollutants (HAP). The specific ratios that were used for this analysis were 0.278 pounds VOC per pound of methane and 0.105 pounds HAP per pound of methane for the production and processing segments, and 0.0277 pounds VOC per pound of methane and 0.0008 pounds HAP per pound of methane for the transmission and storage segments. A summary of the reciprocating compressor emissions are presented in Table 6-3.

The compressor emission factors for wet seals and dry seals are based on data used in the GHG inventory. The wet seals methane emission factor was calculated based on a sampling of 48 wet seal centrifugal compressors. The dry seal methane emission factor was based on data collected by the

Table 6-1. Major Studies Reviewed for Consideration Of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Information	Emissions Information	Control Information
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008[1]	EPA	2010	Nationwide	X	
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Document[2]	EPA	2010	Nationwide	X	
Methane Emissions from the Natural Gas Industry[3]	Gas Research Institute/EPA	1996	Nationwide	X	
Natural Gas STAR Program[4,5]	EPA	1993-2010	Nationwide	X	X

Table 6-2. Methane Emission Factors for Reciprocating and Centrifugal Compressors

Oil and Gas Industry Segment	Reciprocating Compressors			Centrifugal Compressors	
	Methane Emission Factor (scf/hr-cylinder)	Average Number of Cylinders	Pressurized Factor (% of hour/year Compressor Pressurized)	Wet Seal Methane Emission Factor (scf/minute)	Dry Seals Methane Emission Factor (scf/minute)
Production (Well Pads)	0.271[a]	4	100%	N/A[f]	N/A[f]
Gathering & Boosting	25.9[b]	3.3	79.1%	N/A[f]	N/A[f]
Processing	57[c]	2.5	89.7%	47.7[g]	6[g]
Transmission	57[d]	3.3	79.1%	47.7[g]	6[g]
Storage	51[e]	4.5	67.5%	47.7[g]	6[g]

a. EPA/GRI. (1996). “Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks.” Table 4-8.
b. Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites.* (Draft): 2006.
c. EPA/GRI. (1996). Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks. Table 4-14.
d. EPA/GRI. (1996). “Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks.” Table 4-17.
e. EPA/GRI. (1996). “Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks.” Table 4-24.
f. The 1996 EPA/GRI Study Volume 11[3], does not report any centrifugal compressors in the production or gathering/boosting sectors, therefore no emission factor data were published for those two sectors.
g. U.S Environmental Protection Agency. Methodology for Estimating CH4 and CO2 Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks1990-2009. Washington, DC. April 2011. Annex 3. Page A-153.

Table 6-3.Baseline Emission Estimates for Reciprocating and Centrifugal Compressors

Industry Segment/ Compressor Type	**Baseline Emission Estimates (tons/year)**		
	Methane	**VOC**	**HAP**
Reciprocating Compressors			
Production (Well Pads)	0.198	0.0549	0.00207
Gathering & Boosting	12.3	3.42	0.129
Processing	23.3	6.48	0.244
Transmission	27.1	0.751	0.0223
Storage	28.2	0.782	0.0232
Centrifugal Compressors (Wet seals)			
Processing	228	20.5	0.736
Transmission	126	3.50	0.104
Storage	126	3.50	0.104
Centrifugal Compressors (Dry seals)			
Processing	28.6	2.58	0.0926
Transmission	15.9	0.440	0.0131
Storage	15.9	0.440	0.0131

Natural Gas STAR Program. The methane emissions were converted to VOC and HAP emissions using the same gas composition ratios that were used for reciprocating engines.[4] A summary of the emission factors are presented in Table 6-2 and the individual compressor emission are shown in Table 6-3 for each of the oil and gas industry segments.

6.3 Nationwide Emissions from New Sources

6.3.1 Overview of Approach

The number of new affected facilities in each of the oil and gas sectors was estimated using data from the U.S. Greenhouse Gas Inventory,[5,6] with some exceptions. This basis was used whenever the total number of existing facilities was explicitly estimated as part of the Inventory, so that the difference between two years can be calculated to represent the number of new facilities. The Inventory was not used to estimate the new number of reciprocating compressor facilities in gas production, since more recent information is available in the comments received to subpart W of the mandatory reporting rule. Similarly, the Inventory was not used to estimate the new number of reciprocating compressor facilities in gas gathering, since more recent information is available in comments received as comments to subpart W of the mandatory reporting rule. For both gas production and gas gathering, information received as comments to subpart W of the mandatory reporting rule was combined with additional EPA estimates and assumptions to develop the estimates for the number of new affected facilities.

Nationwide emission estimates for new sources were then determined by multiplying the number of new sources for each oil and gas segment by the expected emissions per compressor using the emission data in Table 6-3. A summary of the number of new reciprocating and centrifugal compressors for each of the oil and gas segments is presented in Table 6-4.

6.3.2 Activity Data for Reciprocating Compressors

6.3.2.1 Wellhead Reciprocating Compressors

The number of wellhead reciprocating compressors was estimated using data from industry comments on Subpart W of the Greenhouse Gas Mandatory Reporting Rule.[7] The 2010 U.S. GHG Inventory reciprocating compressor activity data was not considered in the analysis because it does not distinguish between wellhead and gathering and boosting compressors. Therefore, using data submitted to EPA during the subpart W comment period from nine basins supplied by the El Paso Corporation,[8] the

Table 6-4.Approximate Number of New Sources in the Oil and Gas Industry in 2008

Industry Segment	Number of New Reciprocating Compressors	Number of New Centrifugal Compressors
Wellheads	6,000	0
Gathering and Boosting	210	0
Processing	209	16
Transmission	20	14
Storage	4	

average number of new wellhead compressors per new well was calculated using the 315 well head compressors provided in the El Paso comments and 3,606 wells estimated in the Final Subpart W onshore production threshold analysis. This produced an average of 0.087 compressors per wellhead. The average wellhead compressors per well was multiplied by the total well completions (oil and gas) determined from the HPDI® database[9] between 2007 and 2008, which came to 68,000 new well completions. Using this methodology, the estimated number of new reciprocating compressors at production pads was calculated to be 6,000 for 2008. A summary of the number of new reciprocating compressors located at well pads is presented in Table 6-4.

6.3.2.2 Gathering and Boosting Reciprocating Compressors

The number of gathering & boosting reciprocating compressors was also estimated using data from industry comments on Subpart W. DCP Midstream stated on page 3 of its 2010 Subpart W comments that it operates 48 natural gas processing plants and treaters and 700 gathering system compressor stations. Using this data, there were an average of 14.583 gathering and boosting compressor stations per processing plant. The number of new gathering and boosting compressors was determined by taking the average difference between the number of processing plants for each year in the 2010 U.S Inventory, which references the total processing plants in the Oil and Gas Journal. This was done for each year up to 2008. An average was taken of only the years with an increase in processing plants, up to 2008. The resulting average was multiplied by the 14.583 ratio of gathering and boosting compressor stations to processing plants and the 1.5 gathering and boosting compressors per station yielding 210 new source gathering and boosting compressor stations and is shown in Table 6-4.

6.3.2.3 Processing Reciprocating Compressors

The number of new processing reciprocating compressors at processing facilities was estimated by averaging the increase of reciprocating compressors at processing plants in the greenhouse gas inventory data for 2007, 2008, and 2009.[10,11] The estimated number of existing reciprocating compressors in the processing segment was 4,458, 4,781, and 4,876 for the years 2007, 2008, and 2009 respectively. This calculated to be 323 new reciprocating compressors between 2007 and 2008, and 95 new reciprocating compressors between 2008 and 2009. The average difference was calculated to be 209 reciprocating compressors and was used to estimate the number of new sources in Table 6-4.

6.3.2.4 Transmission and Storage Reciprocating Compressors

The number of new transmission and storage reciprocating compressors was estimated using the differences in the greenhouse gas inventory[12,13] data for 2007, 2008, and 2009 and calculating an average of those differences. The estimated number of existing reciprocating compressors at transmission stations was 7,158, 7,028, and 7,197 for the years 2007, 2008, and 2009 respectively. This calculated to be -130 new reciprocating compressors between 2007 and 2008, and 169 new reciprocating compressors between 2008and 2009. The average difference was calculated to be 20 reciprocating compressors and was used to estimate the number of new sources at transmission stations. The number of existing reciprocating compressors at storage stations was 1,144, 1,178, and 1,152 for the years 2007, 2008, and 2009 respectively. This calculated to be 34 new reciprocating compressors between 2007 and 2008, and -26 new reciprocating compressors between 2008and 2009. The average difference was calculated to be 4 reciprocating compressors and was used to estimate the number of new sources at storage stations in Table 6-4.

6.3.3 Activity Data for Centrifugal Compressors

The number of new centrifugal compressors in 2008 for the processing and transmission/storage segments was determined by taking the average difference between the centrifugal compressor activity data for each year in the 2008 U.S. Inventory . For example, the number of compressors in 1992 was subtracted from the number of compressors in 1993 to determine the number of new centrifugal compressors in 1993. This was done for each year up to 2008. An average was taken of only the years with an increase in centrifugal compressors, up to 2008, to determine the number of new centrifugal compressors in 2008. The result was 16 and 14 new centrifugal compressors in the processing and transmission segments respectively. A summary of the estimates for new centrifugal compressor is presented in Table 6-4.

6.3.4 Emission Estimates

Nationwide baseline emission estimates for new reciprocating and centrifugal compressors are summarized in Table 6-5 by industry segment.

Table 6-5.Nationwide Baseline Emissions for New Reciprocating and Centrifugal Compressors

Industry Segment/ Compressor Type	**Nationwide baseline Emissions (tons/year)**		
	Methane	**VOC**	**HAP**
Reciprocating Compressors			
Production (Well Pads)	1,186	330	12.4
Gathering & Boosting	2,587	719	27.1
Processing	4,871	1,354	51.0
Transmission	529	14.6	0.435
Storage	113	3.13	0.0929
Centrifugal Compressors			
Processing	3,640	329	11.8
Transmission/Storage	1,768	48.9	1.45

6.4 Control Techniques

6.4.1 Potential Control Techniques

The potential control options reviewed for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. This includesreplacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment of the piston rod.

The replacement of the rod packing is a maintenance task performed on reciprocating compressors to reduce the leakage of natural gas past the piston rod. Over time the packing rings wear and allow more natural gas to escape around the piston rod. Regular replacement of these rings reduces methane and VOC emissions. Therefore, this control technique was determined to be an appropriate optionfor reciprocating compressors.

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Piston rods, however, wear more slowly than packing rings, having a life of about 10 years.[14] Rods wear "out-of-round" or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. Also, upgrading piston rods by coating them with tungsten carbide or chrome reduces wear over the life of the rod. This analysis assumes operators will choose, at their discretion, when to replace the rod and hence, does not consider this control technique to be a practical control option for reciprocating compressors. A summary of these techniques are presented in the following sections.

Potential control options to reduce emissions from centrifugal compressors include control techniques that limit the leaking of natural gas across the rotating shaft, or capture and destruction of the emissions using a flare. A summary of these techniques are presented in the following sections.

A control technique for limiting or reducing the emission from the rotating shaft of a centrifugal compressor is a mechanical dry seal system. This control technique uses rings to prevent the escape of natural gas across the rotating shaft. This control technique was determined to be a viable option for reducing emission from centrifugal compressors.

For centrifugal compressors equipped with wet seals, a flare was considered to be a reasonable option for reducing emissions from centrifugal compressors. Centrifugal compressors require seals around the rotating shaft to prevent natural gas from escaping where the shaft exits the compressor casing. “Beam” type compressors have two seals, one on each end of the compressor, while “over-hung” compressors have a seal on only the “inboard” (motor end) side. These seals use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. The seal also includes “O-ring” rubber seals, which prevent leakage around the stationary rings. The oil barrier allows some gas to escape from the seal, but considerably more gas is entrained and absorbed in the oil under the high pressures at the “inboard” (compressor side) seal oil/gas interface, thus contaminating the seal oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated back to the seal. As a control measure, the recovered gas would then be sent to a flare or other combustion device.

6.4.2 Reciprocating Compressor Rod Packing Replacement

6.4.2.1 Description

Reciprocating compressor rod packing consists of a series of flexible rings that fit around a shaft to create a seal against leakage. As the rings wear, they allow more compressed gas to escape, increasing rod packing emissions. Rod packing emissions typically occur around the rings from slight movement of the rings in the cups as the rod moves, but can also occur through the “nose gasket” around the packing case, between the packing cups, and between the rings and shaft. If the fit between the rod packing rings and rod is too loose, more compressed gas will escape. Periodically replacing the packing rings ensures the correct fit is maintained between packing rings and the rod.

6.4.2.2 Effectiveness

As discussed above, regular replacement of the reciprocating compressor rod packing can reduce the leaking of natural gas across the piston rod. The potential emission reductions were calculated by comparing the average rod packing emissionswith the average emissions from newly installed and worn-in rod packing. Since the estimate for newly installed rod packing was intended for larger processing and transmission compressors, this analysis uses the estimate to calculate reductions from only gathering and boosting compressors and not wellhead compressor which are known to be smaller. The calculation for gathering and boosting reductions is shown in Equation 1.

$$R_{WP}^{G\&B} = \frac{Comp_{New}^{G\&B}\left(E_{G\&B} - E_{New}\right) \times C \times O \times 8760}{10^6} \qquad \textbf{Equation 1}$$

where,

$R_{WP}^{G\&B}$ = Potential methane emission reductions from gathering and boosting compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);

$Comp_{New}^{G\&B}$ = Number of new gathering and boosting compressors;

$E_{G\&B}$ = Methane emission factor for gathering and boosting compressors inTable 6-2, in cubic feet per hour per cylinder;

E_{New}=Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[15] for this analysis;

C = Average number of cylinders for gathering and boosting compressors in Table 6-2;

O = Percent of time during the calendar year the average gathering and boosting compressor is in the operating and standby pressurized modes, 79.1%;

8760 = Number of days in a year;

10^6 = Number of cubic feet in a million cubic feet.

For wellhead reciprocating compressors, this analysis calculates a percentage reduction using the transmission emission factor from the 1996 EPA/GRI report and the minimum emissions rate from a newly installed rod packing to determine methane emission reductions. The calculation for wellhead compressor reductions is shown in Equation 2 below.

$$R_{Well} = \frac{Comp_{New}^{Well}\left(E_{Well}\right) \times C \times O \times 8760}{10^6}\left(\frac{E_{Trans} - E_{New}}{E_{Trans}}\right) \qquad \textbf{Equation 2}$$

where,

R_{Well} = Potential methane emission reductions from wellhead compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);

$Comp_{New}^{Well}$ = Number of new wellhead compressors;

E_{Well} = Methane emission factor for wellhead compressors from Table 6-2, cubic feet per hour per cylinder;

C = Average number of cylinders for wellhead compressors in Table 6-2;

O = Percent of time during the calendar year the average gathering and boosting compressor is in the operating and standby pressurized modes, 100%;

E_{Trans} = Methane emissions factor for transmission compressors from Table 6-2 in cubic feet per hour per cylinder;
E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[16] for this analysis;
8760 = Number of days in a year;
10^6 = Number of cubic feet in a million cubic feet.

The emission reductions for the processing, transmission, and storage segments were calculated by multiplying the number of new reciprocating compressors in each segment by the difference between the average rod packing emission factors in Table 6-2 by the average emission factor from newly installed rod packing. This calculation, shown in the Equation 3 below, was performed for each of the natural gas processing, transmission, and storage/LNG sectors.

$$R_{PTS} = \frac{Comp_{New}^{PTS}\left(E_{G\&B} - E_{New}\right) \times C \times O \times 8760}{10^6} \qquad \textbf{\textit{Equation 3}}$$

where,

R_{PTS} = Potential methane emission reductions from processing, transmission, or storage compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);
$Comp_{New}^{PTS}$ = Number of new processing, transmission, or storage compressors;
$E_{G\&B}$ = Methane emission factor for processing, transmission, or storage compressors in Table 6-2, in cubic feet per hour per cylinder;
E_{New}=Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[17] for this analysis;
C = Average number of cylinders for processing, transmission, or storage compressors in Table 6-2;
O = Percent of time during the calendar year the average processing, transmission, or storage compressor is in the operating and standby pressurized modes, 89.7%, 79.1%, 67.5% respectively;
8760 = Number of days in a year;
10^6 = Number of cubic feet in a million cubic feet.

A summary of the potential emission reductions for reciprocating rod packing replacement for each of the oil and gas segments is shown in Table 6-6. The emissions of VOC and HAP were calculated using the methane emission reductions calculated above the gas composition[18] for each of the segments. Reciprocating compressors in the processing sector were assumed to be used to compress production gas.

Table 6-6.Estimated Annual Reciprocating Compressor Emission Reductions from Replacing Rod Packing

Oil & Gas Segment	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)			Nationwide Emission Reductions (tons/year)		
		Methane	VOC	HAP	Methane	VOC	HAP
Production (Well Pads)	6,000	0.158	0.0439	0.00165	947	263	9.91
Gathering & Boosting	210	6.84	1.90	0.0717	1,437	400	15.1
Processing	375	18.6	5.18	0.195	3,892	1,082	40.8
Transmission	199	21.7	0.600	0.0178	423	11.7	0.348
Storage	9	21.8	0.604	0.0179	87.3	2.42	0.0718

6.4.2.3 Cost Impacts

Costs for the replacement of reciprocating compressor rod packing were obtained from a Natural Gas Star Lessons Learned document[19] which estimated the cost to replace the packing rings to be $1,620 per cylinder. It was assumed that rod packing replacement would occur during planned shutdowns and maintenance and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring becausethe rod packingplacement is based on number of hours that the compressor operates. The replacement of rod packing for reciprocating compressors occurs on average every four years based on industry information from the Natural Gas STAR Program. [20] The cost impacts arebased on the replacement of the rod packing 26,000 hours that the reciprocating compressor operates in the pressurized mode. The number of hours used for the cost impacts was determined using a weighted average of the annual percentage that the reciprocating compressors are pressurized for all of the new sources. This weighted hours, on average, per year the reciprocating compressor is pressurized was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. This calculates to an average of 3 years for production compressors, 3.8 years for gathering and boosting compressors, 3.3 years for processing compressors, 3.8 years for transmission compressors, and 4.4 years for storage compressors using the operating factors in Table 6-2. The calculated years were assumed to be the equipment life of the compressor rod packing and were used to calculate the capital recovery factor for each of the segments. Assuming an interest rate of 7 percent, the capital recovery factors were calculated to be 0.3848, 0.3122, 0.3490, 0.3122, and 0.2720 for the production, gathering and boosting, processing, transmission, and storage sectors, respectively. The capital costs were calculated using the average rod packing cost of $1,620 and the average number of cylinders per segment in Table 6-2. The annual costs were calculated using the capital cost and the capital recovery factors. A summary of the capital and annual costs for each of the oil and gas segments is shown in Table 6-7.

Monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement was estimated using a natural gas price of $4.00 per Mcf.[21] This cost was used to calculate theannual cost with gas savings using the methane emission reductions in Table 6-6. The annual cost with savings is shown in Table 6-7 for each of the oil and gas segments. The cost effectiveness for the reciprocating rod packing replacement option is presented in Table 6-7. There is no gas savings cost benefits for transmission and storage facilities, because they do not own the natural gas that is

Table 6-7. Cost Effectiveness for Reciprocating Compressor Rod Packing Replacement

Oil and Gas Segment	**Capital Cost ($2008)**	**Annual Cost per Compressor ($/compressor-year)**		**VOC Cost Effectiveness ($/ton)**		**Methane Cost Effectiveness ($/ton)**	
		Without savings	With savings	Without savings	With savings	Without savings	With savings
Production	$6,480	$2,493	$2,457	$56,847	$56,013	$15,802	$15,570
Gathering & Boosting	$5,346	$1,669	$83	$877	$43	$244	$12
Processing	$4,050	$1,413	-$2,903	$273	-$561	$76	-$156
Transmission	$5,346	$1,669	N/A	$2,782	N/A	$77	N/A
Storage	$7,290	$2,276	N/A	$3,766	N/A	$104	N/A

compressed at their compressor stations.

6.4.2.4 Secondary Impacts

The reciprocating compressor rod packing replacement is an option that prevents the escape of natural gas from the piston rod. No wastes should be created, no wastewater generated, and no electricity maintenance and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring becausethe rod packing

6.4.3 Centrifugal Compressor Dry Seals

6.4.3.1 Description

Centrifugal compressor dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This gas is pumped between the rings by grooves in the rotating ring. The opposing force of high-pressure gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little gas can leak. While the compressor is operating, the rings are not in contact with each other, and therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case.

Dry seals substantially reduce methane emissions. At the same time, they significantly reduce operating costs and enhance compressor efficiency. Economic and environmental benefits of dry seals include:

- Gas Leak Rates. During normal operation, dry seals leak at a rate of 6scfmmethane per compressor.[22] While this is equivalent to a wet seal's leakage rate at the seal face, wet seals generate additional emissions during degassing of the circulating oil. Gas separated from the seal oil before the oil is re-circulated is usually vented to the atmosphere, bringing the total leakage rate for tandem wet seals to 47.7 scfm methane per compressor.[23,24]
- Mechanically Simpler. Dry seal systems do not require additional oil circulation components and treatment facilities.

- Reduced Power Consumption. Because dry seals have no accessory oil circulation pumps and systems, they avoid “parasitic” equipment power losses. Wet seal systems require 50 to 100 kW per hour, while dry seal systems need about 5 kW of power per hour.
- Improved Reliability. The highest percentage of downtime for a compressor using wet seals is due to seal system problems. Dry seals have fewer ancillary components, which translates into higher overall reliability and less compressor downtime.
- Lower Maintenance. Dry seal systems have lower maintenance costs than wet seals because they do not have moving parts associated with oil circulation (e.g., pumps, control valves, relief valves, and the seal oil cost itself).
- Elimination of Oil Leakage from Wet Seals. Substituting dry seals for wet seals eliminates seal oil leakage into the pipeline, thus avoiding contamination of the gas and degradation of the pipeline.

Centrifugal compressors were found in the processing and transmission sectors based on information in the greenhouse gas inventory.[25] Therefore, it was assumed that new compressors would be located in these sectors only.

6.4.3.2 Effectiveness

The control effectiveness of the dry seals was calculated by subtracting the dry seal emissions from a centrifugal compressor equipped with wet seals. The centrifugal compressor emission factors in Table 6-2 were used in combination with an operating factor of 43.6 percent for processing centrifugal compressors and 24.2 percent for transmission centrifugal compressors. The operating factors are used to account for the percent of time in a year that a compressor is in the operating mode. The operating factors for the processing and transmission sectors are based on data in the EPA/GRI study.[26] The wet seals emission factor is an average of 48 different wet seal centrifugal compressors. The dry seal emission factor is based on information from the Natural Gas STAR Program.[27] A summary of the emission reduction from the replacement of wet seals with dry seals is shown in Table 6-8.

6.4.3.3 Cost Impacts

The price difference between a brand new dry seal and brand new wet seal centrifugal compressor is insignificant relative to the cost for the entire compressor. General Electric (GE) stated that a natural gas transmission pipeline centrifugal compressor with dry seals cost between $50,000 and $100,000 more than the same centrifugal compressor with wet seals. However, this price difference is only about 1 to 3

Table 6-8. Estimated Annual Centrifugal Compressor Emission Reductions from Replacing Wet Seals with Dry Seals

Oil & Gas Segment	Number of New Sources Per Year	Individual Compressor Emission Reductions (ton/compressor-year)			Nationwide Emission Reductions (ton/year)		
		Methane	VOC	HAP	Methane	VOC	HAP
Transmission/Storage	16	199	18.0	0.643	3,183	287	10.3
Storage	14	110	3.06	0.0908	1,546	42.8	1.27

percent of the total cost of the compressor. The price of a brand new natural gas transmission pipeline centrifugal compressor between 3,000 and 5,000 horsepower runs between \$2 million to \$5 million depending on the number of stages, desired pressure ratio, and gas throughput. The larger the compressor, the less significant the price difference is between dry seals and wet seals. This analysis assumes the additional capital cost for a dry seal compressor is \$75,000. The annual cost was calculatedas the capital recovery of this capital cost assuming a 10-year equipment life and 7 percent interest which came to \$10,678 per compressor. The Natural Gas STAR Program estimated that the operation and maintenance savings from the installation of dry seals is \$88,300 in comparison to wet seals. Monetary savings associated with the amount of gas saved with the replacement of wet seals with dry seals for centrifugal compressors was estimated using a natural gas price of \$4.00 per Mcf.[28] This cost was used to calculate the annual cost with gas savings using the methane emission reductions in Table 6-8. A summary of the capital and annual costs for dry seals is presented in Table 6-9. The methane and VOC cost effectiveness for the dry seal option is also shown in Table 6-9. There is no gas savings cost benefits for transmission and storage facilities, because it is assumed the owners of the compressor station may not own the natural gas that is compressed at the station.

6.4.3.4 Secondary Impacts

Dry seals for centrifugal compressors are an option that prevents the escape of natural gas across the rotating compressor shaft. No wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the installation of dry seals on centrifugal compressors.

6.4.4 Centrifugal Compressor Wet Seals with a Flare

6.4.4.1 Description

Another control option used to reduce pollutant emissions from centrifugal compressors equipped withwet seals is to route the emissions to a combustion device or capture the emissions and route them to afuel system. A wet seal system uses oil that is circulated under high pressure between three rings aroundthe compressor shaft, forming a barrier against the compressed gas. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. Compressed gas becomes absorbed and entrained in the fluid barrier and is removed using a heater, flash tank, or other degassing technique so that the oil can be recirculated back to the wet seal. The removed gas is either

Table 6-9. Cost Effectiveness for Centrifugal Compressor Dry Seals

Oil and Gas Segment	**Capital Cost ($2008)**	**Annual Cost per Compressor ($/compressor-yr)**		**VOC Cost Effectiveness ($/ton)**		**Methane Cost Effectiveness ($/ton)**	
		without savings	**with O&M and gas savings**	**without savings**	**with O&M and gas savings**	**without savings**	**with O&M and gas savings**
Processing	$75,000	$10,678	-$123,730	$595	-$6,892	$54	-$622
Transmission/Storage	$75,000	$10,678	-$77,622	$3,495	-$25,405	$97	-$703

combusted or released to the atmosphere. The control technique investigated in this section is the use of wet seals with the removed gas sent to an enclosed flare.

6.4.4.2 Effectiveness

Flares have been used in the oil and gas industry to combust gas streams that have VOC and HAP. A flare typically achieves 95 percent reduction of these compounds when operated according to the manufacturer instructions. For this analysis, it was assumed that the entrained gas from the seal oil that is removed in the degassing process would be directed to a flare that achieves 95 percent reduction of methane, VOC, and HAP. The wet seal emissions in Table 6-5 were used along with the control efficiency to calculate the emissions reductions from this option. A summary of the emission reductions is presented in Table 6-10.

6.4.4.3 Cost Impacts

The capital and annual cost of the enclosed flare was calculated using the methodology in the EPA Control Cost Manual.[29] The heat content of the gas stream was calculated using information from the gas composition memorandum.[30] A summary of the capital and annual costs for wet seals routed to a flare is presented in Table 6-11. The methane and VOC cost effectiveness for the wet seals routed to a flare option is also shown in Table 6-12. There is no cost saving estimated for this option because the recovered gas is combusted.

6.4.4.4 Secondary Impacts

There are secondary impacts with the option to use wet seals with a flare. The combustion of the recovered gas creates secondary emissions of hydrocarbons, nitrogen oxide (NO_X), carbon dioxide (CO_2), and carbon monoxide (CO) emissions. A summary of the estimated secondary emission are presented in Table 6-11. No other wastes should be created or wastewater generated.

6.5 Regulatory Options

The affected facility definition for a reciprocating compressor is defined as a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of thedriveshaft. A centrifugal compressor is defined as a piece of equipment that compresses a process gas by means of mechanical rotating vanes or impellers. Therefore these types of compressor would be

Table 6-10. Estimated Annual Centrifugal Compressor Emission Reductions from Wet Seals Routed to a Flare

Oil & Gas Segment	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)			Nationwide Emission Reductions (tons/year)		
		Methane	VOC	HAP	Methane	VOC	HAP
Processing	16	216	19.5	0.699	3,283	296	10.6
Transmission/Storage	14	120	3.32	0.0986	1,596	44.2	1.31

Table 6-11. Secondary Impacts from Wet Seals Equipped with a Flare

Industry Segment	Secondary Impacts from Wet Seals Equipped with a Flare (tons/year)				
	Total Hydrocarbons	**Carbon Monoxide**	**Carbon Dioxide**	**Nitrogen Oxides**	**Particulate Matter**
Processing	0.0289	0.0205	7.33	0.00377	Negligible
Transmission/Storage	0.00960	0.00889	3.18	0.00163	Negligible

Table 6-12. Cost Effectiveness for Centrifugal Compressor Wet Seals Routed to a Flare

Oil and Gas Segment	**Capital Cost ($2008)**	**Annual Cost per Compressor ($/compressor-year)**		**VOC Cost Effectiveness ($/ton)**		**Methane Cost Effectiveness ($/ton)**	
		without savings	**with gas savings**	**without savings**	**with gas savings**	**without savings**	**with gas savings**
Processing	$67,918	$103,371	N/A	$5,299	N/A	$478	N/A
Transmission/Storage	$67,918	$103,371	N/A	$31,133	N/A	$862	N/A

subject to a New Performance Standard (NSPS) at the time of installation. The following Regulatory options were evaluated:

- Regulatory Option 1: Require replacement of the reciprocating compressor rod packing based on26,000 hours of operation while the compressor is pressurized.
- Regulatory Option 2: Require all centrifugal compressors to be equipped with dry seals.
- Regulatory Option 3: Require centrifugal compressors equipped with a wet seal to route the recovered gas emissions to a combustion device.

6.5.1 Evaluation of Regulatory Options

The first regulatory option for replacement of the reciprocating compressor rod packing based on the number of hours that the compressor operates in the pressurized mode was described in Section 6.4.1. The VOC cost effectiveness from $56,847 for reciprocating compressors located at production pads to $273 for reciprocating compressors located at processing plants. The VOC cost effectiveness for the gathering and boosting, transmission, and storage segments were $877, $2,782, and 3,766 respectively. Based on these cost effectiveness values, Regulatory Option 1 was accepted for the processing, gathering and boosting, transmission, and storage segments and rejected for the production segment.

The second regulatory option would require all centrifugal compressors to be equipped with dry seals. As presented in Section 6.4.2, dry seals are effective at reducing emissions from the rotating shaft of a centrifugal compressor. Dry seals also reduce operation and maintenance costs in comparison to wet seals. In addition, a vendor reported in 2003 that 90 percent of new compressors that were sold by the company were equipped with dry seals. Another vendor confirmed in 2010 that the rate at which new compressor sales have dry seals is still 90 percent; thus, it was assumed that from 2003 onward, 90 percent of new compressors are equipped with dry seals. The VOC cost effectiveness of dry seals was calculated to be $595 for centrifugal compressors located at processing plants, and $3,495 for centrifugal compressors located at transmission or storage facilities. Therefore, Regulatory Option 2 was accepted as a regulatory option for centrifugal compressors located at processing, transmission, or storage facilities.

The third regulatory option would allow the use of wet seals if the recovered gas emissions were routed to a flare. Centrifugal compressors with wet seals are commonly used in high pressure applications over 3,000 pounds per square inch (psi). None of the applications in the oil and gas industry operate at these pressures. Therefore, it does not appear that any facilities would be required to operate a centrifugal compressor with wet seals. The VOC control effectiveness for the processing and transmission/storage segments were $5,299 and $31,133 respectively. Therefore, Regulatory Option 3 was rejected due to the high VOC cost effectiveness.

6.5.2 Nationwide Impacts of Regulatory Options

Tables 6-13 and 6-14 summarize the impacts of the selected regulatory options by industry segment. Regulatory Option 1 is estimated to affect 210 reciprocating compressors at gathering and boosting stations, 209 reciprocating compressors at processing plants, 20 reciprocating compressors at transmission facilities, and 4 reciprocating compressors at underground storage facilities. A summary of the capital and annual costs and emission reductions for this option is presented in Table 6-13.

Regulatory Option 2 is expected to affect 16 centrifugal compressors in the processing segment and 14 centrifugal compressors in the transmission and storage segments. A summary of the capital and annual costs and emission reductions for this option is presented in Table 6-14.

Table 6-13. Nationwide Cost Impacts for Regulatory Option 1

Oil & Gas Segment	Number of New Sources Per Year	Nationwide Emission Reductions (tons/year)			Total Nationwide Costs		
		VOC	Methane	HAP	Capital Cost ($)	Annual Cost without savings ($/yr)	Annual Cost with savings ($/yr)
Gathering & Boosting	210	400	1,437	15.1	$1,122,660	$350,503	$17,337
Processing	209	1,082	3,892	40.8	$846,450	$295,397	-$606,763
Transmission	20	11.7	423	0.348	$104,247	$32,547	$32,547
Storage	4	2.42	87.3	0.0718	$29,160	$9,104	$9,104

Table 6-14. Nationwide Cost Impacts for Regulatory Option 2

Oil & Gas Segment	**Number of New Sources Per Year**	**Nationwide Emission Reductions[1] (tons/year)**			**Total Nationwide Costs[a]**		
		VOC	**Methane**	**HAP**	**Capital Cost ($)**	**Annual Cost w/o Savings ($/year)**	**Annual Cost w/ Savings ($/year)**
Production (Well Pads)	0	0	0	0	0	0	0
Gathering & Boosting	0	0	0	0	0	0	0
Processing	16	118	422	4.42	$100,196	$14,266	-$120,144
Transmission/Storage	14	3.24	117	0.0962	$50,098	$7,133	-$37,017

a. The nationwide emission reduction and nationwide costs are based on the emission reductions and costs for 2 centrifugal compressors with wet seals located a processing facility and 1 centrifugal compressor equipped with wet seal located at a transmission or storage facility.

6.6 References

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7.0 STORAGE VESSELS

Storage vessels, or storage tanks, are sources of air emissions in the oil and natural gas sector. This chapter provides a description of the types of storage vessels present in the oil and gas sector, and provides emission estimates for a typical storage vessel as well as nationwide emission estimates. Control techniques employed to reduce emissions from storage vessels are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter provides a discussion of considerations used in developing regulatory alternatives for storage vessels.

7.1 Process Description

Storage vessels in the oil and natural gas sector are used to hold a variety of liquids, including crude oil, condensates, produced water, etc. Underground crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the surface and processed, many of the dissolved lighter hydrocarbons (as well as water) are removed through as series of high-pressure and low-pressure separators. Crude oil under high pressure conditions is passed through either a two phase separator (where the associated gas is removed and any oil and water remain together) or a three phase separator (where the associated gas is removed and the oil and water are also separated). At the separator, low pressure gas is physically separated from the high pressure oil. The remaining low pressure oil is then directedto a storage vessel where it is stored for a period of time before being shipped off-site. The remaining hydrocarbons in the oil are released from the oil as vapors in the storage vessels. Storage vessels are typically installed with similar or identical vessels in a group, referred to in the industry as a tank battery.

Emissions of the remaining hydrocarbons from storage vessels are a function of working, breathing (or standing), and flash losses. Working losses occur when vapors are displaced due to the emptying and filling of storage vessels. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage vesselfrom a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flash emissions will occur in the storage stage. Temperature of the liquid may also influence the amount of flash emissions.

The volume of gas vapor emitted from a storage vessel depends on many factors. Lighter crude oils flash more hydrocarbons than heavier crude oils. In storage vessels where the oil is frequently cycled and the overall throughput is high, working losses are higher. Additionally, the operating temperature and pressure of oil in the separator dumping into the storage vesselwill affect the volume of flashed gases coming out of the oil.

The composition of the vapors from storage vessels varies, and the largest component is methane, but also includes ethane, butane, propane, and hazardous air pollutants (HAP) such as benzene, toluene, ethylbenzene, xylene (collectively referred to as BTEX), and n-hexane.

7.2 Emissions Data

7.2.1 Summary of Major Studies and Emissions

Given the potentially significant emissions from storage vessels, there have been numerous studies conducted to estimate these emissions. Many of these studies were consulted to evaluate the emissions and emission reduction options for emissions from storage vessels. Table 7-1 presents a summary of these studies, along with an indication of the type of information available in each study.

7.2.2 Representative Storage Vessel Emissions

Due to the variability in the sizes and throughputs, model tank batteries were developed to represent the ranges of sizes and population distribution of storage vessels located attank batteries throughout the sector. Model tank batteries were not intended to represent any single facility, but rather a range of facilities with similar characteristics that may be impacted by standards. Model tank batteries were developed for condensate tank batteries and crude oil tank batteries. Average VOC emissions were then developed and applied to the model tank batteries.

7.2.2.1 Model Condensate Tank Batteries

During the development of the national emissions standards for HAP (NESHAP) for oil and natural gas production facilities (40 CFR part 63, subpart HH), model plants were developed to represent condensate tank batteries across the industry.[1]For this current analysis, the most recent inventory data available was the 2008 U.S. Greenhouse Gas Emissions Inventory.[2,3] Therefore, 2008 was chosen to represent the base year for this impacts analysis.To estimate the current condensate battery population and distribution across the model plants, the number of tanks represented by the model plants was scaled

Table 7-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emission Figures	Control Information
VOC Emissions from Oil and Condensate Storage Tanks[4]	Texas Environmental Research Consortium	2009	Regional	X	X
Lessons Learned from Natural Gas STAR Partners:Installing Vapor Recovery Units on Crude Oil Storage Tanks[5]	EPA	2003	National		X
Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation – Final Report[6]	Texas Commission on Environmental Quality	2009	Regional	X	
Initial Economics Impact Analysis for Proposed State Implementation Plan Revisions to the Air Quality Control Commission's Regulation Number [7]	Colorado	2008	n/a		X
E&P TANKS[8]	American Petroleum Institute		National	X	
Inventory of U.S. Greenhouse Gas Emissions and Sinks[2,3]	EPA	2008 and 2009	National	X	

from 1992 (the year for which that the model plants were developed under the NESHAP) to 2008 for this analysis. Based on this approach, it was estimated that there were a total of 59,286 existing condensate tanks in 2008. Condensate throughput data from the U.S. Greenhouse Gas Emissions Inventory was used to scale up from 1992 the condensate tank populations for each model condensate tank battery under the assumption that an increase in condensate production would be accompanied by a proportional increase in number of condensate tanks. The inventory data indicate that condensate production increased from a level of 106 million barrels per year (MMbbl/yr) in 1992to 124 MMbbl/yr in 2008.This increase in condensate production was then distributed across the model condensate tank batteriesin the same proportion as was done for the NESHAP. The model condensate tank batteries are presented in Table 7-2.

7.2.2.2 Model Crude Oil Tank Batteries

According to the Natural Gas STAR program,[5] there were 573,000 crude oil storage tanksin 2003. According to the U.S. Greenhouse Gas Emissions Inventory, crude oil production decreased from 1,464 MMbbl/yr in 2003 to 1,326 MMbbl/yr (a decrease of approximately 9.4 percent) in 2008. Therefore, it was assumed that the number of crude oil tanks in 2008 were approximately 90.6 percent of the number of tanks identified in 2003. Therefore, for this analysis it was assumed that there were 519,161 crude oil storage tanks in 2008. During the development of the NESHAP, model crude oil tank batteries were not developed and a crude oil tank population was not estimated. Therefore, it was assumed that the percentage distribution of crude oil storage tanks across the four model crude oil tank battery classifications was the same as for condensate tank batteries.Table 7-3 presents the model crude oil tank batteries.

7.2.2.3 VOC Emissions from Condensate and Crude Oil Storage Vessels

Once the modelcondensate and crude oil tank battery distributionswere developed, VOC emissions from a representative storage vessel were estimated. Emissions from storage vessels vary considerably depending on many factors, including, but not limited to, throughput, API gravity, Reid vapor pressure, separator pressure, etc. The American Petroleum Institute (API) has developed a software program called E&P TANKS which contains a dataset of more than 100 storage vessels from across the country.[8] A summary of the information contained in the dataset, as well as the output from the E&P TANKS program, is presented in Appendix A of this document. According to industry representatives, this

Table 7-2. Model Condensate Tank Batteries

	Model Condensate Tank Battery			
Parameter	**E**	**F**	**G**	**H**
Condensate throughput (bbl/day)[a]	15	100	1,000	5,000
Condensate throughput (bbl/yr) [a]	5,475	36,500	365,000	1,825,000
Number of fixed-roof product storage vessels [a]				
210 barrel capacity	4	2		
500 barrel capacity		2	2	
1,000 barrel capacity			2	4
Estimated tank battery population (1992)[a]	12,000	500	100	70
Estimated tank battery population (2008) [b]	14,038	585	117	82
Total number of storage vessels (2008) [b]	56,151	2,340	468	328
Percent of number of storage vessels in model condensate tank battery	94.7%	3.95%	0.789%	0.552%
Percent of throughput per model condensate tank battery[a]	26%	7%	15%	51%
Total tank battery condensate throughput (MMbbl/yr)[c]	32.8	9.11	18.2	63.8
Condensate throughput per model condensate battery (bbl/day)	6.41	42.7	427	2,135
Condensate throughput per storage vessel (bbl/day)	1.60	10.7	106.8	534

Minor discrepancies may be due to rounding.

a. Developed for NESHAP (Reference 1).
b. Population of tank batteries for 2008 determined based on condensate throughput increase from 106 MMbbl/yr in 1992 to 124 MMbbl/yr in 2008 (References2,3).
c. 2008 condensate production rate of 124 MMbbl/yr distributed across model tank batteries using same relative ratio as developed for NESHAP (Reference 1).

Table 7-3. Model Crude Oil Tank Batteries

	Model Crude Oil Tank Battery			
Parameter	**E**	**F**	**G**	**H**
Percent of number of condensate storage vessels in model size range[a]	94.7%	3.95%	0.789%	0.552%
Number of storage vessels[b]	491,707	20,488	4,098	2,868
Percent of throughput across condensate tank batteries	26%	7%	15%	51%
Crude oil throughput per model plant category (MMbbl/yr)	351	97.5	195	683
Crude oil throughput per storage vessel (bbl/day)	1.96	13.0	130	652

Minor discrepancies may be due to rounding.

a. Same relative percent of storage vessel population developed for model condensate tank batteries.Refer to Table 7-2.

b. Calculated by applying the percent of number of condensate storage vessels in model size range to total number of crude oil storage vessels (519,161 crude oil storage vessels estimated for 2008) (Reference 5).

c. Same relative percent of throughput developed for model condensate tank batteries.Refer to Table 7-2.

dataset in combination with the output of the E&P TANKS program is representative of the various VOC emissions from storage vessels across the country.[9]

The more than 100 storage vesselsprovided with the E&P TANKS program, which had varying characteristics, were modeled with a constant throughput (based on the assumption that emissions would increase in proportion with throughput) and the relationship of these different characteristics and emissionswas studied. While many of the characteristics impacted emissions, a correlation was found to exist between API gravity and emissions. The average API gravity for all storage vessels in the data set was approximately 40 degrees. Therefore, we selected an API gravity of 40 degrees as a parameter to distinguish between lower emitting storage vessels and higher emitting storage vessels.[i] While the liquid type was not specified for the storage vessels modeled in the study, it was assumed that condensate storage vessels would have higher emissions than crude oil storage vessels. Therefore, based on this study using the E&P TANKS program, it was assumed for this analysis that liquids with API gravity equal to or greater than 40 degrees should be classified as condensate and liquids with API gravity less than 40 degrees should be classified as crude oil.

The VOC emissions from all storage vessels in the analysis are presented in Appendix A.Table 7-4 presents a summary of the average VOC emissions from all storage vessels as well as the average VOC emissions from the storage vessels identified as being condensate storage vessels and those identified as being crude oil storage vessels. As shown in Table 7-4, the storage vessels were modeled at a constant throughput of 500 bpd.[ii]An average emission factor was developed for each type of liquid. The average of condensate storage vessel VOC emissions was modeled to be 1,046 tons/year or 11.5 lb VOC/bbl and the average of crude oil storage vessel VOC emissions was modeled to be 107 tons/year or 1.18 lb VOC/bbl. These emission factors were then applied to each of the two sets of model storage vessels in Tables 7-2 and 7-4 to develop the VOC emissions from the model tank batteries. These are presented in Table 7-5.

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[i] The range of VOC emissions within the 95 percent confidence interval for storage vessels with an API gravity greater than 40 degrees was from 667 tons/year to 1425 tons/year. The range for API gravity less than 40 degrees was 76 tons/year to 138.

[ii] This throughput was originally chosen for this analysis to be equal to the 500 bbl/day throughput cutoff in subpart HH. While not part of the analysis described in this document, one of the original objectives of the E&P TANKS analysis was to assess the level of emissions associated with a storage vessel with a throughput below this cutoff. Due to the assumption that emissions increase and decrease in proportion with throughput, it was decided that using a constant throughput of 500 bbl/day would still provide the information necessary to determine VOC emissions from model condensate and crude oil storage vessels for this document.

Table 7-4. Summary of Data from E&P TANKS Modeling

Parameter[a]		Average of Dataset	Average of Storage Vessels with API Gravity > 40 degrees	Average of Storage Vessels with API Gravity ≤ 40 degrees
Throughput Rate (bbl)		500	500	500
API Gravity		40.6	52.8	30.6
VOC	Emissions (tons/year)	531	1046	107
	Emission factor (lb/bbl)	5.8	11.5	1.18

a. Information from analysis of E&P Tanks dataset, refer to Appendix A.

Table 7-5. Model Storage Vessel VOC Emissions

Parameter	Model Tank Battery			
	E	**F**	**G**	**H**
Model Condensate Tank Batteries				
Condensate throughput per storage vessel (bbl/day)	1.60	10.7	107	534
VOC Emissions (tons/year)[b]	3.35	22.3	223	1117
Model Crude Oil Tank Batteries				
Crude Oil throughput per storage vessel (bbl/day)[c]	2.0	13	130	652
VOC Emissions (tons/year)[d]	0.4	2.80	28	140

a. Condensate throughput per storage vessel from table 7-2.
b. Calculated using the VOC emission factor for condensate storage vessels of 11.5 lb VOC/bbl condensate.
c. Crude oil throughput per storage vessel from table 7-3.
d. Calculated using the VOC emission factor for crude oil storage vessels of 1.18 lb VOC/bbl crude oil.

7.3 Nationwide Baseline Emissions from New or Modified Sources

7.3.1 Overview of Approach

The first step in this analysis is to estimate nationwide emissions in absence of a federal rulemaking, referred to as the nationwide baseline emissions estimate. In order to develop the baseline emissions estimate, the number of new storage vessels expected in a typical year was calculated and then multiplied by the expected uncontrolled emissions per storage vessels presented in Table 7-5. In addition, to ensure no emission reduction credit was attributed to new sources that would already be required to be controlled under State regulations, it was necessary to account for the number of storage vessels already subject to State regulations as detailed below.

7.3.2 Number of New Storage Vessels Expected to be Constructed or Reconstructed

The number of new storage vessels expected to be constructed was determined for the year 2015 (the year of analysis for the regulatory impacts). To do this, it was assumed that the number of new or modified storage vessels would increase in proportion with increases in production. The Energy Information Administration (EIA), published crude oil production rates up to the year 2011.[10]Therefore, using the forecast function in Microsoft Excel® , crude oil production was predicted for the year 2015.[iii] From 2009 to 2015,[iv] the expected growth of crude oil production was projected to be 8.25 percent (from 5.36 bpd to 5.80 bpd). Applying this expected growth to the number of existing storage vessels results in an estimate of 4,890 new or modified condensate storage vessels and 42,811 new or modified crude oil storage vessels. The number of new or modified condensate and crude oil storage vessels expected to be constructed or reconstructed is presented in Table 7-6.

7.3.3 Level of Controlled Sources in Absence of Federal Regulation

As stated previously, to determine the impact of a regulation, it was first necessary to determine the current level of emissions from the sources being evaluated, or baseline emissions. To more accurately estimate baseline emissions for this analysis, and to ensure no emission reduction credit was attributed

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[iii] The crude oil production values published by the EIA include leased condensate. Therefore, the increase in crude oil production was assumed to be valid for both crude oil and condensate tanks for the purpose of this analysis.
[iv] For the purposes of estimating growth, the crude oil production rate in the year 2008 was considered an outlier for production and therefore was not used in this analysis.

Table 7-6. Nationwide Baseline Emissions for Storage Vessels

	Model Tank Battery				
	E	**F**	**G**	**H**	**Total**
Model Condensate Tank Batteries					
Total number of storage vessels (2008)	56,151	2,340	468	328	59,286
Total projected number of new or modified storage vessels (2015) [a]	4,630	193	39	27	4,889
Number of uncontrolled storage vessels in absence of federal regulation[b]	1,688	70	14	10	1,782
Uncontrolled VOC Emissions from storage vessel at model tank battery[c]	3.35	22.3	223	1,117	1,366
Total Nationwide Uncontrolled VOC Emissions	5,657	1,572	3,143	11,001	21,373
Model Crude Oil Tank Batteries					
Total number of storage vessels (2008)	491,707	20,488	4,098	2,868	519,161
Total projected number of new or modified storage vessels (2015) [a]	40,548	1,689	338	237	42,812
Number of uncontrolled storage vessels in absence of federal regulation[b]	14,782	616	123	86	15,607
Uncontrolled VOC Emissions from storage vessel at model tank battery[c]	0.4	2.80	28	140	171
Total Nationwide Uncontrolled VOC Emissions	6,200	1,722	3,444	12,055	23,421

Minor discrepancies may be due to rounding

a. Calculated by applying the expected 8.25 percent industry growth to the number of storage vessels in 2008.
b. Calculated by applying the estimated 36 percent of storage vessels that are uncontrolled in the absence of a Federal Regulation to the total projected number of new or modified storage vessels in 2015.
c. VOC Emissions from individual storage vessel at model tank battery, see Table 7-5.

for sources already being controlled, it was necessary to determine which storage vessels were already being controlled. To do this, the 2005 National Emissions Inventory (NEI) was used.Storage vessels in the oil and natural gas sector were identified under the review of the maximum achievable control technology (MACT) standards.[11] There were 5,412 storage vessels identified in the NEI, and of these, 1,973 (or 36 percent) were identified as being uncontrolled. Therefore, this percent of storage vessels that would not require controls under State regulations was applied to the number of new or modified storage vessels results in an estimate of 1,782 new or modified condensate storage vessels and 15,607 new or modified crude oil storage vessels.These are also presented in Table 7-6.

7.3.4 Nationwide Emission Estimates for New or Modified Storage Vessels

Nationwide emissions estimates are presented in Table 7-6 for condensate storage vessels and crude oil storage vessels. Model storage vessel emissions were multiplied by the number of expected new or modified storage vessels that would be uncontrolled in the absence of a federal regulation.As shown in Table 7-6, the baseline nationwide emissions are estimated to be 21,373 tons/year for condensate storage vessels and 23,421 tons/year for crude oil storage vessels.

7.4 Control Techniques

7.4.1 Potential Control Techniques

In analyzing controls for storage vessels, we reviewed control techniques identified in the Natural Gas STAR program and state regulations. We identified two ways of controlling storage vessel emissions, both of which can reduce VOC emissions by 95 percent. One option would be to install a vapor recovery unit (VRU) and recover all the vapors from the storage vessels. The other option would be to route the emissions from the storage vessels to a combustor. These control technologies are described below along with their effectiveness as they apply to storage vessels in the oil and gas sector, cost impacts associated with the installation and operation of these control technologies, and any secondary impacts associated with their use.

7.4.2 Vapor Recovery Units

7.4.2.1 Description

Typically, with a VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and are piped to a separator, or suction scrubber, to collect any condensed liquids, which are typically recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system. Vapors are then either sent to the pipeline for sale or used as on-site fuel.[5]

7.4.2.2 Effectiveness

Vapor recovery units have been shown to reduce VOC emissions from storage vessels by approximately 95 percent.***Error! Bookmark not defined.***A VRU recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold.If natural gas is recovered, it can be sold as well, as long as a gathering line is available to convey the recovered salable gas product to market or to further processing. A VRU also does not have secondary air impacts, as described below. However, a VRU cannot be used in all instances. Some conditions that affect the feasibility of VRU are: availability of electrical service sufficient to power the compressor; fluctuations in vapor loading caused by surges in throughput and flash emissions from the storage vessel; potential for drawing air into condensate storage vessels causing an explosion hazard; and lack of appropriate destination or use for the vapor recovered.

7.4.2.3 Cost Impacts

Cost data for a VRU was obtained from an Initial Economic Impact Analysis (EIA) prepared for proposed state-only revisions to a Colorado regulation.Cost information contained in the EIA was assumed to be giving in 2007 dollars.[7]Therefore costs were escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4).[12] According to the EIA, the purchased equipment cost of a VRU was estimated to be $85,423 (escalated to 2008 dollars from $75,000 in 2007 dollars). Total capital investment, including freight and design and installation was estimated to be $98,186. These cost data are presented in Table 7-7. Total annual costs were estimated to be $18,983/year.

7.4.2.4 Secondary Impacts

A VRU is a pollution prevention technique that is used to recover natural gas that would otherwise be emitted. No secondary emissions (e.g., nitrogen oxides, particulate matter, etc.) would be generated, no wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the use of a VRU.

Table 7-7. Total Capital Investment and Total Annual Cost of a Vapor Recovery Unit

Cost Item[a]	**Capital Costs ($)**	**Non-Recurring, One-time Costs ($)**	**Total Capital Investment ($)**[b]	**O&M Costs ($)**	**Savings due to Fuel Sales ($/yr)**	**Annualized Total Cost ($/yr)**[c]
VRU	$78,000					
Freight and Design		$1,500				
VRU Installation		$10,154				
Maintenance				$8,553		
Recovered natural gas					($1,063)	
Subtotal Costs (2007)	$78,000	$11,654		$8,553	($1,063)	
Subtotal Costs (2008)[d]	$85,423	$12,763	$98,186	$9,367	($1,164)	
Annualized costs (using 7% interest, 15 year equipment life)	$9,379	$1,401		n/a	n/a	$18,983

Minor discrepancies may be due to rounding

a. Assume cost data provided is for the year 2007. Reference 7.

b. Total Capital Investment is the sum of the subtotal costs for capital costs and nonrecurring one-time costs.

c. Total Annual Costs is the sum of the annualized capital and recurring costs, O&M costs, and savings due to fuel sales.

d. Costs are escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4). Reference 12.

7.4.3 Combustors

7.4.3.1 Description and Effectiveness

Combustors are also used to control emissions from condensate and crude oil storage vessels.The type of combustor used is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.[13] Combustors are used to control VOC in many industrial settings, since thecombustorcan normally handle fluctuations in concentration, flow rate, heating value, and inert species content.[14] For this analysis, the types of combustors installed for the oil and gas sector are assumed to achieve 95 percent efficiency.[7] Combustors do not have the same operational issues as VRUs, however secondary impacts are associated with combustors as discussed below.

7.4.3.2 Cost Impacts

Cost data for a combustor was also obtained from the Initial EIA prepared for proposed state-only revisions to the Colorado regulation.[7] As performed for the VRU, costs were escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4).[12] According to the EIA, the purchased equipment cost of a combustor, including an auto igniter and surveillance system was estimated to be $23,699 (escalated to 2008 dollars from $21,640 in 2007 dollars). Total capital investment, including freight and design and installation was estimated to be $32,301. These cost data are presented in Table 7-8. Total annual costs were estimated to be $8,909/year.

7.4.3.3 Secondary Impacts

Combustion and partial combustion of many pollutants also create secondary pollutants including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide, and smoke/particulates. Reliable data for emission factors from combustors on condensate and crude oil storage vessels are limited. Guidelines published in AP-42 for flare operations are based on tests from a mixture containing 80 percent propylene and 20 percent propane.[13] These emissions factors, however, are thebest indication for secondary pollutants from combustors currently available. The secondary emissionsper storage vessel are provided in Table 7-9.

Table 7-8. Total Capital Investment and Total Annual Cost of a Combustor

Cost Item[a]	Capital Costs ($)	Non-Recurring, One-time Costs ($)	Total Capital Investment ($)[b]	O&M Costs ($)	Annualized Total Cost ($/yr) [c]
Combustor	$16,540				
Freight and Design		$1,500			
Combustor Installation		$6,354			
Auto Igniter	$1,500				
Surveillance System[d]	$3,600				
Pilot Fuel				$1,897	
Maintenance				$2,000	
Data Management				$1,000	
Subtotal Costs (2007)	$21,640	$7,854		$4,897	
Subtotal Costs (2008) [e]	$23,699	$8,601	$32,301	$5,363	
Annualized costs (using 7% interest, 15 year equipment life)	$2,602	$944		n/a	$8,909

Minor discrepancies may be due to rounding

a. Assume cost data provided is for the year 2007. Reference 7.
b. Total Capital Investment is the sum of the subtotal costs for capital costs and nonrecurring one-time costs.
c. Total Annual Costs is the sum of the annualized capital and recurring costs, O&M costs, and savings due to fuel sales.
d. Surveillance system identifies when pilot is not lit and attempt to relight it, documents the duration of time when the pilot is not lit, and notifies and operator that repairs are necessary.
e. Costs are escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4). Reference 12.

Table 7-9. Secondary Impacts for Combustors used to Control Condensate and Crude Oil Storage Vessels

Pollutant	**Emission Factor**	**Units**	**Emissions per Storage Vessel (tons/year)[a]**
THC	0.14	lb/MMBtu	0.0061
CO	0.37	lb/MMBtu	0.0160
CO_2	60	Kg/MMBtu[b]	5.62
NO_X	0.068	lb/MMBtu	2.95E-03
PM	40	µg/l (used lightly smoking flares due to criteria that flares should not have visible emissions i.e. should not smoke)	5.51E-05

a. Converted using average saturated gross heating value of the storage vessel vapor (1,968 Btu/scf) and an average vapor flow rate of 44.07 Mcf per storage vessel. See Appendix A.

b. CO_2 emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

7.5 Regulatory Options and Nationwide Impacts of Regulatory Options

7.5.1 Consideration of Regulatory Options for Condensate and Crude Oil Storage Vessels

The VOC emissions from storage vessels vary significantly, depending on the rate of liquid entering and passing through the vessel (i.e., its throughput), the pressure of the liquid as it enters the atmospheric pressure storage vessel, the liquid’s volatility and temperature of the liquid.Some storage vessels have negligible emissions, such as those with very little throughput and/or handling heavy liquids entering at atmospheric pressure. Therefore, in order to determine the most cost effective means of controlling the storage vessels, a cutoff was evaluated to limit the applicability of the standards to these storage vessels. Rather than require a cutoff in terms of emissions that would require a facility to conduct an emissions test on their storage vessel, a throughput cutoff was evaluated. It was assumed that facilities would have storage vessel throughput data readily available. Therefore, we evaluated the costs of controlling storage vessels with varying throughputs to determine which throughput level would provide the most cost effective control option.

The standard would require an emission reduction of 95 percent, which, as discussed above, could be achieved with a VRU or a combustor. A combustoris an option for tank batteries because of the operational issues associated with a VRU as discussed above.However the use of a VRU is preferable to a combustorbecause a combustordestroys, rather than recycles, valuable resources and there are secondary impacts associated with the use of a combustor. Therefore, the cost impacts associated a VRU installed for the control of storage vessels were evaluated.

To conduct this evaluation, emission factor data from a study prepared for the Texas Environmental Research Consortium[15] was used to represent emissions from the different throughputs being evaluated. For condensate storage vessels, an emission factor of 33.3 lb VOC/bbl was used and for crude oil storage vessels, an emission factor of 1.6 lb VOC/bbl was used.Using the throughput for each control option, an equivalent emissions limit was determined.Table 7-10 presents the following regulatory options considered for condensate storage vessels:

- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 0.5 bbl/day (equivalent emissions of 3.0 tons/year);

Table 7-10. Options for Throughput Cutoffs for Condensate Storage Vessels

Regulatory Option	Throughput Cutoff (bbl/day)	Equivalent Emissions Cutoff (tons/year)[a]	Emission Reduction (tons/year)[b]	Annual Costs for VRU ($/yr)[c]	Cost Effectiveness ($/ton)	Number of impacted units[d]
1	0.5	3.0	2.89	$18,983	$6,576	1782
2	1	6.1	5.77	$18,983	$3,288	94
3	2	12.2	11.55	$18,983	$1,644	94
4	5	30.4	28.87	$18,983	$658	24

Minor discrepancies may be due to rounding

a. Emissions calculated using emission factor of 33.3 lb VOC/bbl condensate and the throughput associated with each option.
b. Calculated using 95 percent reduction
c. Refer to Table 7-7 for VRU Annual Costs.
d. Number of impacted units determined by evaluating which of the model tank batteries and storage vessel populations associated with each model tank battery (refer to Table 7-6) would be subject to each regulatory option. A storage vessel at a model tank battery was considered to be impacted by the regulatory option if its throughput and emissions were greater than the cutoffs for the option.

- Regulatory Option 2: Control condensate storage vessels with a throughput greater than 1 bbl/day (equivalent emissions of 6 tons/year);
- Regulatory Option 3: Control condensate storage vessels with a throughput greater than 2 bbl/day (equivalent emissions of 12 tons/year);
- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 5.0 bbl/day (equivalent emissions of 30 tons/year);

As shown in Table 7-10, Regulatory Option 1 is not cost effective for condensate storage vessels with a throughput of 0.5 bbl/day.Therefore Regulatory Option 1 is rejected.Since the cost effectiveness associated with Regulatory Option 2 is acceptable ($3,288/ton), this option was selected. As shown in Table 7-5, Model Condensate Storage Vessel Categories F, G, and H have throughputs greater than 1 bbl/day and emissions greater than 6 tons/year. Therefore, for the purposes of determining impacts, the populations of new and modified condensate storage vessels associated with categories F, G, and H are assumed to be required to reduce their emissions by 95 percent, a total of 94 new or modified condensate storage vessels.

A similar evaluation was performed for crude oil vessels and is presented in Table 7-11 for the following regulatory options:

- Regulatory Option 1: Control crude oil storage vessels with a throughput greater than 1 bbl/day (equivalent emissions of 0.3 tons/year);
- Regulatory Option 2: Control condensate storage vessels with a throughput greater than 5 bbl/day (equivalent emissions of 1.5 tons/year);
- Regulatory Option 3: Control condensate storage vessels with a throughput greater than 20 bbl/day (equivalent emissions of 6 tons/year);
- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 50 bbl/day (equivalent emissions of 15 tons/year);

As shown in Table 7-11, Regulatory Options 1 and 2 are not cost effective crude oil storage vessels with a throughput of 1 and 5 bbl/day, respectively. Therefore Regulatory Options 1 and 2 are rejected.Since the cost effectiveness associated with Regulatory Option 3 is acceptable ($3,422/ton), this option was selected. As shown in Table 7-5, Model Crude Oil Storage Vessel CategoriesG and H have throughputs greater than 20 bbl/day and emissions greater than 6 tons/year. Therefore, for the purposes of determining impacts, the populations of new and modified crude oil storage vessels associated with categories G

Table 7-11. Options for Throughput Cutoffs for Crude Oil Storage Vessels

Regulatory Option	Throughput Cutoff (bbl/day)	Equivalent Emissions Cutoff (tons/year) [a]	Emission Reduction (tons/year) [b]	Annual Costs for VRU ($/yr) [c]	Cost Effectiveness ($/ton)	Number of impacted units[d]
1	1	0.3	0.28	$18,983	$68,432	15607
2	5	1.5	1.4	$18,983	$13,686	825
3	20	5.8	5.55	$18,983	$3,422	209
4	50	14.6	13.87	$18,983	$1,369	209

Minor discrepancies may be due to rounding

a. Emissions calculated using emission factor of 1.6 lb VOC/bbl condensate and the throughput associated with each option.
b. Calculated using 95 percent reduction
c. Refer to Table 7-7 for VRU Annual Costs.
d. Number of impacted units determined by evaluating which of the model tank batteries and storage vessel populations associated with each model tank battery (refer to Table 7-6) would be subject to each regulatory option. A storage vessel at a model tank battery was considered to be impacted by the regulatory option if its throughput and emissions were greater than the cutoffs for the option.

and H are assumed to be required to reduce their emissions by 95 percent, a total of 209 new or modified condensate storage vessels.

7.5.2 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to Regulatory Option 2 for condensate storage vessels and Regulatory Option 3 for crude oil storage vessels which were selected as viable options for setting standards for storage vessels.In addition, combined impacts for a typical storage vessel are presented.

7.5.3 Primary Environmental Impacts of Regulatory Options

Regulatory Option2 (condensate storage vessels) and 3 (crude oil storage vessels) were selected as options for setting standards for storage vessels as follows:

- Regulatory Option 2 (Condensate Storage Vessels): Reduce emissions from condensate storage vessels with an average throughput greater than 1 bbl/day.

- Regulatory Option 3 (Crude Oil Storage Vessels): Reduce emissions from crude oil storage vessels with an average throughput greater than 20 bbl/day.

The number of storage vessels that would be subject to the regulatory options listed above are presented in Tables7-10 and 7-11. It was estimated that there would be 94 new or modified condensate storage vessels not otherwise subject to State regulationsand impacted by Regulatory Option 2 (condensate storage vessels).As shown in Table 7-11, 209 new or modified crude oil storage vessels not otherwise subject to State regulations would be impacted by Regulatory Option 3 (crude oil storage tanks).

Table 7-12 presents the nationwide emission reduction estimates for each regulatory option. Emissions reductions were estimated by applying 95 percent control efficiency to the VOC emissions presented in Table 7-6 for each storage vessel in the model condensate and crude oil tank batteries and multiplying by the number of impacted storage vessels. For Regulatory Option 2 (condensate storage vessels), the total nationwide VOC emission reduction was estimated to be 15,061 tons/year and 14,710 tons/year for Regulatory Option 3 (crude oil storage vessels).

Table 7-12. Nationwide Impacts of Regulatory Options

Model Tank Battery	Number of Sources subject to Regulatory Option[a]	VOC Emissions for a Typical Storage Vessel (tons/year)	Capital Cost forTypical Storage Vessel[b] ($)	Annual Cost for a Typical Storage Vessel[b] ($/yr)		Nationwide Emission Reductions (tons/year)[c]		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
				without savings	**with savings**	**VOC**	**Methane[d]**	**without savings**	**with savings**	**without savings**	**with savings**	**Capital Cost**	**Annual without savings**	**Annual with savings**
Regulatory Option 2: Condensate Storage Vessels														
F	70	22.3	65,243	14,528	13,946	1,483	325	685	658	3129	3004	4.57	1.02	0.98
G	14	223	65,243	14,528	13,946	2,966	649	68	66	313	301	0.913	0.203	0.195
H	10	1117	65,243	14,528	13,946	10,612	2,322	14	13	62.6	60.1	0.652	0.145	0.139
Total for Regulatory Option 2						**15,061**	**3,296**	▨	▨	▨	▨	**6.14**	**1.37**	**1.31**
Regulatory Option 3: Crude Oil Storage Vessels														
G	123	28	65,243	14,528	13,946	3,272	716	546	524	2496	2396	8.02	1.79	1.71
H	86	140	65,243	14,528	13,946	11,438	2,503	109	104	499	479	5.61	1.25	1.20
Total for Regulatory Option 3						**14,710**	**3,219**	▨	▨	▨	▨	**13.6**	**3.04**	**2.91**
Combined Impacts[e]														
Typical Storage Vessel	**304**	**103**	**65,243**	**14,528**	**13,946**	**29,746**	**6,490**	**149**	**143**	**680**	**652**	**19.8**	**4.41**	**4.24**

Minor discrepancies may be due to rounding

a. Number of storage vessels in each model tank battery (refer to Table 7-6) determined to be subject to the regulatory option as outlined in Table 7-10.

b. It was assumed for the purposes of estimating nationwide impacts that 50 percent of facilities would install a combustor and 50 percent a VRU.This accounts for the operational difficulties of using a VRU. Capital and Annual Costs determined using the average of costs presented in Tables 7-7 and 7-8.

c. Nationwide emission reductions calculated by applying a 95 percent emissions reduction to the VOC emissions for a typical storage vessel multiplied by the number of sources subject to the regulatory option.

d. Methane Reductions calculated by applying the average Methane to VOC factor from the E&P Tanks Study (see Appendix A).Methane:VOC = 0.219

e. For purposes of evaluating NSPS impact, impacts were determined for an average storage vessel by calculating total VOC emissions from all storage vessels and dividing by the total number of impacted storage vessels to obtain the average VOC emissions per storage vessel.

7.5.4 Cost Impacts

Cost impacts of the individual control techniques (VRU and combustors) were presented in Section 7.4. For both regulatory options, it was assumed that 50 percent of facilities would install a combustor and 50 percent a VRU. This accounts for the operational difficulties of using a VRU. Therefore, the average capital cost of control for each storage vessel was estimated to be $65,243 (the average of the total capital investment for a VRU of $98,186 and $32,301 for a combustor from Tables 7-7 and 7-8, respectively). Similarly, the average annual cost for a typical storage vessel was estimated to be $14,528/yr (average of the total annual cost for a VRU of $20,147/yr and $8,909/yr for a combustor from Tables 7-7 and 7-8, respectively) without including any cost savings due to fuel sales and $13,946/yr (average of the total annual cost for a VRU of $18,983/yr and $8,909/yr for a combustorfrom Tables 7-7 and 7-8, respectively) including cost savings.

Nationwide capital and annual costs were calculated by applying the number of storage vessels subject to the regulatory option. As shown in Table 7-12, the nationwide capital cost of Regulatory Option 2 (condensate storage vessels) was estimated to be $6.14 million and for RegulatoryOption 3 (crude oil storage vessels) nationwide capital cost was estimated to be $13.6 million.Total annual costs without fuel savings were estimated to be $1.37 million/yr for Regulatory Option 2 (condensate storage vessels) and $3.04 million/yr for Regulatory Option 3 (crude oil storage vessels). Total annual costs with fuel savings were estimated to be $1.31 million/yr for Regulatory Option 2 (condensate storage vessels) and $2.91 million/yr for Regulatory Option 3 (crude oil storage vessels).

For purposes of evaluating the impact of a federal standard, impacts were determined for an average storage vessel by calculating the total VOC emissions from all storage vessels and dividing by the total number of impacted storage vessels (304) to obtain the average VOC emissions per storage vessel (103 tons/year).Therefore, the nationwide annual costs were estimated to be $4.41 million/yr. A total nationwide VOC emission reduction of 29,746 tons/year results in a cost effectiveness of $149/ton.

7.5.5 Nationwide Secondary Emission Impacts

Regulatory Options 2 (condensate storage vessels) and 3 (crude oil storage vessels) allow for the use of a combustor; therefore the estimated nationwide secondary impacts are a result of combusting 50 percent of all storage vessel emissions. The secondary impacts for controlling a single storage vessel using a combustor are presented in Table 7-9. Nationwide secondary impacts are calculated by

Table 7-13. Nationwide Secondary Combined Impacts for Storage Vessels

Pollutant	Emissions per Storage Vessel (tons/year) [a]	Nationwide Emissions (tons/year)[b]
THC	0.0061	0.927
CO	0.0160	2.43
CO_2	5.62	854
NO_X	2.95E-03	0.448
PM	5.51E-05	0.0084

a. Emissions per storage vessel presented in Table 7-9.
b. Nationwide emissions calculated by assuming that 50 percent of the 304 impacted storage vessels would install a combustor.

multiplying 50 percent of the estimated number of impacted storage vessels (152) by the secondary emissions and are presented in Table 7-13.

7.6 References

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8.0 EQUIPMENT LEAKS

Leaks from components in the oil and natural gas sector are a source of pollutant emissions. This chapter explains the causes for these leaks, and provides emission estimates for "model" facilities in the various segments of the oil and gas sector. In addition, nationwide equipment leak emission estimates from new sources are estimated. Programs that are designed to reduce equipment leak emissions are explained, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for equipment leaks.

8.1 Equipment Leak Description

There are several potential sources of equipment leak emissions throughout the oil and natural gas sector. Components such as pumps, valves, pressure relief valves, flanges, agitators, and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines, and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. The following sub-sections describe potential equipment leak sources and the magnitude of the volatile emissions from typical facilities in the oil and gas industry.

Due to the large number of valves, pumps, and other components within oil and natural gas production, processing, and/or transmission facilities, total equipment leak VOC emissions from these components can be significant. Tank batteries or production pads are generally small facilities as compared with other oil and gas operations, and are generally characterized by a small number of components. Natural gas processing plants, especially those using refrigerated absorption, and transmission stations tend to have a large number of components.

8.2. Equipment leak Emission Data and Emissions Factors

8.2.1 Summary of Major Studies and Emission Factors

Emissions data from equipment leaks have been collected from chemical manufacturing and petroleum production to develop control strategies for reducing HAP and VOC emissions from these sources.[1,2,3] In the evaluation of the emissions and emission reduction options for equipment leaks, many of these studies were consulted. Table 8-1 presents a list of the studies consulted along with an indication of the type of information contained in the study.

8.2.2 Model Plants

Facilities in the oil and gas sector can consist of a variety of combinations of process equipment and components. This is particularly true in the production segment of the industry, where “surface sites” can vary from sites where only a wellhead and associated piping is located to sites where a substantial amount of separation, treatment, and compression occurs. In order to conduct analyses to be used in evaluating potential options to reduce emissions from leaking equipment, a model plant approach was used. The following sections discuss the creation of these model plants.

Information related to equipment counts was obtained from a natural gas industry report. This document provided average equipment counts for gas production, gas processing, natural gas transmission and distribution. These average counts were used to develop model plants for wellheads, well pads, and gathering line and boosting stations in the production segment of the industry, for a natural gas processing plant, and for a compression/transmission station in the natural gas transmission segment. These equipment counts are consistent with those contained in EPA’s analysis to estimate methane emissions conducted in support of the Greenhouse Gas Mandatory Reporting Rule (subpart W), which was published in the *Federal Register* on November 30, 2010 (75 FR 74458), These model plants are discussed in the following sections.

8.2.2.1 Oil and Natural Gas Production

Oil and natural gas production varies from site-to site. Many production sites may include only a wellhead that is extracting oil or natural gas from the ground. Other production sites consist of wellheads attached to a well pad. A well pad is a site where the production, extraction, recovery, lifting, stabilization, separation and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) associated with these operations. A well pad can serve one well on a pad or several wells on a pad. A wellhead site consisting of only the wellhead and affiliated piping is not considered to be a well pad. The number of wells feeding into a well pad can vary from one to as many as 7 wells. Therefore, the number of components with potential for equipment leaks can vary depending on the number of wells feeding into the production pad and the amount of processing equipment located at the site.

Table 8-1. Major Studies Reviewed for Consideration or Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor (s)	Emissions Data	Control Options
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Documents	EPA	2010	Nationwide	X	X
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008[4]	EPA	2010	Nationwide	X	
Methane Emissions from the Natural Gas Industry[567]	Gas Research Institute / EPA	1996	Nationwide	X	X
Methane Emissions from the US Petroleum Industry (Draft) [8]	EPA	1996	Nationwide	X	
Methane Emissions from the US Petroleum Industry [9]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States [10]	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories [11]	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State[12]	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements [13]	Environmental Defense Fund	2009	Regional	X	X
Emissions from oil and Natural Gas Production Facilities [14]	Texas Commission for Environmental Quality	2007	Regional	X	X
Petroleum and Natural Gas Statistical Data[15]	U.S. Energy Information Administration	2007-2009	Nationwide		
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations [16]	EPA	1999		X	X
Protocol for Equipment Leak Emission Estimates[17]	EPA	1995	Nationwide	X	X

In addition to wellheads and well pads, model plants were developed for gathering lines and boosting stations. The gathering lines and boosting stations are sites that collect oil and gas from well pads and direct them to the gas processing plants. These stations have similar equipment to well pads; however they are not directly connected to the wellheads.

The EPA/GRI report provided the average number of equipment located at a well pad and the average number of components for each of these pieces of equipment.[4]The type of production equipment located at a well pad include: gas wellheads, separators, meters/piping, gathering compressors, heaters, and dehydrators. The types of components that are associated with this equipment include: valves, connectors, open-ended lines, and pressure relief valves. Four model plants were developed for well pads and are presented in Table 8-2. These model plants were developed starting with one, three, five and seven wellheads, and adding the average numberof other pieces of equipment per wellhead. Gathering compressors are not included at well pads and were included in the equipment for gathering lines and boosting stations.

Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S and the Western U.S. for the EPA/GRI document. A summary of the component counts for oil and gas production well pads is presented in Table 8-3.

Gathering line and boosting station model plants were developed using the average equipment counts for oil and gas production. The average equipment count was assigned Model Plant 2 and Model Plants 1 and 3 were assumed to be equally distributed on either side of the average equipment count. Therefore, Model Plant 1 can be assumed to be a small gathering and boosting station, and Model Plant 3 can be assumed to be a large gathering and boosting station. A summary of the model plant production equipment counts for gathering lines and boosting stations is provided in Table 8-4.

Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S and the Western U.S. from the EPA/GRIdocument. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressors seals are addressed in a Chapter 6 of this document. A summary of the component counts for oil and gas gathering line and boosting stations are presented in Table 8-5.

Table 8-2.Average Equipment Count for Oil and Gas Production Well Pad Model Plants

Equipment	Model Plant 1	Model Plant 2	Model Plant 3
Gas Wellheads	1	5	48
Separators	---	4	40
Meter/Piping	---	2	24
In-Line Heaters	---	2	26
Dehydrators	---	2	19

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and Table 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-3.Average Component Count for Oil and Gas Production Well Pad Model Plants

Component	Model Plant 1	Model Plant 2	Model Plant 3	Model Plant 4
Valve	9	122	235	348
Connectors	37	450	863	1,276
Open-Ended Line	1	15	29	43
Pressure Relief Valve	0	5	10	15

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-4.Average Equipment Count for Oil and Gas Production Gathering Line and Boosting Station Model Plants

Equipment	Model Plant 1	Model Plant 2	Model Plant 3
Separators	7	11	15
Meter/Piping	4	7	10
Gathering Compressors	3	5	7
In-Line Heaters	4	7	10
Dehydrators	3	5	7

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and Table 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-5. Average Component Count for Oil and Gas Production Gathering Line and Boosting Station Model Plants

Component	Model Plant 1	Model Plant 2	Model Plant 3
Valve	547	906	1,265
Connectors	1,723	2,864	4,005
Open-Ended Line	51	83	115
Pressure Relief Valve	29	48	67

DataSource: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8:Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

8.2.2.2 Oil and Natural Gas Processing

Natural gas processing involves the removal of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. The types of process equipment used to separate the liquids are separators, glycol dehydrators, and amine treaters. In addition, centrifugal and/or reciprocating compressors are used to pressurize and move the gas from the processing facility to the transmission stations.

New Source Performance Standards (NSPS) have already been promulgated for equipment leaks at new natural gas processing plants (40 CFR Part 60, subpart KKK), and were assumed to be the baseline emissions for this analysis. Only one model plant was developed for the processing sector. A summary of the model plant production components counts for an oil and gas processing facility is provided in Table 8-6.

8.2.2.3 Natural Gas Transmission/Storage

Natural gas transmission/storage stations are facilities that use compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, transmission stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment. This source category also does not include emissions from gathering lines and boosting stations. Component counts were obtained from the EPA/GRI report and are presented in Table 8-7.

8.3 Nationwide Emissions from New Sources

8.3.1 Overview of Approach

Nationwide emissions were calculated by using the model plant approach for estimating emissions. Baseline model plant emissions for the natural gas production, processing, and transmission sectors were calculated using the component counts and the component gas service emission factors.[5]Annual emissions were calculated assuming 8,760 hours of operation each year. The emissions factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The emission factors for the production and processing sectors that were used to estimate the new source emissions are presented in Table 8-8. Emission factors for the transmission sector are presented in

Table 8-6.Average Component Count for Oil and Gas Processing Model Plant

Component	Gas Plant (non-compressor components)
Valve	1,392
Connectors	4,392
Open-Ended Line	134
Pressure Relief Valve	29

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-13, June 1996. (EPA-600/R-96-080h)

Table 8-7.Average Component Count for a Gas TransmissionFacility

Component	Processing Plant Component Count
Valve	704
Connection	3,068
Open-Ended Line	55
Pressure Relief Valve	14

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-16, June 1996. (EPA-600/R-96-080h)

Table 8-8 Oil and Gas Production and Processing Operations Average Emissions Factors

Component Type	Component Service	Emission Factor (kg/hr/source)
Valves	Gas	4.5E-03
Connectors	Gas	2.0E-04
Open-Ended Line	Gas	2.0E-03
Pressure Relief Valve	Gas	8.8E-03

Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

Table 8-9. Emissions for VOC, hazardous air pollutants (HAP), and methane were calculated using TOC weight fractions.[6] A summary of the baseline emissions for each of the sectors are presented in Table 8-10.

8.3.2 Activity Data

Data from oil and gas technical documents and inventories were used to estimate the number of new sources for each of the oil and gas sectors. Information from the Energy Information Administration (EIA) was used to estimate the number of new wells, well pads, and gathering and boosting stations. The number of processing plants and transmission/storage facilities was estimated using data from the Oil and Gas Journal, and the EPA Greenhouse Gas Inventory. A summary of the steps used to estimate the new sources for each of the oil and gas sectors is presented in the following sections.

8.3.2.1 Well Pads

The EIA provided a forecast of the number of new conventional and unconventional gas wells for the Year 2015 for both exploratory and developmental wells. The EIA projected 19,097 conventional and unconventional gas wells in 2015. The number of wells was converted to number of well pads by dividing the total number of wells by the average number of wells serving a well pad which is estimated to be 5. Therefore, the number of new well pads was estimated to be 3,820. The facilities were divided into the model plants assuming a normal distribution of facilities around the average model plant (Model Plant 2).

8.3.2.2 Gathering and Boosting

The number of new gathering and boosting stations was estimated using the current inventory of gathering compressors listed in the EPA Greenhouse Gas Inventory. The total number of gathering compressors was listed as 32,233 in the inventory. The GRI/EPA document does not include a separate list of compressor counts for gathering and boosting stations, but it does list the average number of compressors in the gas production section. It was assumed that this average of 4.5 compressors for gas production facilities is applicable to gathering and boosting stations. Therefore, using the inventory of 32,233 compressors and the average number of 4.5 compressors per facility, we estimated the number of gathering and boosting stations to be 7,163. To estimate the number of new gathering and boosting stations, we used the same increase of 3.84 percent used to estimate well pads to estimate the number of new gathering and boosting stations. This provided an estimate of 275 new gathering and boosting

Table 8-9 Oil and Gas Transmission/Storage Average Emissions Factors

Component Type	Component Service	Emission Factor (kg/hr/source)
Valves	Gas	5.5E-03
Connectors	Gas	9.3E-04
Open-Ended Line	Gas	7.1E-02
Pressure Relief Valve	Gas	3.98E-02

Data Source:EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-17, June 1996. (EPA-600/R-96-080h)

Table 8-10. Baseline Emissions for the Oil and Gas Production, Processing, and Transmission/Storage Model Plants

Oil and Gas Sector	**Model Plant**	**TOC Emissions (Tons/yr)**	**Methane Emissions (Tons/yr)**	**VOC Emissions (Tons/yr)**	**HAP Emissions (Tons/yr)**
Well Pads	1	0.482	0.335	0.0930	0.00351
	2	13.3	9.24	2.56	0.0967
	3	139	96.5	26.8	1.01
Gathering & Boosting	1	30.5	21.2	5.90	0.222
	2	50.6	35.2	9.76	0.368
	3	70.6	49.1	13.6	0.514
Processing	1	74.0	51.4	14.3	0.539
Transmission/Storage	1	108.1	98.1	2.71	0.0806

stations that would be affected sources under the proposed NSPS. The new gathering and boosting stations were assumed to be normally distributed around the average model plant (Model Plant 2).

8.3.2.3 Processing Facilities

The number of new processing facilities was estimated using gas processing data from the Oil and Gas Journal. The Oil and Gas Journal Construction Survey currently shows 6,303 million cubic feet of gas per day (MMcf/day) additional gas processing capacity in various stages of development. The OGJ Gas Processing Survey shows that there is 26.9 trillion cubic feet per year (tcf/year) in existing capacity, with a current throughput of 16.6 tcf/year or 62 percent utilization rate. If the utilization rate remains constant, the new construction would add approximately 1.4 tcf/year to the processing system. This would be an increase of 8.5 percent to the processing sector. The recent energy outlook published by the EIApredicts a 1.03 tcf/year increase in natural gas processing from 21.07 to22.104 tcf/year. This would be an annual increase of 5 percent over the next five years.

The EPA Greenhouse Gas Inventory estimates the number of existing processing facilities to be 577 plants operating in the U.S. Based on the projections provided in Oil and Gas Journal and EIA, it was assumed that the processing sector would increase by 5 percent annually. Therefore the number of new sources was estimated to be 29 new processing facilities in the U.S.

8.3.2.4 Transmission/Storage Facilities

The number of new transmission and storage facilities was estimated using the annual growth rate of 5 percent used for the processing sector and the estimated number of existing transmission and storage facilities in the EPA Greenhouse Inventory. The inventory estimates 1,748 transmission stations and 400 storage facilities for a total of 2,148. Therefore, the number of new transmission/storage facilities was estimated to be 107.

8.3.3 Emission Estimates

Nationwide emission estimates for the new sources for well pads, gathering and boosting, processing, and transmission/storage are summarized in Table 8-11. For well pads and gathering and boosting stations, the numbers of new facilities were assumed to be normally distributed across the range of model plants.

Table 8-11. Nationwide Baseline Emissions for New Sources

Oil and Gas Sector	Model Plant	Number of New Facilities	TOC Emissions (tons/yr)	Methane Emissions (tons/yr)	VOC Emissions (tons/yr)	HAP Emissions (tons/yr)
Well Pads	1	605	292	203	56.3	2.12
	2	2,610	34,687	24,116	6,682	252
	3	605	84,035	58,389	16,214	612
	Total	3,820	119,014	82,708	22,952	866
Gathering & Boosting	1	44	1,312	912	254	9.55
	2	187	9,513	6,618	1,835	69.2
	3	44	3,106	2,160	598	22.6
	Total	275	13,931	9,690	2,687	101
Processing	1	29	2,146	1,490	415	15.6
Transmission/Storage	1	107	11,567	10,497	290	8.62

8.4 Control Techniques

8.4.1 Potential Control Techniques

EPA has determined that leaking equipment, such as valves, pumps, and connectors, are a significant source of VOC and HAP emissions from oil and gas facilities. The following section describes the techniques used to reduce emissions from these sources.

The most effective control technique for equipment leaks is the implementation of a leak detection and repair program (LDAR). Emissions reductions from implementing an LDAR program can potentially reduce product losses, increase safety for workers and operators, decrease exposure of hazardous chemicals to the surrounding community, reduce emissions fees, and help facilities avoid enforcement actions. The elements of an effective LDAR program include:

- Identifying Components;
- Leak Definition;
- Monitoring Components;
- Repairing Components; and
- Recordkeeping.

The primary source of equipment leak emissions from oil and gas facilities are from valves and connectors, because these are the most prevalent components and can number in the thousands. The major cause of emissions from valves and connectors is a seal or gasket failure due to normal wear or improper maintenance. A leak is detected whenever the measured concentration exceeds the threshold standard (i.e., leak definition) for the applicable regulation. Leak definitions vary by regulation, component type, service (e.g., light liquid, heavy liquid, gas/vapor), and monitoring interval. Most NSPS regulations have a leak definition of 10,000 ppm, while many NESHAP regulations use a 500-ppm or 1,000-ppm leak definition. In addition, some regulations define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting or clouding from or around components), sound (such as hissing), and smell.

For many NSPS and NESHAP regulations with leak detection provisions, the primary method for monitoring to detect leaking components is EPA Reference Method 21 (40 CFR Part 60, Appendix A). Method 21 is a procedure used to detect VOC leaks from process equipment using toxic vapor analyzer (TVA) or organic vapor analyzer (OVA). In addition, other monitoring tools such as; infrared camera, soap solution, acoustic leak detection, and electronic screening device, can be used to monitor process components.

In optical gas imaging, a live video image is produced by illuminating the view area with laser light in the infrared frequency range. In this range, hydrocarbons absorb the infrared light and are revealed as a dark image or cloud on the camera. The passive infrared cameras scan an area to produce images of equipment leaks from a number of sources. Active infrared cameras point or aim an infrared beam at a potential source to indicate the presence of equipment leaks. The optical imaging camera is easy to use and very efficient in monitoring many components in a short amount of time. However, the optical imaging camera cannot quantify the amount or concentration of equipment leak. To quantify the leak, the user would need to measure the concentration of the leak using a TVA or OVA. In addition, the optical imaging camera has a high upfront capital cost of purchasing the camera.

Acoustic leak detectors measure the decibel readings of high frequency vibrations from the noise of leaking fluids from equipment leaks using a stethoscope-type device. The decibel reading, along with the type of fluid, density, system pressure, and component type can be correlated into leak rate by using algorithms developed by the instrument manufacturer. The acoustic detector does not decrease the monitoring time because components are measured separately, like the OVA or TVA monitoring. The accuracy of the measurements using the acoustic detector can also be questioned due to the number of variables used to determine the equipment leak emissions.

Monitoring intervals vary according to the applicable regulation, but are typically weekly, monthly, quarterly, and yearly. For connectors, the monitoring interval can be every 1, 2, 4, or 8 years. The monitoring interval depends on the component type and periodic leak rate for the component type. Also, many LDAR requirements specify weekly visual inspections of pumps, agitators, and compressors for indications of liquids leaking from the seals. For each component that is found to be leaking, the first attempt at repair is to be made no later than five calendar days after each leak is detected. First attempts at repair include, but are not limited to, the following best practices, where practicable and appropriate:

- Tightening of bonnet bolts;

- Replacement of bonnet bolts;
- Tightening of packing gland nuts; and
- Injection of lubricant into lubricated packing.

Once the component is repaired; it should be monitored daily over the next several days to ensure the leak has been successfully repaired. Another method that can be used to repair component is to replace the leaking component with “leakless” or other technologies.

The LDAR recordkeeping requirement for each regulated process requires that a list of all ID numbers be maintained for all equipment subject to an equipment leak regulation. A list of components that are designated as “unsafe to monitor” should also be maintained with an explanation/review of conditions for the designation. Detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams should also be maintained with the results of performance testing and leak detection monitoring, which may include leak monitoring results per the leak frequency, monitoring leakless equipment, and non-periodic event monitoring.

Other factors that can improve the efficiency of an LDAR program that are not addressed by the standards include training programs for equipment monitoring personnel and tracking systems that address the cost efficiency of alternative equipment (e.g., competing brands of valves in a specific application).

The first LDAR option is the implementation of a subpart VVa LDAR program. This program is similar to the VV monitoring, but finds more leaks due to the lower leak definition, thereby achieving better emission reductions. The VVa LDAR program requires the annual monitoring of connectors using an OVA or TVA (10,000 ppm leak definition), monthly monitoring of valves (500 ppm leak definition) and requires open-ended lines and pressure relief devices to operate with no detectable emissions (500 ppm leak definition). The monitoring of each of the equipment types were also analyzed as a possible option for reducing equipment leak emissions. The second option involves using the monitoring requirements in subpart VVa for each type of equipment which include: valves; connectors; pressure relief devices; and open-ended lines for each of the oil and gas sectors.

The thirdoption that was investigated was the implementation of a LDAR program using an optical gas imaging system. This option is currently available as an alternative work practice (40 CFR Part 60, subpart A) for monitoring emissions from equipment leaks in subpart VVa. The alternative work practice requires monthly monitoring of all components using the optical gas imaging system and an annual monitoring of all components using a Method 21 monitoring device. The Method 21 monitoring allows the facility to quantify emissions from equipment leaks, since the optical gas imaging system can only provide the magnitude of the equipment leaks.

A fourth option that was investigated is a modification of the 40 CFR Part 60, subpart Aalternative work practice. The alternative work practice was modified by removing the required annual monitoring using a Method 21 instrument. This option only requires the monthly monitoring of components using the optical gas imaging system.

8.4.2 Subpart VVa LDAR Program

8.4.2.1 Description

The subpart VVa LDAR requires the monitoring of pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines, valves, and connectors. These components are monitored with an OVA or TVA to determine if a component is leaking and measure the concentration of the organics if the component is leaking. Connectors, valves, and pressure relief devices have a leak definition of 500 parts per million by volume (ppmv). Valves are monitored monthly, connectors are monitored annually, and open-ended lines and pressure relief valves have no monitoring requirements, but are required to operate without any detectable emissions. Compressors are not included in this LDAR option and are regulated separately.

8.4.2.2 Effectiveness

The control effectiveness of the LDAR program is based on the frequency of monitoring, leak definition, frequency of leaks, percentage of leaks that are repaired, and the percentage of reoccurring leaks. A summary of the chemical manufacturing and petroleum refinery control effectiveness for each of the components is shown in Table 8-12. As shown in the table the control effectiveness for all of the components varies from 45 to 96 percent and is dependent on the frequency of monitoring and the leak definition. Descriptions of the frequency of monitoring and leak definition are described further below.

> Monitoring Frequency: The monitoring frequency is the number of times each component is checked for leaks. For an example, quarterly monitoring requires that each component be checked for leaks 4 times per year, and annual monitoring requires that each component be checked for leaks once per year. As shown in Table 8-12, monthly monitoring provides higher control effectiveness than quarterly

Table 8-12. Control Effectiveness for an LDAR program at a Chemical Process Unit and a Petroleum Refinery

Equipment Type and Service	Control Effectiveness (% Reduction)		
	Monthly Monitoring 10,000 ppmv Leak Definition	Quarterly Monitoring 10,000 ppmv Leak Definition	500 ppm Leak Definition[a]
Chemical Process Unit			
Valves – Gas Service[b]	87	67	92
Valves – Light Liquid Service[c]	84	61	88
Pumps – Light Liquid Service[c]	69	45	75
Connectors – All Services	---	---	93
Petroleum Refinery			
Valves – Gas Service[b]	88	70	96
Valves – Light Liquid Service[c]	76	61	95
Pumps – Light Liquid Service[c]	68	45	88
Connectors – All Services	---	---	81

Source: Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, Nov 1995.

a. Control effectiveness attributable to the HON-negotiated equipment leak regulation (40 CFR 63, Subpart H) is estimated based on equipment-specific leak definitions and performance levels. However, pumps subject to the HON at existing process units have a 1,000 to 5,000 ppm leak definition, depending on the type of process.

b. Gas (vapor) service means the material in contact with the equipment component is in a gaseous state at the process operating conditions.

c. Light liquid service means the material in contact with the equipment component is in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure above 0.3 kilopascals (kPa) at 20°C is greater than or equal to 20% by weight.

monitoring. This is because leaking components are found and repaired more quickly, which lowers the amount of emissions that are leaked to the atmosphere.

> <u>Leak Definition:</u> The leak definition describes the local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present. The leak definition is an instrument meter reading based on a reference compound. Decreasing the leak definition concentration generally increases the number of leaks found during a monitoring period, which generally increases the number of leaks that are repaired.

The control effectiveness for the well pad, gathering and boosting stations, processing facilities, and transmissions and storage facilities were calculated using the LDAR control effectiveness and leak fraction equations for oil and gas production operation units in the EPA equipment leaks protocol document. The leak fraction equation uses the average leak rate (e.g., the component emission factor) and leak definition to calculate the leak fraction.[7] This leak fraction is used in a steady state set of equations to determine the final leak rate after implementing a LDAR program.[8] The initial leak rate and the final leak rate after implementing a LDAR program were then used to calculate the control effectiveness of the program. The control effectiveness for implementing a subpart VVa LDAR program was calculated to be 93.6 perccent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.2.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Subpart VVa monitoring frequency and leak definition were used for processing plants since they are already required to do subpart VV requirements. Connectors were assumed to be monitored over a 4-year period after initial annual compliance monitoring.
- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Subsequent monitoring costs are $1.50 for valves and connectors, $2.00 for pressure relief valve disks, and $5.00 for pressure relief valve devices and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The capital cost also includes $14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of $4.00 per 1000 standard cubic feet.

It was assumed that a single Method 21 monitoring device could be used at multiple locations for production pads, gathering and boosting stations, and transmission and storage facilities. To calculate the shared cost of the Method 21 device, the time required to monitor a single facility was estimated. For production pads and gathering and boosting stations, it was assumed that it takes approximately 1 minute to monitor a single component, and approximately 451 components would have to be monitored at an average facility in a month. This calculates to be 451 minutes or 7.5 hours per day. Assuming 20 working days in a typical month, a single Method 21 device could monitor 20 facilities. Therefore, the capital cost of the Method 21 device ($6,500) was divided by 20 to get a shared capital cost of $325 per facility. It was assumed for processing facilities that the full cost of the Method 21 monitoring device would apply to each individual plant. The transmission and storage segment Method 21 device cost was estimated using assuming the same 1 minute per component monitoring time. The average number of components that would need to be monitored in a month was estimated to be 1,440, which calculates to be 24 hours of monitoring time or 3 days. Assuming the same 20 day work month, the total number of facilities that could be monitored by a single Method 21 device is 7. Therefore, the shared cost of the Method 21 monitoring device was calculated to be $929 per site.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectors are provided in Table 8-13. In addition to the full subpart VVa LDAR monitoring, a component by component LDAR analysis was performed for each of the oil and gas sectors using the component count for an average size facility. This Model Plant 2 for well pads, Model Plant 2 for gathering and boosting stations, and Model Plant 1 for processing plants and transmission and storage facilities.

Table 8-13. Summary of the Model Plant Cost Effectiveness for the Subpart VVa Option

Model Plant	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/year)		Cost Effectiveness ($/ton)		
	VOC	HAP	Methane		without savings	with savings	VOC	HAP	Methane
Well Pads									
1	0.0876	0.00330	0.315	$15,418	$23,423	$23,350	$267,386	$7,088,667	$74,253
2	2.43	0.0915	8.73	$69,179	$37,711	$35,687	$15,549	$412,226	$4,318
3	25.3	0.956	91.3	$584,763	$175,753	$154,595	$6,934	$183,835	$1,926
Gathering and Boosting Stations									
1	5.58	0.210	20.1	$148,885	$57,575	$52,921	$10,327	$273,769	$2,868
2	9.23	0.348	33.2	$255,344	$84,966	$77,259	$9,203	$243,987	$2,556
3	12.9	0.486	46.4	$321,203	$105,350	$94,591	$8,174	$216,692	$2,270
Processing Plants									
1	13.5	0.508	48.5	$7,522	$45,160	$33,915	$3,352	$88,870	$931
Transmission/Storage Facilities									
1	2.62	0.0780	94.9	$94,482	$51,875	N/A	$19,769	$665,155	$546

Note: Transmission and storage facilities do not own the natural gas; therefore they do not receive any cost benefits from reducing the amount of natural gas as the result of equipment leaks.

The component costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Subsequent monitoring costs are $1.50 for valves and connectors, $2.00 for pressure relief valve disks, and $5.00 for pressure relief valve devices and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.
- Administrative costs and initial planning and training costs are were included for the component option and are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The capital cost for purchasing a TVA or OVA monitoring system was estimated to be $6,500.

The component control effectiveness for the subpart VVa component option were 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices. These were the same control effectiveness's that were used for the subpart VVa facility option. The control effectiveness for the modified subpart VVa option with less frequent monitoring was estimated assuming the control effectiveness follows a hyperbolic curve or a 1/x relationship with the monitoring frequency. Using this assumption the component cost effectiveness's were determined to be 87.2 percent for valves, 81.0 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices. The assumption is believed to provide a conservative estimate of the control efficiency based on less frequent monitoring. A summary of the capital and annual costs and the cost effectiveness for each of the components for each of the oil and gas sectors are provided in Tables 8-14, 8-15, 8-16, and 8-17.

8.4.2.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

Table 8-14. Summary of Component Cost Effectiveness for Well Pads for the Subpart VVa Options

Component	**Average Number of Components**	**Monitoring Frequency (Times/yr)**	**Annual Emission Reductions (tons/year)**			**Capital Cost ($)**	**Annual Cost ($/yr)**	**Cost-effectiveness ($/ton)**		
			VOC	**HAP**	**Methane**			**VOC**	**HAP**	**Methane**
Subpart VVa Option										
Valves	235	12	1.84	0.0696	6.64	$11,175	$27,786	$15,063	$399,331	$4,183
Connectors	863	1/0.25[a]	0.308	0.0116	1.11	$7,830	$22,915	$74,283	$1,969,328	$20,628
PRD	10	0	0.164	0.00619	0.591	$48,800	$29,609	$180,537	$4,786,215	$50,135
OEL	29	0	0.108	0.00408	0.389	$9,458	$22,915	$211,992	$5,620,108	$58,870
Modified Subpart VVa– Less Frequent Monitoring										
Valves	235	1	1.31	0.0496	4.73	$11,175	$23,436	$17,828	$472,640	$4,951
Connectors	863	1/0.125[b]	0.261	0.00983	0.938	$7,830	$22,740	$87,277	$2,313,795	$24,237
PRD	5	0	0.164	0.00619	0.591	$48,800	$29,609	$180,537	$4,786,215	$50,135
OEL	29	0	0.108	0.00408	0.389	$9,458	$22,915	$211,992	$5,620,108	$58,870

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

Table 8-15. Summary of Component Cost Effectiveness for Gathering and Boosting Stations for the Subpart VVa Options

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Subpart VVa Option										
Valves	906	12	7.11	0.268	25.6	$24,524	$43,234	$6,079	$161,162	$1,688
Connectors	2,864	1/0.25[a]	1.02	0.0386	3.69	$10,914	$24,164	$23,603	$625,752	$6,555
PRD	48	0	0.787	0.0297	2.83	$195,140	$57,091	$72,523	$1,922,648	$20,139
OEL	83	0	0.309	0.0117	1.11	$14,966	$23,917	$77,310	$2,049,557	$21,469
Modified Subpart VVa – Less Frequent Monitoring										
Valves	906	1	5.07	0.191	18.2	$24,524	$24,461	$5,221	$138,417	$1,450
Connectors	2,864	1/0.125[b]	0.865	0.0326	3.11	$10,914	$23,584	$27,274	$723,067	$7,574
PRD	48	0	0.787	0.0297	2.83	$195,140	$57,091	$72,523	$1,922,648	$20,139
OEL	83	0	0.309	0.0117	1.11	$14,966	$23,917	$77,310	$2,049,557	$21,469

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

Table 8-16. Summary of Incremental Component Cost Effectiveness for Processing Plants for the Subpart VVa Option

Component	**Average Number of Components**	**Monitoring Frequency (Times/yr)**	**Annual Emission Reductions (tons/year)**			**Capital Cost ($)**	**Annual Cost ($/yr)**	**Cost-effectiveness ($/ton)**		
			VOC	**HAP**	**Methane**			**VOC**	**HAP**	**Methane**
Incremental Component Cost for Subpart VV to Subpart VVa Option										
Valves	1,392	12	10.9	0.412	39.3	$6,680	$1,576	$144	$3,824	$40
Connectors	4,392	1/0.25[a]	1.57	0.0592	5.65	$2,559	$6,845	$4,360	$115,585	$1,211
PRD	29	0	0.499	0.0188	1.80	$0	$0	$0	$0	$0
OEL	134	0	0.476	0.0179	1.71	$0	$0	$0	$0	$0

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.

Table 8-17. Summary of Component Cost Effectiveness for Transmission and Storage Facilities for the Subpart VVa Options

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Subpart VVa Option										
Valves	673	12	0.878	0.0261	31.8	$19,888	$37,870	$43,111	$1,450,510	$1,192
Connectors	3,068	1/0.25[a]	0.665	0.0198	24.1	$11,229	$24,291	$36,527	$1,229,005	$1,010
PRD	14	0	0.133	0.00397	4.83	$61,520	$32,501	$243,525	$8,193,684	$6,732
OEL	58	0	0.947	0.0282	34.3	$12,416	$23,453	$24,762	$833,137	$684
Modified Subpart VVa – Less Frequent Monitoring										
Valves	673	1	0.626	0.0186	22.6	$19,888	$25,410	$40,593	$1,365,801	$1,122
Connectors	3,068	1/0.125[b]	0.562	0.0167	20.3	$11,229	$23,669	$42,140	$1,417,844	$1,165
PRD	14	0	0.133	0.00397	4.83	$61,520	$32,501	$243,525	$8,193,684	$6,732
OEL	58	0	0.947	0.0282	34.3	$12,416	$23,453	$24,762	$833,137	$684

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

8.4.3 LDAR with Optical Gas Imaging

8.4.3.1 Description

The alternative work practice for equipment leaks in §60.18 of 40 CFR Part 60, subpart A allows the use of an optical gas imaging system to monitor leaks from components. This LDAR requires monthly monitoring and repair of components using an optical gas imaging system, and annual monitoring of components using a Method 21 instrument. This requirement does not have a leak definition because the optical gas imaging system can only measure the magnitude of a leak and not the concentration. However, this alternative work practice does not require the repair of leaks below 500 ppm. Compressors are not included in this LDAR option and arediscussed in Chapter 6 of this document.

8.4.3.2 Effectiveness

No data was found on the control effectiveness of the alternative work practice. It is believed that this option would provide the same control effectiveness as the subpart VVa monitoring program. Therefore, the control effectiveness's for implementing an alternative work practice was assumed to be 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.3.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Monthly optical gas imaging monitoring costs are estimated to be $0.50 for valves, connectors, pressure relief valve devices, and open-ended lines.
- Annual monitoring costs using a Method 21 device are estimated to be $1.50 for valves and connectors, $2.00 for pressure relief valve disks, and $5.00 for pressure relief devices and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The capital cost also includes $14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of $4.00 per 1000 standard cubic feet.

It was assumed that a single optical gas imaging and a Method 21 monitoring device could be used at multiple locations for production pads, gathering and boosting stations, and transmission and storage facilities. To calculate the shared cost of the optical gas imaging system and the Method 21 device, the time required to monitor a single facility was estimated. For production pads and gathering and boosting stations, it was assumed that 8 production pads could be monitored per day. This means that 160 production facilities could be monitored in a month. In addition, it was assumed 13 gathering and boosting station would service these wells and could be monitored during the same month for a total of 173 facilities. Therefore, the capital cost of the optical gas imaging system (Flir Model GF320, $85,000) and the Method 21 device ($6,500) was divided by 173 to get a shared capital cost of $529 per facility. It was assumed for processing facilities that the full cost of the optical gas imaging system and the Method 21 monitoring device would apply to each individual plant. The transmission and storage segment Method 21 device cost was estimated assuming that one facility could be monitored in one hour, and the travel time between facilities was one hour. Therefore, in a typical day 4 transmission stations could be monitored in one day. Assuming the same 20 day work month, the total number of facilities that could be monitored by a single optical gas imaging system and Method 21 device is 80. Therefore, the shared cost of the Method 21 monitoring device was calculated to be $1,144 per site.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectorusing the alternative work practice monitoring is provided in Table 8-18. A component cost effectiveness analysis for the alternative work practice was not performed, because the optical gas imaging system is not conducive to component monitoring, but is intended for facility-wide monitoring.

8.4.3.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of

Table 8-18. Summary of the Model Plant Cost Effectiveness for the Optical Gas Imaging and Method 21 Monitoring Option

Model Plant	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/year)		Cost Effectiveness ($/ton)		
	VOC	HAP	Methane		without savings	with savings	VOC	HAP	Methane
Well Pads									
1	0.0876	0.00330	0.315	$15,428	$21,464	$21,391	$245,024	$6,495,835	$68,043
2	2.43	0.0915	8.73	$64,858	$39,112	$37,088	$16,127	$427,540	$4,478
3	25.3	0.956	91.3	$132,891	$135,964	$114,807	$5,364	$142,216	$1,490
Gathering and Boosting Stations									
1	5.58	0.210	20.1	$149,089	$63,949	$59,295	$11,470	$304,078	$3,185
2	9.23	0.348	33.2	$240,529	$93,210	$85,503	$10,096	$267,659	$2,804
3	12.9	0.486	46.4	$329,725	$121,820	$111,060	$9,451	$250,567	$2,625
Processing Plants									
1	13.5	0.508	48.5	$92,522	$87,059	$75,813	$6,462	$171,321	$1,795
Transmission/Storage Facilities									
1	2.62	0.0780	94.9	$20,898	$51,753	N/A	$19,723	$663,591	$545

Minor discrepancies may be due to rounding.

Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission segment..

equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

8.4.4 Modified Alternative Work Practice with Optical Gas Imaging

8.4.4.1 Description

The modified alternative work practice for equipment leaks in §60.18 of 40 CFR Part 60, subpart A allows the use of an optical gas imaging system to monitor leaks from components, but removes the requirement of the annual Method 21 device monitoring. Therefore, the modified work practice would require only monthly monitoring and repair of components using an optical gas imaging system. This requirement does not have a leak definition because the optical gas imaging system can only measure the magnitude of a leak and not the concentration. However, this alternative work practice does not require the repair of leaks below 500 ppm. Compressors are not included in this LDAR option and are regulated separately.

8.4.4.2 Effectiveness

No data was found on the control effectiveness of this modified alternative work practice. However, it is believed that this option would provide the similar control effectiveness and emission reductions as the subpart VVa monitoring program. Therefore, the control effectiveness's for implementing an alternative work practice was assumed to be 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.4.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Monthly optical gas imaging monitoring costs are estimated to be $0.50 for valves, connectors, pressure relief valve devices, and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The shared capital cost for optical gas imaging system is $491 for production and gathering and boosting, $85,000 for processing, and $1,063 for transmission for a FLIR Model GF320 optical gas imaging system.
- The capital cost also includes $14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of $4.00 per 1000 standard cubic feet.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectors using the alternative work practice monitoring is provided in Table 8-19. A component cost effectiveness analysis for the alternative work practice was not performed, because the optical gas imaging system is not conducive to component monitoring, but is intended for facility-wide monitoring.

8.4.4.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

8.5 Regulatory Options

The LDAR pollution prevention approach is believed to be the best method for reducing pollutant emissions from equipment leaks. Therefore, the following regulatory options were considered for reducing equipment leaks from well pads, gathering and boosting stations, processing facilities, and transmission and storage facilities:

- Regulatory Option 1: Require the implementation of a subpart VVa LDAR program;
- Regulatory Option 2: Require the implementation of a component subpart VVa LDAR program;
- Regulatory Option 3: Require the implementation of the alternative work practice in §60.18 of 40 CFR Part 60;

Table 8-19. Summary of the Model Plant Cost Effectiveness for Monthly Gas Imaging Monitoring

Model Plant	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/year)		Cost Effectiveness ($/ton)		
	VOC	HAP	Methane		without savings	with savings	VOC	HAP	Methane
Well Pads									
1	N/A	N/A	N/A	$15,390	$21,373	N/A	N/A	N/A	N/A
2	N/A	N/A	N/A	$64,820	$37,049	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	$537,313	$189,174	N/A	N/A	N/A	N/A
Gathering and Boosting Stations									
1	N/A	N/A	N/A	$149,051	$59,790	N/A	N/A	N/A	N/A
2	N/A	N/A	N/A	$240,491	$86,135	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	$329,687	$11,940	N/A	N/A	N/A	N/A
Processing Plants									
1	N/A	N/A	N/A	$92,522	$76,581	N/A	N/A	N/A	N/A
Transmission/Storage Facilities									
1	N/A	N/A	N/A	$20,817	$45,080	N/A	N/A	N/A	N/A

Note: This option only provides the number and magnitude of the leaks. Therefore, the emission reduction from this program cannot be quantified and the cost effectiveness values calculated.

- Regulatory Option 4: Require the implementation of a modified alternative work practice in §60.18 of 40 CFR Part 60 that removes the requirement for annual monitoring using a Method 21 device.

The following sections discuss these regulatory options.

8.5.1 Evaluation of Regulatory Options for Equipment Leaks

8.5.1.1 Well pads

The first regulatory option of a subpart VVa LDAR program was evaluated for well pads, which include the wells, processing equipment (separators, dehydrators, acid gas removal), as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. For well pads the VOC cost effectiveness for the model plants ranged from $267,386 per ton of VOC for a single well head facility to $6,934 ton of VOC for a well pad servicing 48 wells. Because of the high VOC cost effectiveness, Regulatory Option 1 was rejected for well pads.

The second regulatory option that was evaluated for well pads was Regulatory Option 2, which would require the implementation of a component subpart VVa LDAR program. The VOC cost effectiveness of this option ranged from $15,063 for valves to $211,992 for open-ended lines. These costs were determined to be unreasonable and therefore this regulatory option was rejected.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option ranged from $5,364 per ton of VOC for Model Plant 3to $245,024 per ton of VOC for Model Plant 1. This regulatory option was determined to be not cost effective and was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.2 Gathering and Boosting Stations

The first regulatory option was evaluated for gathering and boosting stations which include the processing equipment (separators, dehydrators, acid gas removal), as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. The VOC cost effectiveness for the gathering and boosting model plants ranged from $10,327 per ton of VOC for

Model Plant 1 to $8,174per ton of VOC for Model Plant 3. Regulatory Option 1 was rejected due to the high VOC cost effectiveness.

The second regulatory option that was evaluated for gathering and boosting stations was Regulatory Option 2. The VOC cost effectiveness of this option ranged from $6,079 for valves to $77,310 per ton of VOC for open-ended lines. These costs were determined to be unreasonable and therefore this regulatory option was also rejected.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option was calculated to be $10,724 per ton of VOC for Model Plant 1 and $8,685 per ton of VOC for Model Plant 3. This regulatory option was determined to be not cost effective and was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.3 Processing Plants

The VOC cost effectiveness of the first regulatory option was calculated to be $3,352 per ton of VOC. This cost effectiveness was determined to be reasonable and therefore this regulatory option was accepted.

The second option was evaluated for processing plants and the VOC cost effectiveness ranged from $0 for open-ended lined and pressure relief devices to $4,360 for connectors. Because the emission benefits and the cost effectiveness of Regulatory Option 1 were accepted, this option was not accepted.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option was calculated to be $6,462 per ton of VOC and was determined to be not cost effective. Therefore, this regulatory option was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.4 Transmission and Storage Facilities

The first regulatory option was evaluated for transmission and storage facilities which include separators and dehydrators, as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. This sector moves processed gas from the processing facilities to the city gates. The VOC cost effectiveness for Regulatory Option 1 was $19,769per ton of VOC. The high VOC cost effectiveness is due to the inherent low VOC concentration in the processed natural gas, therefore the VOC reductions from this sector are low in comparison to the other sectors. Regulatory Option 1 was rejected due to the high VOC cost effectiveness.

The second option was evaluated for transmission facilities and the VOC cost effectiveness ranged from $24,762 for open-ended lined to $243,525 for connectors. This option was not accepted because of the high cost effectiveness.

The third regulatory option that was evaluated for transmission and storage facilities was Regulatory Option 3. The VOC cost effectiveness of this option was calculated to be $19,723 per ton of VOC. Again, because of the low VOC content of the processed gas, the regulatory option has a low VOC reduction. This cost was determined to be unreasonable and therefore this regulatory option was also rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.2 Nationwide Impacts of Regulatory Options

Regulatory Option 1 was selected as an option for setting standards for equipment leaks at processing plants. This option would require the implementation of an LDAR program using the subpart VVa requirements. For production facilities, 29 facilities per year are expected to be affected sources by the NSPS regulation annually. Table 8-20 provides a summary of the expected emission reductions from the implementation of this option.

Table 8-20. Nationwide Emission and Cost Analysis of Regulatory Options

Category	Estimated Number of Sources subject to NSPS	Facility Capital Cost ($)	Nationwide Emission Reductions (tpy)			VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
			VOC	Methane	HAP	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 2 (Subpart VVa LDAR Program)												
Processing Plants	29	$7,522	392	1,407	14.7	$3,352	$2,517	$931	$699	0.218	1.31	0.984

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APPENDIX A

E&P TANKS ANALYSIS FOR STORAGE VESSELS

Tank ID	**Sample Tank No. 1**	**Sample Tank No. 2**	**Sample Tank No. 3**	**Sample Tank No. 4**	**Sample Tank No. 5**	**Sample Tank No. 6**	**Sample Tank No. 7**	**Sample Tank No. 8**
E&P Tank Number	**Tank No. 58**	**Tank No. 59**	**Tank No. 60**	**Tank No. 61**	**Tank No. 62**	**Tank No. 63**	**Tank No. 64**	**Tank No. 65**
Total Emissions (tpy)	289.778	230.196	129.419	129.853	201.547	738.511	294.500	142.371
VOC Emissions (tpy)	43.734	111.414	101.853	63.343	154.313	578.379	205.794	89.728
Methane Emissions (tpy)	0.197	56.006	10.064	50.910	8.343	47.831	26.305	24.276
HAP Emissions (tpy)	**4.236**	**13.100**	**5.050**	**2.730**	**3.500**	**37.840**	**4.480**	**2.680**
Benzene	*0.828*	*6.343*	*0.501*	*0.285*	*0.051*	*7.568*	*0.116*	*0.219*
Toluene	*1.194*	*3.539*	*0.648*	*0.243*	*0.067*	*5.950*	*0.085*	*0.301*
E-Benzene	*0.041*	*0.083*	*0.040*	*0.008*	*0.002*	*0.086*	*0.006*	*0.020*
Xylenes	*0.165*	*0.327*	*0.233*	*0.066*	*0.046*	*0.679*	*0.018*	*0.152*
n-C6	*2.008*	*2.809*	*3.623*	*2.132*	*3.333*	*23.553*	*4.252*	*1.989*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	66	66	13	64	28	95	29	44
Separator Temperature (F)	83	90	110	74	78	118	60	71
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	83	90	110	74	78	118	60	71
C10+ SG	0.848	0.865	0.879	0.866	0.864	0.862	0.841	0.849
C10+ MW	234	237	294	301	281	312	224	349
API Gravity	**40.0**	**40.0**	**40.0**	**40.0**	**42.0**	**42.0**	**44.0**	**44.0**
Production Rate (bbl/day)	500	500	500	500	500	500	500	500
Reid Vapor Pressure (psia)	3.00	4.10	4.80	3.90	4.20	8.10	5.70	7.00
GOR (scf/bbl)	25.96	30.32	12.30	19.58	19.68	68.74	32.46	16.92
Heating Value of Vapor (Btu/s	398.80	1689.70	2486.42	1567.19	2261.27	2529.29	2162.56	2003.83
LP Oil Component	mol %							
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	5.0200	0.2700	0.0000	0.0800	0.0400	0.0000	0.0100	0.0200
N2	0.0000	0.0100	0.0000	0.0200	0.3100	0.0200	0.0200	0.0100
C1	0.0100	2.2600	0.4700	2.6500	0.4000	2.2500	1.1300	1.2900
C2	0.0400	1.2000	0.4800	0.3900	0.6500	3.1100	1.4100	1.0300
C3	0.2000	1.3200	1.5800	0.9200	1.7500	4.1100	3.2900	2.3000
i-C4	0.2800	0.7100	0.6200	0.9800	0.9200	1.3300	0.4500	1.1200
n-C4	0.4800	1.0800	2.6100	1.4700	2.4500	3.8100	4.0200	3.2200
i-C5	0.7600	1.2000	1.8100	2.0500	2.3900	2.5400	0.7000	2.3600
n-C5	0.7400	1.1300	2.9300	2.1600	2.9500	3.5100	4.0700	2.9600
C6	1.5100	2.0000	3.8800	3.4500	2.7600	3.0900	0.9600	3.0600
C7	4.6600	6.7600	10.7300	7.9400	10.8800	8.0100	5.5900	9.5000
C8	6.6100	9.4200	12.5300	9.6900	11.6400	7.6800	5.5200	11.5900
C9	4.8700	6.5600	6.9400	6.5600	6.1800	4.4400	4.2700	6.3200
C10+	70.1100	49.2600	47.3100	56.3900	52.0200	47.6400	63.0500	47.7200
Benzene	0.5700	4.9100	0.5800	0.4300	0.0700	1.3400	0.1600	0.3600
Toluene	2.1400	7.7900	1.9900	1.1000	0.2700	2.6800	0.3700	1.4900
E-Benzene	0.1700	0.4600	0.2900	0.1000	0.0200	0.0900	0.0700	0.2600
Xylenes	0.7600	2.0500	1.9000	0.9000	0.5500	0.8000	0.2500	2.2900
n-C6	1.0700	1.6100	3.3500	2.7200	3.7500	3.5500	4.6600	3.1000
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 9**	**Sample Tank No. 10**	**Sample Tank No. 11**	**Sample Tank No. 12**	**Sample Tank No. 13**	**Sample Tank No. 14**	**Sample Tank No. 15**
E&P Tank Number	**Tank No. 66**	**Tank No. 67**	**Tank No. 68**	**Tank No. 69**	**Tank No. 70**	**Tank No. 71**	**Tank No. 72**
Total Emissions (tpy)	357.688	134.789	314.446	505.131	306.443	256.029	1061.274
VOC Emissions (tpy)	243.348	79.118	224.158	437.555	252.987	204.571	987.647
Methane Emissions (tpy)	56.846	37.876	18.892	21.472	15.159	21.237	32.940
HAP Emissions (tpy)	**5.590**	**5.680**	**7.030**	**13.450**	**15.330**	**6.500**	**56.780**
Benzene	*0.244*	*1.308*	*0.242*	*0.119*	*1.048*	*0.464*	*5.791*
Toluene	*0.440*	*1.184*	*0.385*	*0.146*	*1.488*	*0.927*	*6.793*
E-Benzene	*0.039*	*0.029*	*0.043*	*0.019*	*0.062*	*0.051*	*0.303*
Xylenes	*0.208*	*0.488*	*0.167*	*0.162*	*0.734*	*0.590*	*4.255*
n-C6	*4.661*	*2.671*	*6.191*	*13.008*	*12.001*	*4.468*	*39.634*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	60	41	20	23	24	52	45
Separator Temperature (F)	60	72	68	85	114	108	140
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	60	72	68	85	114	108	140
C10+ SG	0.878	0.854	0.926	0.848	0.87	0.886	0.893
C10+ MW	270	270	290	275	274	269	277
API Gravity	**44.0**	**45.0**	**45.0**	**46.0**	**46.0**	**47.0**	**47.0**
Production Rate (bbl/day)	500	500	500	500	500	500	500
Reid Vapor Pressure (psia)	10.10	5.20	8.10	4.70	5.00	5.30	6.00
GOR (scf/bbl)	41.30	17.66	30.80	43.26	26.30	24.28	78.80
Heating Value of Vapor (Btu/s	2060.54	1812.87	2234.66	2651.81	2611.90	2491.55	3120.85
LP Oil Component							
H2S	0.0000	0.0000	0.0000	0.0500	0.0700	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0500	0.0400	0.3100	0.2400	0.1700	0.0000	0.0400
N2	0.0000	0.0100	0.0200	0.0100	0.0000	0.0000	0.0000
C1	2.3400	1.8400	0.6900	0.9400	0.6200	0.9700	1.2100
C2	1.5600	0.6100	0.9400	0.6600	0.5200	0.7700	0.7600
C3	3.8500	1.2700	2.7300	2.1500	1.6800	2.0200	2.9200
i-C4	1.3600	0.8900	1.7300	1.1100	0.9900	1.5500	4.1500
n-C4	3.9600	1.5600	3.9300	4.5400	3.1200	2.1400	3.0600
i-C5	3.1300	1.8000	3.8800	3.0600	2.4500	3.3400	3.9300
n-C5	4.0300	1.8800	4.1000	4.9800	3.4200	2.8800	3.0900
C6	3.6100	3.4300	5.1500	4.1100	4.4300	3.2600	4.9100
C7	7.7900	10.7400	12.0700	10.2100	8.8900	9.0800	13.0800
C8	13.7700	12.6900	18.2000	10.6800	18.5800	11.7900	14.6200
C9	4.8300	7.8700	8.8800	5.4300	8.7200	5.8500	7.6300
C10+	42.2300	43.0100	27.3600	45.2800	36.2600	49.3100	31.1400
Benzene	0.2400	1.5600	0.3000	0.0600	0.5300	0.3000	0.6900
Toluene	1.3400	3.8100	1.4700	0.2100	1.9700	1.6000	1.9400
E-Benzene	0.3200	0.2200	0.4400	0.0700	0.1900	0.2100	0.1900
Xylenes	1.9700	4.1900	1.9600	0.6700	2.5500	2.7300	2.9800
n-C6	3.6200	2.5800	5.8400	5.5400	4.8400	2.2000	3.6600
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 16**	**Sample Tank No. 17**	**Sample Tank No. 18**	**Sample Tank No. 19**	**Sample Tank No. 20**	**Sample Tank No. 21**
E&P Tank Number	**Tank No. 73**	**Tank No. 74**	**Tank No. 75**	**Tank No. 76**	**Tank No. 77**	**Tank No. 78**
Total Emissions (tpy)	464.597	214.658	1331.488	3972.618	540.533	1228.897
VOC Emissions (tpy)	383.349	135.482	1146.617	2331.105	399.555	940.078
Methane Emissions (tpy)	18.132	32.283	31.967	755.826	38.624	105.184
HAP Emissions (tpy)	**10.980**	**7.530**	**77.780**	**82.380**	**7.580**	**13.230**
Benzene	*0.222*	*1.269*	*7.661*	*12.470*	*2.447*	*0.543*
Toluene	*0.208*	*0.708*	*3.775*	*23.584*	*1.643*	*0.466*
E-Benzene	*0.058*	*0.019*	*0.113*	*0.056*	*0.051*	*0.006*
Xylenes	*0.193*	*0.411*	*0.929*	*0.635*	*0.256*	*0.052*
n-C6	*10.296*	*5.124*	*65.304*	*45.632*	*3.186*	*12.160*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	40	31	50	700	20	98
Separator Temperature (F)	76	76	125	100	48	40
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	76	76	125	100	48	40
C10+ SG	0.885	0.839	0.842	0.878	0.877	0.929
C10+ MW	318	296	287	178	179	324
API Gravity	**47.0**	**49.0**	**49.0**	**50.0**	**50.0**	**51.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	10.60	5.00	8.90	7.40	9.40	11.20
GOR (scf/bbl)	41.32	24.48	106.60	491.90	56.44	128.16
Heating Value of Vapor (Btu/s	2421.27	2045.68	2822.40	1916.15	2275.04	2279.83
LP Oil Component						
H2S	0.0000	0.0000	1.2800	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0400	0.0800	0.0300	0.4200	0.0100	0.0100
N2	0.8400	0.0100	0.0000	0.0700	0.0100	0.0400
C1	0.7800	1.4000	1.2700	15.3300	1.1400	3.2200
C2	0.7500	0.9700	2.0800	8.9600	1.6000	2.9500
C3	3.5300	1.3500	4.5700	8.2100	4.0100	6.4800
i-C4	2.0700	1.0500	1.8900	2.3100	2.3400	2.2000
n-C4	6.8800	2.4200	6.4800	4.1900	4.7300	8.5300
i-C5	5.0000	2.7100	3.8800	2.4300	4.1700	4.6800
n-C5	7.4800	3.2900	7.0400	2.3500	2.9700	7.4700
C6	4.1000	4.6900	3.0500	3.1100	4.3800	5.7300
C7	11.3200	11.3500	6.8200	8.4700	8.8100	15.8300
C8	11.7900	12.4100	7.7800	8.8400	12.3800	12.6400
C9	6.1100	9.3100	7.2300	3.7100	5.4900	4.0800
C10+	32.0700	36.0900	37.9300	23.5600	32.1400	18.1600
Benzene	0.1400	1.4000	0.8300	0.8200	2.8900	0.3400
Toluene	0.3800	2.3200	1.0200	4.6700	6.4200	1.0200
E-Benzene	0.2700	0.1600	0.0700	0.0300	0.5700	0.0400
Xylenes	1.0300	4.0200	0.6500	0.3900	3.3000	0.4000
n-C6	5.4200	4.9700	6.1000	2.1300	2.6400	6.1800
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 22**	**Sample Tank No. 23**	**Sample Tank No. 24**	**Sample Tank No. 25**	**Sample Tank No. 26**	**Sample Tank No. 27**
E&P Tank Number	**Tank No. 79**	**Tank No. 80**	**Tank No. 81**	**Tank No. 82**	**Tank No. 83**	**Tank No. 84**
Total Emissions (tpy)	362.298	790.092	557.188	5007.636	175.911	714.052
VOC Emissions (tpy)	175.304	665.349	483.599	3386.300	77.584	639.895
Methane Emissions (tpy)	109.676	24.115	10.288	842.206	54.660	18.553
HAP Emissions (tpy)	**7.150**	**28.770**	**14.580**	**101.610**	**4.770**	**30.190**
Benzene	*0.353*	*3.892*	*1.930*	*9.782*	*0.929*	*4.165*
Toluene	*0.102*	*6.465*	*1.651*	*12.547*	*0.909*	*2.542*
E-Benzene	*0.120*	*0.119*	*0.055*	*0.040*	*0.050*	*0.192*
Xylenes	*0.437*	*2.017*	*0.631*	*0.716*	*0.221*	*1.424*
n-C6	*6.133*	*16.273*	*10.317*	*78.528*	*2.665*	*21.871*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	115	30	15	770	39	38
Separator Temperature (F)	73	100	86	100	66	95
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	73	100	86	100	66	95
C10+ SG	0.873	0.901	0.878	0.858	0.854	0.823
C10+ MW	200	220	254	195	175	375
API Gravity	**54.0**	**54.0**	**54.0**	**55.0**	**57.0**	**57.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	5.30	9.40	10.30	7.80	5.70	9.60
GOR (scf/bbl)	51.34	68.32	47.12	578.20	25.46	57.38
Heating Value of Vapor (Btu/s	1678.80	2676.21	2764.90	2043.18	1632.00	2897.16
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0900	0.1100	0.0200	0.5500	0.0700	0.0400
N2	0.0300	0.0200	0.0100	0.0300	0.0000	0.0000
C1	3.5600	0.7100	0.3300	16.1500	1.7200	0.7000
C2	1.4300	1.5400	1.0900	7.1400	0.9000	1.0900
C3	1.8700	4.5900	3.8300	9.6600	1.3800	3.5600
i-C4	0.6800	2.3400	3.7000	3.8100	1.0000	2.9000
n-C4	2.0000	4.4400	4.8700	5.9600	1.4900	6.2100
i-C5	1.6600	3.9000	4.4800	3.5300	1.4600	6.0400
n-C5	2.0600	3.8000	3.9800	3.7200	1.5300	5.8400
C6	2.4100	5.0900	6.0500	3.8400	4.0600	7.3200
C7	15.0800	12.9700	15.6400	8.7600	14.5700	13.0000
C8	25.1900	19.0700	17.5800	8.9200	23.7200	12.2200
C9	12.4900	6.9500	6.1000	3.1000	13.7700	7.9600
C10+	24.3900	18.9200	21.1300	17.9300	20.9800	20.0200
Benzene	0.2400	1.2000	1.0500	0.5800	1.4900	1.2200
Toluene	0.2100	5.5400	2.6000	2.3000	4.5300	2.0500
E-Benzene	0.6600	0.2500	0.2200	0.0200	0.6700	0.3800
Xylenes	2.7600	4.8300	2.8900	0.4200	3.4200	3.2200
n-C6	3.1900	3.7300	4.4300	3.5800	3.2400	6.2300
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 28**	**Sample Tank No. 29**	**Sample Tank No. 30**	**Sample Tank No. 31**	**Sample Tank No. 32**	**Sample Tank No. 33**
E&P Tank Number	**Tank No. 85**	**Tank No. 86**	**Tank No. 87**	**Tank No. 88**	**Tank No. 89**	**Tank No. 90**
Total Emissions (tpy)	801.228	983.881	4326.573	3074.670	2951.879	616.490
VOC Emissions (tpy)	757.176	750.313	2406.579	1892.668	1439.584	332.126
Methane Emissions (tpy)	5.307	49.123	1088.727	746.499	999.175	120.918
HAP Emissions (tpy)	**29.510**	**14.080**	**58.180**	**47.230**	**44.040**	**9.140**
Benzene	*3.415*	*1.119*	*4.653*	*5.891*	*1.409*	*0.576*
Toluene	*5.329*	*1.453*	*5.785*	*6.575*	*2.934*	*1.658*
E-Benzene	*0.192*	*0.049*	*0.186*	*0.022*	*0.159*	*0.079*
Xylenes	*1.786*	*0.263*	*0.989*	*0.316*	*1.136*	*0.806*
n-C6	*18.788*	*11.194*	*46.561*	*34.427*	*38.406*	*6.016*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	65	54	870	600	780	60
Separator Temperature (F)	80	60	78	70	70	56
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	80	60	78	70	70	60
C10+ SG	0.899	0.868	0.868	0.847	0.905	0.905
C10+ MW	166	268	268	176	174	174
API Gravity	**57.0**	**57.0**	**57.0**	**57.0**	**58.0**	**58.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.80	13.10	13.10	7.50	8.00	8.00
GOR (scf/bbl)	61.26	97.00	578.20	396.24	436.98	79.54
Heating Value of Vapor (Btu/s	3046.83	2390.47	1789.23	1831.51	1633.60	1851.14
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0100	0.0800	0.4200	0.5800	0.2700	0.0800
N2	0.0000	0.0000	0.0800	0.0200	0.0200	0.0100
C1	0.1500	1.4800	21.2000	16.0200	20.3000	3.3900
C2	0.5700	2.9100	8.2900	4.1200	5.1800	2.4300
C3	2.4100	6.9600	8.5400	6.9000	5.6800	3.8400
i-C4	1.7300	2.6300	2.3000	2.7500	1.4200	1.3000
n-C4	3.5500	7.2100	5.8400	4.9100	4.1400	3.2000
i-C5	4.1400	4.6400	3.3500	3.6000	2.5400	2.4100
n-C5	3.8600	5.7100	4.0400	3.9000	3.1000	2.5600
C6	6.5100	5.0100	3.4200	3.9500	3.7700	3.7700
C7	18.7100	13.5500	9.1200	10.3800	11.2200	13.2600
C8	19.4300	15.0600	10.0900	11.3000	14.7500	22.4400
C9	6.8400	6.2300	4.1700	4.2100	7.0600	11.1300
C10+	15.5200	18.8400	12.5900	19.2800	13.5400	16.0600
Benzene	1.1800	0.5900	0.4000	0.8200	0.1800	0.4100
Toluene	5.2100	2.5000	1.6800	3.0600	1.2600	3.8600
E-Benzene	0.4600	0.2400	0.1600	0.0300	0.2000	0.5200
Xylenes	4.8600	1.4900	1.0000	0.5000	1.6700	6.1500
n-C6	4.8600	4.8700	3.3100	3.6700	3.7000	3.1800
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 34**	**Sample Tank No. 35**	**Sample Tank No. 36**	**Sample Tank No. 37**	**Sample Tank No. 38**	**Sample Tank No. 39**
E&P Tank Number	**Tank No. 91**	**Tank No. 92**	**Tank No. 93**	**Tank No. 94**	**Tank No. 95**	**Tank No. 96**
Total Emissions (tpy)	2575.122	2774.089	653.459	3495.242	363.650	4744.399
VOC Emissions (tpy)	1494.749	2092.925	394.781	2876.860	223.772	3658.384
Methane Emissions (tpy)	581.208	346.071	121.446	169.818	84.912	381.967
HAP Emissions (tpy)	**65.980**	**48.710**	**14.210**	**93.030**	**10.760**	**89.970**
Benzene	*9.303*	*2.750*	*0.871*	*10.232*	*0.500*	*11.564*
Toluene	*14.114*	*2.311*	*2.688*	*11.558*	*0.279*	*11.735*
E-Benzene	*0.019*	*0.128*	*0.136*	*0.034*	*0.060*	*0.033*
Xylenes	*0.409*	*0.872*	*1.400*	*0.580*	*0.256*	*0.472*
n-C6	*42.130*	*42.650*	*9.111*	*70.629*	*9.661*	*66.162*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	500	300	110	750	85	730
Separator Temperature (F)	84	80	72	90	85	84
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	84	80	72	90	85	84
C10+ SG	0.909	0.882	0.901	0.898	0.9	0.898
C10+ MW	204	296	162	215	202	225
API Gravity	**58.0**	**58.0**	**59.0**	**60.0**	**61.0**	**61.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	9.10	10.60	10.00	9.40	7.00	9.80
GOR (scf/bbl)	323.88	287.10	79.90	320.48	45.04	475.20
Heating Value of Vapor (Btu/s	1892.64	2289.04	1946.32	2541.49	1921.87	2340.56
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.2300	0.0300	0.0800	0.3400	0.0400	0.4100
N2	0.0600	0.0900	0.0100	0.0200	0.0200	0.0300
C1	12.9800	8.4300	3.3900	3.7500	2.6100	7.3900
C2	5.7800	4.2300	2.4300	4.7700	1.1600	6.6400
C3	4.6400	5.9100	3.8400	9.2600	2.2100	10.9400
i-C4	2.0900	5.1700	1.3000	4.8100	0.9300	4.5800
n-C4	4.1800	6.2200	3.2000	7.0200	2.4900	8.3400
i-C5	4.9600	8.9100	2.4100	5.5900	2.1300	5.5000
n-C5	4.0700	4.9700	2.5600	6.1200	2.9200	5.8200
C6	6.0700	9.1100	3.7700	6.1300	3.5400	5.3200
C7	13.1100	11.3400	13.2600	12.8200	19.5300	11.2900
C8	11.9500	10.3900	22.4400	12.5200	27.1600	11.1800
C9	4.8600	5.9600	11.1300	4.0100	14.7000	3.1900
C10+	14.1100	11.7500	16.0600	11.4200	13.8800	8.8000
Benzene	1.1400	0.3700	0.4100	1.1000	0.2900	1.1400
Toluene	5.4100	0.9800	3.8600	3.7900	0.4700	3.7600
E-Benzene	0.0200	0.1500	0.5200	0.0300	0.2600	0.0300
Xylenes	0.5000	1.1900	6.1500	0.5900	1.2600	0.5000
n-C6	3.8400	4.8000	3.1800	5.9100	4.4000	5.1400
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 40**	**Sample Tank No. 41**	**Sample Tank No. 42**	**Sample Tank No. 43**	**Sample Tank No. 44**	**Sample Tank No. 45**
E&P Tank Number	**Tank No. 97**	**Tank No. 98**	**Tank No. 99**	**Tank No. 100**	**Tank No. 101**	**Tank No. 102**
Total Emissions (tpy)	907.495	277.197	3410.034	2122.607	8152.118	6780.555
VOC Emissions (tpy)	734.651	158.333	2732.261	1066.705	5678.554	4276.160
Methane Emissions (tpy)	49.578	75.426	159.904	736.341	1206.981	1045.765
HAP Emissions (tpy)	**24.160**	**8.820**	**67.500**	**64.680**	**81.710**	**48.890**
Benzene	*1.573*	*0.204*	*9.290*	*9.500*	*10.844*	*5.934*
Toluene	*3.102*	*0.854*	*9.192*	*15.007*	*8.516*	*1.416*
E-Benzene	*0.094*	*0.042*	*0.016*	*0.161*	*0.012*	*0.222*
Xylenes	*1.079*	*0.375*	*0.371*	*1.585*	*0.288*	*1.359*
n-C6	*18.314*	*7.344*	*48.628*	*38.425*	*62.050*	*39.961*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	57	72	730	580	730	807
Separator Temperature (F)	82	80	80	77	80	96
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	82	80	80	77	80	96
C10+ SG	0.884	0.869	0.883	0.85	0.895	0.811
C10+ MW	240	190	226	190	197	173
API Gravity	**62.0**	**63.0**	**63.0**	**64.0**	**64.0**	**66.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	10.40	7.00	11.90	6.40	11.00	11.80
GOR (scf/bbl)	84.20	36.56	321.62	309.64	924.96	804.54
Heating Value of Vapor (Btu/s	2521.70	1805.12	2477.18	1622.20	2083.02	2013.21
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0800	0.0400	0.3200	0.0700	0.5600	0.2200
N2	0.0100	0.0300	0.0200	0.0700	0.0300	0.0800
C1	1.4000	2.3500	3.4800	16.3500	16.9100	16.2600
C2	1.7700	1.0000	5.5300	3.6400	8.6200	11.7100
C3	4.8200	2.0700	10.1700	3.5600	12.0400	11.6100
i-C4	2.8200	0.7100	4.9900	1.6900	5.2700	4.3900
n-C4	5.9700	2.2600	8.1400	2.9800	9.0700	7.5600
i-C5	4.3100	1.7000	5.8700	2.6800	5.6500	4.5200
n-C5	4.1900	2.7400	6.1600	2.7900	5.8200	3.9400
C6	6.5100	3.4900	5.7200	3.8200	5.1000	3.3600
C7	17.7500	17.7300	12.3800	18.1400	8.0600	5.9200
C8	18.6400	27.9100	12.3100	19.4700	7.5500	11.6900
C9	7.4400	16.1500	3.7900	4.5900	2.2200	5.9200
C10+	11.6100	12.2800	9.9100	6.7300	5.6700	8.9300
Benzene	0.5600	0.1600	1.2800	1.2200	0.8500	0.3700
Toluene	3.2800	1.9800	4.0500	6.0700	2.3800	0.3000
E-Benzene	0.2600	0.2500	0.0200	0.1800	0.0100	0.1400
Xylenes	3.4100	2.5800	0.5300	2.0600	0.2900	1.0100
n-C6	5.1700	4.5700	5.3300	3.8900	3.9000	2.0700
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 46**	**Sample Tank No. 47**	**Sample Tank No. 48**	**Sample Tank No. 49**	**Sample Tank No. 50**	**Sample Tank No. 51**
E&P Tank Number	**Tank No. 103**	**Tank No. 1**	**Tank No. 2**	**Tank No. 3**	**Tank No. 4**	**Tank No. 5**
Total Emissions (tpy)	927.902	95.816	112.738	74.503	155.244	93.073
VOC Emissions (tpy)	623.038	6.175	61.936	28.446	61.470	51.471
Methane Emissions (tpy)	167.129	0.115	1.927	0.309	46.064	0.440
HAP Emissions (tpy)	**20.320**	**0.460**	**2.960**	**0.990**	**1.760**	**3.190**
Benzene	*1.625*	*0.006*	*0.076*	*0.012*	*0.010*	*0.218*
Toluene	*1.876*	*0.013*	*0.060*	*0.031*	*0.037*	*0.074*
E-Benzene	*0.062*	*0.007*	*0.019*	*0.002*	*0.025*	*0.006*
Xylenes	*0.696*	*0.018*	*0.105*	*0.041*	*0.069*	*0.048*
n-C6	*16.059*	*0.421*	*2.704*	*0.904*	*1.616*	*2.845*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	170	45	22	20	53	15
Separator Temperature (F)	75	106	155	160	101	120
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	75	106	155	160	101	120
C10+ SG	0.801	0.972	0.972	0.952	0.961	0.984
C10+ MW	196	425	436	458	394	551
API Gravity	**68.0**	**15.0**	**17.0**	**18.0**	**19.0**	**19.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	12.50	0.80	2.00	0.60	2.30	4.80
GOR (scf/bbl)	106.60	8.88	9.60	6.44	17.78	7.52
Heating Value of Vapor (Btu/s	2081.33	181.43	1738.61	1076.97	1365.68	1718.17
LP Oil Component						
H2S	0.0000	0.1100	0.0000	0.0400	0.5100	0.1400
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0100	2.8500	1.3000	1.5400	1.1900	1.5000
N2	0.0100	0.0000	0.0000	0.0300	0.0100	0.0000
C1	4.9300	0.0100	0.1500	0.0300	1.5300	0.0400
C2	2.5800	0.0100	0.4000	0.0400	0.5300	0.2400
C3	3.4200	0.0200	0.7800	0.2200	0.8100	0.8500
i-C4	3.4300	0.0500	0.5600	0.1600	0.5000	0.6500
n-C4	3.7300	0.1800	1.2600	0.4700	1.2000	1.6500
i-C5	5.5500	0.3200	0.8700	0.4300	1.1500	2.1900
n-C5	3.6500	0.4500	1.2400	0.6500	1.3400	3.1500
C6	8.0700	0.6000	1.9800	0.6100	1.7500	4.7300
C7	14.6500	1.7200	3.4500	1.5800	3.6200	6.2500
C8	13.2600	2.1800	4.2600	2.0700	3.5300	10.2800
C9	7.8000	1.8400	3.6600	2.2800	3.5300	5.9300
C10+	19.6300	88.7100	78.1500	88.9700	76.8100	57.9100
Benzene	0.5400	0.0100	0.0500	0.0100	0.0100	0.3000
Toluene	1.9200	0.0600	0.0900	0.0600	0.1000	0.2600
E-Benzene	0.1700	0.0800	0.0600	0.0100	0.1600	0.0500
Xylenes	2.2200	0.2300	0.3700	0.1800	0.5100	0.4300
n-C6	4.4300	0.5700	1.3700	0.6200	1.2100	3.4500
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 52**	**Sample Tank No. 53**	**Sample Tank No. 54**	**Sample Tank No. 55**	**Sample Tank No. 56**	**Sample Tank No. 57**
E&P Tank Number	**Tank No. 6**	**Tank No. 7**	**Tank No. 8**	**Tank No. 9**	**Tank No. 10**	**Tank No. 11**
Total Emissions (tpy)	24.484	26.091	29.739	114.630	42.075	
VOC Emissions (tpy)	3.087	17.629	11.288	74.707	8.263	
Methane Emissions (tpy)	15.587	2.836	5.908	25.400	27.176	
HAP Emissions (tpy)	**0.190**	**0.510**	**0.330**	**2.120**	**0.090**	
Benzene	*0.003*	*0.007*	*0.013*	*0.039*	*0.028*	
Toluene	*0.006*	*0.014*	*0.008*	*0.071*	*0.010*	
E-Benzene	*0.000*	*0.001*	*0.003*	*0.007*	*0.000*	
Xylenes	*0.005*	*0.012*	*0.007*	*0.090*	*0.001*	
n-C6	*0.175*	*0.474*	*0.298*	*1.919*	*0.052*	
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	
Separator Pressure (psig)	23	17	18	54	35	
Separator Temperature (F)	79	106	75	125	76	
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	
Ambient Temperature (F)	79	106	75	125	76	
C10+ SG	0.947	0.967	0.963	0.943	0.923	
C10+ MW	368	383	401	363	278	
API Gravity	**20.0**	**20.0**	**20.0**	**21.0**	**23.0**	
Production Rate (bbl/day)	500	500	500	500	500	
Reid Vapor Pressure (psia)	1.20	3.30	3.80	1.10	1.80	
GOR (scf/bbl)	4.98	2.82	3.94	13.90	8.52	
Heating Value of Vapor (Btu/s	1067.32	2208.23	1236.41	1980.20	1192.63	
LP Oil Component						
H2S	0.0100	0.0000	0.0000	0.0000	0.0000	
O2	0.0000	0.0000	0.0000	0.0000	0.0000	
CO2	0.0700	0.0000	0.2500	0.0000	0.0600	
N2	0.0900	0.0000	0.2100	0.0100	0.0100	
C1	1.2500	0.1900	0.5300	1.8000	1.7700	
C2	0.2000	0.2300	0.3300	0.5400	0.2900	
C3	0.0800	0.7500	0.7500	0.5200	0.3700	
i-C4	0.0900	0.4900	0.4900	0.2800	0.2300	
n-C4	0.1800	1.5700	1.5000	0.9200	0.3100	
i-C5	0.4000	1.5300	1.3500	0.9800	0.4900	
n-C5	0.4500	1.9100	1.7700	0.9700	0.2400	
C6	1.0500	2.7500	2.3700	1.6800	0.2500	
C7	2.3300	3.9000	4.3000	3.0100	0.5900	
C8	2.9800	6.8100	5.5200	3.7300	0.5000	
C9	2.6000	4.0100	3.5700	3.5400	0.2500	
C10+	87.0300	73.0300	74.2800	80.2500	94.2100	
Benzene	0.0200	0.0400	0.1000	0.0300	0.1100	
Toluene	0.1100	0.2200	0.1900	0.1400	0.1200	
E-Benzene	0.0200	0.0500	0.1900	0.0300	0.0100	
Xylenes	0.2700	0.5100	0.4700	0.4500	0.0500	
n-C6	0.7700	2.0100	1.8300	1.1200	0.1400	
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	
	100.0000	100.0000	100.0000	100.0000	100.0000	0.0000

Tank ID	**Sample Tank No. 58**	**Sample Tank No. 59**	**Sample Tank No. 60**	**Sample Tank No. 61**	**Sample Tank No. 62**	**Sample Tank No. 63**
E&P Tank Number	**Tank No. 12**	**Tank No. 13**	**Tank No. 14**	**Tank No. 15**	**Tank No. 16**	**Tank No. 17**
Total Emissions (tpy)	134.719	26.214	195.573	142.068	191.224	35.095
VOC Emissions (tpy)	63.729	5.207	109.615	69.135	105.838	25.578
Methane Emissions (tpy)	16.689	12.924	7.759	5.438	4.313	3.029
HAP Emissions (tpy)	**1.170**	**0.430**	**2.810**	**1.760**	**2.110**	**0.750**
Benzene	*0.020*	*0.008*	*0.033*	*0.024*	*0.041*	*0.011*
Toluene	*0.014*	*0.032*	*0.032*	*0.053*	*0.079*	*0.022*
E-Benzene	*0.007*	*0.002*	*0.023*	*0.003*	*0.003*	*0.003*
Xylenes	*0.027*	*0.019*	*0.064*	*0.041*	*0.016*	*0.011*
n-C6	*1.104*	*0.371*	*2.659*	*1.640*	*1.969*	*0.701*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	30	20	20	22	20	19
Separator Temperature (F)	66	122	88	86	68	133
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	66	122	88	86	68	133
C10+ SG	0.946	0.926	0.945	0.944	0.964	0.928
C10+ MW	382	336	381	404	444	327
API Gravity	**23.0**	**24.0**	**24.0**	**24.0**	**24.0**	**25.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.00	0.60	3.90	4.60	4.80	4.10
GOR (scf/bbl)	15.42	4.60	19.12	13.74	17.84	3.48
Heating Value of Vapor (Btu/s	1553.86	1059.39	1747.39	1543.44	1703.42	2314.31
LP Oil Component						
H2S	0.4400	0.0000	0.5200	0.4500	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.6400	0.1200	0.9600	1.1500	1.4200	0.0500
N2	0.0100	0.1000	0.1200	0.0200	0.0200	0.0000
C1	1.0700	0.9400	0.4900	0.3600	0.2700	0.2500
C2	0.5400	0.0500	0.6500	0.5000	0.6200	0.4900
C3	1.4100	0.0700	1.7300	1.5900	1.9400	1.1600
i-C4	0.7000	0.0600	0.7400	0.7600	1.1000	0.6000
n-C4	1.9400	0.1000	2.4600	2.4000	3.0100	1.5900
i-C5	1.8900	0.2400	1.7900	1.7300	2.1900	1.4300
n-C5	2.3600	0.2300	2.3100	2.1400	3.2100	1.4400
C6	2.7100	0.9100	2.6100	2.6400	3.9300	1.9900
C7	5.1800	2.8000	5.3300	5.5200	5.6800	3.5100
C8	5.3700	4.2200	5.5400	6.0700	11.3000	4.4100
C9	3.9800	4.3400	4.2100	4.6000	6.7600	4.4400
C10+	68.6500	84.5400	67.0700	66.9000	54.5000	76.8100
Benzene	0.0500	0.0200	0.0400	0.0400	0.0800	0.0300
Toluene	0.1100	0.2100	0.1100	0.2600	0.4700	0.1500
E-Benzene	0.1500	0.0300	0.2000	0.0400	0.0400	0.0400
Xylenes	0.6500	0.3100	0.6300	0.5800	0.2900	0.1800
n-C6	2.1500	0.7100	2.4900	2.2500	3.1700	1.4300
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 64**	**Sample Tank No. 65**	**Sample Tank No. 66**	**Sample Tank No. 67**	**Sample Tank No. 68**	**Sample Tank No. 69**
E&P Tank Number	**Tank No. 18**	**Tank No. 19**	**Tank No. 20**	**Tank No. 21**	**Tank No. 22**	**Tank No. 23**
Total Emissions (tpy)	139.887	70.761	171.538	38.394	215.631	148.757
VOC Emissions (tpy)	89.426	46.290	110.120	12.834	164.956	138.780
Methane Emissions (tpy)	21.590	4.142	15.382	16.424	8.875	1.515
HAP Emissions (tpy)	**1.190**	**2.570**	**1.670**	**0.720**	**4.240**	**5.310**
Benzene	*0.011*	*0.371*	*0.013*	*0.224*	*0.985*	*1.086*
Toluene	*0.035*	*0.697*	*0.017*	*0.209*	*0.787*	*0.854*
E-Benzene	*0.010*	*0.039*	*0.004*	*0.007*	*0.020*	*0.025*
Xylenes	*0.025*	*0.176*	*0.025*	*0.066*	*0.118*	*0.122*
n-C6	*1.109*	*1.292*	*1.613*	*0.216*	*2.331*	*3.227*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	30	25	31	23	17	20
Separator Temperature (F)	60	136	64	79	86	120
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	60	136	64	79	86	120
C10+ SG	0.94	0.916	0.938	0.908	0.946	0.932
C10+ MW	380	431	340	324	323	326
API Gravity	**25.0**	**27.0**	**27.0**	**29.0**	**29.0**	**29.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.90	3.30	5.20	3.10	4.80	4.90
GOR (scf/bbl)	16.66	6.76	18.46	6.36	20.11	11.50
Heating Value of Vapor (Btu/s	1966.88	2041.97	1887.18	1405.21	2354.30	2985.81
LP Oil Component						
H2S	0.0000	0.3800	0.2400	0.0000	0.2700	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0600	0.2200	0.2100	0.0900	0.0800	0.0300
N2	0.0400	0.1000	0.3000	0.0000	0.0000	0.0000
C1	1.3500	0.3200	0.8600	1.1200	0.4400	0.0800
C2	0.8500	0.4100	0.5400	0.5300	0.7000	0.2000
C3	2.0900	1.0700	1.7500	0.7000	2.0600	1.3000
i-C4	1.1400	0.5700	1.1600	0.4500	0.9700	1.0400
n-C4	2.7100	1.4500	3.1500	0.6300	2.7500	3.8800
i-C5	2.1900	1.5700	2.9100	0.6400	2.7000	2.2100
n-C5	2.4600	1.5100	2.5900	0.4600	2.3200	3.2000
C6	2.2400	2.5400	3.7200	0.8400	3.5000	2.5500
C7	5.7900	3.5300	5.8600	4.7900	8.3100	7.2000
C8	4.7900	4.9600	5.6200	8.9000	7.2900	7.2300
C9	4.4800	4.1700	3.7300	5.8000	7.0500	4.7500
C10+	66.3000	72.0600	63.8500	67.7100	53.9500	59.2600
Benzene	0.0300	0.4300	0.0300	1.0000	1.2400	1.1600
Toluene	0.2900	1.9600	0.1200	2.7600	2.8500	2.3500
E-Benzene	0.2200	0.2400	0.0800	0.2400	0.1800	0.1600
Xylenes	0.6500	1.2100	0.5400	2.5900	1.2300	0.8600
n-C6	2.3200	1.3000	2.7400	0.7500	2.1100	2.5400
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 70**	**Sample Tank No. 71**	**Sample Tank No. 72**	**Sample Tank No. 73**	**Sample Tank No. 74**	**Sample Tank No. 75**
E&P Tank Number	**Tank No. 24**	**Tank No. 25**	**Tank No. 26**	**Tank No. 27**	**Tank No. 28**	**Tank No. 29**
Total Emissions (tpy)	243.873	502.831	13.397	154.387	119.805	263.134
VOC Emissions (tpy)	151.292	330.274	4.231	125.001	48.333	168.558
Methane Emissions (tpy)	7.881	124.465	6.395	4.603	45.716	54.016
HAP Emissions (tpy)	**2.480**	**13.120**	**0.070**	**10.900**	**1.090**	**3.440**
Benzene	*0.188*	*0.954*	*0.008*	*0.053*	*0.189*	*0.435*
Toluene	*0.276*	*1.256*	*0.003*	*0.110*	*0.076*	*0.413*
E-Benzene	*0.007*	*0.086*	*0.000*	*0.031*	*0.004*	*0.046*
Xylenes	*0.114*	*0.732*	*0.008*	*0.305*	*0.033*	*0.285*
n-C6	*1.896*	*10.096*	*0.055*	*10.401*	*0.785*	*2.257*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	22	280	4	25	64	80
Separator Temperature (F)	98	106	80	180	70	77
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	98	106	80	180	70	77
C10+ SG	0.917	0.921	0.893	0.916	0.898	0.896
C10+ MW	311	450	313	304	368	309
API Gravity	**29.0**	**30.0**	**30.0**	**30.0**	**30.0**	**33.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	6.20	4.80	2.60	2.70	2.80	2.20
GOR (scf/bbl)	24.26	61.80	2.34	11.76	18.78	32.78
Heating Value of Vapor (Btu/s	2141.84	1933.26	1394.74	2814.20	1478.45	1920.70
LP Oil Component						
H2S	1.0100	0.0000	0.0000	0.0300	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.1100	0.1200	0.0200	0.2700	0.1700	0.0300
N2	0.0000	0.0500	0.0000	0.0000	0.0200	0.0200
C1	0.4000	7.9800	0.5900	0.2600	3.1300	2.9000
C2	1.6600	1.5600	0.4000	0.4800	0.7000	1.1000
C3	2.2300	2.8200	0.5500	0.8100	1.0700	1.7100
i-C4	1.1500	1.4300	0.4500	0.3600	0.8800	1.0700
n-C4	1.9500	2.4400	0.6300	1.1800	1.1100	1.1500
i-C5	2.8400	2.1200	0.4800	1.2900	1.0500	1.5000
n-C5	1.3600	2.0900	0.4500	2.0600	1.0000	1.2300
C6	3.0700	2.5400	1.0000	2.6800	1.5300	2.3300
C7	6.9000	6.3500	4.3100	6.5200	4.4300	6.0000
C8	7.6500	8.0300	4.9000	7.3900	5.8900	8.7700
C9	5.8200	3.5600	4.1700	4.8600	4.2200	6.3100
C10+	61.2100	54.9600	80.5100	68.2000	72.4400	60.3600
Benzene	0.1500	0.2000	0.0900	0.0200	0.3100	0.3800
Toluene	0.6100	0.6800	0.1100	0.0900	0.3800	1.0700
E-Benzene	0.0400	0.1100	0.0200	0.0500	0.0500	0.3100
Xylenes	0.7000	1.0600	0.8100	0.5400	0.5000	2.2000
n-C6	1.1400	1.9000	0.5100	2.9100	1.1200	1.5600
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 76**	**Sample Tank No. 77**	**Sample Tank No. 78**	**Sample Tank No. 79**	**Sample Tank No. 80**	**Sample Tank No. 81**
E&P Tank Number	**Tank No. 30**	**Tank No. 31**	**Tank No. 32**	**Tank No. 33**	**Tank No. 34**	**Tank No. 35**
Total Emissions (tpy)	75.697	67.111	33.481	98.139	246.837	206.565
VOC Emissions (tpy)	48.997	21.176	9.640	41.538	186.576	136.694
Methane Emissions (tpy)	15.026	39.198	18.906	45.393	13.777	5.258
HAP Emissions (tpy)	**1.330**	**0.460**	**0.290**	**1.230**	**7.150**	**4.120**
Benzene	*0.115*	*0.055*	*0.025*	*0.118*	*1.477*	*0.060*
Toluene	*0.088*	*0.025*	*0.040*	*0.085*	*1.336*	*0.122*
E-Benzene	*0.010*	*0.002*	*0.004*	*0.008*	*0.030*	*0.010*
Xylenes	*0.038*	*0.011*	*0.023*	*0.165*	*0.263*	*0.100*
n-C6	*1.075*	*0.362*	*0.196*	*0.852*	*4.047*	*3.833*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	20	60	18	40	18	15
Separator Temperature (F)	115	78	70	110	80	108
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	115	78	70	110	80	108
C10+ SG	0.885	0.866	0.875	0.87	0.923	0.887
C10+ MW	280	324	277	297	346	272
API Gravity	**33.0**	**34.0**	**34.0**	**34.0**	**35.0**	**35.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	3.10	2.00	2.20	3.20	4.70	4.50
GOR (scf/bbl)	8.96	12.60	6.20	16.18	24.36	18.78
Heating Value of Vapor (Btu/s	1989.27	1308.40	1280.62	1473.81	2361.43	2135.62
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0100	0.0500
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0300	0.0500	0.0700	0.0400	0.0600	0.6100
N2	0.0000	0.0000	0.0000	0.0100	0.0100	0.0500
C1	0.8400	2.8100	1.1600	2.9100	0.6400	0.2600
C2	0.3700	0.3100	0.2400	0.4400	1.0500	0.7800
C3	0.9200	0.6200	0.4900	0.6800	2.2200	1.7400
i-C4	1.0000	0.4700	0.4300	0.5800	0.8300	0.8400
n-C4	1.3200	0.7300	0.6500	0.6300	2.7600	2.3700
i-C5	1.3500	0.7100	0.8000	0.5300	2.1100	2.2400
n-C5	1.2200	0.6600	0.7000	0.4900	3.1100	2.2500
C6	1.8500	1.0800	1.2900	0.8900	3.5800	3.1500
C7	4.6800	2.3500	3.6200	4.6300	11.4200	6.1800
C8	5.5400	2.9600	5.5500	5.3100	11.2400	6.7100
C9	3.8000	1.9300	3.8000	4.5800	8.3200	5.0700
C10+	74.8700	84.1900	78.1200	76.3800	40.2000	64.3300
Benzene	0.1700	0.1100	0.1400	0.1000	1.6600	0.0500
Toluene	0.3400	0.1500	0.6900	0.1900	4.4100	0.2700
E-Benzene	0.0900	0.0300	0.1800	0.0400	0.2500	0.0500
Xylenes	0.3900	0.2000	1.2000	0.9800	2.5500	0.5900
n-C6	1.2200	0.6400	0.8700	0.5900	3.5700	2.4100
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 82**	**Sample Tank No. 83**	**Sample Tank No. 84**	**Sample Tank No. 85**	**Sample Tank No. 86**	**Sample Tank No. 87**
E&P Tank Number	**Tank No. 36**	**Tank No. 37**	**Tank No. 38**	**Tank No. 39**	**Tank No. 40**	**Tank No. 41**
Total Emissions (tpy)	176.370	34.019	82.578	113.253	204.693	178.190
VOC Emissions (tpy)	121.493	16.601	32.683	56.649	107.904	100.629
Methane Emissions (tpy)	10.526	12.380	40.189	30.738	57.039	28.323
HAP Emissions (tpy)	**3.520**	**1.050**	**1.820**	**2.310**	**3.540**	**2.460**
Benzene	*0.068*	*0.262*	*0.364*	*0.285*	*0.530*	*0.307*
Toluene	*0.092*	*0.297*	*0.293*	*0.292*	*0.386*	*0.280*
E-Benzene	*0.019*	*0.011*	*0.016*	*0.018*	*0.030*	*0.012*
Xylenes	*0.072*	*0.048*	*0.125*	*0.138*	*0.208*	*0.068*
n-C6	*3.266*	*0.435*	*1.023*	*1.573*	*2.383*	*1.789*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	17	30	50	57	75	28
Separator Temperature (F)	100	125	68	80	81	60
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	100	125	68	80	81	60
C10+ SG	0.887	0.863	0.879	0.883	0.883	0.891
C10+ MW	283	276	356	294	288	277
API Gravity	**35.0**	**36.0**	**36.0**	**36.0**	**36.0**	**36.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.90	2.50	3.80	3.90	4.10	3.80
GOR (scf/bbl)	17.62	5.02	14.02	15.52	27.84	22.04
Heating Value of Vapor (Btu/s	2307.25	1616.36	1437.32	1721.01	1718.90	1846.39
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.2000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0900	0.0300	0.0300	0.0600	0.1400	0.0600
N2	0.0100	0.0000	0.0100	0.0100	0.0100	0.0100
C1	0.5300	0.9100	2.4200	1.5900	2.9000	1.3300
C2	1.1100	0.3200	0.4500	0.7200	0.9500	0.9300
C3	1.7600	0.5700	0.8100	1.1100	1.4500	1.7200
i-C4	0.8000	0.3900	0.5400	0.7700	1.0000	0.4400
n-C4	2.3800	0.5800	1.1700	1.6000	1.8400	1.9800
i-C5	2.1600	0.6500	1.3400	1.5200	1.6700	1.2300
n-C5	2.6700	0.5700	1.6000	1.6700	1.7900	2.2100
C6	3.3700	1.0700	2.4800	2.5900	2.1500	2.4300
C7	6.0700	3.3600	7.6400	7.1400	6.1000	9.4100
C8	6.8700	5.7300	10.3500	9.7000	7.9700	10.5500
C9	6.0400	4.2600	5.9100	5.1000	5.2600	6.0500
C10+	62.5300	77.9200	57.3100	59.8700	61.4100	54.5600
Benzene	0.0700	0.5500	0.8300	0.5000	0.5100	0.6300
Toluene	0.2600	1.5800	2.0500	1.5100	1.0900	1.8200
E-Benzene	0.1300	0.1300	0.2900	0.2400	0.2200	0.2100
Xylenes	0.5600	0.6500	2.6900	2.1000	1.7300	1.4100
n-C6	2.5900	0.7300	2.0800	2.2000	1.8100	2.8200
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 88**	**Sample Tank No. 89**	**Sample Tank No. 90**	**Sample Tank No. 91**	**Sample Tank No. 92**	**Sample Tank No. 93**
E&P Tank Number	**Tank No. 42**	**Tank No. 43**	**Tank No. 44**	**Tank No. 45**	**Tank No. 46**	**Tank No. 47**
Total Emissions (tpy)	264.744	77.810	341.571	746.422	120.452	114.826
VOC Emissions (tpy)	197.667	45.796	126.289	598.797	71.033	53.659
Methane Emissions (tpy)	4.156	20.047	121.935	12.450	24.855	41.873
HAP Emissions (tpy)	**5.070**	**1.720**	**2.060**	**7.990**	**1.310**	**1.960**
Benzene	*0.536*	*0.269*	*0.294*	*3.587*	*0.126*	*0.496*
Toluene	*6.120*	*0.232*	*0.161*	*0.449*	*0.199*	*0.291*
E-Benzene	*0.040*	*0.014*	*0.036*	*0.061*	*0.009*	*0.009*
Xylenes	*0.205*	*0.121*	*0.106*	*0.072*	*0.077*	*0.052*
n-C6	*3.677*	*1.081*	*1.462*	*3.820*	*0.900*	*1.109*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	18	18	190	22	24	60
Separator Temperature (F)	95	98	70	50	68	72
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	95	98	70	50	68	72
C10+ SG	0.9	0.871	0.861	0.918	0.872	0.863
C10+ MW	288	270	270	372	239	318
API Gravity	**36.0**	**37.0**	**37.0**	**37.0**	**38.0**	**38.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	7.20	3.90	3.00	4.90	3.60	4.50
GOR (scf/bbl)	23.68	10.02	53.74	67.22	15.46	17.44
Heating Value of Vapor (Btu/s	2352.89	1820.80	1489.35	2491.03	1867.10	1590.85
LP Oil Component						
H2S	0.8700	0.0000	0.0000	0.1400	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.1200	0.0500	0.3100	0.5300	0.0200	0.0500
N2	0.0200	0.0000	0.0300	0.0000	0.0000	0.0000
C1	0.1900	1.0400	6.2500	0.5600	1.1400	2.5500
C2	0.6800	0.4200	2.2000	2.3100	0.5800	0.8600
C3	2.5400	0.9700	2.0200	4.1000	1.2600	1.3500
i-C4	1.1400	1.1500	0.5500	1.9100	0.9300	0.9700
n-C4	3.8100	1.3100	1.1800	5.0000	1.4400	1.3600
i-C5	2.9900	1.6600	0.8300	3.4000	1.6100	1.4200
n-C5	2.9100	1.2800	0.7100	3.5100	1.3900	1.3400
C6	3.7100	2.1200	1.3200	3.0200	2.3200	2.1100
C7	9.0500	5.2700	3.8300	13.2800	6.5000	5.5300
C8	7.1100	7.7200	6.7800	13.1300	8.7200	7.6500
C9	5.9500	4.7200	2.8000	5.9600	5.9100	5.6600
C10+	52.8400	67.1300	69.1900	36.1900	62.7500	64.2400
Benzene	0.4700	0.5000	0.1800	2.6100	0.3100	0.8400
Toluene	1.5000	1.1900	0.3000	1.0600	1.5000	1.4900
E-Benzene	0.2400	0.1800	0.1800	0.4000	0.1800	0.1200
Xylenes	1.4100	1.7200	0.6100	0.5500	1.7900	0.8100
n-C6	2.4500	1.5700	0.7300	2.3400	1.6500	1.6500
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 94**	**Sample Tank No. 95**	**Sample Tank No. 96**	**Sample Tank No. 97**	**Sample Tank No. 98**	**Sample Tank No. 99**
E&P Tank Number	**Tank No. 48**	**Tank No. 49**	**Tank No. 50**	**Tank No. 51**	**Tank No. 52**	**Tank No. 53**
Total Emissions (tpy)	54.705	437.309	165.905	279.758	608.810	254.487
VOC Emissions (tpy)	37.588	181.269	149.208	103.605	571.582	161.927
Methane Emissions (tpy)	8.963	1.079	0.600	12.141	8.030	48.433
HAP Emissions (tpy)	**2.550**	**4.660**	**4.640**	**1.630**	**17.380**	**7.830**
Benzene	*0.263*	*0.041*	*0.202*	*0.453*	*0.424*	*2.228*
Toluene	*0.317*	*0.110*	*0.380*	*0.085*	*0.458*	*1.268*
E-Benzene	*0.024*	*0.053*	*0.035*	*0.015*	*0.025*	*0.039*
Xylenes	*0.218*	*0.149*	*0.168*	*0.017*	*0.441*	*0.399*
n-C6	*1.726*	*4.311*	*3.855*	*1.063*	*16.032*	*3.892*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	32	62	13	28	22	66
Separator Temperature (F)	149	80	113	45	114	89
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	149	80	113	45	114	89
C10+ SG	0.862	0.894	0.882	0.904	0.877	0.877
C10+ MW	251	310	294	294	337	282
API Gravity	**38.0**	**38.0**	**38.0**	**38.0**	**38.0**	**39.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	3.00	5.20	5.70	7.40	3.10	3.70
GOR (scf/bbl)	5.82	37.60	13.60	28.24	45.82	30.08
Heating Value of Vapor (Btu/s	2216.65	1206.29	2853.46	1313.43	3053.30	1945.58
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0100	4.1200	0.0100	2.0000	0.0400	0.1800
N2	0.0000	0.0200	0.0000	0.0000	0.2000	0.0000
C1	0.5100	0.0500	0.0300	0.5300	0.4200	2.2600
C2	0.4400	0.3200	0.4500	1.0400	0.5700	0.8400
C3	0.5900	1.4800	2.4200	1.9800	2.1600	1.4800
i-C4	0.5400	0.8700	1.1900	1.4200	1.1400	1.0300
n-C4	0.6500	3.3500	3.2300	3.7800	4.2600	1.6000
i-C5	1.3500	3.0800	2.0600	2.9700	2.9000	2.0600
n-C5	1.1500	2.8200	3.0500	2.9500	4.2900	1.8600
C6	2.5000	4.7100	2.3400	2.6800	3.5200	3.4100
C7	6.4600	10.0400	7.7900	11.8900	10.3400	8.6400
C8	8.5600	11.8100	8.3700	11.7900	9.9300	11.0300
C9	3.4500	6.4100	6.4400	6.6500	4.4300	5.1000
C10+	69.3200	46.8100	57.0400	45.6300	51.0200	51.2400
Benzene	0.3200	0.0300	0.2000	1.1100	0.1100	1.6600
Toluene	0.9100	0.2400	0.9900	0.7100	0.3100	2.6900
E-Benzene	0.1500	0.3000	0.2100	0.3600	0.0400	0.2100
Xylenes	1.4800	0.9700	1.1500	0.4800	0.7800	2.4200
n-C6	1.6100	2.5700	3.0300	2.0300	3.5400	2.2900
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 100**	**Sample Tank No. 101**	**Sample Tank No. 102**	**Sample Tank No. 103**
E&P Tank Number	**Tank No. 54**	**Tank No. 55**	**Tank No. 56**	**Tank No. 57**
Total Emissions (tpy)	173.095	363.718	391.465	274.631
VOC Emissions (tpy)	97.629	237.995	191.567	204.825
Methane Emissions (tpy)	52.151	56.163	3.830	22.453
HAP Emissions (tpy)	**4.410**	**2.820**	**5.090**	**19.640**
Benzene	*0.242*	*0.369*	*0.970*	*5.674*
Toluene	*0.281*	*0.045*	*0.836*	*4.267*
E-Benzene	*0.031*	*0.026*	*0.019*	*0.070*
Xylenes	*0.164*	*0.129*	*0.135*	*0.436*
n-C6	*3.689*	*2.253*	*3.127*	*9.194*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	60	60	33	42
Separator Temperature (F)	80	58	60	110
Ambient Pressure (psia)	14.7	14.7	14.7	14.7
Ambient Temperature (F)	60	58	60	110
C10+ SG	0.891	0.877	0.907	0.879
C10+ MW	265	309	295	283
API Gravity	**39.0**	**39.0**	**39.0**	**39.0**
Production Rate (bbl/day)	500	500	500	500
Reid Vapor Pressure (psia)	5.60	6.80	6.40	5.40
GOR (scf/bbl)	23.36	43.14	36.04	26.60
Heating Value of Vapor (Btu/s	1766.66	2016.56	1509.76	2428.31
LP Oil Component				
H2S	0.0000	0.0000	0.1100	0.0000
O2	0.0000	0.0000	0.0000	0.0000
CO2	0.0500	0.0300	2.4000	0.0100
N2	0.0100	0.0100	0.0000	0.0000
C1	2.3200	2.6700	0.1600	1.0900
C2	0.7200	1.7300	0.7600	1.5000
C3	1.1900	3.6000	2.6400	2.1200
i-C4	0.8900	1.8800	0.9100	0.8400
n-C4	1.8300	3.2300	3.5800	2.2800
i-C5	2.3500	2.4900	2.6500	1.6400
n-C5	3.2400	2.1100	3.4400	2.5200
C6	3.9900	2.7200	3.7800	2.6100
C7	9.9400	8.1600	10.7700	9.7300
C8	11.5600	11.9800	11.8300	8.9300
C9	6.0600	4.9500	6.1900	5.8900
C10+	48.9900	50.3400	40.8600	47.7300
Benzene	0.3000	0.3800	1.2700	2.7500
Toluene	1.0300	0.1500	3.4900	5.3000
E-Benzene	0.2900	0.2400	0.2200	0.2000
Xylenes	1.7800	1.3700	1.8000	1.3900
n-C6	3.4600	1.9600	3.1400	3.4700
224Trimethylp	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000

Tank ID					**API > 40**		
E&P Tank Number		**Average**	**ratios to HAP**	**Ratio to VOC**	**Maximum**	**Minimum**	**Average**
Total Emissions (tpy)	Total	785.812			8152.118	129.419	1530.229
VOC Emissions (tpy)	VOC	530.750	**33.837**		5678.554	43.734	1046.343
Methane Emissions (tpy)	Methane	116.167	**7.406**	**0.219**	1206.981	0.197	230.569
HAP Emissions (tpy)	**HAP**	**15.685**		**0.030**	**101.610**	**2.680**	**30.684**
Benzene							
Toluene							
E-Benzene							
Xylenes							
n-C6							
224Trimethylp							
Separator Pressure (psig)	Separator Pressure	126.451			870.000	13.000	231.870
Separator Temperature (F)	Separator Temperature	88.657			140.000	40.000	82.500
Ambient Pressure (psia)							
Ambient Temperature (F)							
C10+ SG		0.893			0.929	0.801	0.873
C10+ MW		292.72			375.000	162.000	241.304
API Gravity	**API Gravity**	**40.6**			**68.0**	**40.0**	**52.8**
Production Rate (bbl/day)							
Reid Vapor Pressure (psia)	RVP	5.691			13.100	3.000	7.983
GOR (scf/bbl)	GOR	88.149			924.960	12.300	172.479
Heating Value of Vapor (Btu/s	Heating value	1968.085					
LP Oil Component		**Composition**					
H2S		0.0679					
O2		0.0000					
CO2		0.3661					
N2		0.0360					
C1		2.9248					
C2		1.6262					
C3		2.7564					
i-C4		1.3958					
n-C4		2.9738					
i-C5		2.4711					
n-C5		2.7194					
C6		3.2723					
C7		8.5230					
C8		10.3202					
C9		5.6686					
C10+		48.1339					
Benzene		0.6044					
Toluene		1.6882					
E-Benzene		0.1797					
Xylenes		1.4353					
n-C6		2.8369					
224Trimethylp		0.0000					
		100.0000					

Tank ID	**API <40**		
E&P Tank Number	**Maximum**	**Minimum**	**Average**
Total Emissions (tpy)	746.422	13.397	174.327
VOC Emissions (tpy)	598.797	3.087	107.227
Methane Emissions (tpy)	124.465	0.115	22.193
HAP Emissions (tpy)	**19.640**	**0.070**	**3.366**
Benzene	5.674	0.003	0.445
Toluene	6.120	0.003	0.431
E-Benzene	0.086	0.000	0.019
Xylenes	0.732	0.001	0.120
n-C6	16.032	0.052	2.449
224Trimethylp	0.000	0.000	0.000
Separator Pressure (psig)	280.000	4.000	39.857
Separator Temperature (F)			
Ambient Pressure (psia)			
Ambient Temperature (F)			
C10+ SG	0.984	0.861	0.910
C10+ MW	551.000	239.000	334.946
API Gravity	**39.0**	**15.0**	**30.6**
Production Rate (bbl/day)			
Reid Vapor Pressure (psia)	7.400	0.600	3.809
GOR (scf/bbl)	67.220	2.340	18.878
Heating Value of Vapor (Btu/s			
LP Oil Component			
H2S			
O2			
CO2			
N2			
C1			
C2			
C3			
i-C4			
n-C4			
i-C5			
n-C5			
C6			
C7			
C8			
C9			
C10+			
Benzene			
Toluene			
E-Benzene			
Xylenes			
n-C6			
224Trimethylp			

API Gravity >40

VOC Emissions (tpy)	
Mean	1046.343
Standard Error	188.1410357
Median	530.989
Mode	#N/A
Standard Deviation	1276.034588
Sample Variance	1628264.269
Kurtosis	3.35522263
Skewness	1.864492873
Range	5634.82
Minimum	43.734
Maximum	5678.554
Sum	48131.778
Count	46
Largest(1)	5678.554
Confidence Level(95.0%)	378.9354921

	667.4075079
VOC	1046.343
	1425.278492

API Gravity <40

VOC Emissions (tpy)	
Mean	107.2265
Standard Error	15.51304
Median	72.87
Mode	#N/A
Standard Deviation	116.0889
Sample Variance	13476.64
Kurtosis	9.02191
Skewness	2.680349
Range	595.71
Minimum	3.087
Maximum	598.797
Sum	6004.685
Count	56
Largest(1)	598.797
Confidence Level(95.0%)	31.08882

	76.1377
VOC	107.2265
	138.3153

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Pennsylvania Energy Impacts Assessment

Report 1: Marcellus Shale Natural Gas and Wind

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November 15, 2010

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Cover photos: Marcellus gas drilling rig in Lycoming County © Tamara Gagnolet / TNC; wind turbine in Tioga County © Nels Johnson / TNC; log pile © TNC; electric transmission lines in Clinton County © George C. Gress / TNC

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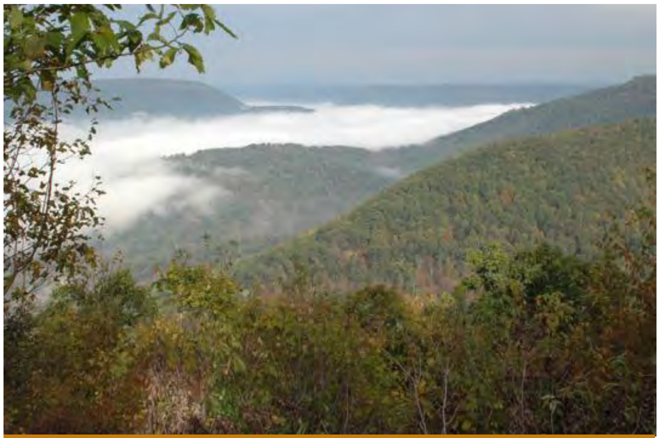
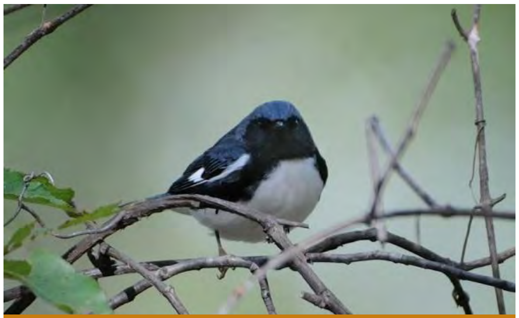


Forest landscape along the West Branch Susquehanna River, Clinton County. © George C. Gress / TNC

Within a few weeks during the summer of 2000, eight towers rose two hundred feet above an agricultural field on a low ridge top along the Pennsylvania Turnpike. Not long after, large blades began sweeping the Somerset County sky as Pennsylvania's first industrial wind facility went on line. Several years later and an hour drive to the west, an unusual natural gas well was drilled over a mile down and pumped full of water. That well in Washington County yielded a surprising amount of gas flowing from fractures in a shale formation that geologists had long suspected held plenty of gas but has been too expensive to develop. Meanwhile, a Canadian company bought a small sawmill in Mifflintown and started producing wood pellets for stoves, boilers, and electric plants. It soon became one of the region's largest producers of wood biomass energy supplies. In the decade since, these three new energy technologies have expanded rapidly across the state. By the end of this year, 500 wind turbines will be turning on Pennsylvania ridgelines, nearly 2,000 Marcellus natural gas wells will be scattered across rolling fields and forests, and over 50 facilities will be producing wood pellets or burning wood for energy. Thousands of miles of pipelines and powerlines already crisscross the state to get energy supplies to major markets in the Northeast.

Each of these energy sources carries both promise and risk for people and nature. The promise is that wind, natural gas, and wood biomass energy can reduce greenhouse gas emissions, generate jobs, and increase energy security. The risk is that extensive land use change and loss of natural habitats could accompany new energy development and transmission lines. Impacts to priority conservation habitats across the state have been modest thus far. For example, aerial photo analysis indicates Marcellus gas development has so far cleared just 3,500 acres of forest (about 1,000 acres for wind turbines). An additional 8,500 acres of forest is now within 300 feet of new fragmenting edges created by well pads, and associated roads and infrastructure (5,000 acres for wind turbines). This fragmentation deprives "interior" forest species, such as black-throated blue warblers, northern goshawks, salamanders, and many woodland flowers, of the shade, humidity and tree canopy protection that only deep forest environments can provide.



Black-throated blue warblers and other interior forest species could be impacted by forest fragmentation caused by energy development. © Gary Irwin

Nine Mile Run Creek in PA's North Central Highlands © George C. Gress / TNC.

By all accounts, each of these energy types is likely to grow substantially in Pennsylvania during the next two decades. The Marcellus shale formation, which underlies two-thirds of the state, is now believed to be one of the largest unconventional shale gas reserves in the world. The Pennsylvania Alternative Energy Portfolio Standards Act of 2004, along with state and federal incentives, will likely boost expansion of wind, wood biomass, and other alternative energy types over the next two decades. But, how much of each energy type might be developed? What transmission infrastructure will be needed to get more electric power and natural gas to consumers? And, where are these energy types most likely to be developed? How does the likely scale and location of future energy development overlap with priority conservation areas? The Pennsylvania Energy Impacts Assessment seeks answers to these questions so that conservationists can work more effectively with energy companies and government agencies to avoid, minimize or mitigate habitat impacts in the future.

Assessment Goal: Develop credible energy development projections and assess how they might affect high priority conservation areas across Pennsylvania. Marcellus natural gas, wind, wood biomass, and associated electric and gas transmission lines were chosen as the focus since these energy types have the most potential to cause land-use change in the state over the next two decades. The conservation impacts focus is on forest, freshwater, and rare species habitats. The assessment **does not** address other potential environmental impacts, including water withdrawal, water quality, air quality and migratory pathways for birds and bats. The assessment also does not address a range of other social, economic, and climate characteristics of these energy types.

Key Assumptions: Any assessment of future trends must include certain assumptions. Among the most important assumptions of the Pennsylvania Energy Impacts Assessment are the following:

- A 20-year time period is used to assess potential cumulative habitat impacts from energy development;
- Given uncertainties about how energy prices could change, it was assumed that prices and capital investment (and policy and social conditions) will be sufficient to promote steady development growth for each energy type during the next two decades;
- Given uncertainty about how technology changes could affect spatial footprints, it was assumed that spatial footprints per well pad, turbine, and mile of transmission line will not change significantly during the next two decades;
- Given the proprietary nature of data on leases, Marcellus Shale porosity, fine resolution wind power, etc., all projections are based on publicly available information;
- It was assumed that recent trends and patterns of energy development will continue for the next two decades absent significant changes in government policies and industry practices;

Energy projections contained in this assessment are informed scenarios – **not predictions** – for how much energy development might take place and where it is more and less probable. Projected impacts, however, are based on measurements of actual spatial footprints measured for hundreds of well pads and wind turbines.

Analytical Steps: Key analytical steps for the Pennsylvania Energy Assessment included:

1) *Data collection* – Over 50 spatial data layers on energy resources, development permits, road and transmission infrastructure, physical features, and conservation priorities were compiled for the assessment;

2) *Spatial footprint analysis* – Spatial footprints for Marcellus gas well and wind turbine pads, associated roads, associated pipelines, associated electric transmission lines, and associated other clearings (*e.g.*, gas containment pits, equipment staging areas, electrical substations) were digitized using aerial photos of sites before and after construction;

3) *Scale projections* – Low, medium, and high scenarios for ***how much*** Marcellus Shale natural gas, wind, wood biomass, and transmission line development might occur were based as much as possible on existing projections and data from credible sources.

4) *Geographic projections* – Projections of ***where*** new Marcellus natural gas and wind energy development is more and less likely to occur were based on modeling the probability of a map pixel's land-use change to energy production based on sets of drivers and constraints developed for each energy type. Geographic projections for wood biomass and energy transmission were not modeled due to a lack of data. Conclusions about regional patterns of wood biomass and transmission development and potential conservation impacts will be presented in Report 2 of the Pennsylvania Energy Impacts Assessment.

5) *Conservation impacts analysis* – The potential impacts of future energy development were assessed for forest and freshwater habitats across the state. In addition, sites recognized as important for species of conservation concern were assessed. Conservation datasets for these assessments included, among others, large forest patches from The Nature Conservancy and the Western Pennsylvania Conservancy, habitat areas for rare species from the Pennsylvania Natural Heritage Program, densities for interior forest nesting bird species from the 2nd Pennsylvania Breeding Bird Atlas, and intact watersheds for native brook trout populations from the Eastern Brook Trout Joint Venture.

6) *Review* – A dozen energy experts in government, industry, and research organizations provided technical review of the energy projections.

Energy Projections: The Pennsylvania Energy Impacts Assessment developed low, medium and high scenarios for the amount of energy development that might take place in Pennsylvania by 2030. The projections include:

- *Marcellus Shale* – Sixty thousand wells could be drilled on between 6,000 and 15,000 new well pads (there are currently about 1,000), depending on how many wells are placed on each pad. Gas development will occur in at least half of the state's counties, with the densest development likely in 15 counties in southwest, north central, and northeast Pennsylvania.

- *Wind* – Between 750 and 2,900 additional wind turbines could be built (there are currently about 500), depending on the wind share of electric generation by 2030. Most turbines would be built along the Allegheny Front in western Pennsylvania and on high Appalachian ridgetops in the central and northeastern parts of the state.

- *Wood Biomass* – Wood biomass energy demand could double or even triple today's wood energy use, depending on whether and how many coal power plants co-fire with wood biomass. Wood biomass energy development is likely to be widespread across the state in all three scenarios.

- *Transmission Lines* – Preliminary findings indicate between 10,000 and 15,000 miles of new high-voltage power lines and gas pipelines (especially gathering lines) could be built during the next twenty years. There is considerable uncertainty about exactly where these lines will be built but recently proposed electric and gas transmission lines provide insights into potential habitat impacts.

Conservation Impacts: This first Pennsylvania Energy Impacts Assessment report focuses on the overlap between likely Marcellus gas and wind development areas and Pennsylvania's most important natural habitats. A second report will focus on the potential for additional impacts from new wood biomass energy plants, electric power lines, and natural gas pipelines. Key findings for impacts from Marcellus natural gas and for wind development include:

Forests. By 2030, a range of between 38,000 to 90,000 acres of forest cover could be cleared by new Marcellus gas development in the state. Forest clearing for the wind development scenarios is much smaller, ranging from 1,900 to 5,200 acres. Such clearings would create new forest edges where the risk of predation, changes in light and humidity levels, and expanded presence of invasive species could threaten forest interior species in 91,000 to 220,000 forest acres adjacent to Marcellus development and 13,400 to 36,000 forest acres adjacent to wind development. Forest impacts will be concentrated in the north central and southwest parts of the state where many of the state's largest and most intact forest patches could be fragmented into smaller patches by well pads, roads, and other infrastructure. Impacts to forest interior species will vary depending on their geographic distribution and density. Some species, such as the black-throated blue warbler, could see widespread impacts to their relatively restricted breeding habitats in the state while widely distributed species, such as the Scarlet Tanager, would be relatively less affected. Locating energy infrastructure in open areas or toward the outer edges of large patches can significantly reduce impacts to important forest areas.

Brook trout © TNC

Freshwater. Aquatic habitats are at risk too. Once widespread, healthy populations of native eastern brook trout in Pennsylvania are now largely confined to small mountain watersheds. Nearly 80 percent of the state's most intact brook trout watersheds could see at least some Marcellus gas and wind development during the next twenty years. Strongholds for brook trout are concentrated in north central Pennsylvania, where Marcellus development is projected to be relatively intensive in over half of the state's best brook trout watersheds. Exceptional Value streams – the Department of Environmental Protection's highest quality designation – could see hundreds of well pads (perhaps 300 - 750) and dozens of wind turbines (perhaps 50 – 200) located within one-half mile under the projections. Because many intact brook trout and EV streams are in steep terrain, rigorous sediment controls, and possibly additional setback measures, are needed to help conserve these sensitive habitats.

Rare Species. Nearly 40 percent of Pennsylvania's globally rare and Pennsylvania threatened species can be found in areas with high potential for Marcellus gas development. These species tend to be associated with riparian areas, streams, and wetlands, while others are concentrated in unusually diverse areas such as the Youghiogheny Gorge. A handful of rare species have most or all of their known locations in high potential areas for Marcellus gas development. For example, three-fourths of all known snow trillium populations are in high potential Marcellus development areas as are all known populations for the green salamander. A much smaller number of known locations for globally and state rare species overlap with high potential wind development sites and they tend to be associated with rocky outcrops and ridgetop barrens habitats. Species with the greatest overlaps include timber rattlesnakes, Allegheny woodrats, and northern long-eared Myotis bats. More intensive surveys for globally rare and state critically endangered species in high potential Marcellus and wind development areas could help to minimize impacts before development begins. The Pennsylvania Game Commission is working with wind companies and other researchers to assess impacts to migratory pathways for birds and bats.

Recreation. Extensive overlaps are projected between Marcellus development and state forests, state parks, and state game lands. Just over ten percent of Pennsylvania's public lands are legally protected from gas development, most of it within State Wild and Natural Areas or in state parks where the Commonwealth owns the mineral rights. The state does not own mineral rights for 80% of State Park and State Game Lands, nearly 700,000 acres of State Forests have already been leased, and only about 300,000 acres of the remaining State Forest Lands are legally off-limits to future leases. Projections indicate between 900 and 2,200 well pads could be developed across all state lands, with most going on State Forest Lands, followed by State Game Lands, and State Parks. Wind development was not projected on state lands, though some facilities are projected near highly visited sites, including natural vistas.

Clearly, the heart of some of Pennsylvania's best natural habitats lies directly in the path of future energy development. Integrating information on conservation priorities into energy planning, operations, and policy by energy companies and government agencies sooner rather than later could dramatically reduce these impacts. Many factors – including energy prices, economic benefits, greenhouse gas reductions, and energy independence – will go into final decisions about where and how to proceed with energy development. Information about Pennsylvania's most important natural habitats should be an important part of the calculus about trade-offs and optimization as energy development proceeds. Would Pennsylvania's conservation pioneers, including Gifford Pinchot, Maurice Goddard, and Rachel Carson, expect anything less?

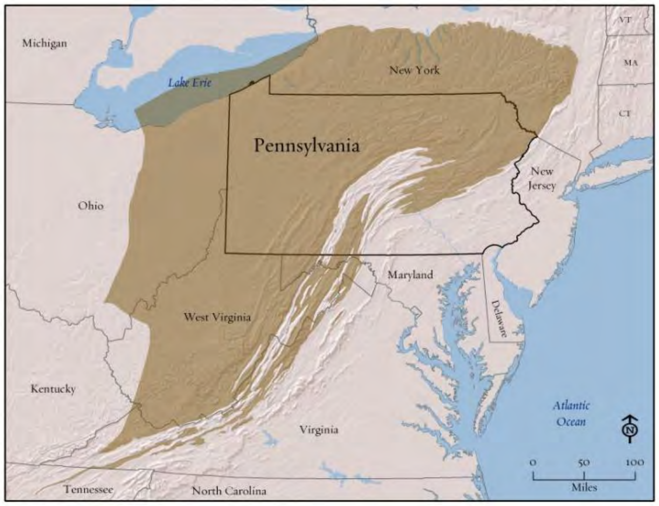
Marcellus Shale Natural Gas

Once thought to be inaccessible, deep shale formations with tightly held natural gas have become the most rapidly growing source of energy in North America. New technologies and methods have allowed companies to drill 6,000 to 10,000 feet down to reach the Marcellus shale, turn the well horizontally to follow the shale layer for a mile or more, and then pump in millions of gallons of water to fracture the shale and release the natural gas. Pennsylvania is at the epicenter of the Marcellus formation, one of the world's largest unconventional shale natural gas reserves. Situated right next door to huge markets in the Mid-Atlantic and Northeastern states, Marcellus gas development has expanded at a furious pace since the first wells were drilled just few years ago in Washington County. There are now approximately 2,000 drilled wells, most of them concentrated in the southwestern and northeastern parts of the state.

The Marcellus boom is bringing rapid economic growth to many rural communities that have been in economic decline for decades. Natural gas is also displacing higher carbon coal and oil supplies thus slowing the rise in greenhouse gas emissions. These benefits are real but not without costs. Large amounts of water must be withdrawn to frac each well (about 5 million gallons). The return flow water that comes back up from the well contains varying levels of chemicals, heavy metals, and even radioactive materials, and must be handled carefully to avoid spills when recycled or disposed. Heavy trucks and compressor stations rumble constantly in gas development areas putting heavy strains on roads, bridges and air quality. Because of known and perceived risks to environmental quality and human health, water use, air emissions and transportation demands are receiving growing attention from government agencies, researchers and energy companies. Thus far, relatively little attention, however, has been focused on Marcellus gas development impacts to natural habitats across the state.

What is Marcellus Shale Natural Gas?

The Marcellus is the largest gas-bearing shale formation in North America in both area and potential gas volume. It spans over 150,000 square miles across 5 states including the southern tier of New York, the northern and western half of Pennsylvania, the eastern third of Ohio, most of West Virginia, and a small slice of western Virginia. Estimates of the potential recoverable volume have increased steadily. The latest estimates by the U.S. Department of Energy are nearly 300 trillion cubic feet – enough to supply all natural gas demand in the United States for at least 10 years.



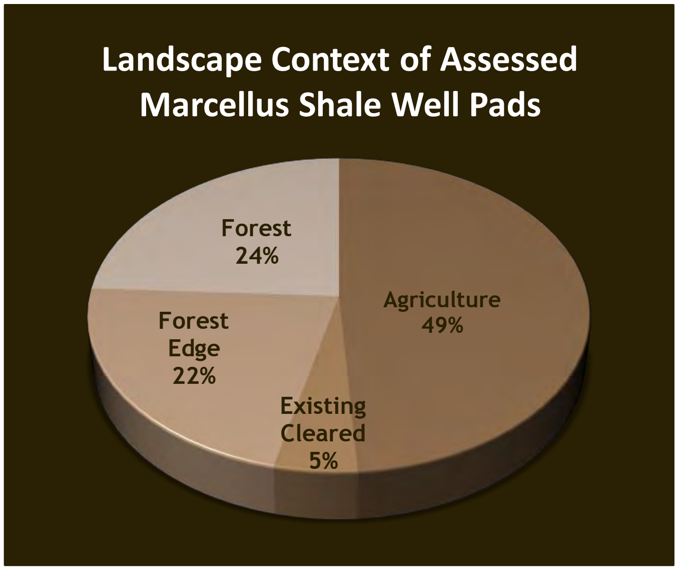
Map showing the extent of the Marcellus Shale formation. Data source: United States Geological Survey.

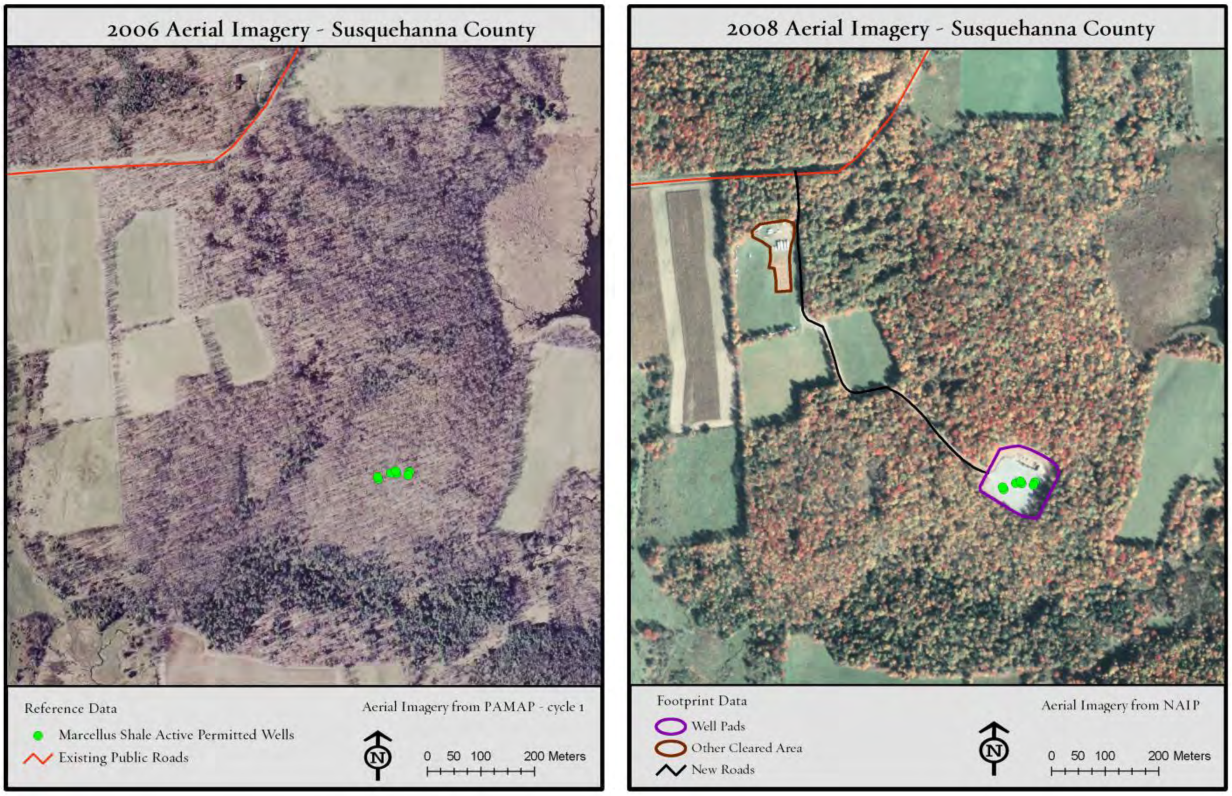
Geologists have long known the Marcellus formation is an organically-rich shale with potentially large amounts of natural gas, but it was too deep, too thin, and too dense to exploit. In 2005, Range Resources drilled the first production Marcellus well using horizontal drilling and hydraulic fracturing methods. The horizontal drilling is necessary because the shale is typically thin and vertical wells will only intercept a small part of the formation. Hydraulic fracturing (or "fracing") is a process that uses large volumes of water, sand, lubricants, and other chemicals to create small fissures in the shale rock. Hydro-fracing is necessary to release the gas which is tightly held in the dense black shale. These methods, first perfected for deep shale gas in the Barnett formation of Texas, unlocked the tremendous gas reserves in the Marcellus and other "unconventional" shale formations previously thought to be out of economic reach.

In contrast to shallow gas deposits in western Pennsylvania, the Marcellus is developed with multiple horizontal wells that can reach out 5,000 feet or more from one well pad. Everything about Marcellus development is bigger than conventional shallow gas plays. The well pads are more expansive (averaging just over 3 acres compared to a small fraction of an acre), the water used to frac wells is much greater (5 million gallons versus a hundred thousand gallons), and the supporting infrastructure is much larger in scale (24" diameter pipelines to gather gas from wells versus 2" or 4" pipelines in shallow fields). Individual wells are also vastly more productive (5 – 10 million cubic feet per day versus less than 100,000 cubic feet in peak early production). While the larger pad, greater water use, and more extensive infrastructure pose more challenges for conservation than shallow gas, the area "drained" by wells on each Marcellus pad is much larger than from shallow gas pads (500-1,000 acres versus 10-80 acres) since there are typically multiple lateral wells on a Marcellus pad versus a single vertical well on a shallow gas pad. The lateral reach of Marcellus wells means there is more flexibility in where pads and infrastructure can be placed relative to shallow gas. This increased flexibility in placing Marcellus infrastructure can be used to avoid or minimize impacts to natural habitats in comparison to more densely-spaced shallow gas fields.

Current and Projected Marcellus Shale Natural Gas Development

Projections of future Marcellus gas development impacts depend on robust spatial measurements of existing Marcellus well pads and infrastructure. By comparing aerial photos of Pennsylvania Department of Environmental Protection (DEP) Marcellus well permit locations taken before and after development, we precisely documented the spatial foot print of 242 Marcellus well pads (totaling 435 drilling permits) in Pennsylvania visible in 2008 aerial imagery from the National Agriculture Imagery Program. The ground excavated for wells and associated infrastructure is the most obvious spatial impact. For each well site, areas cleared for the well pad, new or expanded roads, gathering pipelines, and water impoundments were digitized and measured.





Aerial photos before and after development of a Marcellus gas well pad site in Susquehanna County, PA. To assess the impacts of this type of energy development, we digitized the spatial footprint of 242 gas well pad sites and associated infrastructure.

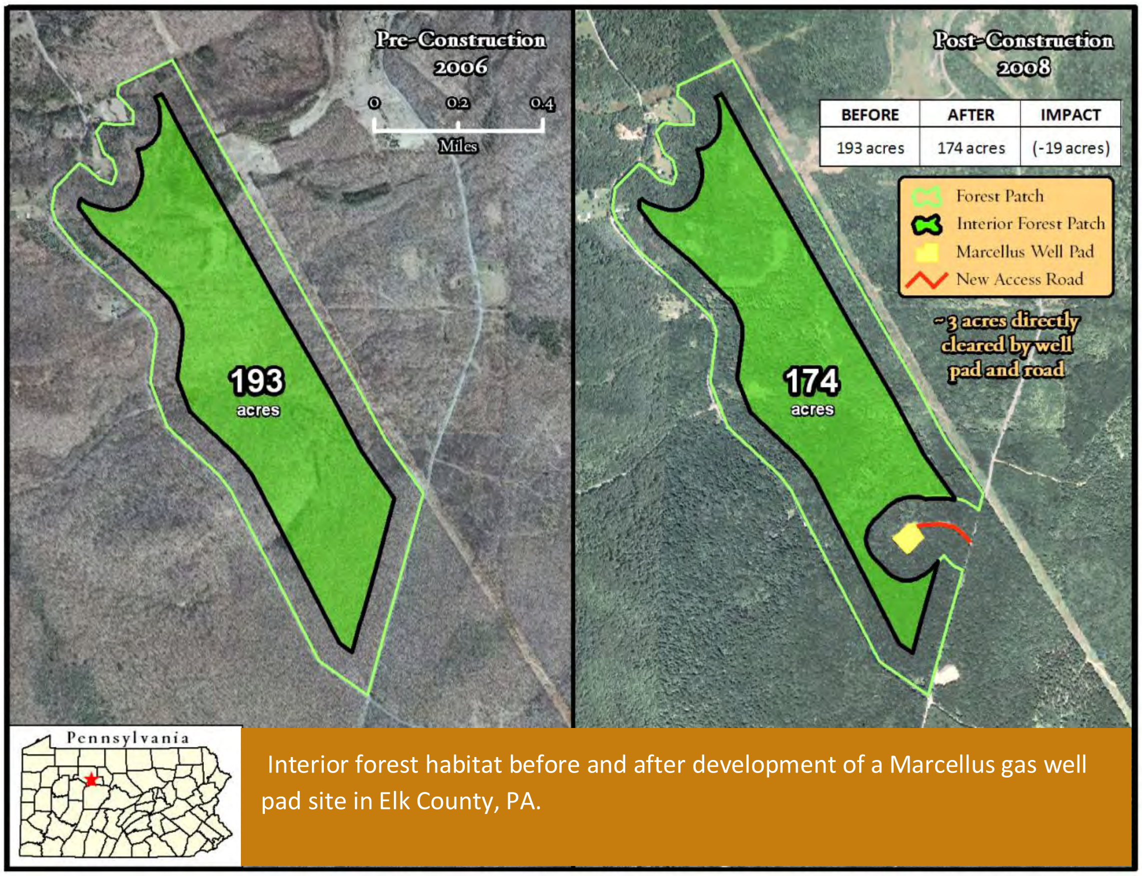
Average Spatial Disturbance for Marcellus Shale Well Pads in Forested Context (acres)		
Forest cleared for Marcellus Shale well pad	**3.1**	**8.8**
Forest cleared for associated infrastructure (roads, pipelines, water impoundments, etc.)	**5.7**	
Indirect forest impact from new edges	**21.2**	
TOTAL DIRECT AND INDIRECT IMPACTS	**30**	

Well pads occupy 3.1 acres on average while the associated infrastructure (roads, water impoundments, pipelines) takes up an additional 5.7 acres, or a total of nearly 9 acres per well pad.

Adjacent lands can also be impacted, even if they are not directly cleared. This is most notable in forest settings where clearings fragment contiguous forest patches, create new edges, and change habitat conditions for sensitive wildlife and plant species that depend on “interior” forest conditions.

Forest ecologists call this the "edge effect." While the effect is somewhat different for each species, research has shown measurable impacts often extend at least 330 feet (100 meters) forest adjacent to an edge. Interior forest species avoid edges for different reasons. Black-throated blue warblers and other interior forest nesting birds, for example, avoid areas near edges because of the increased risk of predation. Tree frogs, flying squirrels and certain woodland flowers are sensitive to forest fragmentation because of changes in canopy cover, humidity and light levels. Some species, especially common species such as whitetail deer and cowbirds, are attracted to forest edges – often resulting in increased competition, predation, parasitism, and herbivory. Invasive plant species, such as tree of heaven, stilt grass, and Japanese barberry, often thrive on forest edges and can displace native forest species. As large forest patches become progressively cut into smaller patches, populations of forest interior species decline.

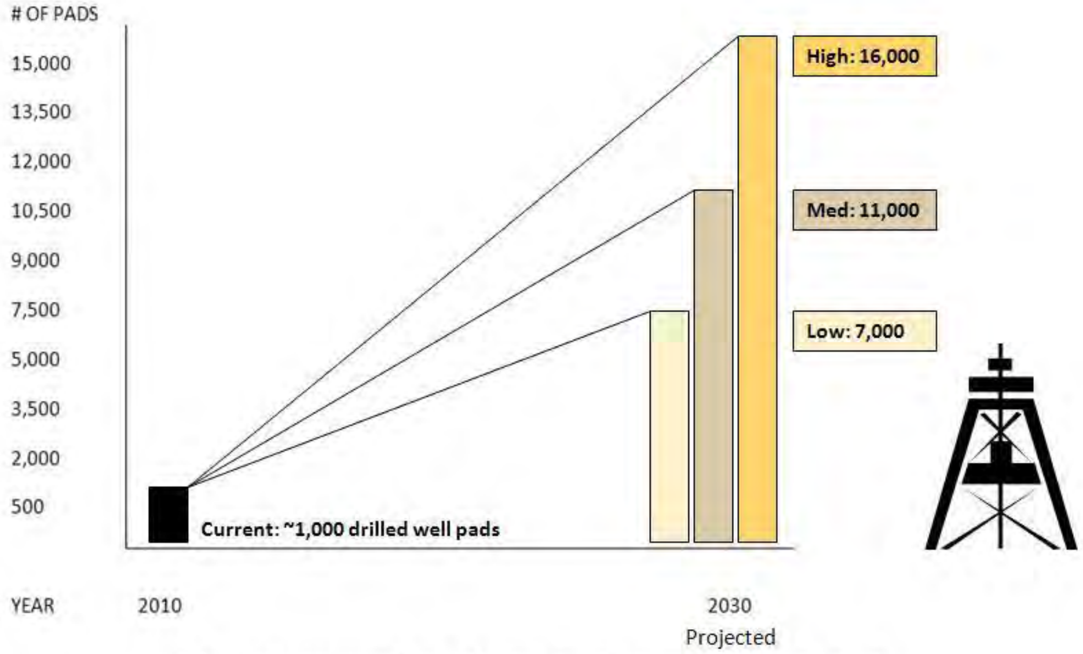
To assess the potential interior forest habitat impact, we created a 100 meter buffer into forest patches from new edges created by well pad and associated infrastructure development. For those well sites developed in forest areas or along forest edges (about half of assessed sites), an average of 21 acres of interior forest habitat was lost.



BEFORE	AFTER	IMPACT
193 acres	174 acres	(-19 acres)

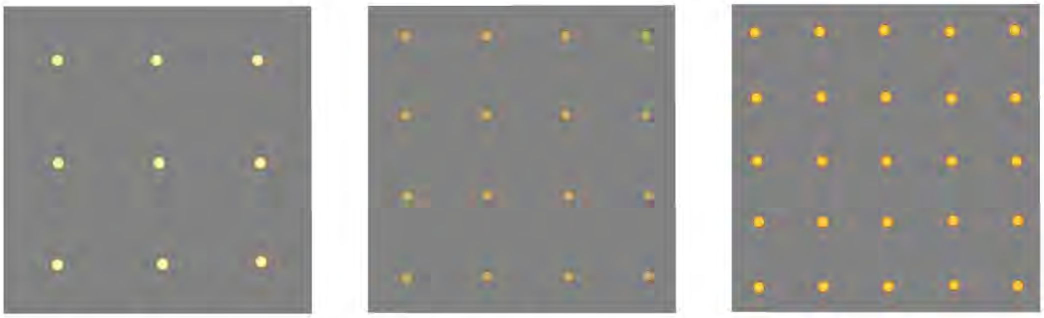
Interior forest habitat before and after development of a Marcellus gas well pad site in Elk County, PA.

The number of Marcellus wells drilled in Pennsylvania during the next two decades will expand steadily. Just how many wells are drilled will be driven by various factors including natural gas prices, technological improvements, human resources, regulatory changes in Pennsylvania and beyond (e.g., end of New York drilling moratorium), and social preferences. Assessing how these factors will change over the next two decades is very difficult; therefore our projections assume economic, policy, and social conditions remain stable enough to promote steady expansion of Marcellus gas development in the state. The first key variable in our projection is the number of drilling rigs that will be operating in Pennsylvania. By October 2010, the industry had moved just over 100 rigs into Pennsylvania to drill Marcellus wells according to the Baker-Hughes weekly rig count. Given the high productivity of the Marcellus and its proximity to major northeastern markets, most industry observers expect this number to continue growing steadily. The number of horizontal drill rigs operating in the Barnett Shale has peaked at about 200, but the



Key drivers: number of rigs, number of wells per pad.

We project 60,000 Marcellus wells will be drilled during the next twenty years based on company investor presentations and academic assessments of gas development potential. Depending on how many wells on average are placed on the same pad site (see illustration below), we project between 7,000 and 16,000 total well pad sites will be developed in Pennsylvania by 2030.



Low Scenario
10 wells per pad
Pads spaced ~5,200 ft apart

Medium Scenario
6 wells per pad
Pads spaced ~4,100 ft apart

High Scenario
4 wells per pad
Pads spaced ~3,350 ft apart

Marcellus Shale is much larger and could reach 300 rigs in Pennsylvania alone. We chose a conservative estimate of 250 maximum horizontal drill rigs for each scale projection scenario. Assuming that each rig can drill one well per month, 3,000 wells are estimated to be drilled annually. At that rate, 60,000 new wells would be drilled by the year 2030.

The second key variable, especially for determining land-use and habitat impacts, is the number of wells on each pad. Because each horizontal well can drain gas from 80 to 170 acres (depending on the lateral well length), more wells per pad translates to less disturbance and infrastructure on the landscape. It is technically possible to put a dozen or more Marcellus wells on one pad. So far, the average in Pennsylvania is two wells per pad as companies quickly move on to drill other leases to test productivity and to secure as many potentially productive leases as possible (leases typically expire after 5 years if there is no drilling activity). In many cases, the gas company will return to these pads later and drill additional wells. The low scenario (6,000 well pads) assumes that each pad on average will have ten wells. Because many leases are irregularly shaped, in mixed ownership, or the topography and geology impose constraints, it is unlikely this scenario will develop. It would take relatively consolidated leaseholds and few logistical constraints for this scenario to occur. The medium scenario for well pads assumes 6 wells on average will be drilled from each pad, or 10,000 new well pads across the state. Industry staff generally agree that six is the most likely number of wells they will be developing per pad for most of their leaseholds, at least where lease patterns facilitate drilling units of 600 acres or larger. The high scenario assumes each pad will have 4 wells drilled on average, or 15,000 well pads across the state. This scenario is more likely if there is relatively little consolidation of lease holds between companies in the next several years.

The number of well pads is less important than where they are located, at least from a habitat conservation perspective. To understand which areas within Pennsylvania's Marcellus formation are more and less likely to be developed, we used a machine-based learning modeling approach known as maximum entropy (Maxent 3.3.3a, Princeton University). Maximum entropy was used to find relationships between 1,461 existing and permitted well pad locations and variables that might be relevant to a company's decision to drill a Marcellus well. Such variables were chosen based on data availability and included Marcellus Shale depth, thickness and thermal maturity as well as percent slope, distance to pipelines, and distance to roads. The model produces a raster surface that represents the probability of an area to potentially support future gas well development. An additional 487 existing and permitted well pads were used to test the validity of the model's probability surface and the model was found to be 80% accurate in predicting existing and permitted wells from randomly sampled undeveloped areas. The resulting probability map indicates wide variation across the Marcellus formation in terms of the likelihood of future gas well development.

To get a better sense of where gas development is most likely, we searched for the highest probability areas where well pads in each scenario might be located. The probability raster was re-sampled to a resolution that reflects the minimum separation distance between well pads for each of the three impact scenarios (low – 1,590 m; medium – 1,260 m; high – 1,020 m). The minimum separation distance depends on the number of wells drilled per pad and accounts for the average gas drainage area assumed for each of the three scenarios. Areas incompatible for future gas exploration (existing drilled Marcellus Shale wells, Pennsylvania State Wild Areas and Natural Areas, and water bodies) were excluded from being selected as probable pixels. For each scenario, the highest probable pixels were selected until the pad threshold was reached (low – 6,000 well pads; medium – 10,000 well pads; high – 15,000 well pads). The highest probable pixels were then converted into points for map display purposes.

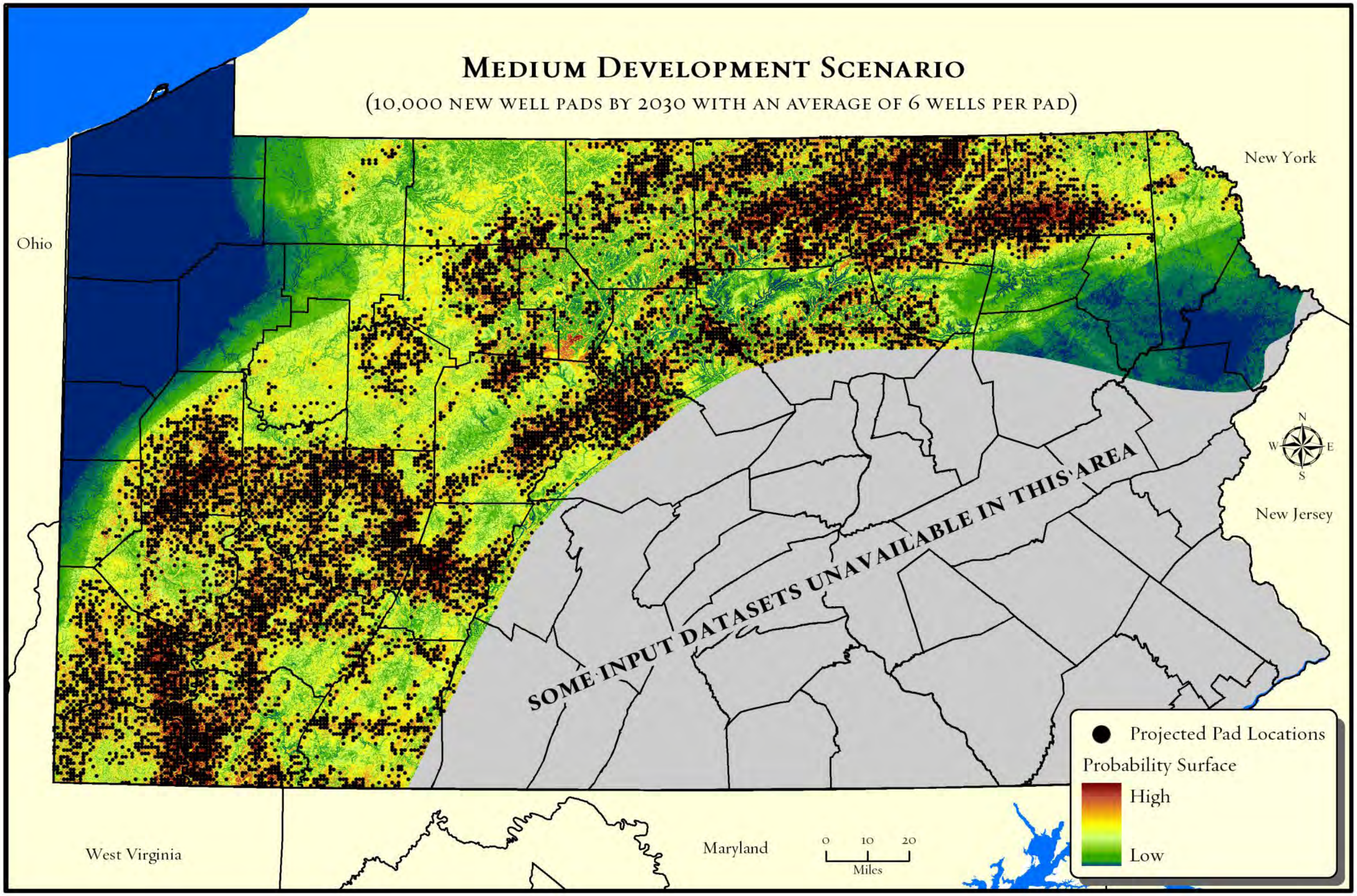
While the geographic area with projected well pads expands from low to high scenarios, the overall geographic pattern is not cumulative due to the differences in minimum separation distance between the three scenarios. Overall, hotspots for future gas development can be seen in half a dozen counties in southwestern Pennsylvania and half a dozen counties in north central and northeastern parts of the state.

These geographic projections of future Marcellus gas development are spatial representations of possible scenarios. They are not predictions. We faced several constraints in developing the geographic scenarios:

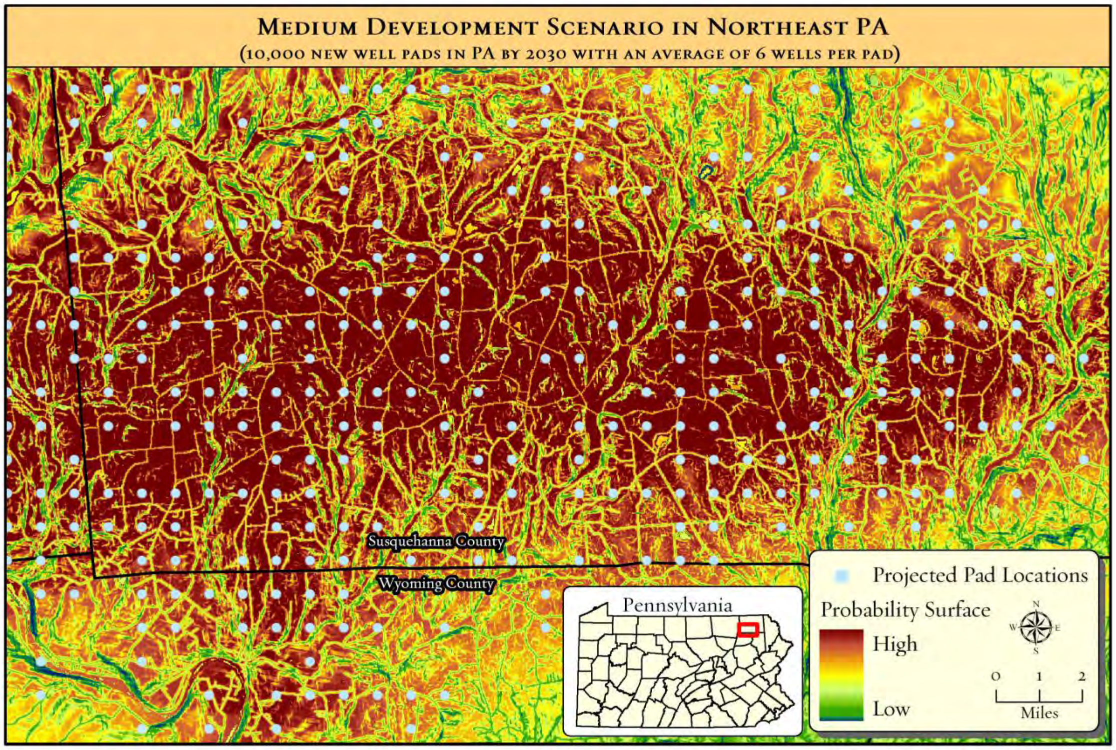
- We do not have access to proprietary seismic and test well geologic data that natural gas companies have. Shale porosity, for example, is a key factor but there are no publicly available data for this.

- We do not have the detailed location of gas company leases. Each company is looking for the highest probability locations across their lease holds while our model looks for the highest probability sites across the entire Marcellus formation in the state. Because there have only been a few Marcellus test wells and permits in the Delaware watershed, we believe the projections for new well pads are probably significantly underestimated in Wayne County.

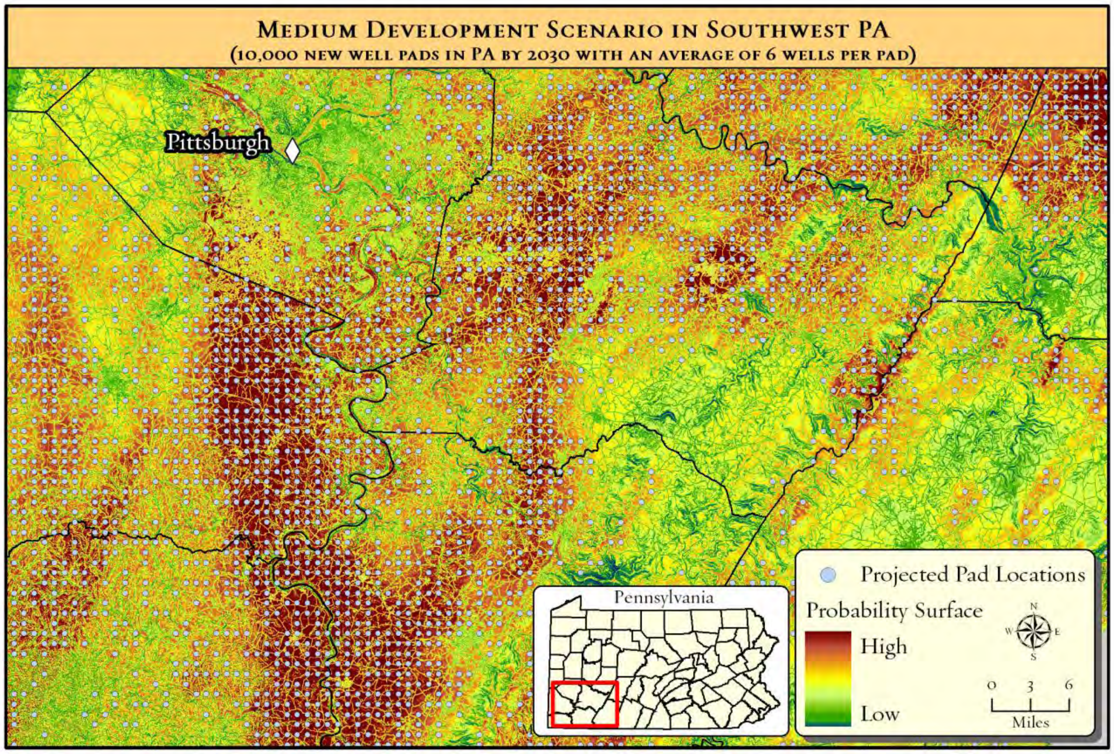
Still, we believe the overall geographic patterns in the projected gas development locations are relatively robust for several reasons. We used nearly 1,500 existing drilled or permitted well pads to build the model and nearly 500 additional drilled and permitted well pads to validate the model. These unique well pad locations represented 4,446 permitted wells. This is typically a sufficient sample size for building predictive models. Additionally, reviews from industry, academic, and government agency reviewers indicate our methods and results are generally sound. Some reviewers expect future well pad locations to be more geographically expansive than our current projections indicate, especially in the Delaware watershed where only a few Marcellus test wells and permits have been issued. Our projections for Wayne County, for example, are likely underestimating future development potential.



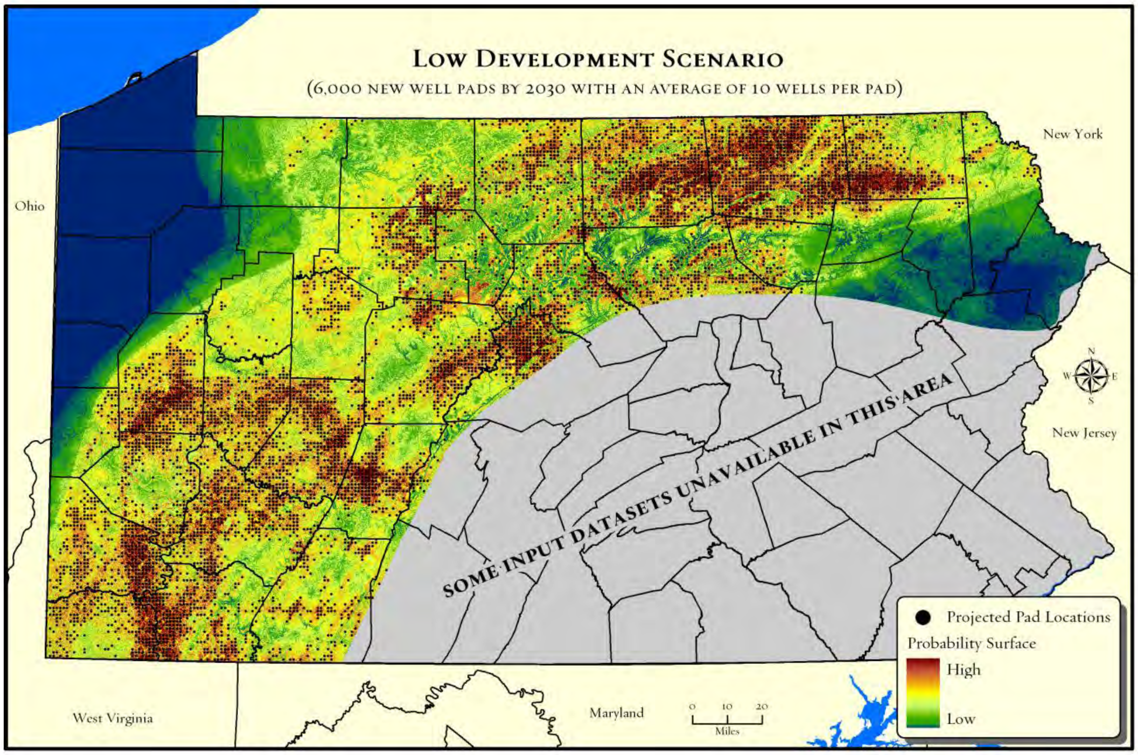
Map showing projected location of 10,000 new Marcellus Shale natural gas pads across Pennsylvania (medium development scenario).



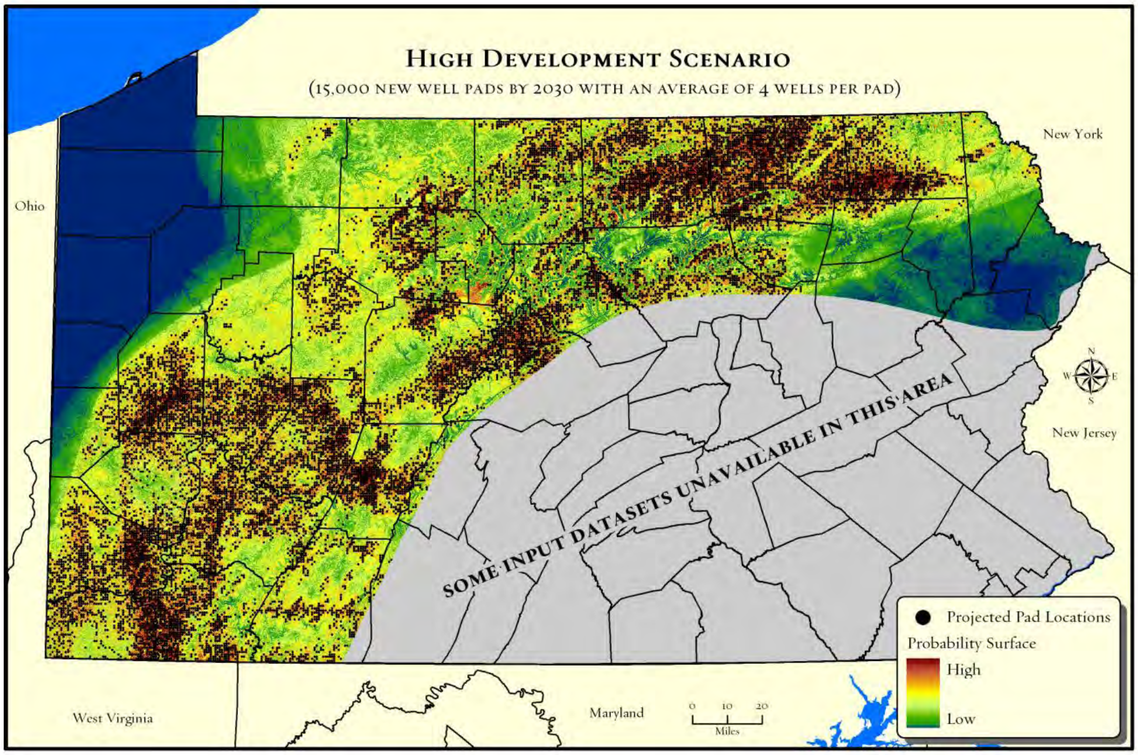
Map showing projected location of new Marcellus well pads in southern Susquehanna County under the medium development scenario.



Map showing projected location of new Marcellus well pads in southwestern Pennsylvania under the medium development scenario.



Map showing projected location of 6,000 new Marcellus well pads across Pennsylvania (low development scenario).



Map showing projected location of 15,000 new Marcellus well pads across Pennsylvania (high development scenario).

Conservation Impacts of Marcellus Shale Natural Gas Development

What is the overlap of the areas with the highest probability of future Marcellus gas development and those areas known to have high conservation values? To answer this question, we intersected the projected Marcellus well pads with areas previously identified and mapped as having high conservation values. We looked at several examples from four categories of conservation value, including:

- Forest habitats
- Freshwater habitats
- Species of conservation concern
- Outdoor recreation

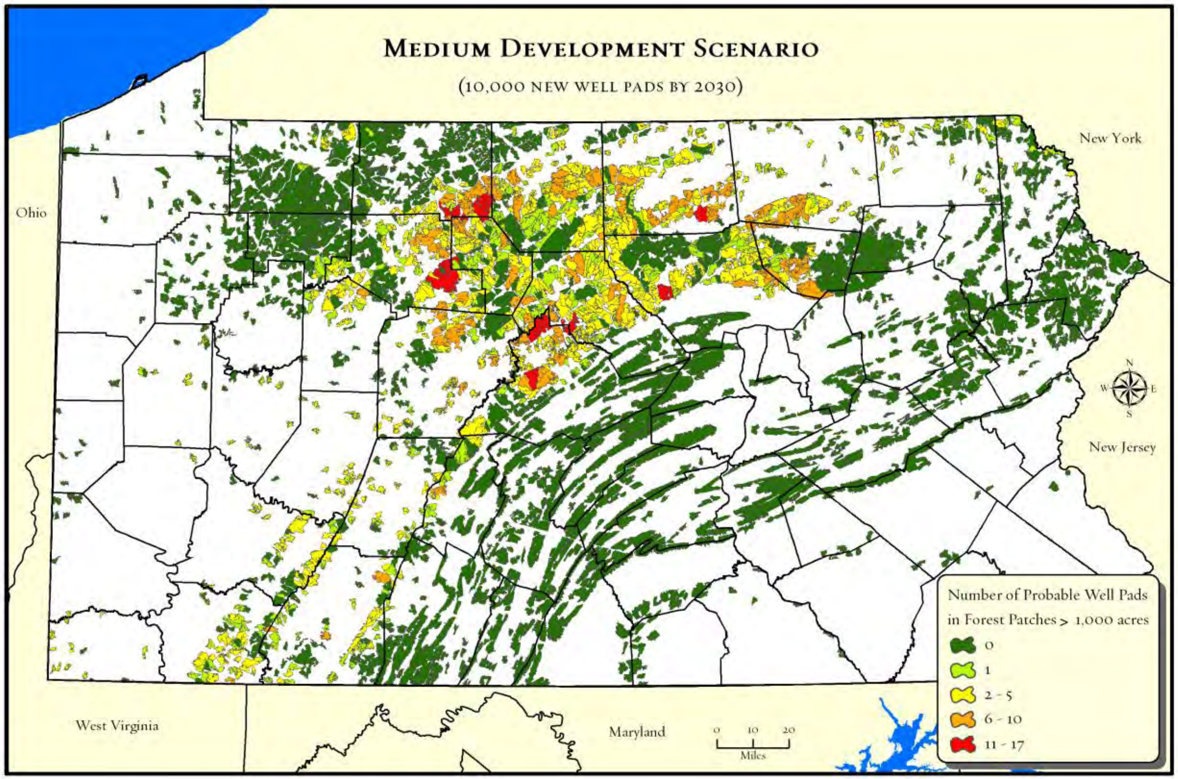
Substantial areas of overlap are indicated between likely future Marcellus development areas and Pennsylvania's most important forest, freshwater, sensitive species habitats, and outdoor recreation sites.

FORESTS

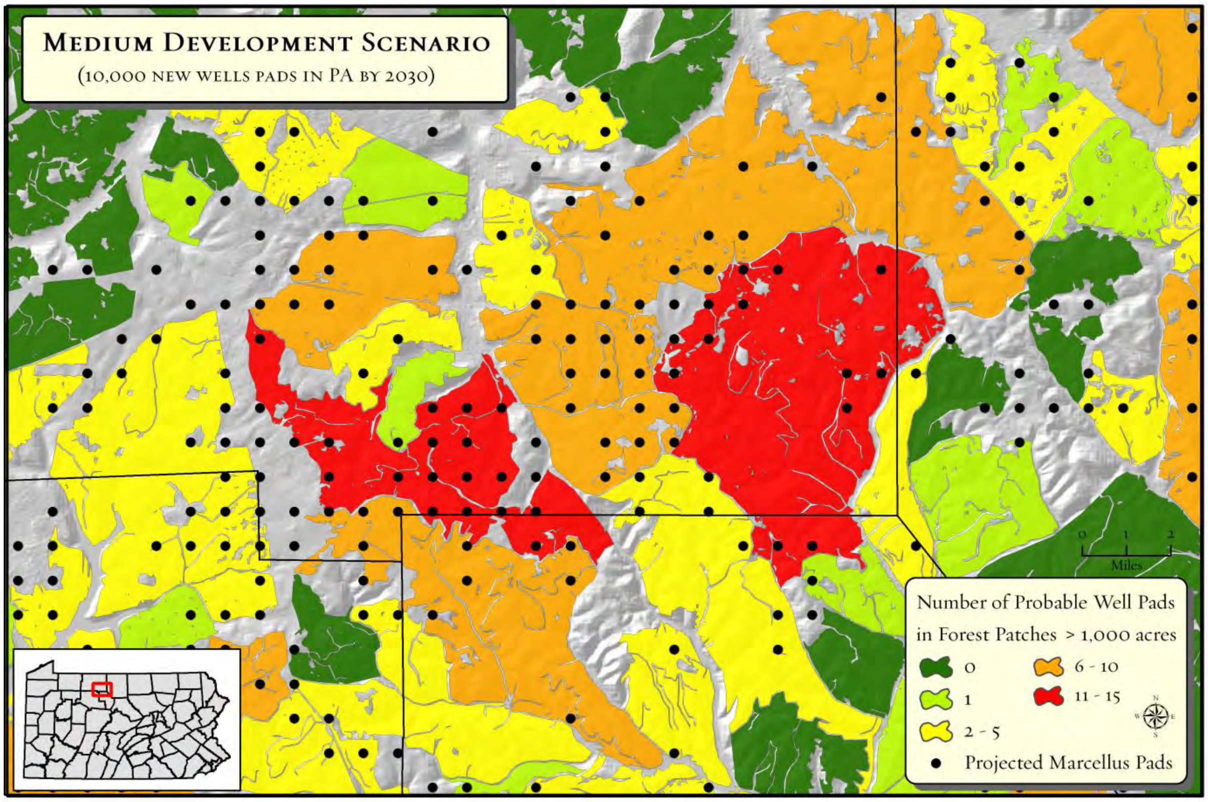
Forests are Pennsylvania's most extensive natural habitat type. Once covering at least 95 percent of the state's land area, forests were whittled away for agriculture, charcoal for iron smelting, and lumber until only a third of the state's forests remained. Forests have rebounded steadily to cover about 60 percent of the state, though a trend toward increasing net loss of forest has emerged during the past decade. Pennsylvania is famous worldwide for its outstanding cherry, oak, and maple hardwoods, and forests provide livelihoods for many thousands of Pennsylvanians in the forest products and tourism industries. They also contribute enormously to the quality of life for all Pennsylvanians by filtering contaminants from water and air, reducing the severity of floods, sequestering carbon dioxide emissions that would otherwise warm the planet, and providing a scenic backdrop to recreational pursuits.

A majority of projected well locations are found in a forest setting for all three scenarios (64% in each case). The low scenario would see 4,310 well pads in forest areas. With an average cleared forest average of 8.8 acres per pad (including roads and other infrastructure), the total forest clearing would be approximately 38,000 acres. Indirect impacts to adjacent forest interior habitats would total an additional 91,000 acres. Forest impacts from the medium scenario (6,950 projected wells in forest locations) would be 61,000 cleared forest acres and an additional 147,000 acres of adjacent forest interior habitat impacts. For the high scenario (10,250 forest well pads), approximately 90,000 acres would be cleared, and an additional 220,000 acres of forest interior habitats would be affected by new adjacent clearings. While the high Marcellus scenario would result in a loss of less than one percent of the state's total forest acreage, areas with intensive Marcellus gas development could see a loss of 2-3 percent of local forest habitats. Some part of the cleared forest area will become reforested after drilling is completed, but there has not been enough time to establish a trend since the Marcellus development started.

Large contiguous forest patches are especially valuable because they sustain wide-ranging forest species, such as northern goshawk, and provide more habitat for forest interior species. They are also more resistant to the spread of invasive species, suffer less tree damage from wind and ice storms, and provide more ecosystem services – from carbon storage to water filtration – than small patches. The Nature Conservancy and the Western Pennsylvania Conservancy's Forest Conservation Analysis mapped nearly 25,000 forest patches in the state greater than 100 acres. Patches at least 1,000 acres in size are about a tenth of the total (2,700) and patches at least 5,000 acres are rare (only 316 patches). In contrast to overall forest loss, projected Marcellus gas development scenarios indicate a more pronounced impact on large forest patches. For example, 40 percent of patches greater than 5,000 acres are projected to have at least one well pad and associated infrastructure located in them in the medium scenario compared to just over 20 percent for patches > 1,000 acres. Most affected large patches have multiple projected well pads (as many as 29). The projections indicate larger patches are likely to be more vulnerable, with over a third projected to have at least one new well pad and road. Many affected large patches have multiple projected well pads (as many as 17 for patches). While one or two well pads and associated infrastructure may not fragment the large patch into smaller patches, each additional well pad increases the likelihood that the large patch will become several smaller patches with a substantially reduced forest interior habitat area.



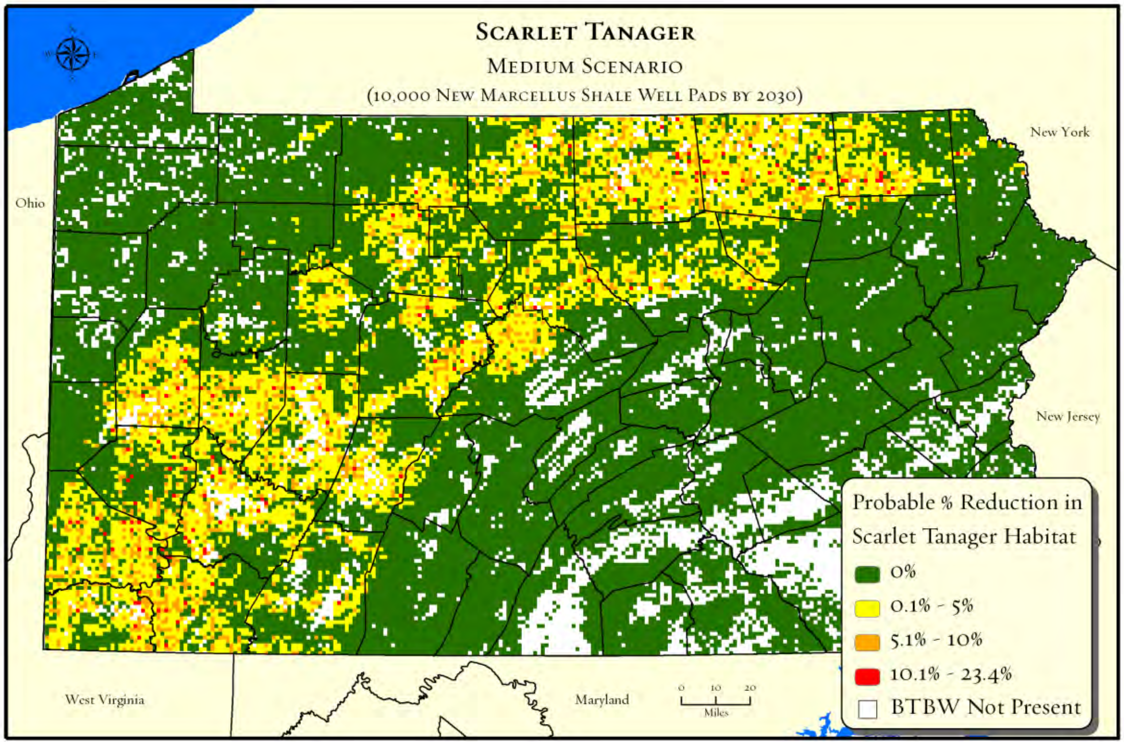
Map showing number of probable Marcellus well pads in forest patches greater than 1,000 acres across Pennsylvania.



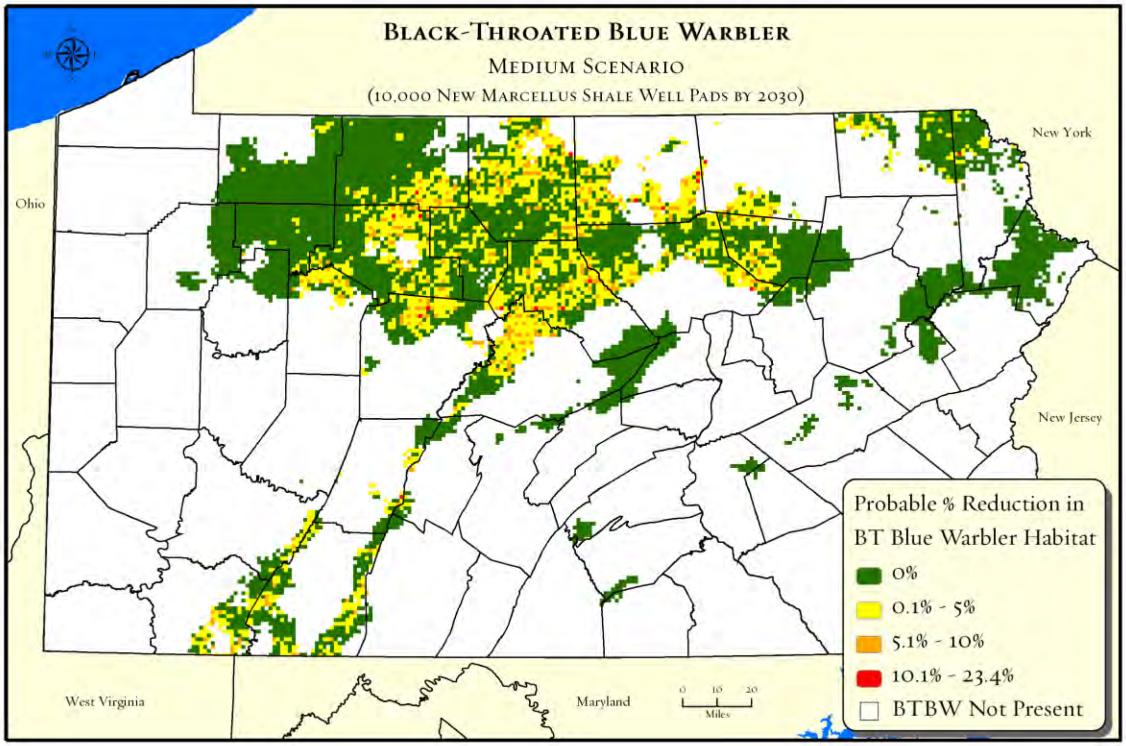
Map showing projected number of well pads in forest patches greater than 1,000 acres under the medium development scenario in Potter, Cameron, McKean and Forest Counties.

Bird species that nest in close canopy forest environments are often referred to as “forest interior” species. The Carnegie Museum of Natural History, Powdermill Nature Reserve and the Pennsylvania Game Commission recently completed Pennsylvania’s Second Breeding Bird Atlas project. As part of the project, trained ornithologists conducted point counts using standardized protocols at 39,000 sites from 2004 to 2009. The result is an incredibly detailed data base that provides the most accurate information on the distribution and density of breeding birds available anywhere in the United States. Density data for several forest interior nesting species were mapped and intersected with the projected Marcellus gas well pad locations. The resulting maps show the estimated reduction in habitat for that species in each Marcellus gas probability pixel (including both cleared forest and adjacent edge effects). Scarlet Tanagers are one of the most widespread forest interior nesting bird in the state. Since they are so widespread, a majority of their range in the state is outside of the most likely Marcellus development areas. In some locations, scarlet tanager populations could decline by as much as 23 percent in the Medium Scenario. Black-throated blue warblers are more narrowly distributed in Pennsylvania favoring mature northern hardwood and coniferous forests with a dense understory, frequently in mountain terrain. Since most of their breeding range in Pennsylvania overlaps with likely Marcellus development areas, a higher proportion of their habitat could be affected.

Scarlet tanager © U.S. Fish and Wildlife Service



Map showing estimated percent loss of habitat for Scarlet Tanagers under medium scenario.

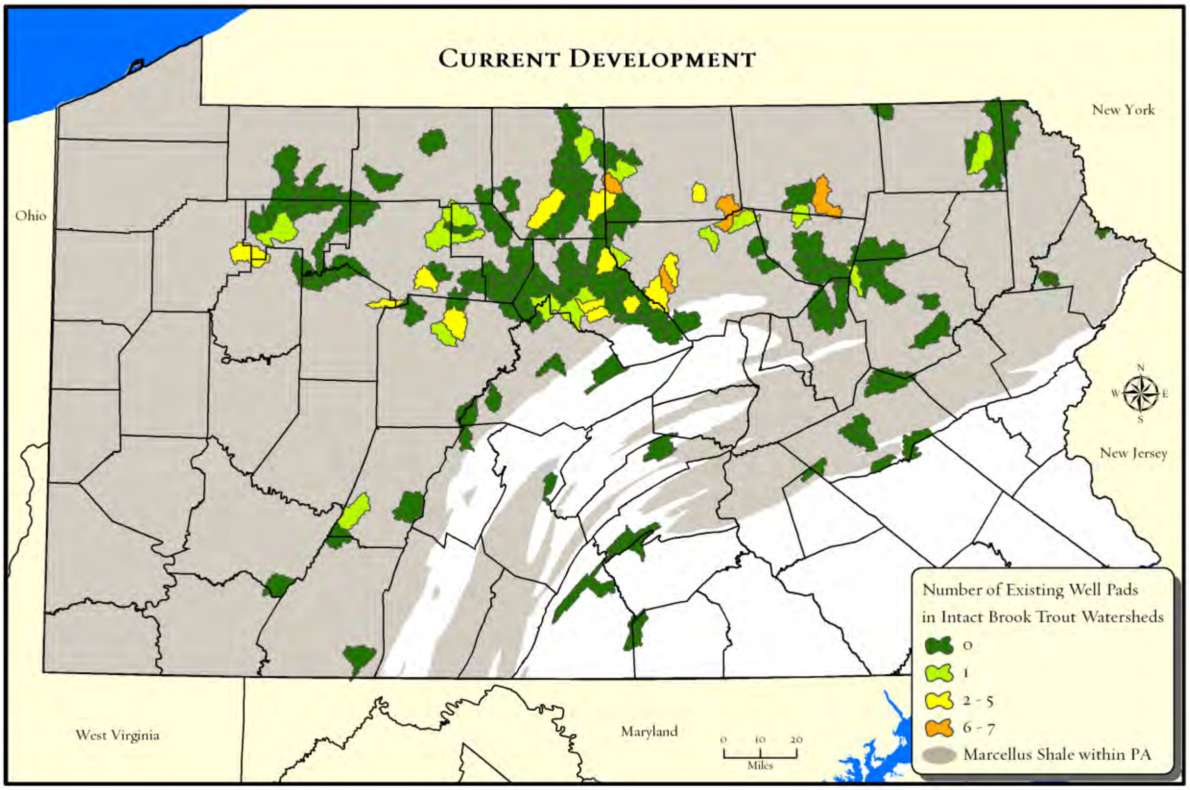


Map showing estimated percent loss of habitat for Black-Throated Blue Warblers under medium scenario.

FRESHWATER

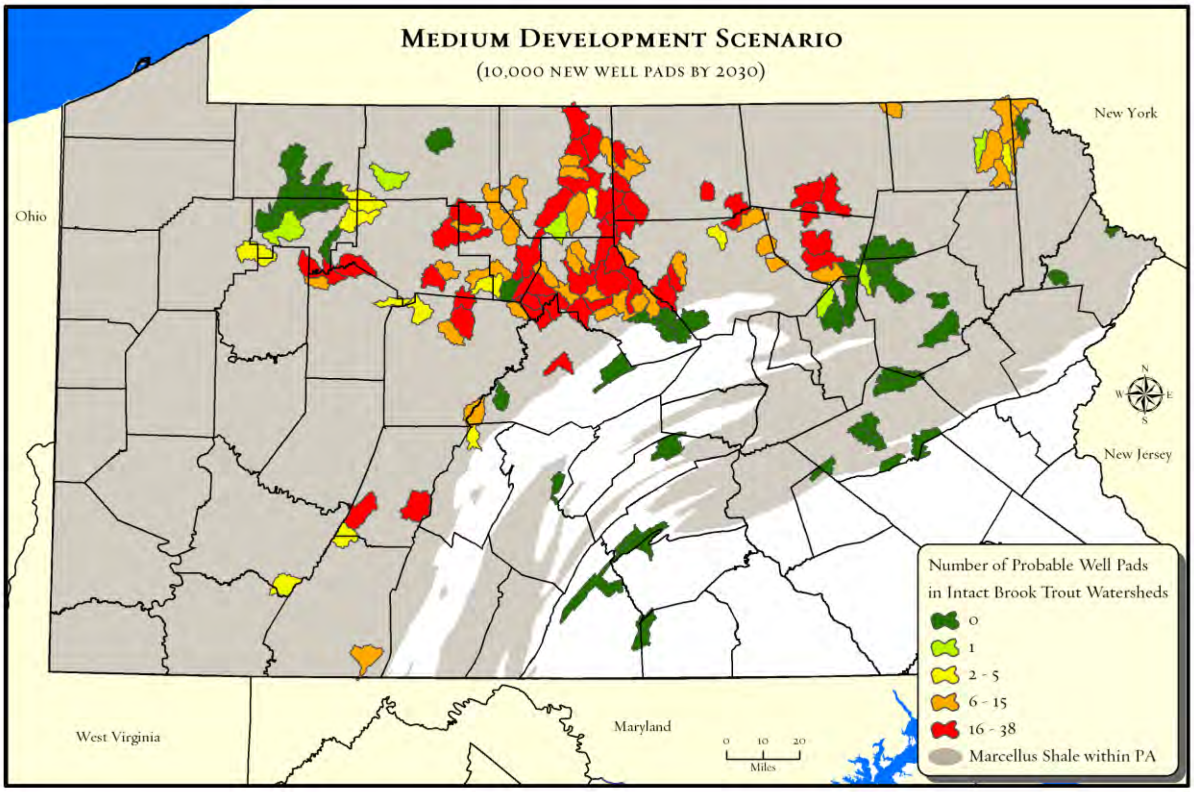
Home to three great river systems and one of the Great Lakes, Pennsylvania's fresh water resources are vital not only to the Commonwealth but to much of the eastern United States. The ***Ohio River*** basin contains the richest fresh water ecosystems in North America. In Pennsylvania, French Creek and parts of the Upper Allegheny River contain some of the most intact aquatic ecosystems in the entire basin. The ***Susquehanna*** **River** is the source of more than half the fresh water that enters the Chesapeake Bay, and most of the water that flows down the Susquehanna River originates in tributary headwaters across a wide swath of central Pennsylvania. Forming Pennsylvania's eastern boundary, the ***Delaware River*** is the longest undammed river in the eastern United States, one of the last strongholds for Atlantic coast migratory fish, and provides the drinking water source for nearly 20 million Americans living in Pennsylvania, New York, and New Jersey. Because of their importance to human health and livelihoods, the potential of Marcellus gas development to affect water flows and quality have received growing attention from regulatory agencies, natural gas companies, and environmental groups.

The intersection of gas development with sensitive watersheds has received less attention. High Quality and Exceptional Value (EV) watersheds have been designated by the Pennsylvania Department of Environmental



Map showing current number of Marcellus well pads in intact and predicted intact brook trout watersheds. Data source: Eastern Brook Trout Joint Venture.

Protection across the state. Our projections indicate 28 percent of High Quality and 5 percent of Exceptional Values streams have or will have Marcellus gas development during the next two decades. Presence of well pads in these watersheds may not be a problem as long as spill containment measures and erosion and sedimentation regulations are strictly observed and enforced in these areas. More specifically, the projections indicate 3,581 well pads could be located within ½ mile of a High Quality or Exceptional Values streams. Pads within close proximity to High Quality and especially Exceptional Value streams pose more risk than those at greater distances, as there is increased risk for potential spills and uncontained sediments to find their way into streams.



Map showing projected number of Marcellus well pads by 2030 in intact and predicted intact brook trout watersheds under medium scenario. Data source: Eastern Brook Trout Joint Venture.

Native brook trout are one of the most sensitive aquatic species in Pennsylvania watersheds. Brook trout favor cold, highly-oxygenated water and are unusually sensitive to warmer temperatures, sediments, and contaminants. Once widely distributed across Pennsylvania, healthy populations have retreated to a shrinking number of small watersheds. Many of these watersheds overlap with the Marcellus shale formation. A large majority (113) of the 138 intact or predicted intact native brook trout watersheds in Pennsylvania are projected to see at least some Marcellus gas development. Over half (74) are projected to host between 6 – 38 well pads, and the number reaches as high as 64 pads for some intact brook trout watersheds in the high scenario. Rigorous sediment controls and carefully designed stream crossings will be critical for brook trout survival in watersheds, especially upper watersheds, with intensive Marcellus development.

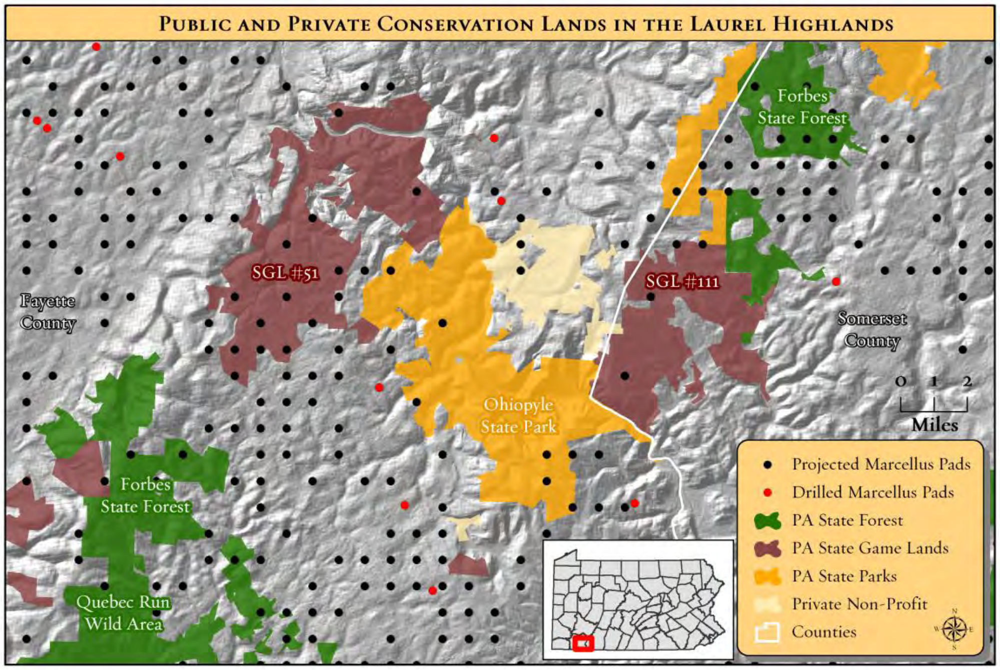
RARE SPECIES


Green salamander © Pennsylvania Fish and Boat Commission

Of the approximately 100,000 species believed to occur in Pennsylvania, just over 1 percent (1052) is tracked by The Pennsylvania Natural Heritage Program (PNHP). Due to low population sizes and immediate threats, these species are rare, declining or otherwise considered to be of conservation concern. PNHP records indicate that 329 tracked species have populations within pixels that have a relatively high modeled probability for Marcellus development. Nearly 40 percent (132) are considered to be globally rare or critically endangered or imperiled in Pennsylvania. Many are found in riparian areas, streams, and wetlands, while others are clustered in unusually biologically diverse areas such as the Youghiogheny Gorge. Some of these species may have only one, two or three populations left in the state. Two examples include the green salamander (*Aniedes aeneus)* with all known populations in relatively high probability Marcellus development pixels and snow trillium (*Trillium nivale*) with 73 percent of known populations in relatively high probability pixels. A well-managed screening system to identify the presence of these species and their preferred habitats will be critical to their survival as energy development expands across the state.

RECREATION

Pennsylvania has built one of the largest networks of public recreation lands in the eastern United States, but much of it could see Marcellus and other natural gas development in coming decades. Of the 4.5 million acres of state and federal lands in the state, we estimate as little as 500,000 acres are permanently protected from surface mineral development, including gas drilling. State and federal agencies do not own mineral rights under at least 2.2 million acres. Most other areas where the state does own mineral rights can be leased, such as the estimated 700,000 acres previously leased for gas development on state forest lands. Severe budget pressures will likely to tempt the legislature to lease additional lands in the future. Our projections excluded state Wild and Natural Areas, National Park lands, and Congressionally-designated Wilderness Areas but otherwise assumed that high probability Marcellus gas pixels on public lands could be developed. The low scenario projects 897 pad locations on State Forest and State Game Lands which expands to 1,438 well pads in the medium scenario and 2,096 pads in the high scenario. The focal area below illustrates what the overlap of future gas development and conservation lands could look like in the medium scenario for the southern Laurel Highlands. It projects 7 well pads in the portion of Forbes State Forest visible in the focal area above, 13 pads on State Game Lands 51, and 3 on State Game Lands 111.



Map showing projected Marcellus well pads under the medium scenario on public and private conservation lands in the Laurel Highlands.

Pennsylvania's state park system, recognized as one of the best in the nation, illustrates the challenge of protecting recreational values in areas of intensive Marcellus development. While the DCNR has a long standing policy of not extracting natural resources in state parks, it does not own the mineral rights under an estimated 80 percent of the system's 283,000 acres. Our projections indicate Marcellus well pads could be located in between 9 and 22 state parks.

AVOIDING FOREST IMPACTS IN THE LAUREL HIGHLANDS

The projected potential impacts of Marcellus gas energy development assume recent patterns of development will continue. Given the relatively large areas drained by Marcellus gas pads (depending on the lateral length and number of wells per pad), there is flexibility in how they are placed. This allows us potentially to optimize between energy production and conservation outcomes. To look at how conservation impacts could be minimized, we examined how projected Marcellus gas pads could be relocated to

Projected Well Pads on State Lands (Medium Scenario)	
DCNR State Forests	**1,002**
DCNR State Parks	**41**
State Game Lands	**436**
Total State Lands	**1,479**

avoid forest patches in the Southern Laurel Highlands in Fayette and Somerset counties. This area is important because it represents a unique ecological region with a large amount of state land as well as private farmland and forest land. The area is also facing great pressure to develop the Marcellus Gas resource. The focus area included approximately 350 square miles and included Chestnut Ridge on its western border and Laurel Ridge on its east. Within the area, there are two state parks (Ohiopyle State Park and Laurel Hill State Park), two State Game Lands (SGL 51, SGL 111), and state forest land (Forbes State Forest).

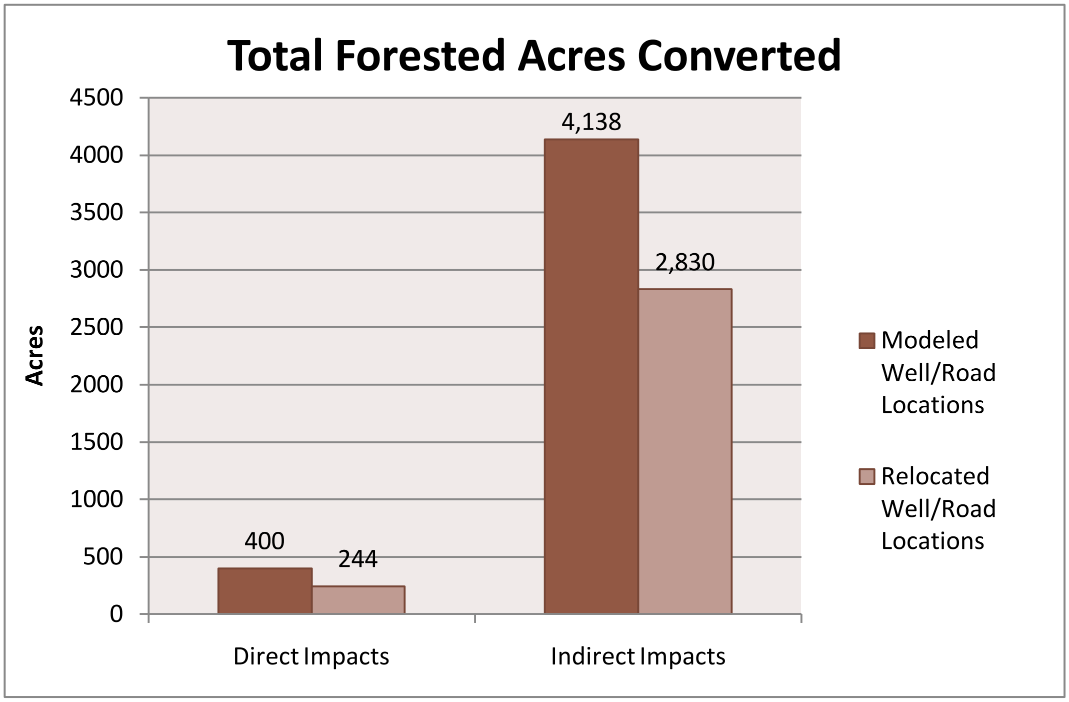
The Medium Scenario projected 127 well pads in the focus area. Fourteen well pads were projected in agricultural fields, 33 were in edge habitat (within 100 m of the forest edge), 11 fell within existing cleared areas (e.g. strip mines), and 69 were in forest. There were five pads on Ohiopyle State Park, and 13 within a mile of its boundary. Laurel Ridge State Park contained two pads. Forbes State Forest had seven modeled pads. State Game Lands 111 had 3 pads, and SGL 51 had 13. It was not clear if DCNR State Parks Bureau or the Game Commission control the sub-surface mineral rights beneath the 23 modeled pads. Given that 80 percent of mineral rights are severed on State Park and State Game Lands (and close to 100 percent in western parts of the state), we have assumed that drilling could happen at those projected locations.

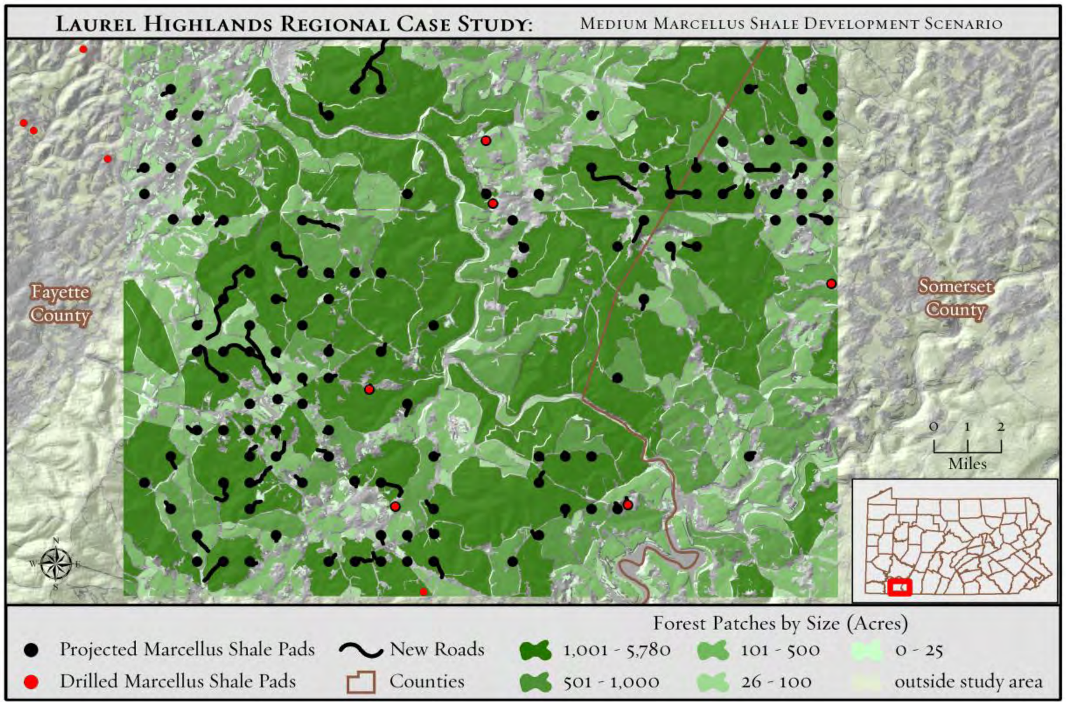
To assess additional impacts beyond the well pad itself, we placed a new and/or improved road from the projected pad to the nearest existing road (ESRI Roads Layer). We placed new roads along existing trails, paths and openings whenever detectable on aerial photo imagery (used Bing Maps and 2005-2006 PA Map imagery), avoiding wetlands, steep slopes, cliffs, rock outcrops, and buildings, and where possible, rivers, streams, and forest patches. The projected pads and roads required clearing 400 acres of forest.

Can a modest shift in the location of well pads reduce impacts to forest patches and conservation lands? To reduce the impacts to forest habitats, the wells were relocated to nearby existing anthropogenic openings, old fields, or agricultural fields. Attempts were made to maintain the 4,200 foot (1,260 m) distance between modeled wells. If nearby open areas did not exist, the locations of the well pads were moved toward the edges of forest patches to minimize impacts to forest interior habitats. A set of rules was developed and followed to minimize bias, including:

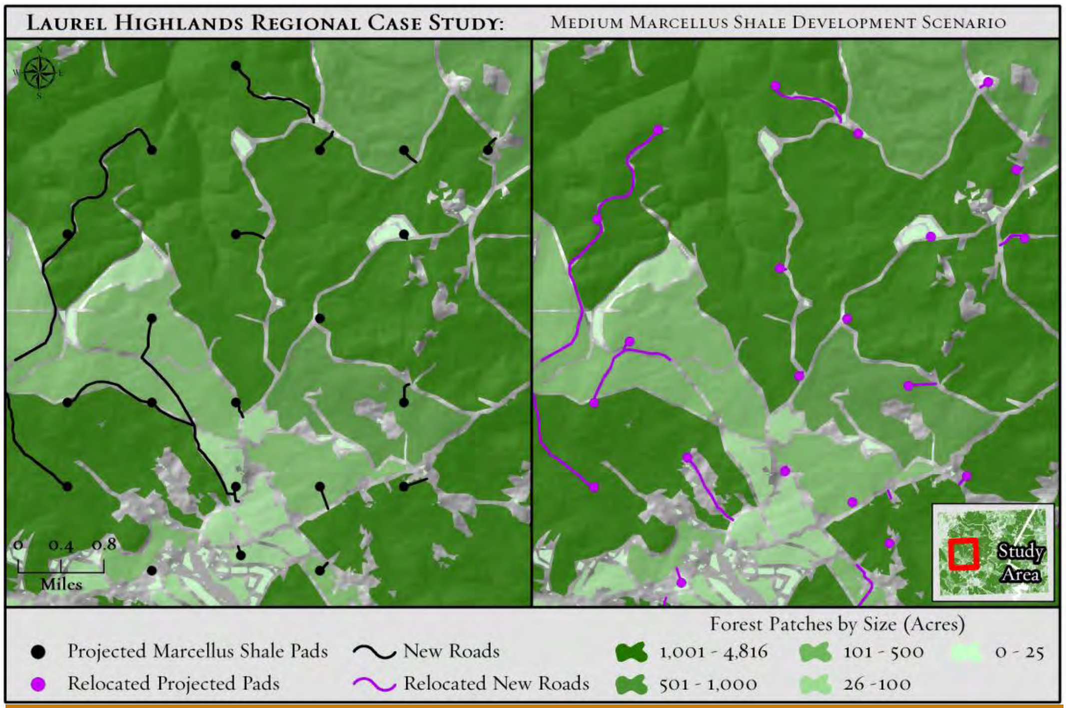
1. Modeled well pads were not relocated if they occurred in old fields or agricultural fields.
2. Modeled well pads that occurred in forest or edge habitat were moved but well pads were placed in the same general areas as the modeled well pad;
3. Attempts were made to avoid placing relocated well pads any closer that the minimum distance between pads, as specified by the medium scenario (1260 m)
4. Agriculture, cleared land (e.g., former strip mines), or otherwise opened land cover was favored over forest or edges for relocating well pads;
5. If the well pad could not be placed in an open area, forest edges were favored over deep interior forest;
6. Residential areas were avoided. Relocated well pads were placed at least 500 feet (150 m) from homes;
7. Wetlands, water, steep slopes, cliffs, rock outcrops, creeks and rivers, buildings and manicured lawns were avoided;
8. Relocated well pads were only placed in areas with similar to those that supported modeled pads.
9. Relocated well pads often were connected to roads using existing trails, paths and openings whenever detectable on aerial photo imagery (used Bing Maps and 2005-2006 PA Map imagery);
10. The same number of relocated well pads were placed on state lands and Western Pennsylvania Conservancy lands as they were in the modeled output;
11. When the modeled well pad occurred within a forest patch with no nearby alternative locations (due to proximity of other wells or environmental constraints), the projected well pad was not relocated.

The relocated wells and roads did not eliminate forest impacts in this heavily forested landscape, but there was a significant reduction. Total forest loss declined almost 40% while impacts to interior forest habitats adjacent to new clearings declined by a third.





Location of 127 projected Marcellus well pads and new roads in the study area in the southern Laurel Highlands.



Relocated well pads (on the right) reduced forest clearing and forest interior habitat impacts by 40 % and 33% respectively compared to the projected well pads (on the left).

Key Findings

Key findings from the Pennsylvania Energy Impacts Assessment for Marcellus Shale natural gas include:

- About 60,000 new Marcellus wells are projected by 2030 in Pennsylvania with a range of 6,000 to 15,000 well pads, depending on the number of wells per pad;

- Wells are likely to be developed in at least 30 counties, with the greatest number concentrated in 15 southwestern, north central, and northeastern counties;

- Nearly two thirds of well pads are projected to be in forest areas, with forest clearing projected to range between 38,000 and 90,000 acres depending on the number of number of well pads that are developed. An additional range of 91,000 to 220,000 acres of forest interior habitat impacts are projected due to new forest edges created by well pads and associated infrastructure (roads, water impoundments);

- On a statewide basis, the projected forest clearing from well pad development would affect less than one percent of the state's forests, but forest clearing and fragmentation could be much more pronounced in areas with intensive Marcellus development;

- Approximately one third of Pennsylvania's largest forest patches (>5,000 acres) are projected to have a range of between 1 and 17 well pads in the medium scenario;

- Impacts on forest interior breeding bird habitats vary with the range and population densities of the species. The widely-distributed scarlet tanager would see relatively modest impacts to its statewide population while black-throated blue warblers, with a Pennsylvania range that largely overlaps with Marcellus development area, could see more significant population impacts;

- Watersheds with healthy eastern brook trout populations substantially overlap with projected Marcellus development sites. The state's watersheds ranked as "intact" by the Eastern Brook Trout Joint Venture are concentrated in north central Pennsylvania, where most of these small watersheds are projected to have between two and three dozen well pads;

- Nearly a third of the species tracked by the Pennsylvania Natural Heritage Program are found in areas projected to have a high probability of Marcellus well development, with 132 considered to be globally rare or critically endangered or imperiled in Pennsylvania. Several of these species have all or most of their known populations in Pennsylvania in high probability Marcellus gas development areas.

- Marcellus gas development is projected to be extensive across Pennsylvania's 4.5 million acres of public lands, including State Parks, State Forests, and State Game Lands. Just over 10 percent of these lands are legally protected from surface development.

- Integration of conservation features into the planning and development of Marcellus gas well fields can significantly reduce impacts. For example, relocating projected wells to open areas or toward the edge of large forest patches in high probability gas development pixels in the southern Laurel Highlands reduces forest clearing by 40 percent and forest interior impacts by over a third.

Additional Information

- Geologic information on the Marcellus shale formation in Pennsylvania: http://www.dcnr.state.pa.us/topogeo/oilandgas/marcellus_shale.aspx

- Estimates of Marcellus shale formation gas reserves: http://geology.com/articles/marcellus-shale.shtml

- Baker-Hughes weekly oil and gas rig count http://gis.bakerhughesdirect.com/Reports/StandardReport.aspx

- Pennsylvania Department of Environmental Protection, Permit and Rig Activity Report: http://www.dep.state.pa.us/dep/deputate/minres/oilgas/RIG10.htm

- Copeland, H. E., K.E. Doherty, D.E. Naugle, A. Pocewicz, and J. M. Kiesecker. 2009. Mapping Oil and Gas Development Potential in the US Intermountain West and Estimating Impacts to Species: http://www.plosone.org/article/info%3Adoi%2F10.1371%2Fjournal.pone.0007400

- Overview of forest fragmentation impacts on forest interior nesting species: http://www.state.nj.us/dep/fgw/neomigr.htm

- Overview of Pennsylvania High Quality and Exceptional Value Streams: http://www.dcnr.state.pa.us/wlhabitat/aquatic/streamdist.aspx

- Pennsylvania Department of Environmental Protection, Chapter 93 Water Quality Standards, Exceptional Value and High Quality Streams: data downloaded from Pennsylvania Spatial Data Access: http://www.pasda.psu.edu

- Eastern Brook Trout Joint Venture intact brook trout watersheds: http://128.118.47.58/EBTJV/ebtjv2.html

- Overview of Carnegie Museum of Natural History, Powdermill Nature Reserve, and the Pennsylvania Game Commission's 2nd Pennsylvania Breeding Bird Atlas Project: http://www.carnegiemnh.org/powdermill/atlas/2pbba.html

- Pennsylvania Natural Heritage Program, including lists of globally rare and state endangered and imperiled species: http://www.naturalheritage.state.pa.us/

- U.S. Department of Agriculture, Natural Resources Conservation Service, National Agriculture Imagery Program: http://datagateway.nrcs.usda.gov/GDGOrder.aspx

- DigitalGlobe, GlobeXplorer, ImageConnect Version 3.1: http://www.digitalglobe.com

Wind

Wind has become one of the country's fastest growing sources of renewable energy. Pennsylvania is a leader in the industry as host to several wind company manufacturing plants and corporate headquarters. Wind energy development has been spurred by its potential to reduce carbon emissions, promote new manufacturing jobs, and increase energy independence. Technological advances have expanded the size and efficiency of wind turbines during the past decade. This, together with state and federal incentive programs, has facilitated wind development in Pennsylvania, which otherwise ranks relatively low among states for its potential wind generation capacity. The eight turbines installed next to the Pennsylvania Turnpike in Somerset County a decade ago have grown to nearly 500 turbines, with more permitted for construction (AWEA, 2010). Topography is a key factor in average wind speeds across Pennsylvania, so nearly all turbines have been built on mountain ridgelines or on top of high elevation plateaus.

Wind energy has become the most symbolic icon of the shift toward a low carbon economy. With no air emissions or water consumption, it is one of the cleanest renewable energy types. Communities across the state benefit economically as rural landowners lease their properties, skilled jobs are created to manufacture turbines, and workers are hired to install and maintain turbines. Wind development has faced controversy in some areas from neighboring landowners and those worried about impacts to migrating birds and bats. The wind industry, government agencies, and independent researchers have invested considerable effort in trying to better understand impacts on birds and bats. For example, 26 wind development companies have signed a cooperative agreement with the Pennsylvania Game Commission to conduct bird, bat and animal surveys using specified protocols in proposed development areas. Among other findings have been the discovery of the Pennsylvania's second largest Indiana bat maternal colony and a variety of previously undocumented foraging and roosting locations for the state's two rarest bats (Indiana and eastern small-footed). Less understood are the potential habitat impacts of wind development in the northeastern United States. This assessment, therefore, focuses on impacts to forest and stream habitats and selected species of conservation concern that may be vulnerable to development of ridgetop habitats.

What is Wind Energy?

Wind mills have powered grain processing and water pumping in agriculture around the world – most famously in the Netherlands – for centuries. The first modern wind facilities to generate electricity were built in California in the early 1980s. Rated at less than 0.5 MW capacity per turbine, the towers were only 50 feet tall. These facilities were poorly designed and generated considerable controversy because they caused significant mortalities to migrating hawks and eagles. Wind energy development did not expand appreciably until the late 1990s when newer turbine designs and federal energy incentives stimulated the development of new facilities. These turbines were rated at 1.0 or 1.5 MW capacity and reached about 200 feet high at the tip of their rotor. Since the power produced by a wind turbine is proportional to the cube of the blade size and how high in the air it is; turbine size, height and power ratings have expanded steadily. The largest turbines installed in Pennsylvania are now rated at

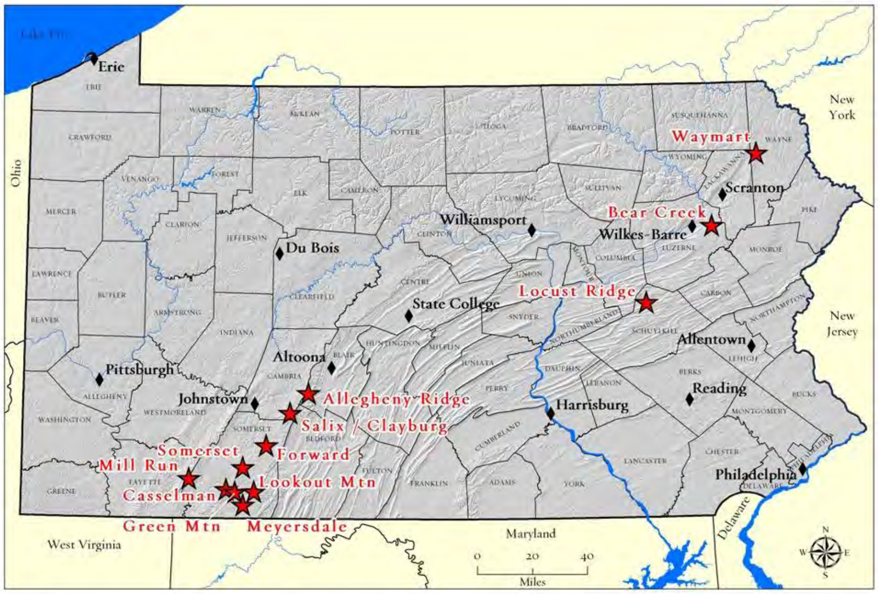
2.5 MW (the average was 1.8 MW in 2009) and reach over 400 feet to the tip of the rotor at the apex of its rotation.

Location is everything for wind development in the northeastern United States. Unlike the vast windswept plains in the Midwest and the intermountain West, high wind speeds in the Northeast are primarily confined to mountain ridgetops, plateau escarpments, and the Atlantic and Great Lake shorelines. Areas that have a wind power class rating of 3 or more (300 watts per m^2) are potentially feasible for wind power development. Wind companies will lease areas that seem to have the most favorable characteristics including wind class, flat pad sites, proximity to transmission lines, and proximity to existing highways. Before development, a wind development company will typically place an anemometer tower on potential development sites to improve knowledge about wind power at the site during a year or longer monitoring period. The turbines are mounted on pads at least 800 feet apart with an access road between towers. The average size of wind facilities has been growing steadily since the first eight were established in 2000. The two largest facilities are now between 75 and 100 turbines.

Several steps have been taken to address potential conflicts between wind development and wildlife in Pennsylvania. The Pennsylvania Game Commission (PGC) has a voluntary agreement in place with most wind companies active in the state to screen proposed facilities for possible impacts to birds and bats and migratory pathways. Participating wind companies carry out pre-construction monitoring for birds and bats. If possible conflicts are identified, PGC works with wind companies to avoid or minimize impacts and to continue monitoring post construction in some cases. Second, the Pennsylvania Wind and Wildlife Collaborative (PWWC) was established in 2005 with a state goal to develop a set of “Pennsylvania-specific principles, policies and best management practices, guidelines and tools to assess risks to habitat and wildlife, and to mitigate for the impact of that development.” Several studies on wildlife and habitat issues have been commissioned, though guidelines and Best Management Practices (BMPs) have not been released.

Current and Projected Wind Energy Development

We documented the spatial foot print of 319 wind turbines at 12 wind facilities across the state by comparing aerial photos taken before and after development. Turbine pads, roads, and other new clearings were digitized for all 12 facilities visible in 2008 images from the

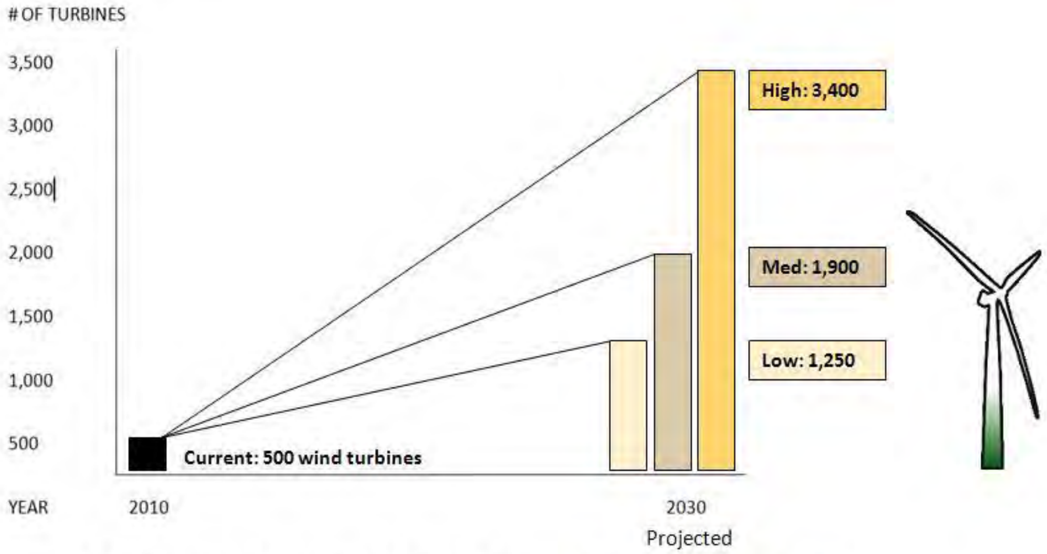


Map showing 12 wind facilities included in the spatial footprint analysis.

National Agriculture Imagery Program. The ground excavated for turbines, roads, and associated infrastructure (e.g., clearings for constructions staging areas or electrical sub-stations) is the most obvious spatial impact. For each turbine site, turbine pads, new roads, staging areas, and sub-stations were digitized and measured. Turbine pads occupy 1.4 acres on average, while the associated infrastructure (roads, staging areas, and substations) takes up an additional half acre, for a total of 1.9 acres of spatial impact per wind turbine.

Average Spatial Disturbance for Wind Energy Development in Forested Context (acres)		
Forest cleared for wind turbine	**1.4**	**1.9**
Forest cleared for associated infrastructure (roads, other cleared areas)	**0.5**	
Indirect forest impact from new edges	**13.4**	
TOTAL DIRECT AND INDIRECT IMPACTS	**15.3**	

As with Marcellus gas development, adjacent lands can also be impacted even if they are not directly cleared (See p. 11 for a description of forest edge impacts on forest "interior" species). To assess the potential interior forest habitat impact, we created a 330 foot buffer into forest patches from new edges created by wind turbine and associated infrastructure development. For turbine sites developed in forest areas (about 80% of the 319 turbines), an average area of 13.4 acres of interior forest habitat was lost in addition to the 1.9 acres of directly cleared forest.



Key drivers: Alternative Energy Portfolio Standard (AEPS) and projected contribution of wind to meeting that standard.

We project between 1,250 and 3,400 total wind turbines will be erected in Pennsylvania by 2030.

The number of wind turbines built in Pennsylvania will certainly expand during the next two decades. Various factors will drive exactly how many turbines are ultimately built including electricity prices, state and federal incentives, technological improvements, energy and climate policy, regulatory changes, and social preferences. Our projections assume economic, policy, and social conditions will remain favorable enough to promote steady expansion of wind development in the state since we cannot reasonably forecast energy prices, technological developments, and policy conditions. The key driver in our low scenario is that companies will use wind energy to meet 70 percent of the current Alternative Energy Portfolio Standard (AEPS) Tier 1 standard (8 percent of electric generation). This projection indicates an additional 750 turbines (2 MW average) will be added to the 500 turbines currently operating. The key driver in our medium scenario is that utilities will use wind energy to meet 70 percent of an expanded AEPS 15% Tier 1 standard, as proposed in recent draft legislation. That scenario would add 1,400 new turbines to those already built. The high scenario used in this assessment is based on the 20% wind power electric generation scenario used by the National Renewable Energy Laboratory in the Eastern Wind Integration Study (EWITS). This scenario would require 2,900 additional turbines.

Where are those new turbines in each scenario more and less likely to go? To start, we created a probability surface by looking at a range of variables that might be relevant to a company's decision to develop a wind facility with wind turbines that have already been built. We used the maximum entropy modeling approach used to develop the Marcellus gas probability surface (see p. 13) and built the model using 580 existing and permitted wind turbines. Variables that potentially drive wind energy development were chosen based on data availability and included wind power (W/m^2), distance to transmission lines, percent slope, distance to roads, and land cover. An additional 193 existing and permitted wind turbines were used to test the validity of the model's probability surface and the model was found to be 95.8% accurate in predicting existing and permitted turbines from randomly sampled undeveloped areas. The resulting probability map indicates many long, narrow high probability sites along ridge tops, and several wider areas on high plateaus and along the Lake Erie coastline.

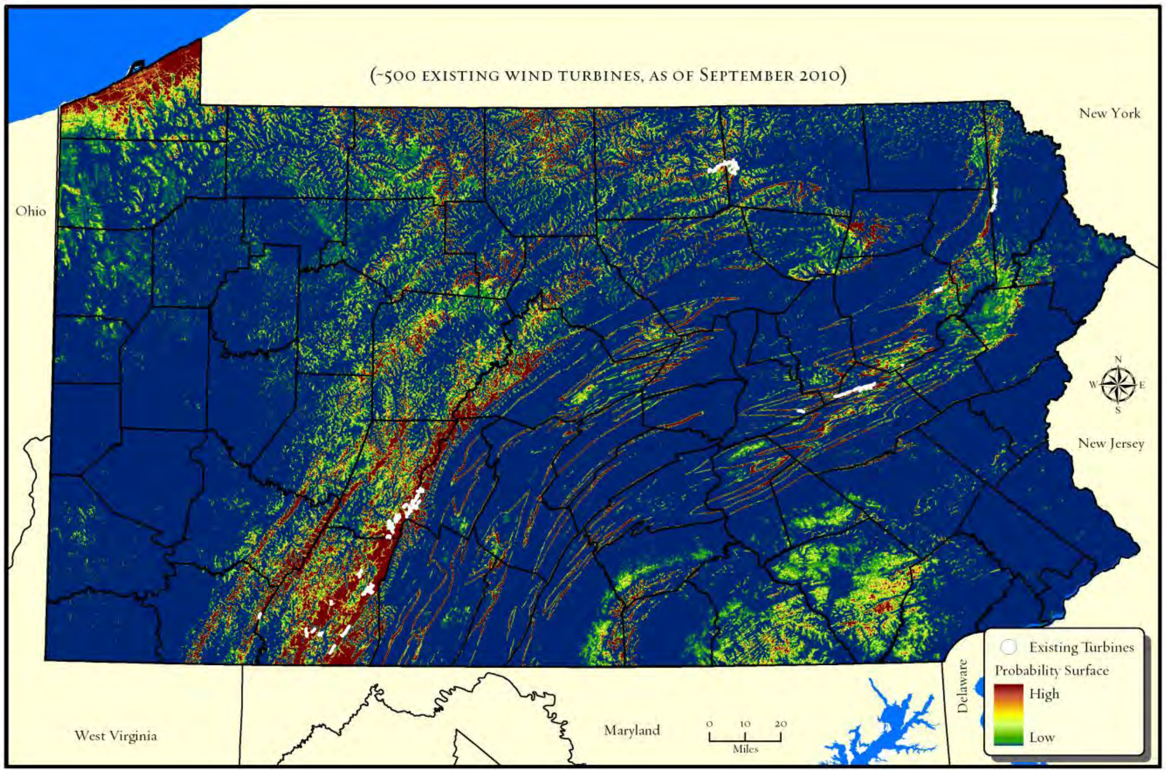
To determine where wind development is more likely, we searched for the highest probability areas where wind turbines in each scenario might be located. The probability surface was re-sampled from 30-meter to 60-meter resolution (0.89 acres) to represent the approximate geographic footprint of wind turbines based on aerial photo assessment. We selected the highest probability pixel, buffered that pixel by a minimum separation distance of 800 feet (240 meters – the average minimum distance between existing turbines), and then selected the next highest probability pixel, and so on. Pixels were selected until the threshold for each scenario was reached (low – 700 turbines; medium – 1,200 turbines; high – 2,700 turbines). The selected pixels were then converted into points for map display purposes.

The resulting projected turbine locations occurred in strings, groups, or scattered single turbines, mostly in southwest, north central and northeastern parts of Pennsylvania. Wind turbines, however, are almost always located in clusters rather than widely separated locations for individual turbines. In order to represent viable wind farms, we selected clusters of pixels with high probability to represent viable wind facilities, based on the following:

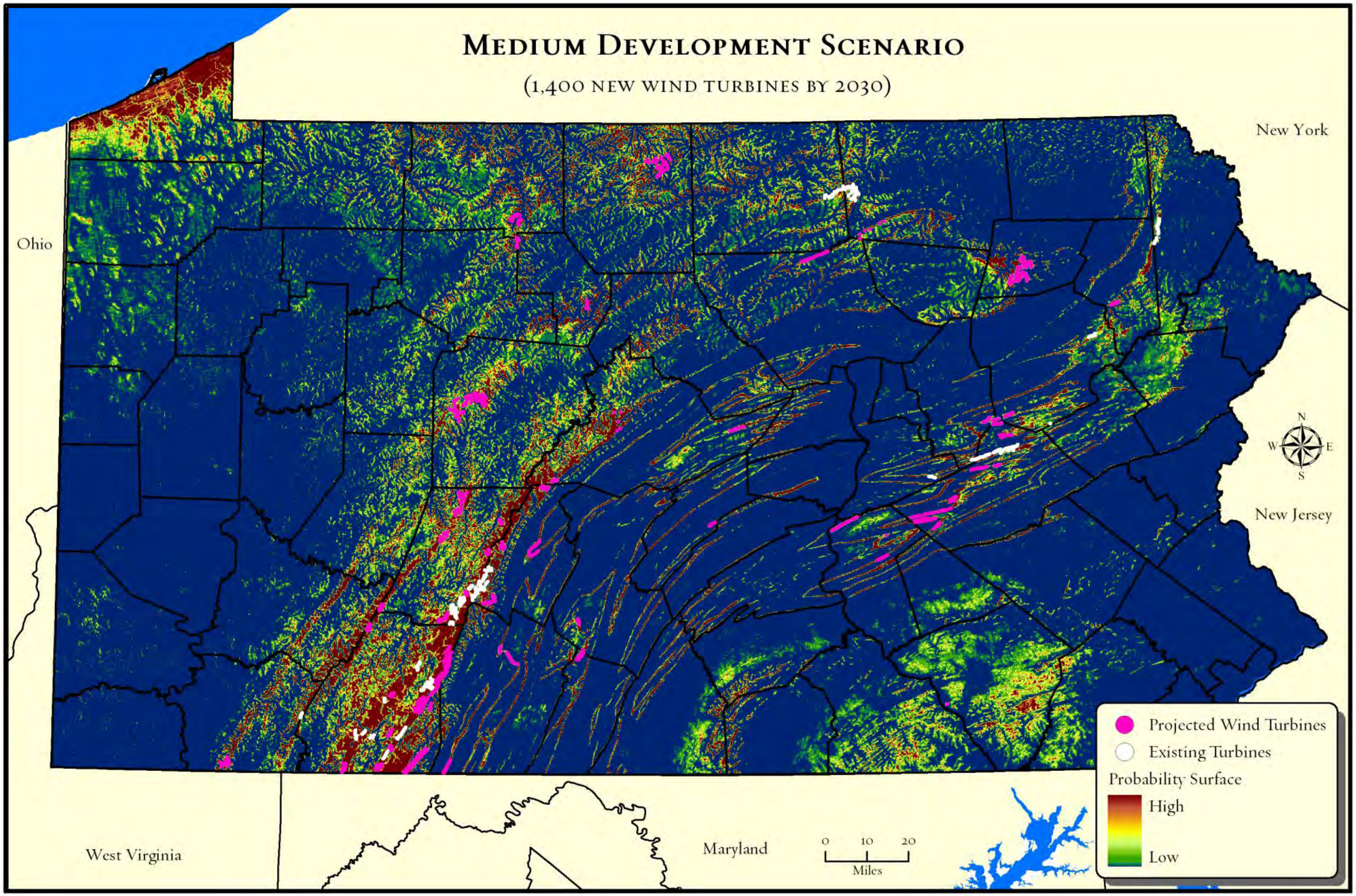
- Excluded areas approximately 300 meters (1,000 ft) from existing homes (as visible in aerial imagery)
- Excluded buffers of regional airports by 6,096 m (20,000 ft) and local airports by 3,048 m (10,000 ft)
- Excluded buffers of existing turbines (buffer = 960 m or 4 times the minimum turbine separation distance of 240 m)
- Excluded Pennsylvania State Parks, Pennsylvania State Forests, and Pennsylvania State Game Lands
- Excluded setbacks of 152 m (500 ft) from the boundaries of state and federal lands

- Required a minimum of 6 projected turbines grouped together to be considered a potentially viable site
- Selected already proposed wind turbines (based on permit data from the Federal Aviation Administration)

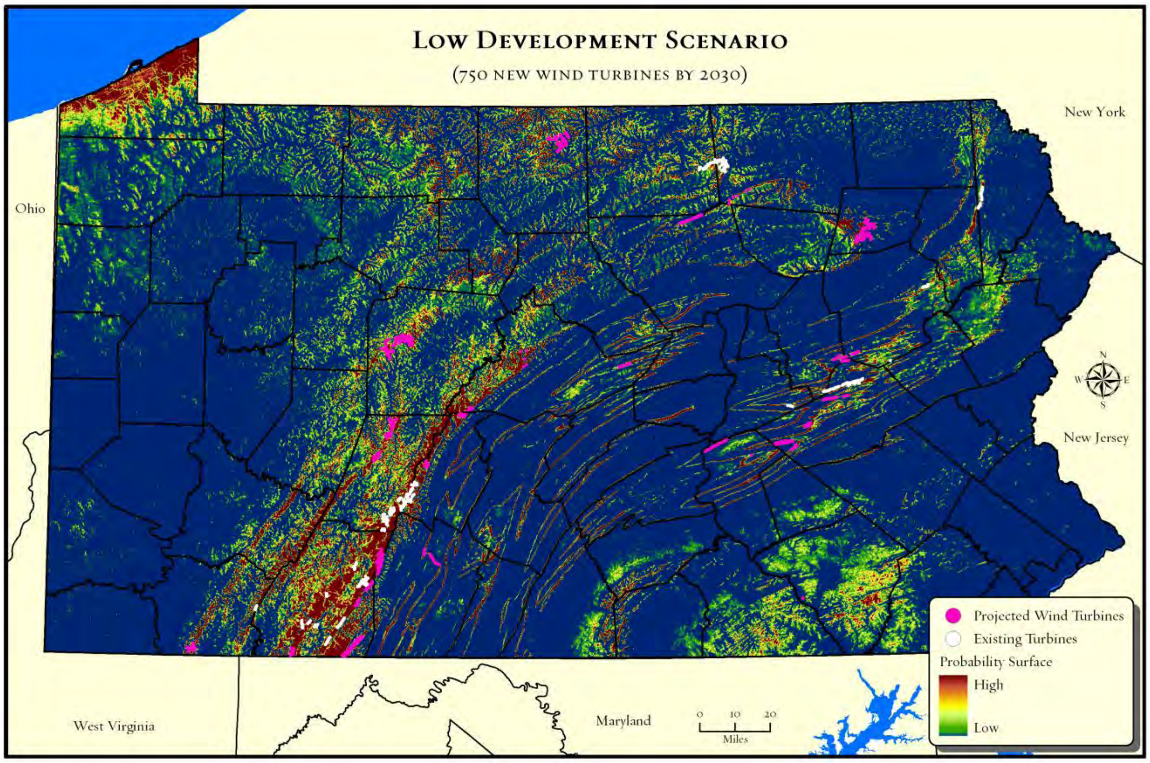
Potential wind facilities were manually selected by identifying groupings of projected wind turbines. Scenarios are cumulative, so the medium scenario includes turbines in both the low and medium scenarios, whereas the high scenario includes all projected turbines.



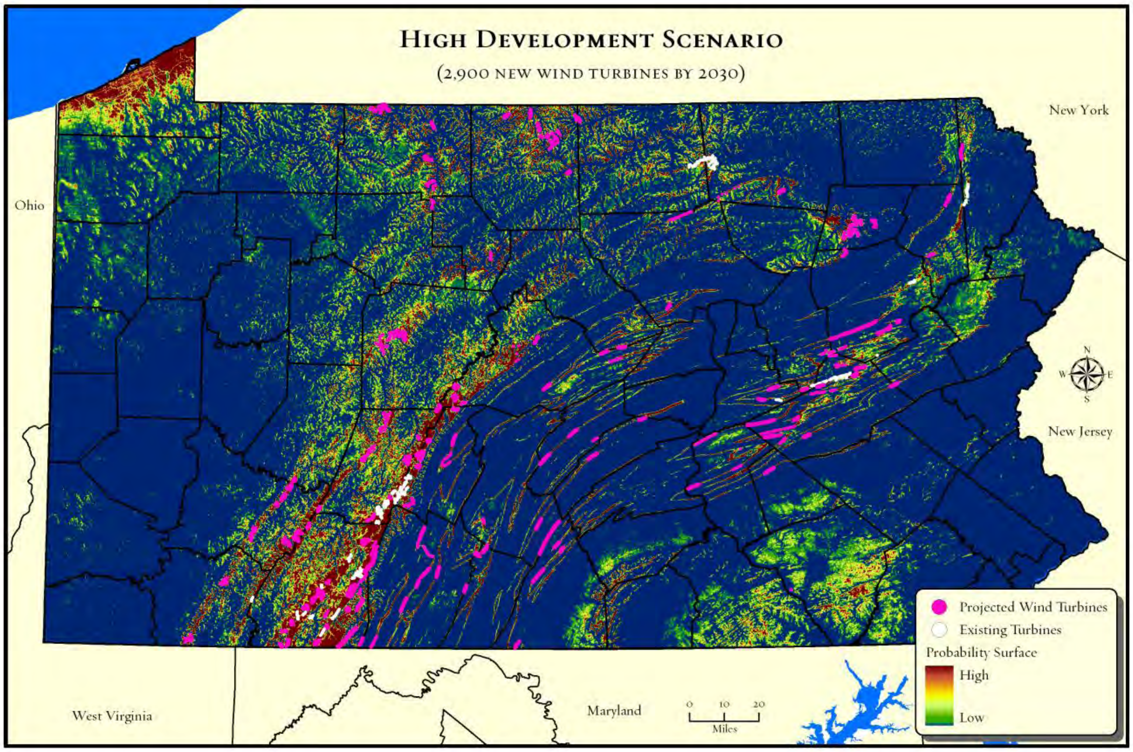
Map showing existing wind turbines with the probability that a given area will be developed indicated by color (dark red is high probability; dark blue is low).



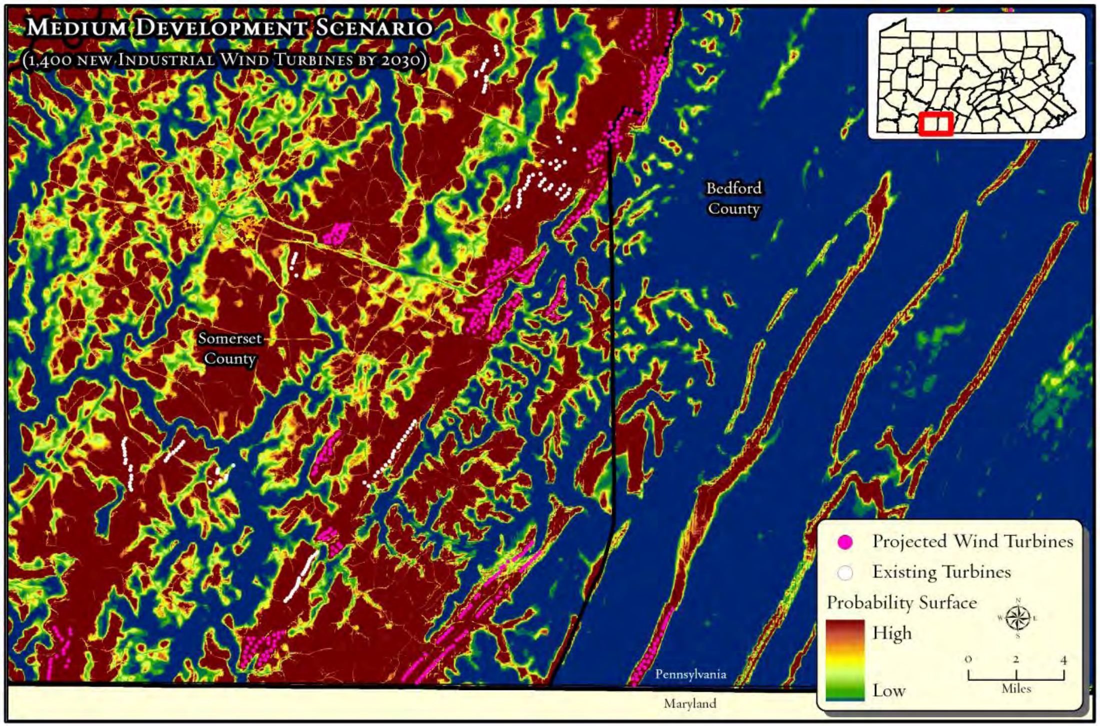
Map showing 1,400 new wind turbines projected by 2030 under the medium development scenario.



Map showing 750 new wind turbines projected by 2030 under the low development scenario.



Map showing 2,900 new wind turbines projected by 2030 under the high development scenario.



Map showing medium wind development scenario within Somerset and Bradford counties.

These geographic projections of future wind energy development are spatial representations of possible scenarios. They are not predictions. We faced several constraints in developing the geographic scenarios:

- We do not have the detailed wind power data that wind companies have developed through anemometer tower monitoring.
- We do not have the detailed location of wind energy leases.

Still, we believe the overall geographic patterns in the projected wind development locations are relatively robust for several reasons. We used over 500 existing or permitted wind turbines to build the model and nearly 200 additional existing and permitted wind turbine sites were used to validate the model. This is typically a sufficient sample size for building predictive models. They are also consistent with Black and Veatch (2010) projected locations for wind facilities under a 15% renewable energy portfolio standard.

Conservation Impacts of Wind Energy Development

What is the overlap of the areas with the highest probability of future wind energy development and those areas known to have high conservation values? To answer this question, we intersected the projected wind energy facilities with high conservation value areas. We looked at several examples from four categories of conservation value, including:

- Forest habitats
- Freshwater habitats

- Species of conservation concern
- Outdoor recreation

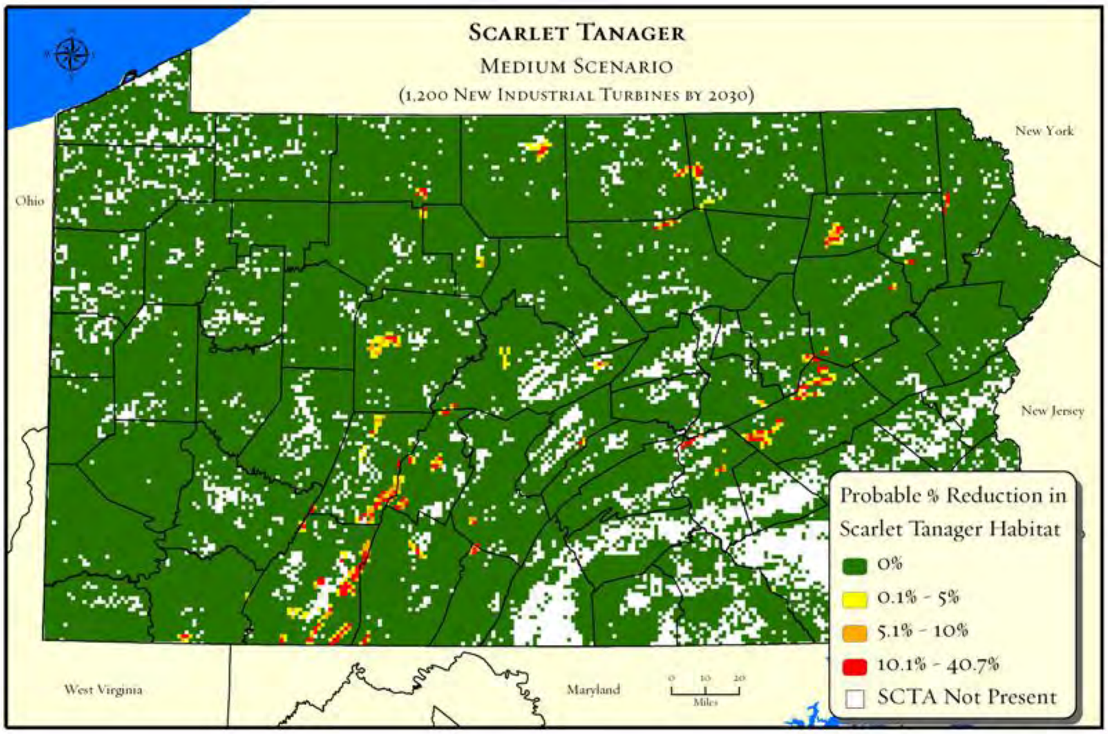
Areas of overlap between likely future wind development areas and priority conservation areas in Pennsylvania are substantially less than the conservation area overlap with likely future Marcellus development areas, largely because the projected foot print will be much smaller.

Forests

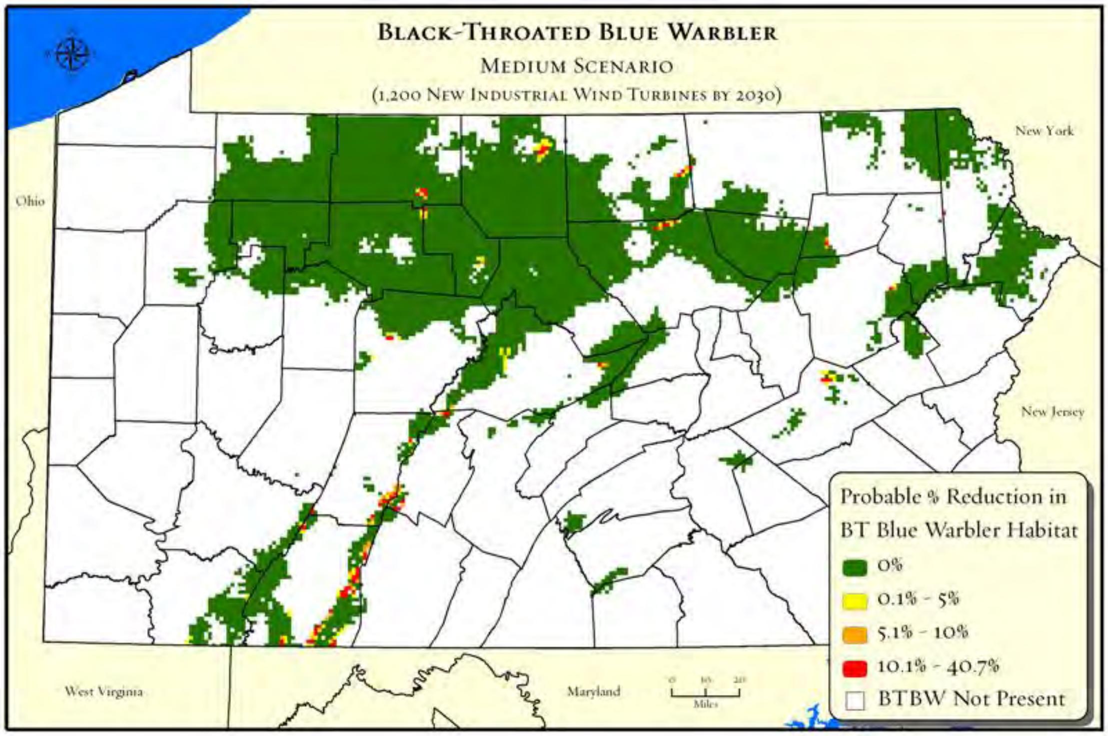
A large majority of projected wind turbines are found in forest patches, about 80 percent for each of the scenarios. The low scenario would see 600 new wind turbines in forest areas. With a cleared forest average of 1.9 acres per turbine (including roads and other infrastructure), the total forest loss would be a modest 1,900 acres. Indirect impacts to adjacent forest interior habitats would total an additional 13,400 acres. Forest impacts from the medium scenario (1,520 projected turbines in forest locations) would be 2,900 cleared forest acres and an additional 20,400 acres of adjacent forest interior habitat impacts. For the high scenario (2,720 turbines in forest areas) 5,200 acres would be cleared and an additional 36,500 acres of forest interior habitats would be affected by new adjacent clearings. On a statewide basis, the projected forest losses and accompanying interior forest habitat impacts will be minor given the Pennsylvania's 16 million acres of forest. Locally, these impacts could be significant for individual large forest patches where wind development takes place.

All forests have conservation value, but large contiguous forest patches are especially valuable because they sustain wide-ranging forest species, such as northern goshawk, than small patches. They are also more resistant to the spread of invasive species, can better withstand damage from wind and ice storms, and provide more ecosystem services – from carbon sequestration to water filtration – than small patches. The Nature Conservancy and the Western Pennsylvania Conservancy's Forest Conservation Analysis mapped nearly 25,000 forest patches in the state greater than 100 acres. Patches at least 1,000 acres in size are about a tenth of the total (2,700). The medium projected wind development scenarios indicate 73 patches (3%) greater than 1,000 acres in size are projected to have at least one wind turbine and associated infrastructure. Patches at least 5,000 acres in size are relatively rare (only 316 patches). The medium wind scenario indicates about 21 (7%) of these patches could be affected by future wind turbine development. Most affected large patches have multiple projected wind turbines (as many as 36). Typically, a large patch is split by wind development into two or three smaller patches due the linear pattern of development. Projected gas well pads, by contrast, are more likely to fragment a large patch into multiple smaller patches.

Forest interior bird species could be affected by the clearing of forest and adjacent edge effects that wind turbine facilities create in a forest context. We used data from the 2nd Breeding Bird Atlas Project (see p. 20) to assess the potential impact on forest interior species. The resulting maps show the estimated reduction in habitat for that species in each high wind development gas probability pixel (including both cleared forest and adjacent edge effects). Scarlet Tanagers are perhaps the most widespread forest interior nesting bird in the state. Since they are so widespread, the vast majority of their range in the state is outside of the most likely wind development areas. Scarlet Tanager populations could decline by an insignificant amount due to habitat losses projected in the medium scenario. Black-throated blue warblers are more narrowly distributed in Pennsylvania favoring mature northern hardwood and coniferous forests with a thick understory, frequently in mountain terrain. Likewise, population declines would also be extremely small for Black-throated blue warblers under the medium scenario.



Map showing estimated percent loss of habitat for Scarlet Tanagers under the medium wind scenario.

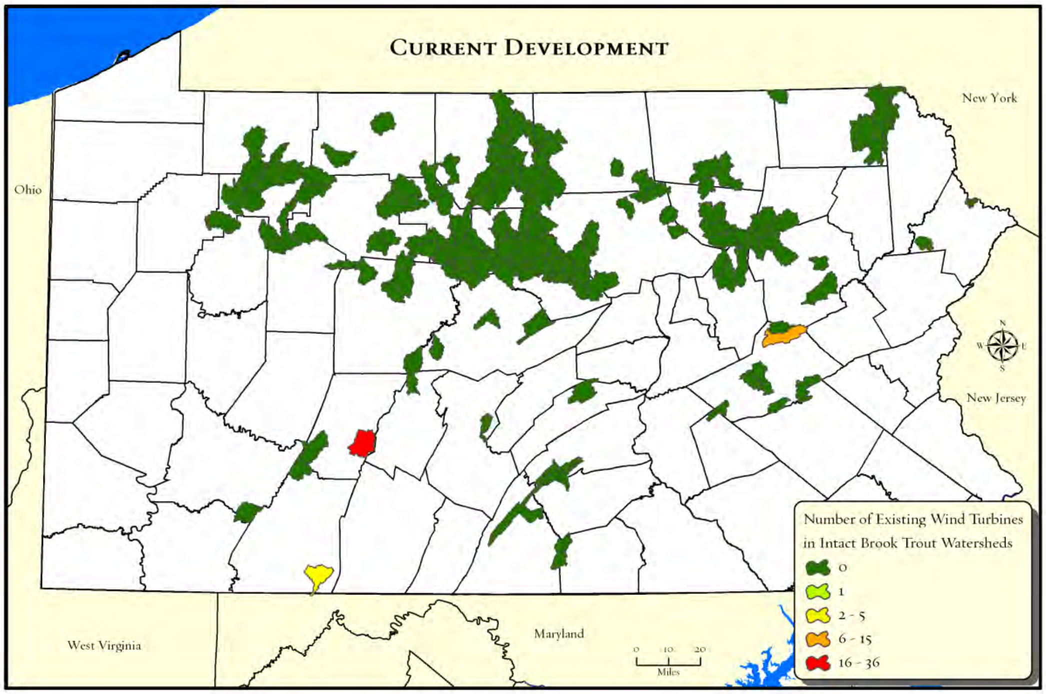


Map showing estimated percent loss of habitat for Black-Throated Blue Warblers under the medium wind scenario.

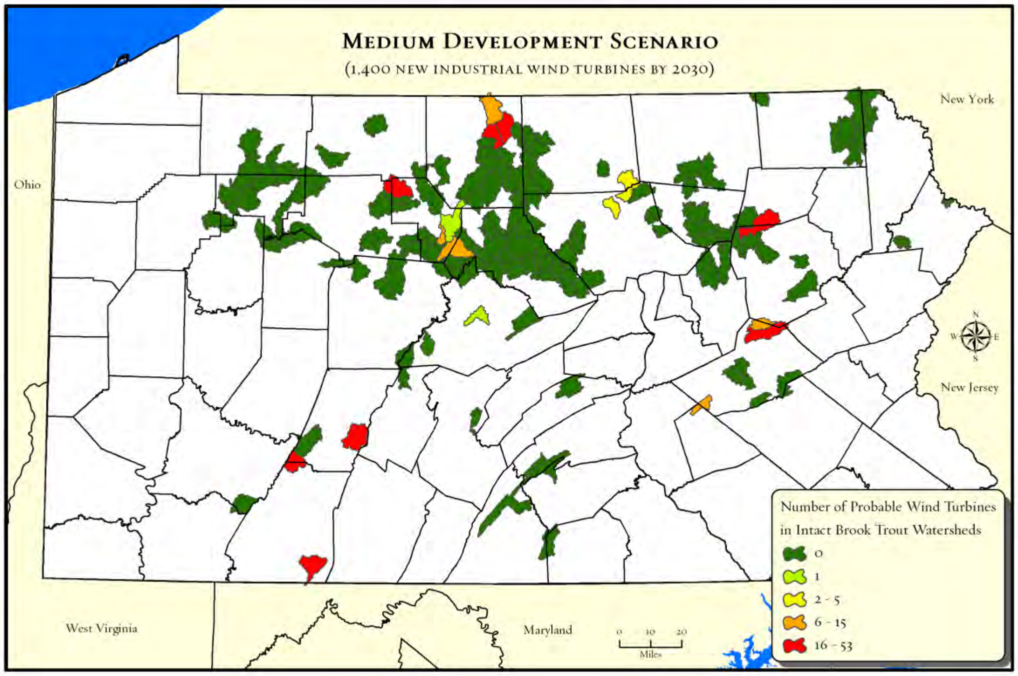
Freshwater

Wind energy and freshwater habitats are not often thought of in the same context since most wind facilities are generally in high elevation areas away from rivers and streams. The exceptions are small headwater streams, some of which may be classified as Exceptional Value watersheds. Our medium scenario projection indicates that 9 percent of future turbine development could be located within ½ mile of an Exceptional Value stream.

Native brook trout are one of the most sensitive species in Pennsylvania watersheds. Brook trout favor cold, highly-oxygenated water and are unusually sensitive to warmer temperatures, sediments, and contaminants. Once widely distributed across Pennsylvania, healthy populations have retreated to a shrinking number of small watersheds. The potential impact on intact brook trout watersheds, however, does increase significantly between the low to high scenarios. Wind turbines have been built in just five of the intact brook trout watersheds identified by the Eastern Brook Trout Joint Venture. That number would expand to 13 in the low scenario, 19 in the medium scenario, and 28 in the high scenario. The presence of wind turbines may pose a limited risk in many of these watersheds, principally from soil disturbance near headwater streams.



Map showing current number of wind turbines in intact and predicted intact brook trout watersheds.



Map showing projected number of wind turbines in intact brook trout watersheds (by 2030) under medium scenario.

Poorly designed or maintained sedimentation measures, especially on road cuts and stream crossings, is the principal risk to these sensitive populations.

Rare Species

Of the approximately 100,000 species believed to occur in Pennsylvania, just over 1 percent is tracked by The Pennsylvania Natural Heritage Program (PNHP). These species are rare, declining or otherwise considered to be of conservation concern. PNHP records indicate that 77 tracked species have populations within pixels that have a relatively high modeled probability for wind development. Most of these species are commonly found in rocky outcrops and scrub oak/pitch pine barrens habitats on ridgetops across the state. Only a handful of species, however, have more than a few occurrences overlapping with the relatively high probability wind development pixels. For example, the eastern timber rattlesnake (*Crotalus horridus*) and Allegheny woodrat (*Neotoma magister*) are strongly associated with rocky outcrops and talus slopes along or near ridgetops. Six percent of the rattlesnake's known rattlesnake breeding/denning sites and three percent of Allegheny woodrat den sites are located in relatively high wind probability pixels. The den sites are very small sites and do not include foraging areas. The Pennsylvania Natural Heritage Program has developed core habitat polygons for each Allegheny woodrat occurrence. Much larger than the den locations, these polygons indicate a much broader overlap – 43 percent – with relatively high probability pixels for wind development. The Northern long-eared Myotis bat (*Myotis septentrionalis*) has about eight percent of its known winter hibernation and summer roosting areas overlapping with relatively high probability wind development pixels. Ridgetop barrens communities in northeastern Pennsylvania have some of the state's largest concentrations of rare terrestrial species. The Nature Conservancy has mapped these communities, and some of these habitats overlap with high wind areas. In general, there appears to be relatively little overlap between tracked species occurrences in Pennsylvania and likely wind development sites. For a handful of species, there is enough overlap to indicate the importance of surveys early in the project planning stage to identify the presence of rare species and their core habitats.

We have not addressed the potential impact of these scenarios on bird migration patterns and bat foraging populations. For more information on wind development impacts on bird and bat species, please see links to the Pennsylvania Game Commission, U.S. Fish and Wildlife Service, American Wind and Wildlife Institute, and Bat Conservation International.

Recreation

Wind development has not occurred on any state or federal lands in Pennsylvania to date. Since our projections assume there will not be a significant change in state land leasing policies for wind development, we have not projected new wind turbines in State Parks, State Forests or State Game Lands. Our projections, however, do indicate that wind turbines will be located in close proximity (sometimes as close as 500 feet) to many state lands. They are likely to be highly visible in some heavily visited areas, such as Blue Knob State Park in Bedford County, where natural landscape vistas are a prime attraction.

Key Findings

Key findings from the Pennsylvania Energy Impacts Assessment include:

- Projections of between 750 and 2,900 new wind turbines developed on ridgetops and high plateaus by 2030, depending on the size of the Pennsylvania Alternative Energy Portfolio standard. There are currently an estimated 500 wind turbines built in the state.

- Wind turbine facilities are likely to be developed in half of the state's counties, especially along the Allegheny front in western Pennsylvania and on high Central Appalachian ridges in central and northeastern parts of the state;

- Nearly eighty percent of turbine locations are projected to be in forest areas, with forest clearing projected to range between 1,900 and 5,200 acres depending on the number of turbines developed. An additional range of 13,400 to 36,500 acres of forest interior habitat impacts are projected due to new edges created by turbine pads and roads;

- On a statewide basis, the projected forest clearing from turbine development is relatively minor, though some of the state's largest forest patches (>5,000 acres) could be fragmented into smaller patches by projected wind turbine development;

- Impacts on forest interior breeding bird habitats appear to be limited, largely because the overall footprint for the projected wind turbine facilities is small in comparison to the typical breeding range of these species in Pennsylvania. The study did not assess impacts to migratory pathways for birds or foraging bats.

- Relatively few watersheds ranked as "intact" by the Eastern Brook Trout Joint Venture are affected by projected wind turbine development. Several intact watersheds, however, could see several dozen wind turbines. In a number of cases, these small watersheds are projected to see significant Marcellus gas development as well. Given the cumulative impact of these activities, rigorously designed and monitored sediment control measures will be needed to protect sensitive brook trout populations.

- A relatively small handful of rare species occurrences tracked by the Pennsylvania Natural Heritage Program are found in areas with high probability for wind development. These species tend to be associated with rocky outcrops and barrens communities typically found on ridge tops, including the Allegheny wood rat, the eastern timber rattlesnake, and the northern long-eared Myotis bat.

- Wind development is not projected to occur on Pennsylvania's public lands. Existing and projected wind turbines, however, will be close to some of Pennsylvania's most heavily visited outdoor recreation areas where scenic natural vistas are a major attraction.

Additional Information

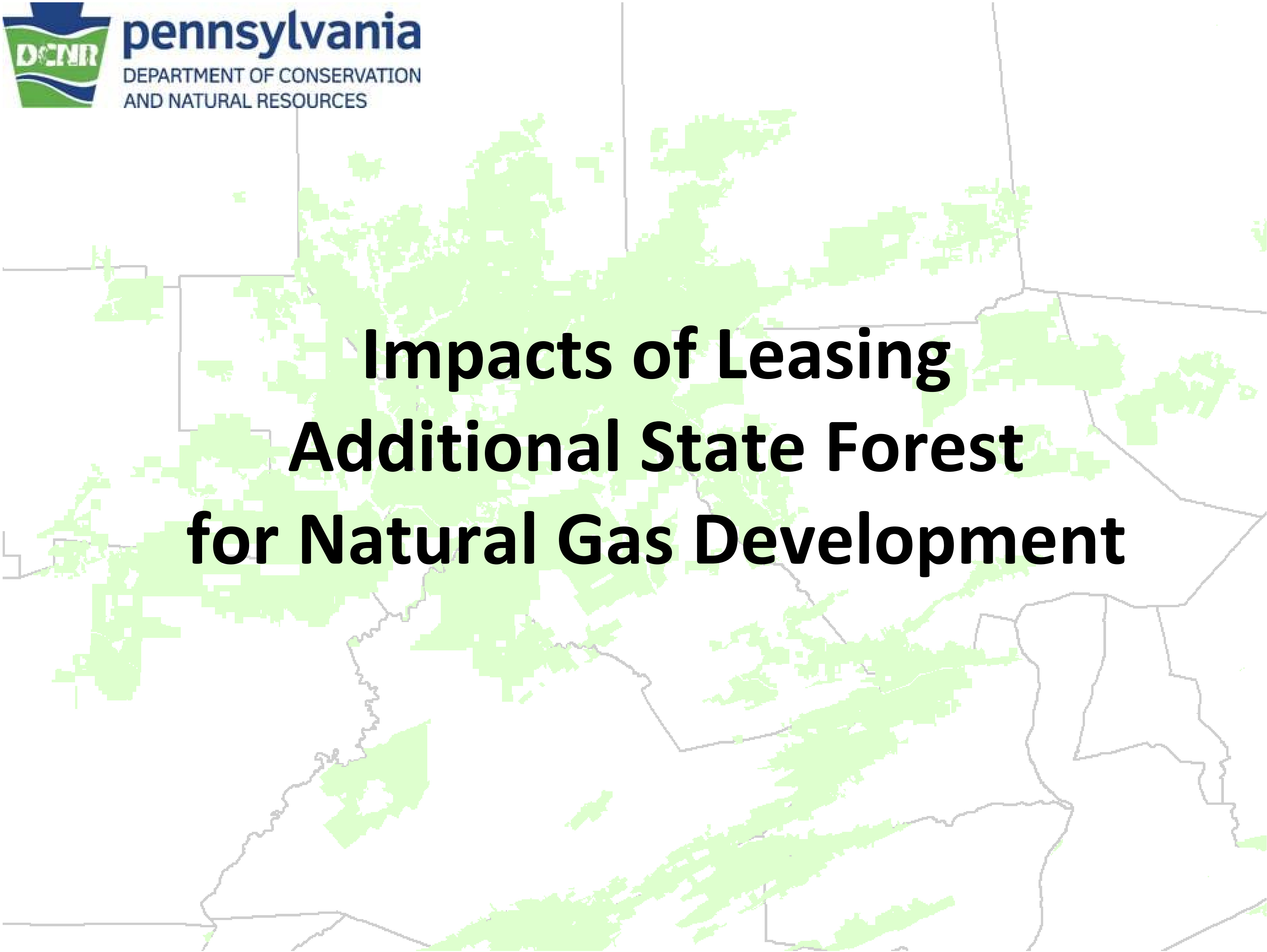
- American Wind Energy Association (2010). U.S. Wind Projects Database. http://www.awea.org/la_usprojects.cfm
- Black and Veatch (2010). Assessment of a 15 Percent Pennsylvania Alternative Energy Portfolio Standard. Report prepared for the Community Foundation for the Alleghenies, Johnstown, PA. http://www.cfalleghenies.org/pdf/aepss.pdf
- Federal Aviation Administration (FAA) permits for wind turbines: https://oeaaa.faa.gov/oeaaa/external/public/publicAction.jsp?action=showCaseDownloadForm
- Federal Aviation Administration (FAA), Obstruction Evaluation / Airport Airspace Analysis (OE/AAA): https://oeaaa.faa.gov/oeaaa/external/public/publicAction.jsp?action=showCaseDownloadForm
- Pennsylvania Wind Farms and Wildlife Collaborative: http://www.dcnr.state.pa.us/wind/index.aspx
- PA Game Commission (2007) Wind Energy Voluntary Cooperative Agreement and First Annual Report for the Wind Energy Voluntary Cooperative Agreement: http://www.portal.state.pa.us/portal/server.pt?open=514&objID=613068&mode=2
- Pennsylvania Department of Environmental Protection, Chapter 93 Water Quality Standards, Exceptional Value and High Quality Streams: data downloaded from Pennsylvania Spatial Data Access: (www.pasda.psu.edu)
- U.S. Department of Energy TrueWind 80 Meter Wind Resource Maps: http://www.windpoweringamerica.gov/wind_maps.asp
- U.S. Fish and Wildlife Service Wind Turbine Advisory Committee: http://www.fws.gov/habitatconservation/windpower/wind_turbine_advisory_committee.html
- U.S. Environmental Protection Agency summary of forest fragmentation effects: http://cfpub.epa.gov/eroe/index.cfm?fuseaction=detail.viewInd&lv=list.listByAlpha&r=219658&subtop=210
- Overview of forest fragmentation impacts on forest interior nesting species: http://www.state.nj.us/dep/fgw/neomigr.htm
- Overview of Pennsylvania High Quality and Exceptional Value Streams: http://www.dcnr.state.pa.us/wlhabitat/aquatic/streamdist.aspx
- Eastern Brook Trout Joint Venture intact brook trout watersheds: http://128.118.47.58/EBTJV/ebtjv2.html

- Overview of Carnegie Museum of Natural History, Powdermill Nature Reserve, and the Pennsylvania Game Commission's 2nd Pennsylvania Breeding Bird Atlas Project: http://www.carnegiemnh.org/powdermill/atlas/2pbba.html

- Pennsylvania Natural Heritage Program, including lists of globally rare and state endangered and imperiled species: http://www.naturalheritage.state.pa.us/

- U.S. Department of Agriculture, Natural Resources Conservation Service, National Agriculture Imagery Program: http://datagateway.nrcs.usda.gov/GDGOrder.aspx

pennsylvania
DEPARTMENT OF CONSERVATION
AND NATURAL RESOURCES



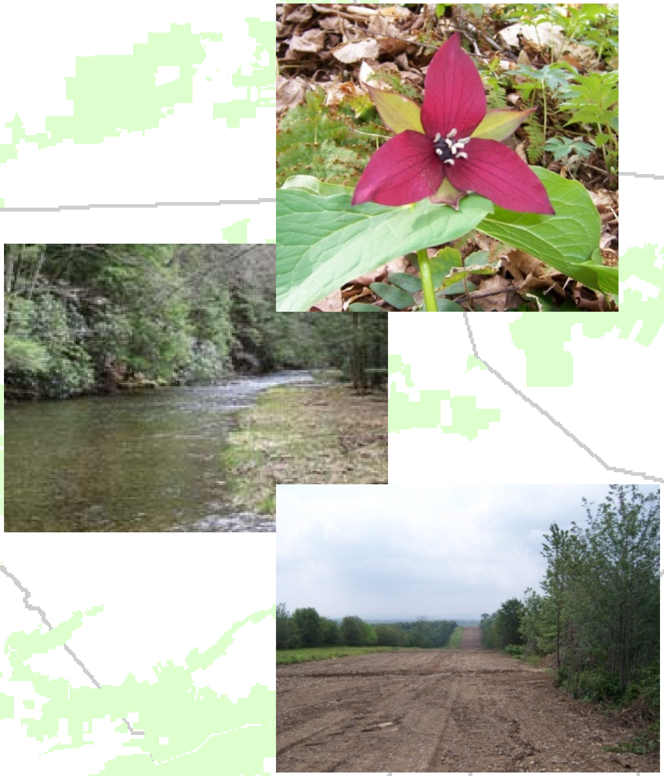
Impacts of Leasing Additional State Forest for Natural Gas Development

pennsylvania
DEPARTMENT OF CONSERVATION
AND NATURAL RESOURCES

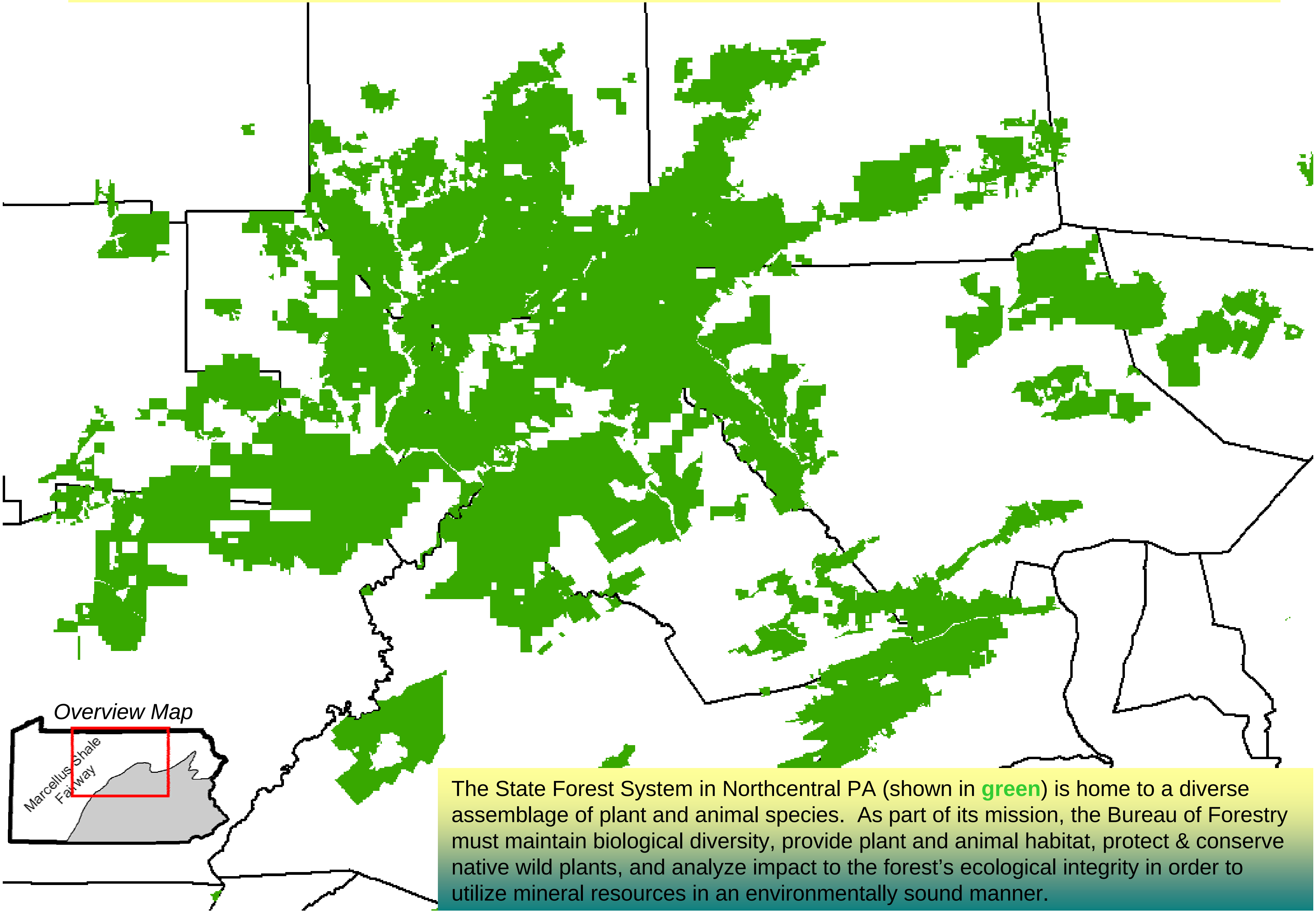
DCNR is entrusted to balance the uses and values of our state forests while protecting the integrity and health of the whole system.

There are proposals and public debate about the merits of a moratorium on natural gas drilling on state forest.

This mapping analysis demonstrates how any additional leasing involving surface disturbance upsets the sustainable balance DCNR is charged to maintain.

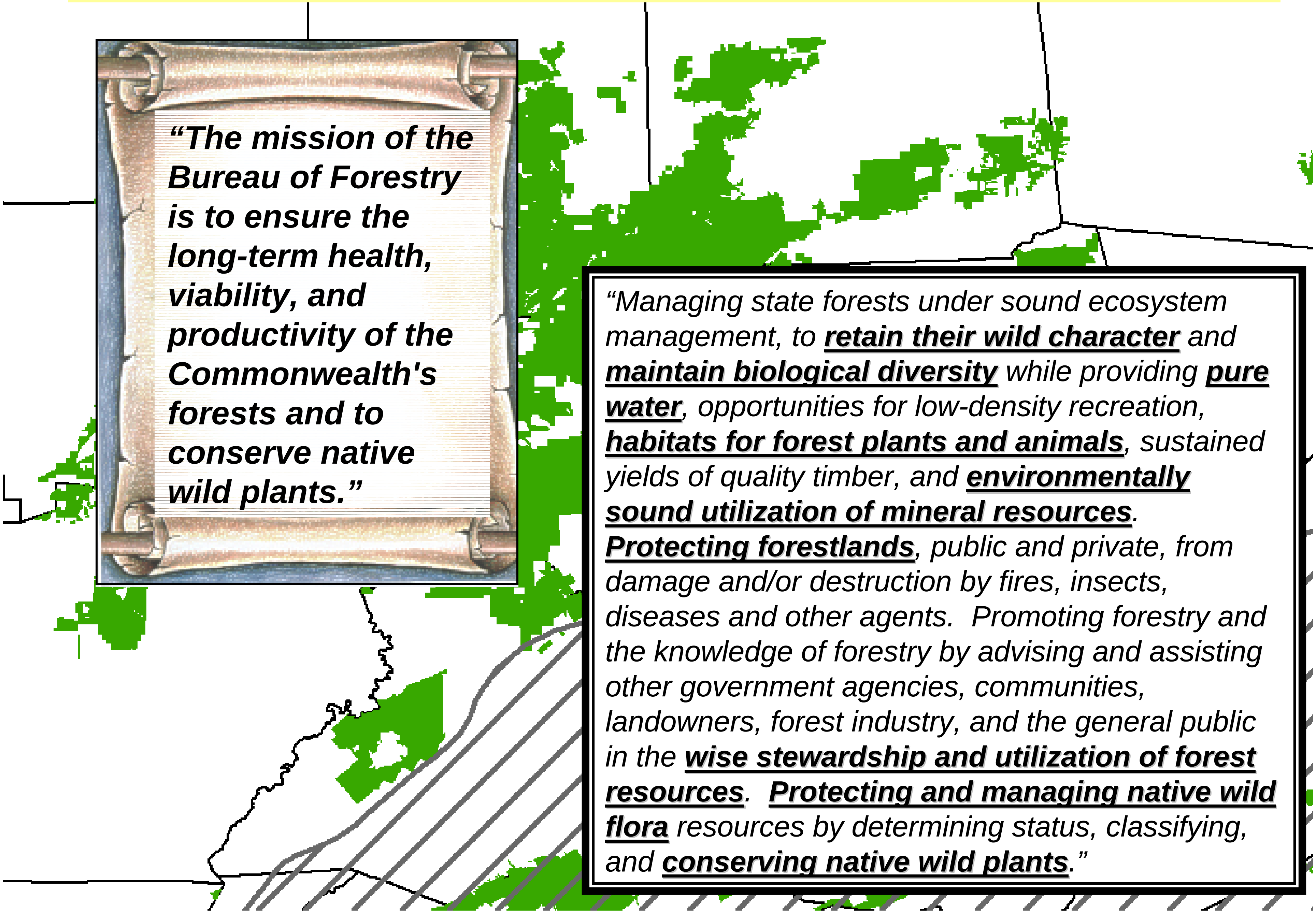


State Forest Land in North-Central Pennsylvania



The State Forest System in Northcentral PA (shown in **green**) is home to a diverse assemblage of plant and animal species. As part of its mission, the Bureau of Forestry must maintain biological diversity, provide plant and animal habitat, protect & conserve native wild plants, and analyze impact to the forest's ecological integrity in order to utilize mineral resources in an environmentally sound manner.

State Forest Land in Northcentral Pennsylvania

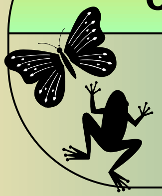


“The mission of the Bureau of Forestry is to ensure the long-term health, viability, and productivity of the Commonwealth's forests and to conserve native wild plants.”

*“Managing state forests under sound ecosystem management, to **retain their wild character** and **maintain biological diversity** while providing **pure water**, opportunities for low-density recreation, **habitats for forest plants and animals**, sustained yields of quality timber, and **environmentally sound utilization of mineral resources**. **Protecting forestlands**, public and private, from damage and/or destruction by fires, insects, diseases and other agents. Promoting forestry and the knowledge of forestry by advising and assisting other government agencies, communities, landowners, forest industry, and the general public in the **wise stewardship and utilization of forest resources**. **Protecting and managing native wild flora** resources by determining status, classifying, and **conserving native wild plants**.”*

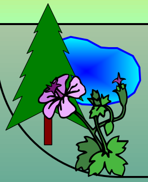
Maintaining the Forest’s Ecological Integrity

Species of Concern



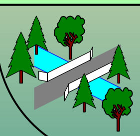
Native Biological Diversity
Threatened / Endangered Spp.
Rare / Declining Spp.

Unique Areas

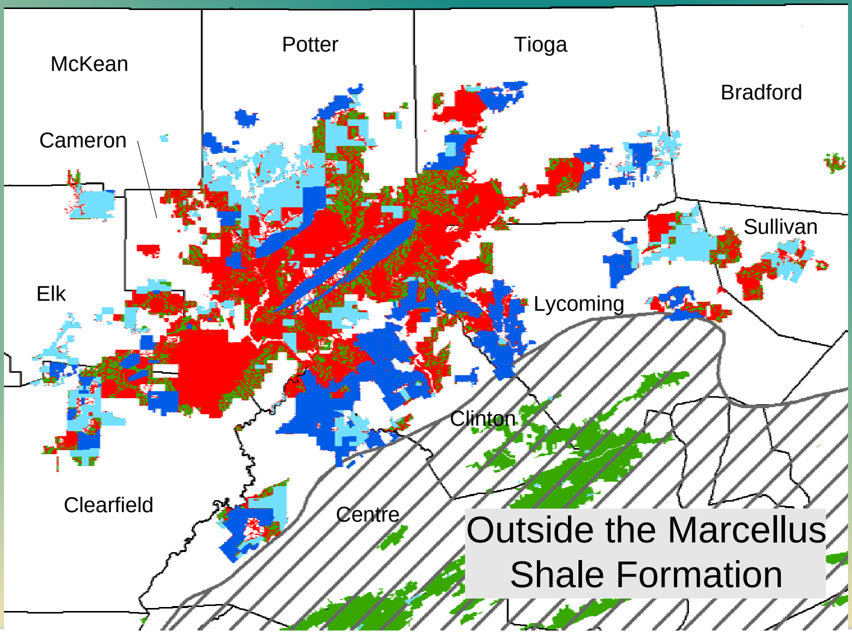


Wild & Natural Areas
Steep, Wet, & Rocky Areas
Old Growth
Wild Plant Sanctuaries

Road, Trail, & Stream Buffers

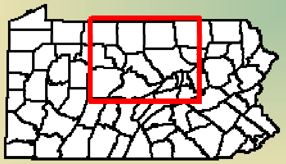


Aesthetics / Scenery
Corridors
Connectivity
Water Quality



Legend

- 🟦 DCNR Gas Lease
- 🟦 Severed Rights
- 🟥 Ecologically Sensitive
- 🟩 Other State Forest



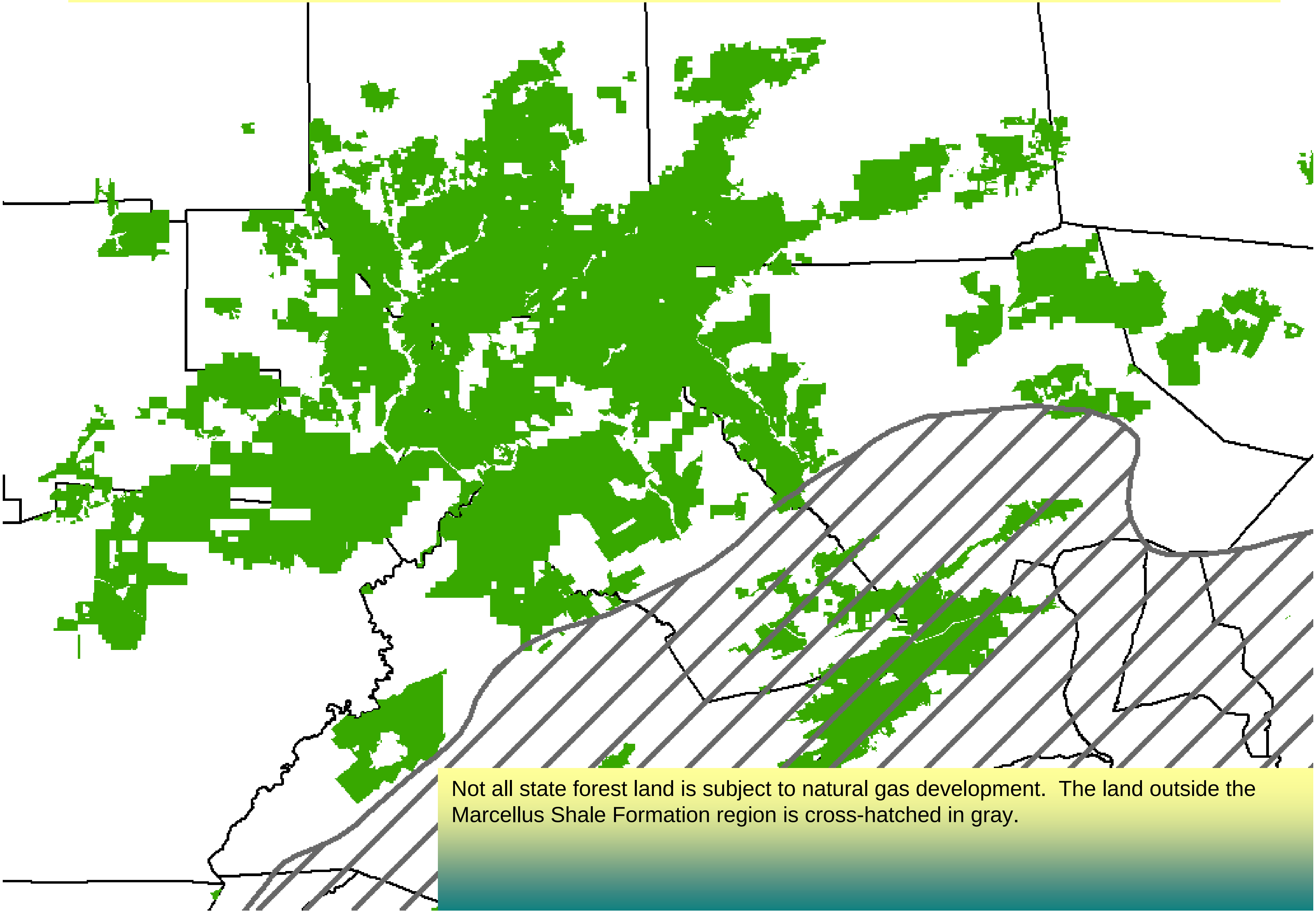
1,500,000 acres — State Forest Land in the Marcellus Shale Region

\- 700,000 acres — State Forest Land Currently Leased or Severed

\- 702,500 acres — Unleased Land in Ecologically Sensitive Areas

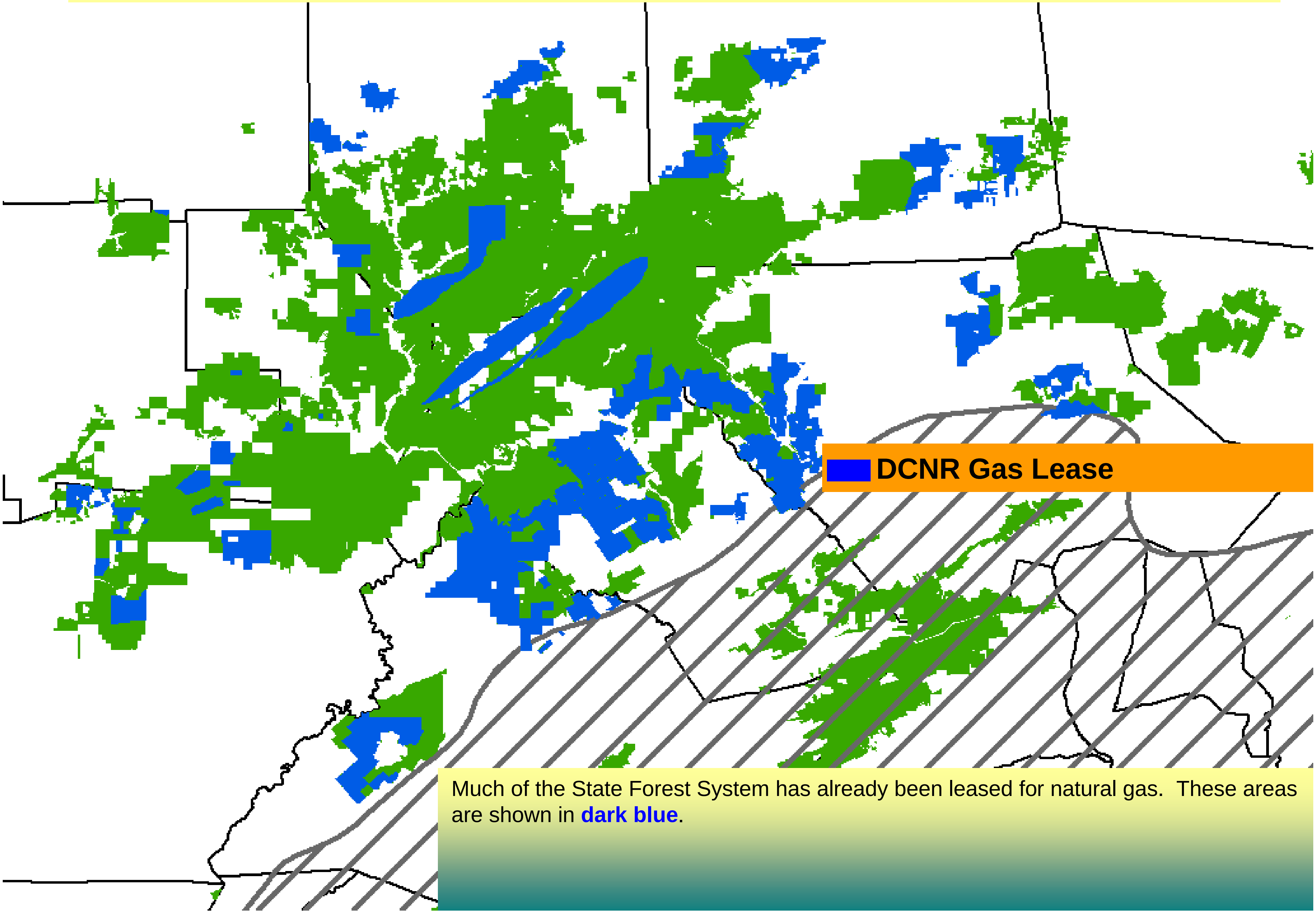
97,500 acres — Inaccessible w/o Damaging Ecologically Sensitive Areas

Maintaining the Forest's Ecological Integrity



Not all state forest land is subject to natural gas development. The land outside the Marcellus Shale Formation region is cross-hatched in gray.

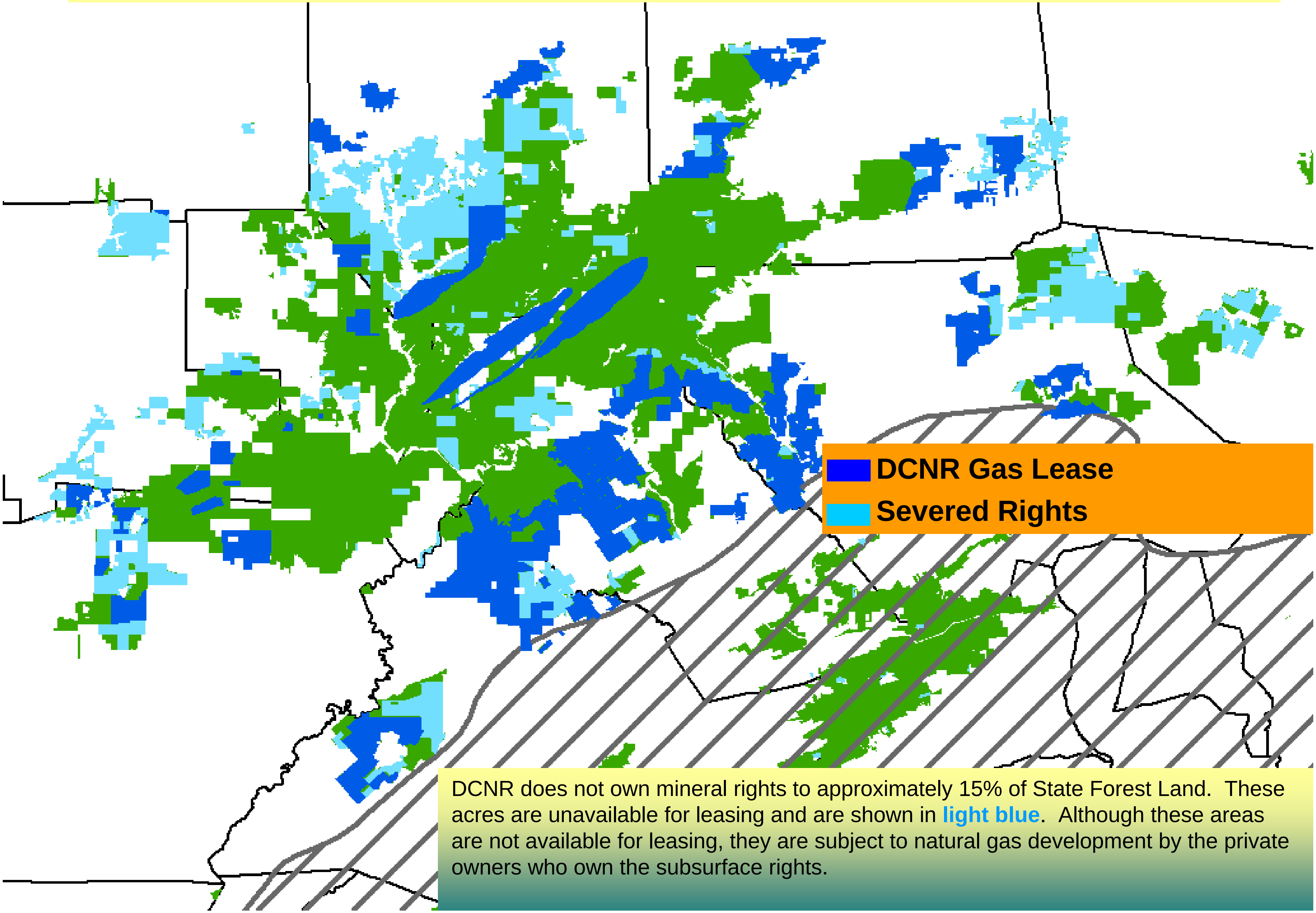
Maintaining the Forest's Ecological Integrity



🟦 **DCNR Gas Lease**

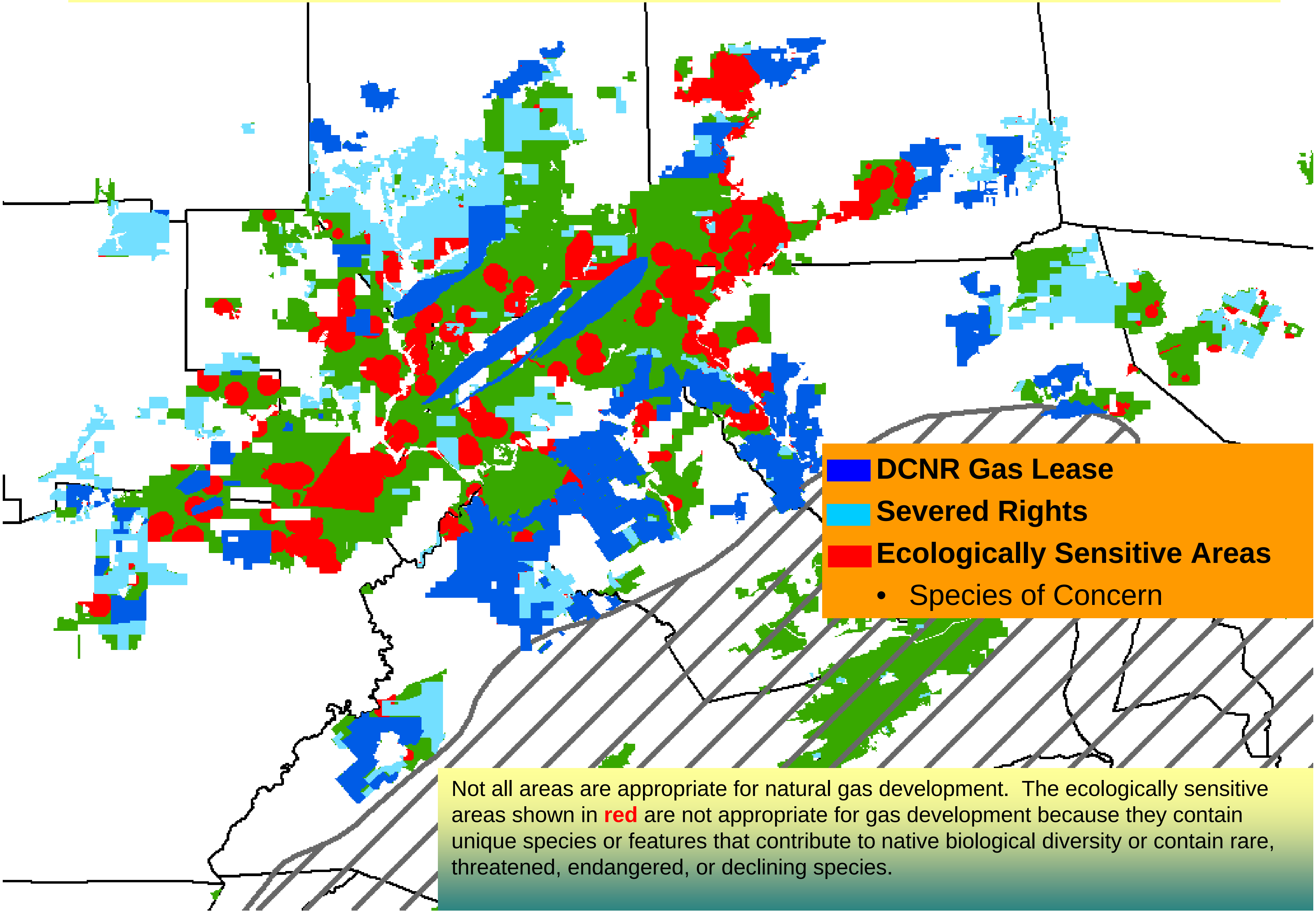
Much of the State Forest System has already been leased for natural gas. These areas are shown in **dark blue**.

Maintaining the Forest's Ecological Integrity



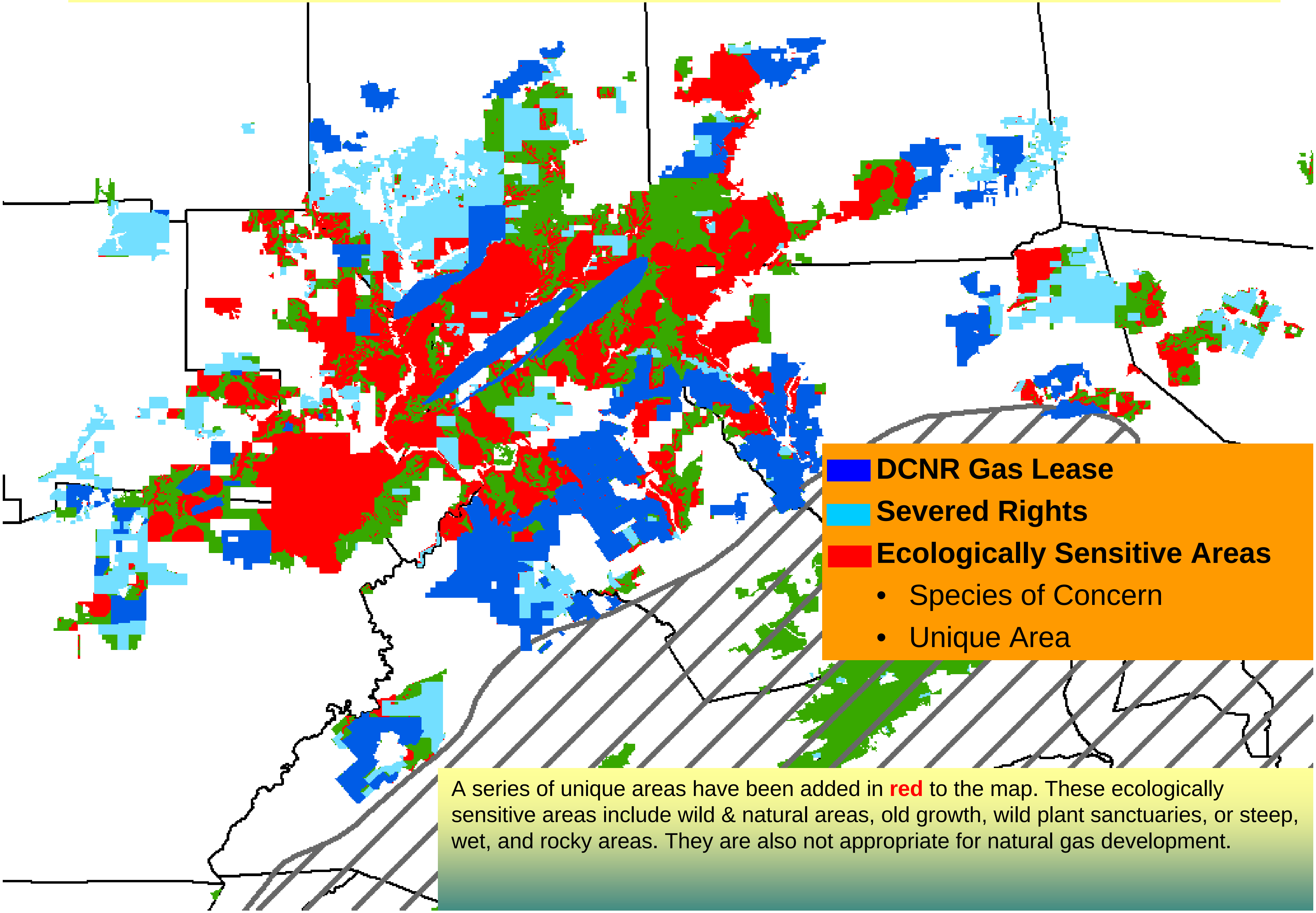
DCNR does not own mineral rights to approximately 15% of State Forest Land. These acres are unavailable for leasing and are shown in **light blue**. Although these areas are not available for leasing, they are subject to natural gas development by the private owners who own the subsurface rights.

Maintaining the Forest's Ecological Integrity



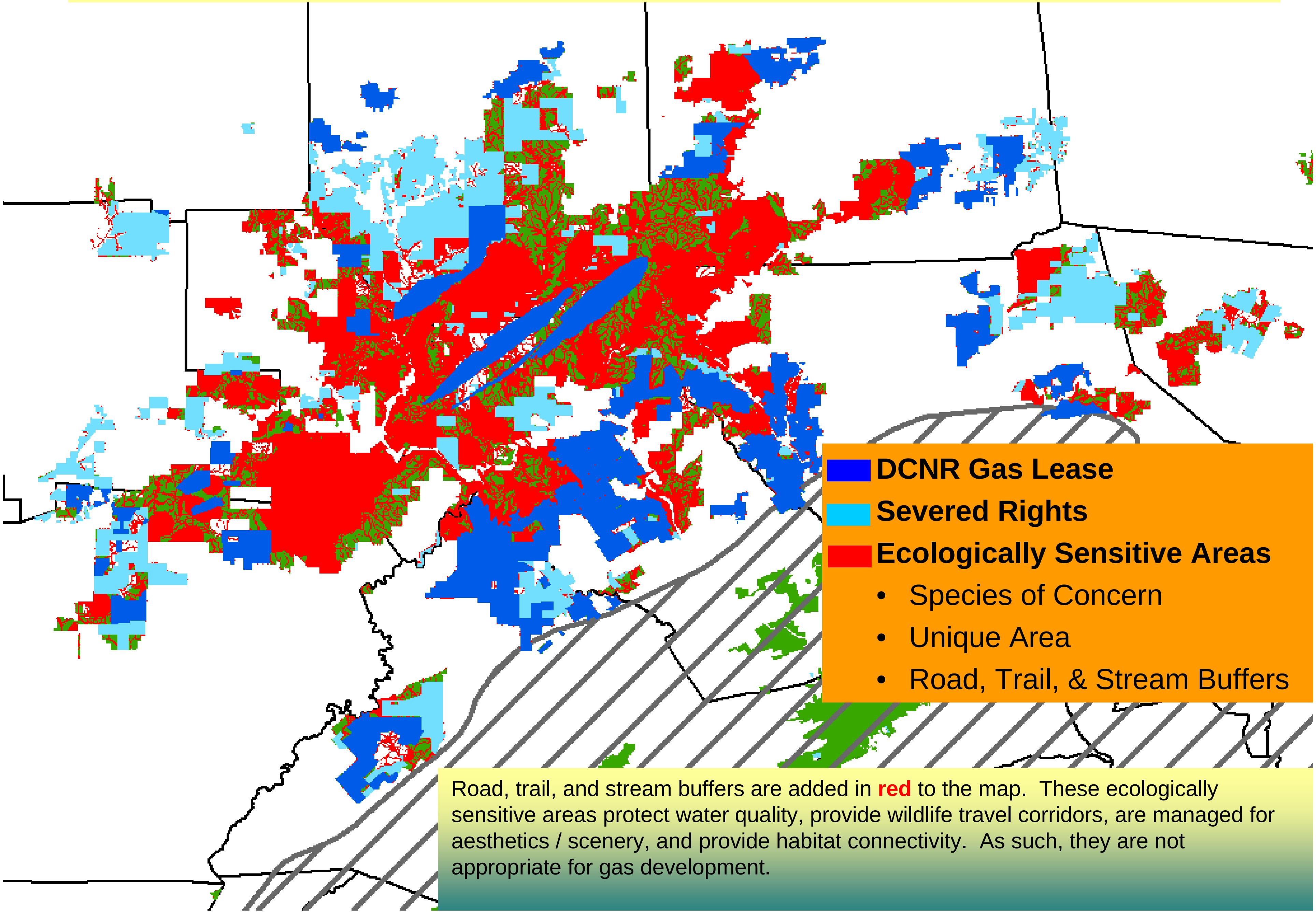
Not all areas are appropriate for natural gas development. The ecologically sensitive areas shown in **red** are not appropriate for gas development because they contain unique species or features that contribute to native biological diversity or contain rare, threatened, endangered, or declining species.

Maintaining the Forest's Ecological Integrity



A series of unique areas have been added in **red** to the map. These ecologically sensitive areas include wild & natural areas, old growth, wild plant sanctuaries, or steep, wet, and rocky areas. They are also not appropriate for natural gas development.

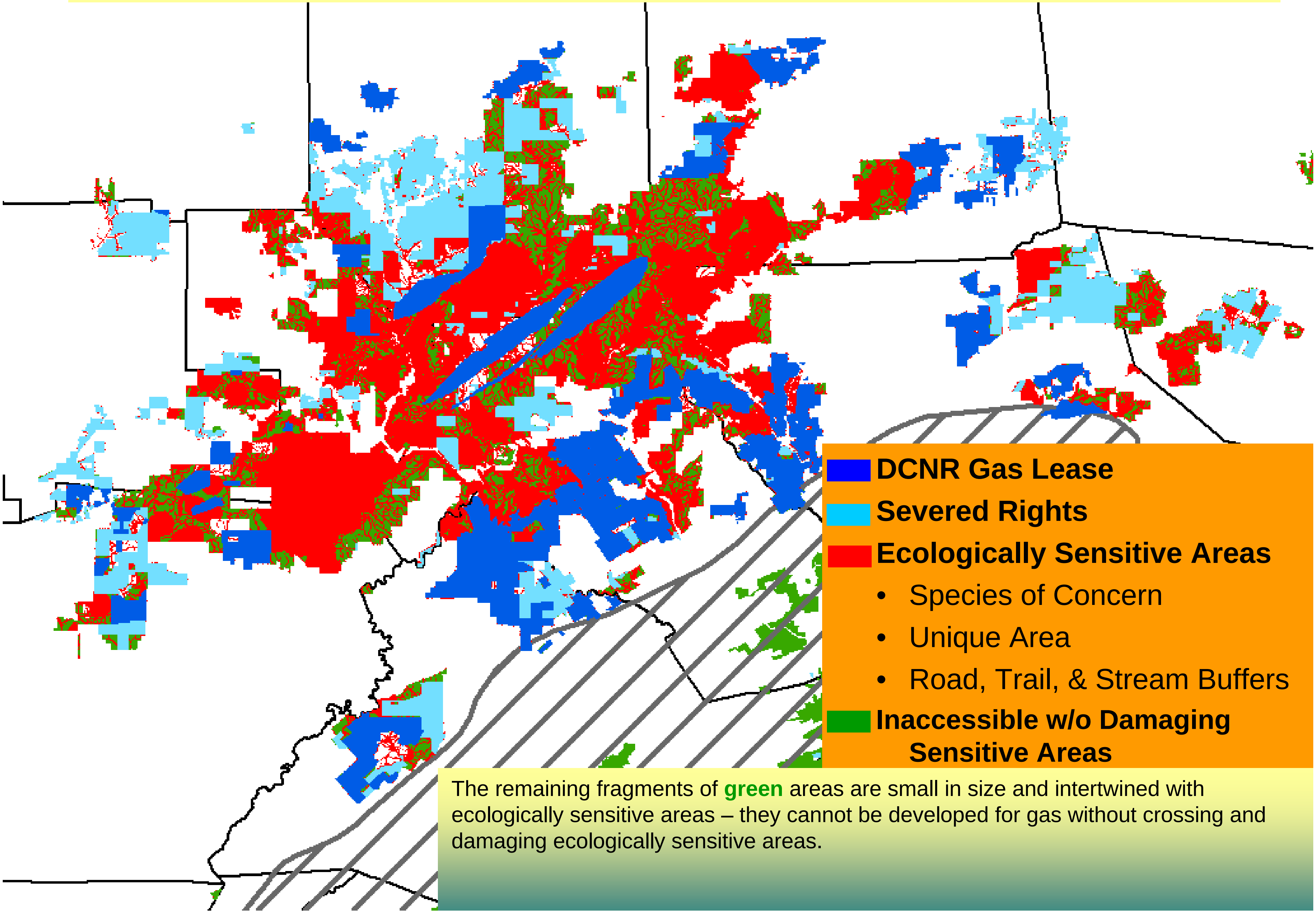
Maintaining the Forest's Ecological Integrity



- 🟦 **DCNR Gas Lease**
- 🟦 **Severed Rights**
- 🟥 **Ecologically Sensitive Areas**
  - Species of Concern
  - Unique Area
  - Road, Trail, & Stream Buffers

Road, trail, and stream buffers are added in **red** to the map. These ecologically sensitive areas protect water quality, provide wildlife travel corridors, are managed for aesthetics / scenery, and provide habitat connectivity. As such, they are not appropriate for gas development.

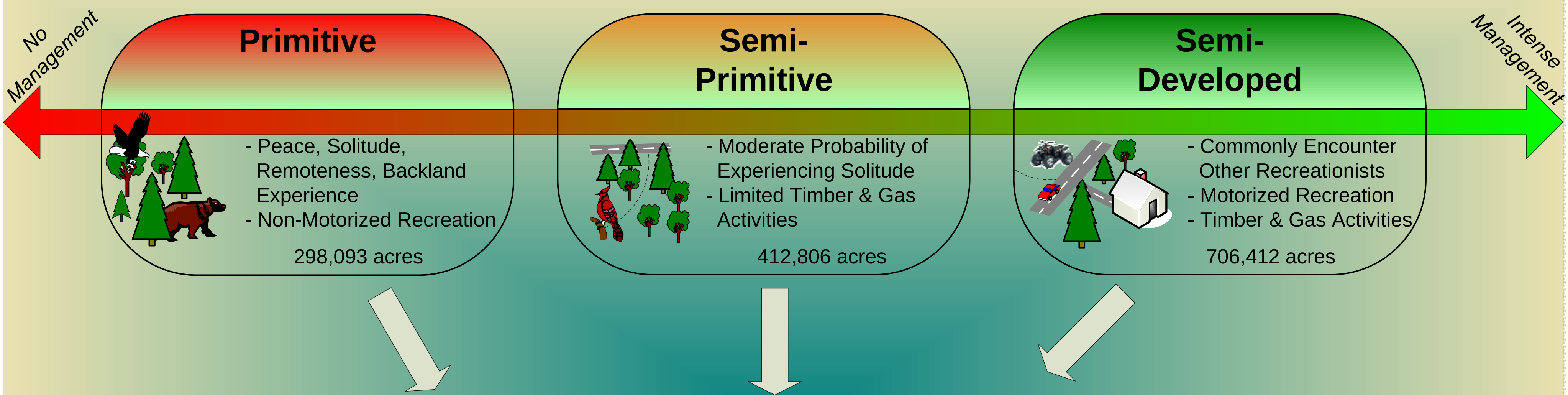
Maintaining the Forest's Ecological Integrity



- 🟦 **DCNR Gas Lease**
- 🟦 **Severed Rights**
- 🟥 **Ecologically Sensitive Areas**
  - Species of Concern
  - Unique Area
  - Road, Trail, & Stream Buffers
- 🟩 **Inaccessible w/o Damaging Sensitive Areas**

The remaining fragments of **green** areas are small in size and intertwined with ecologically sensitive areas – they cannot be developed for gas without crossing and damaging ecologically sensitive areas.

Maintaining the Forest's Wild Character



Primitive

- Peace, Solitude, Remoteness, Backland Experience
- Non-Motorized Recreation

298,093 acres

Semi-Primitive

- Moderate Probability of Experiencing Solitude
- Limited Timber & Gas Activities

412,806 acres

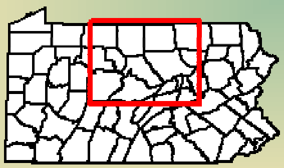
Semi-Developed

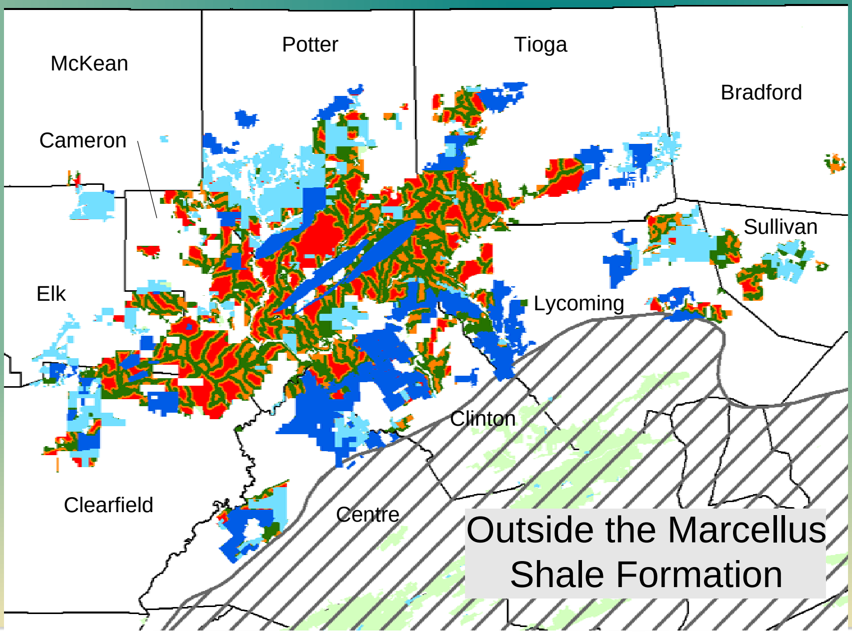
- Commonly Encounter Other Recreationists
- Motorized Recreation
- Timber & Gas Activities

706,412 acres

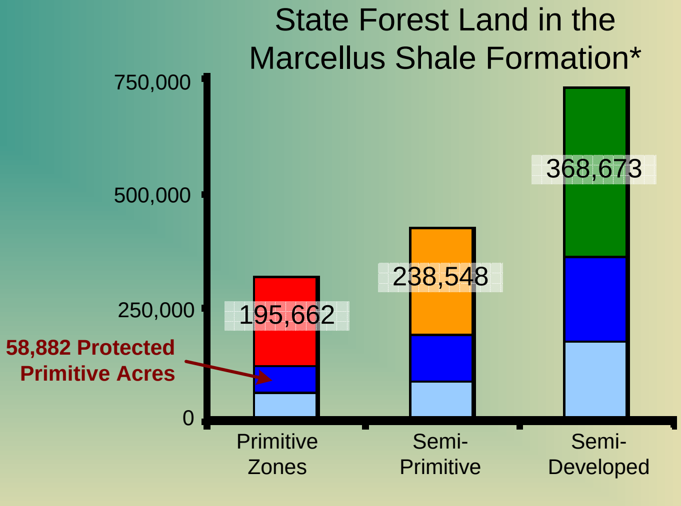
Legend

🟦	DCNR Gas Lease
🟦	Severed Rights
🟩	Semi-Developed
🟧	Semi-Primitive
🟥	Off Limits (Primitive)



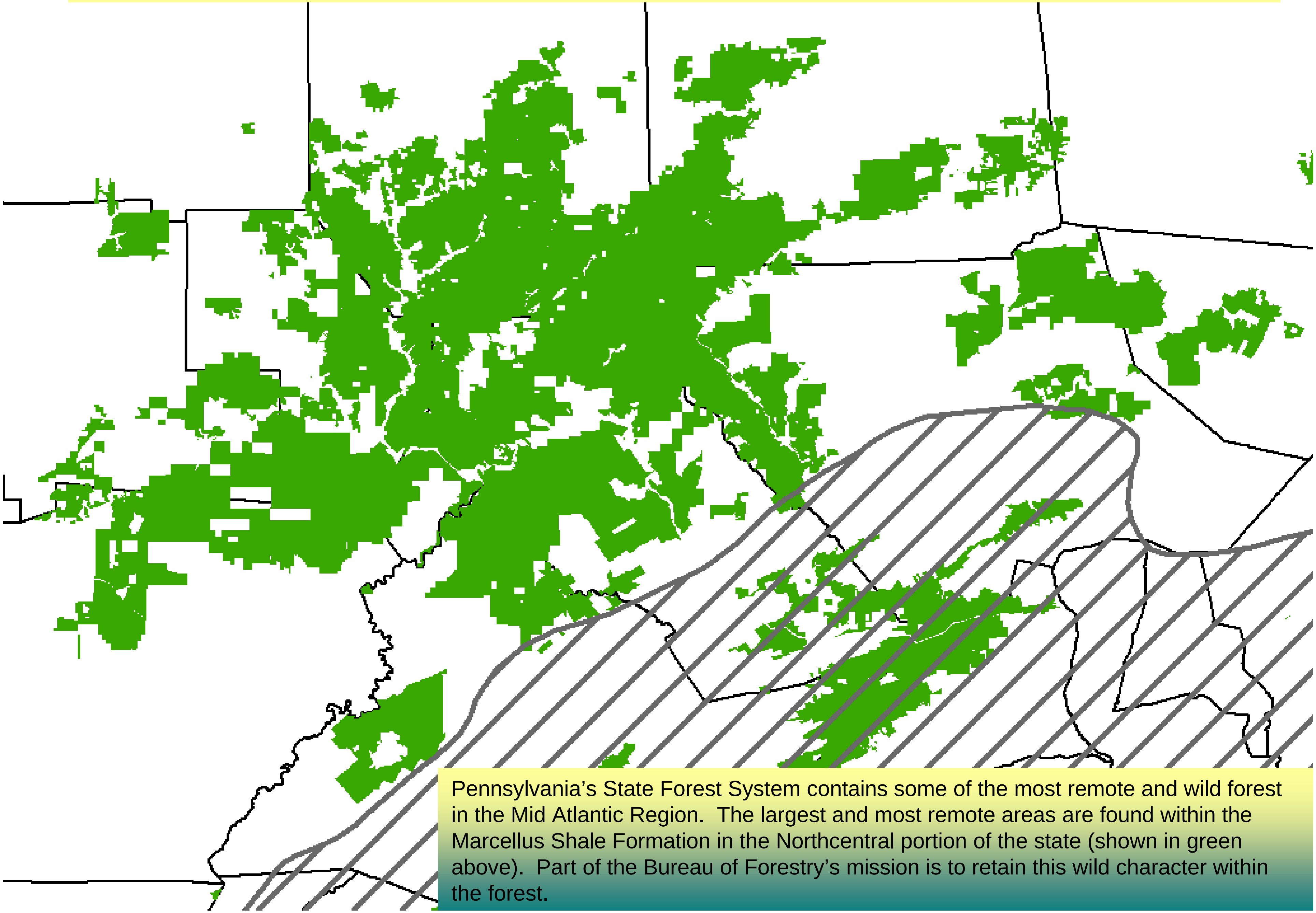


Outside the Marcellus Shale Formation


State Forest Land in the Marcellus Shale Formation*

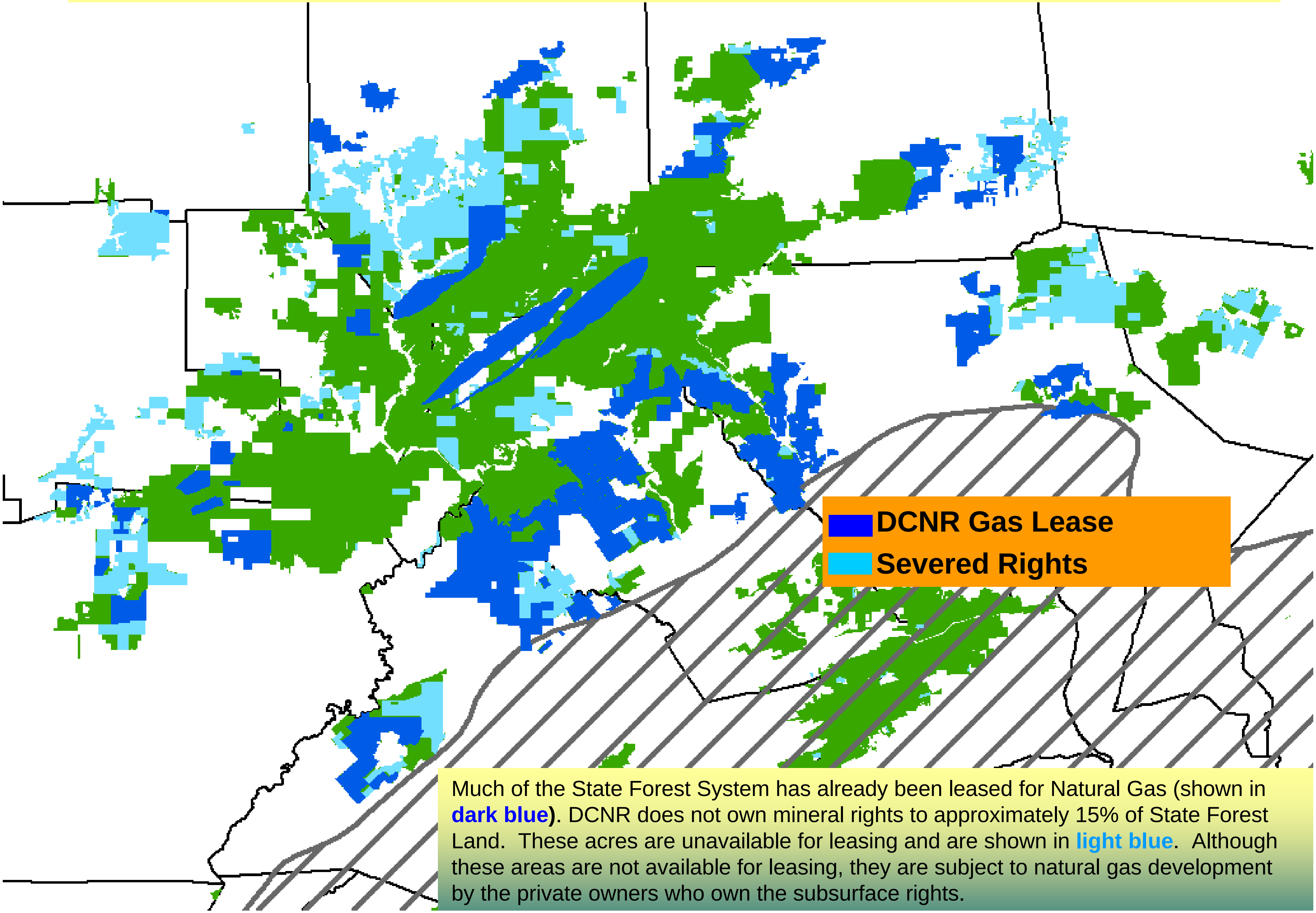
*Delaware State Forest not included.

Maintaining the Forest's Wild Character



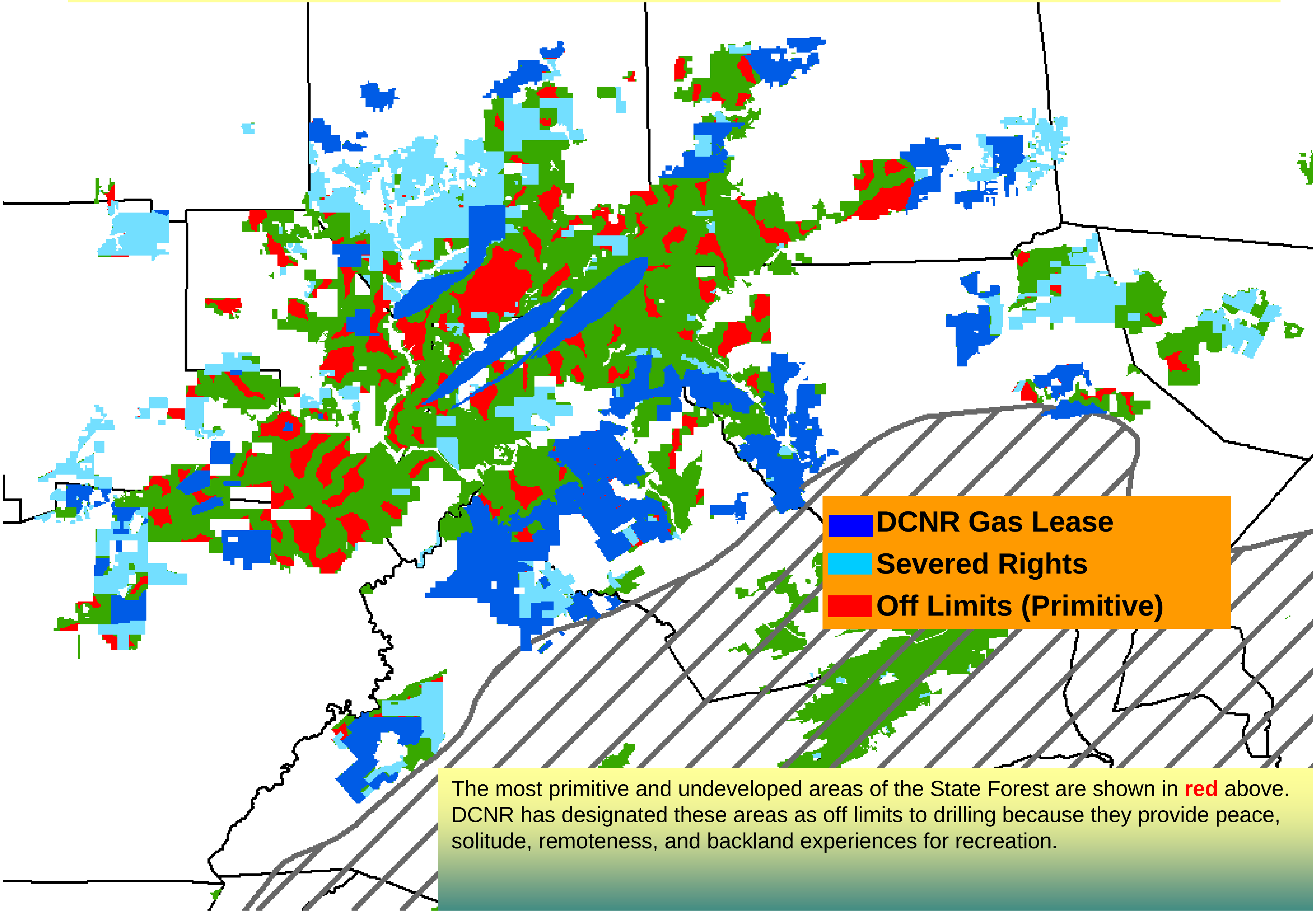
Pennsylvania's State Forest System contains some of the most remote and wild forest in the Mid Atlantic Region. The largest and most remote areas are found within the Marcellus Shale Formation in the Northcentral portion of the state (shown in green above). Part of the Bureau of Forestry's mission is to retain this wild character within the forest.

Maintaining the Forest's Wild Character



Much of the State Forest System has already been leased for Natural Gas (shown in **dark blue**). DCNR does not own mineral rights to approximately 15% of State Forest Land. These acres are unavailable for leasing and are shown in **light blue**. Although these areas are not available for leasing, they are subject to natural gas development by the private owners who own the subsurface rights.

Maintaining the Forest's Wild Character



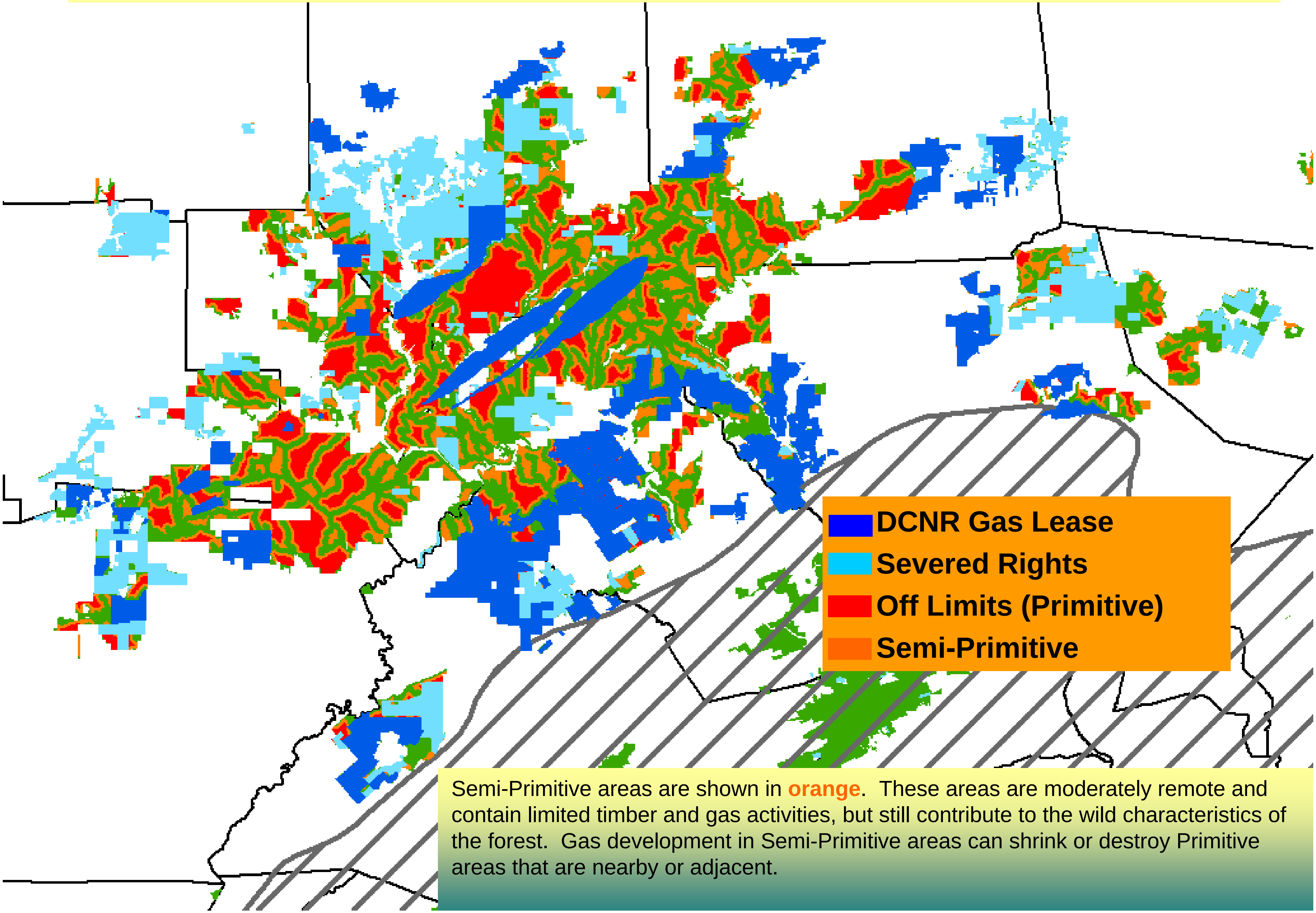
🟦 **DCNR Gas Lease**

🟦 **Severed Rights**

🟥 **Off Limits (Primitive)**

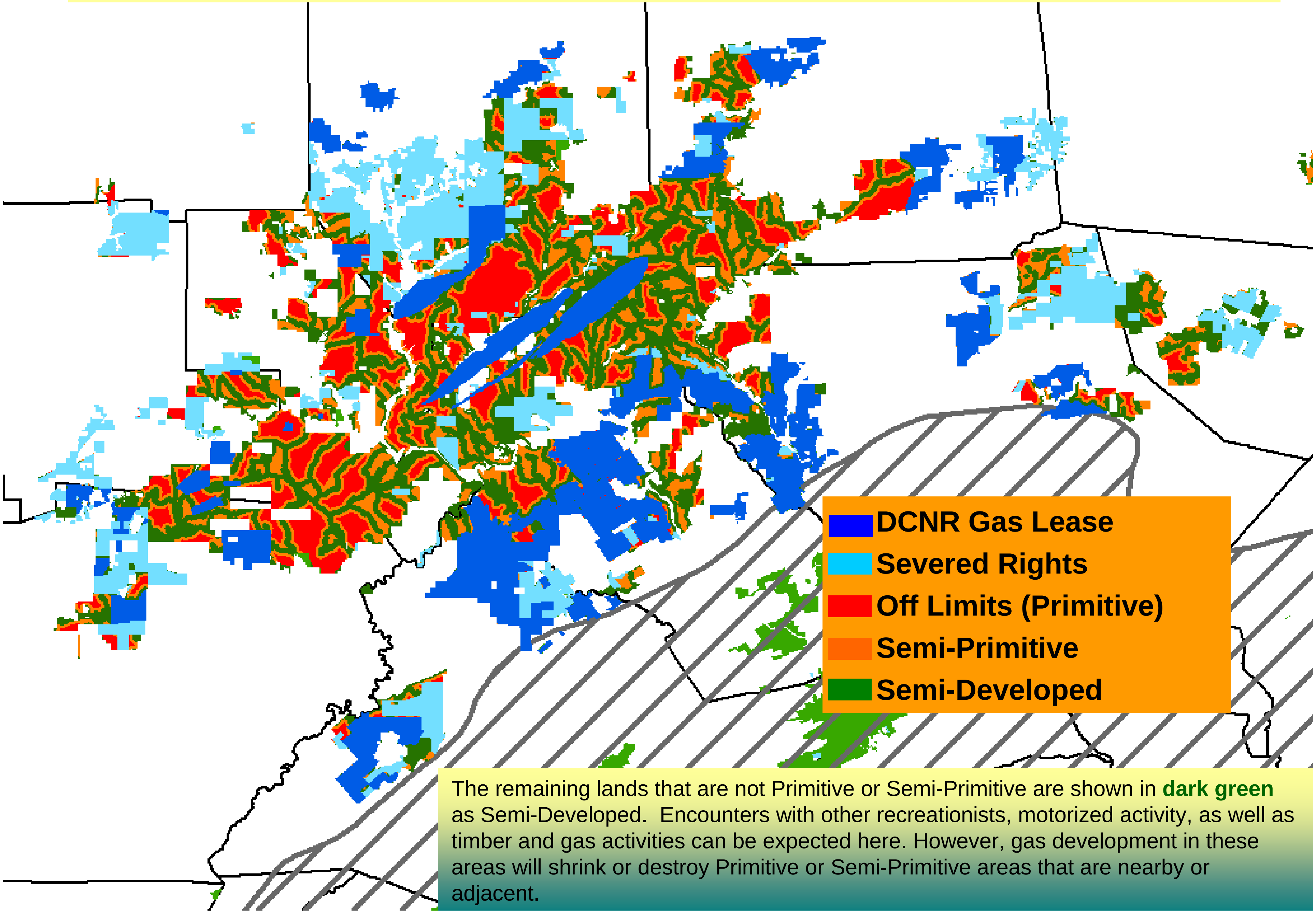
The most primitive and undeveloped areas of the State Forest are shown in **red** above. DCNR has designated these areas as off limits to drilling because they provide peace, solitude, remoteness, and backland experiences for recreation.

Maintaining the Forest’s Wild Character



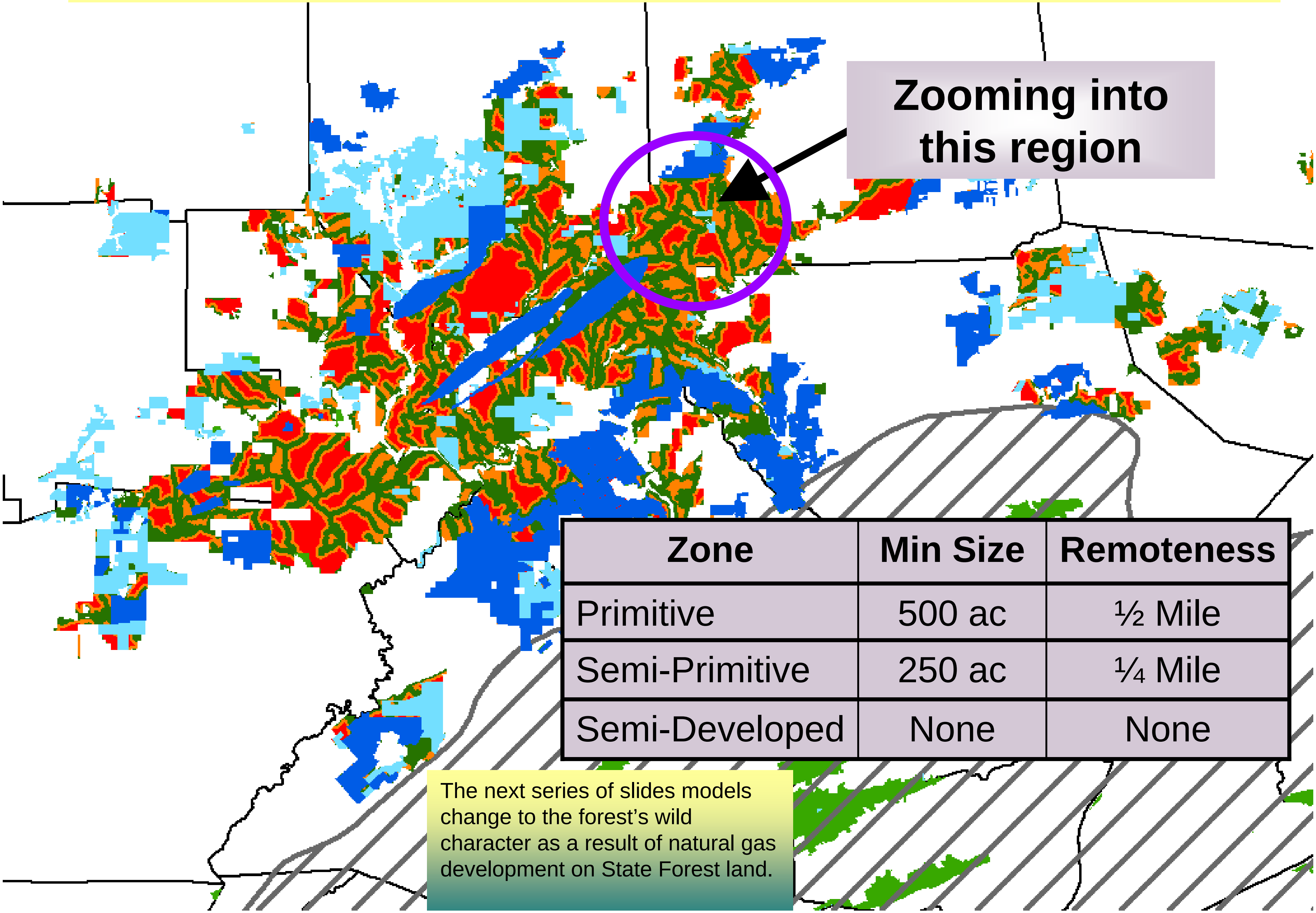
Semi-Primitive areas are shown in **orange**. These areas are moderately remote and contain limited timber and gas activities, but still contribute to the wild characteristics of the forest. Gas development in Semi-Primitive areas can shrink or destroy Primitive areas that are nearby or adjacent.

Maintaining the Forest's Wild Character



The remaining lands that are not Primitive or Semi-Primitive are shown in **dark green** as Semi-Developed. Encounters with other recreationists, motorized activity, as well as timber and gas activities can be expected here. However, gas development in these areas will shrink or destroy Primitive or Semi-Primitive areas that are nearby or adjacent.

Impacts on the Wild Character



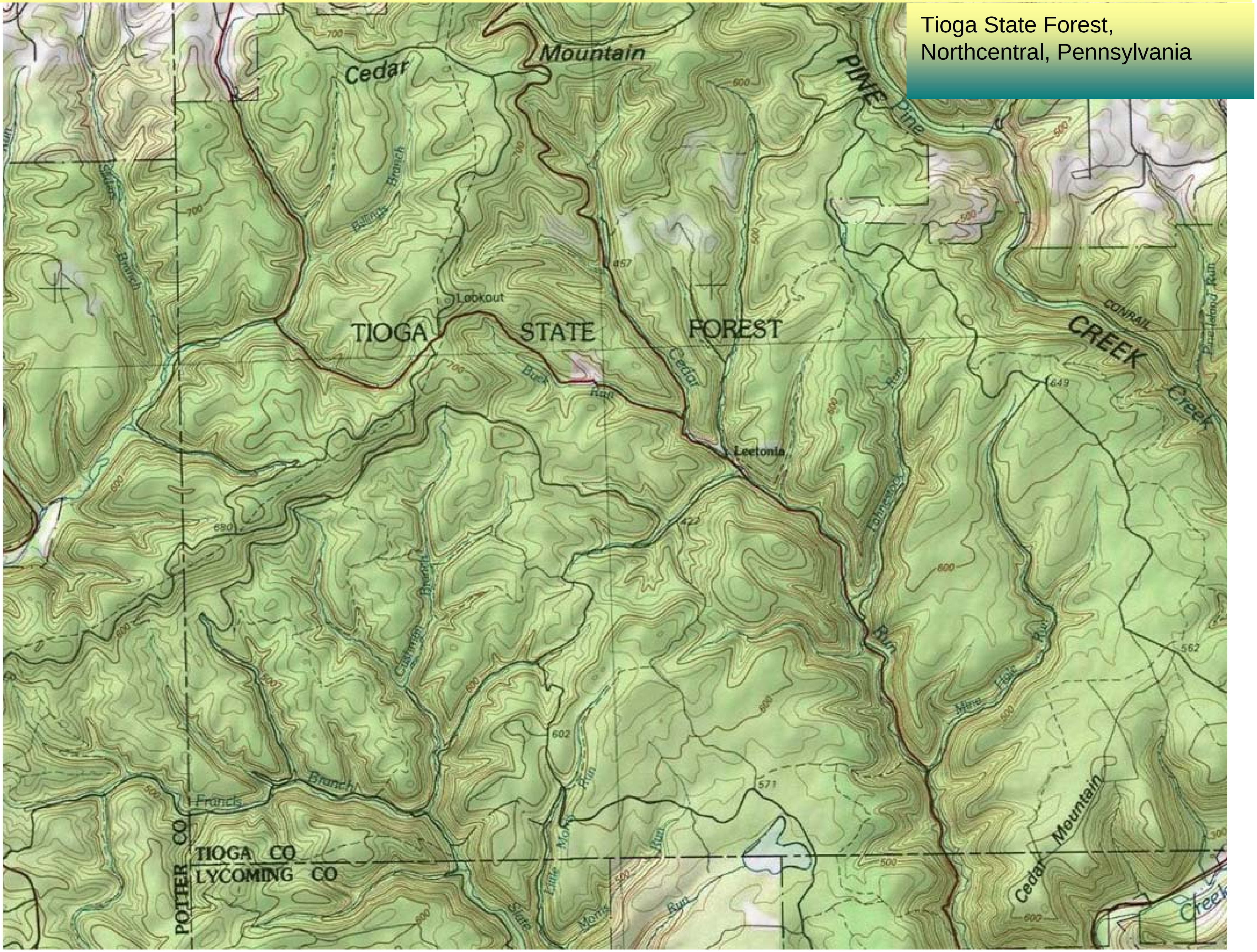
Zooming into this region

Zone	Min Size	Remoteness
Primitive	500 ac	½ Mile
Semi-Primitive	250 ac	¼ Mile
Semi-Developed	None	None

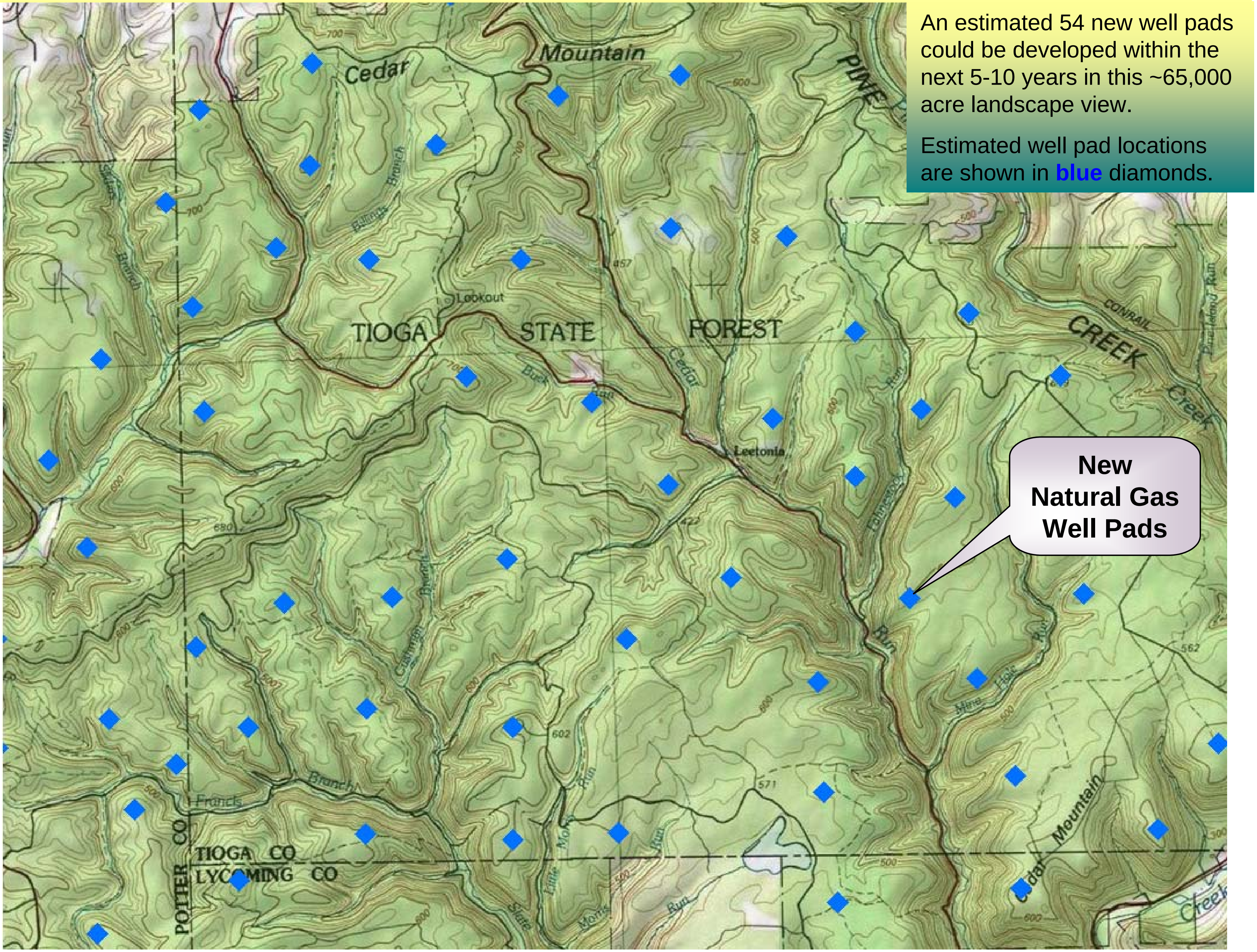
The next series of slides models change to the forest's wild character as a result of natural gas development on State Forest land.

Topography

Tioga State Forest,
Northcentral, Pennsylvania



New Well Pad Locations

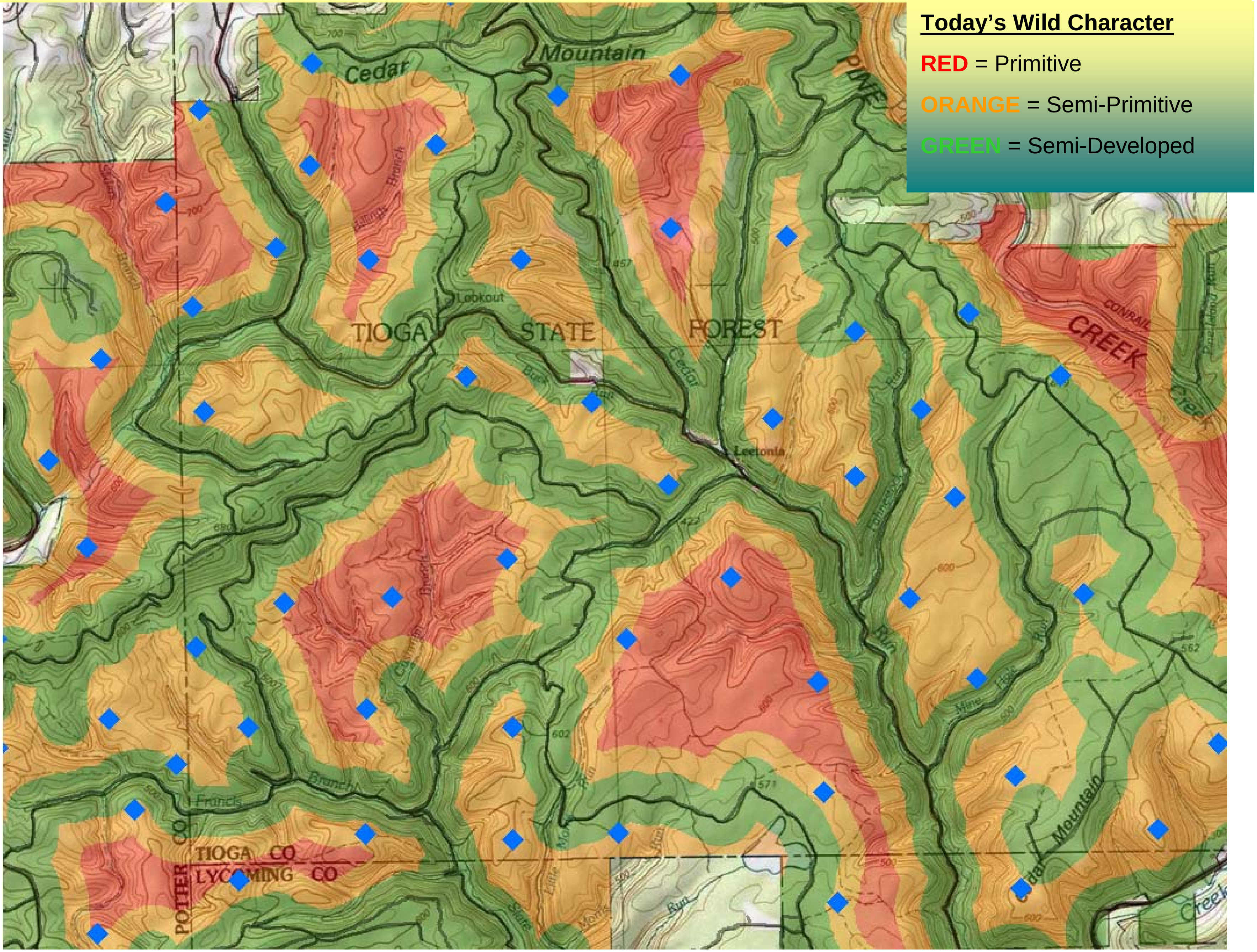


An estimated 54 new well pads could be developed within the next 5-10 years in this ~65,000 acre landscape view.

Estimated well pad locations are shown in **blue** diamonds.

New Natural Gas Well Pads

Wild Character before Well Pads



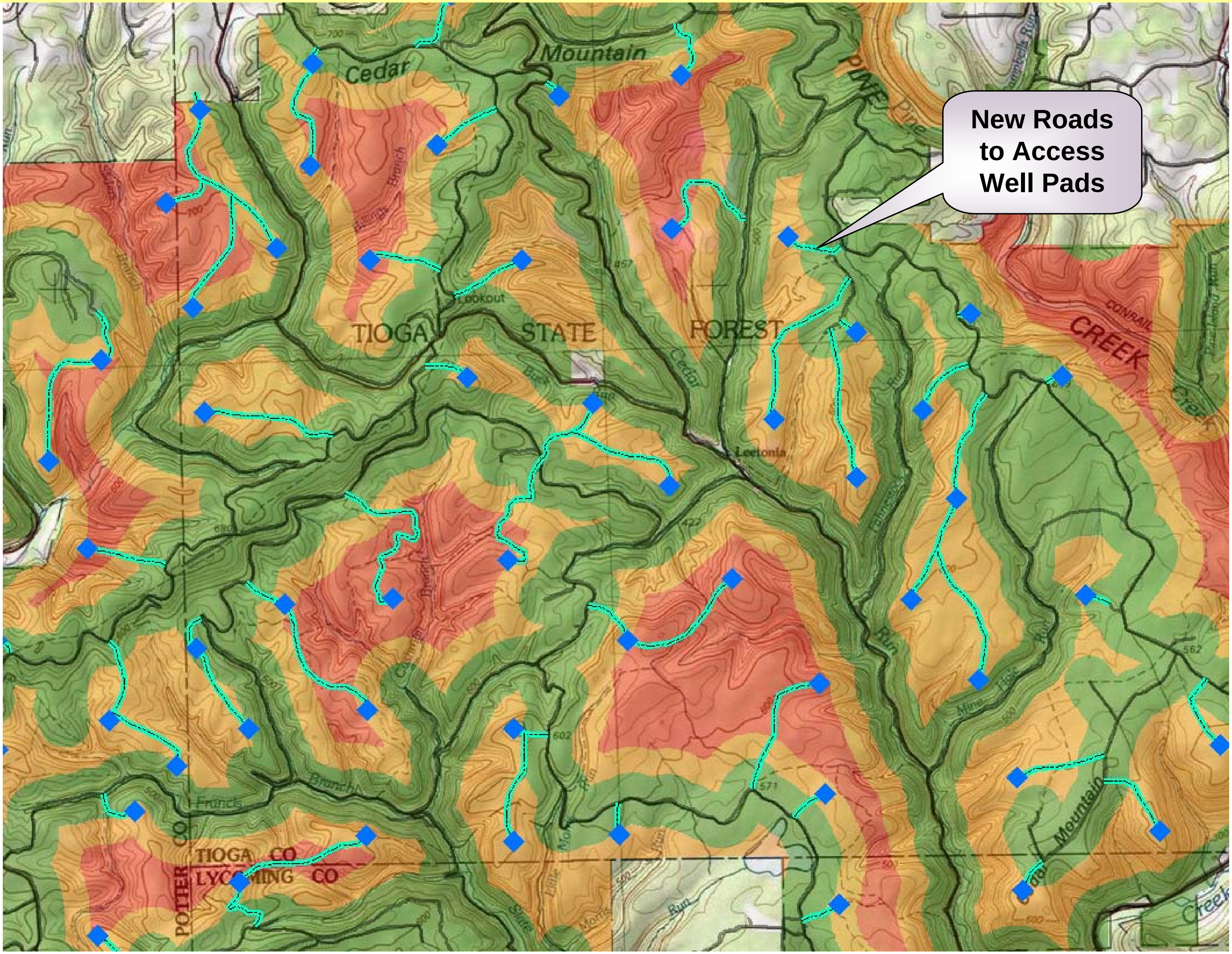
<u>Today's Wild Character</u>

RED = Primitive

ORANGE = Semi-Primitive

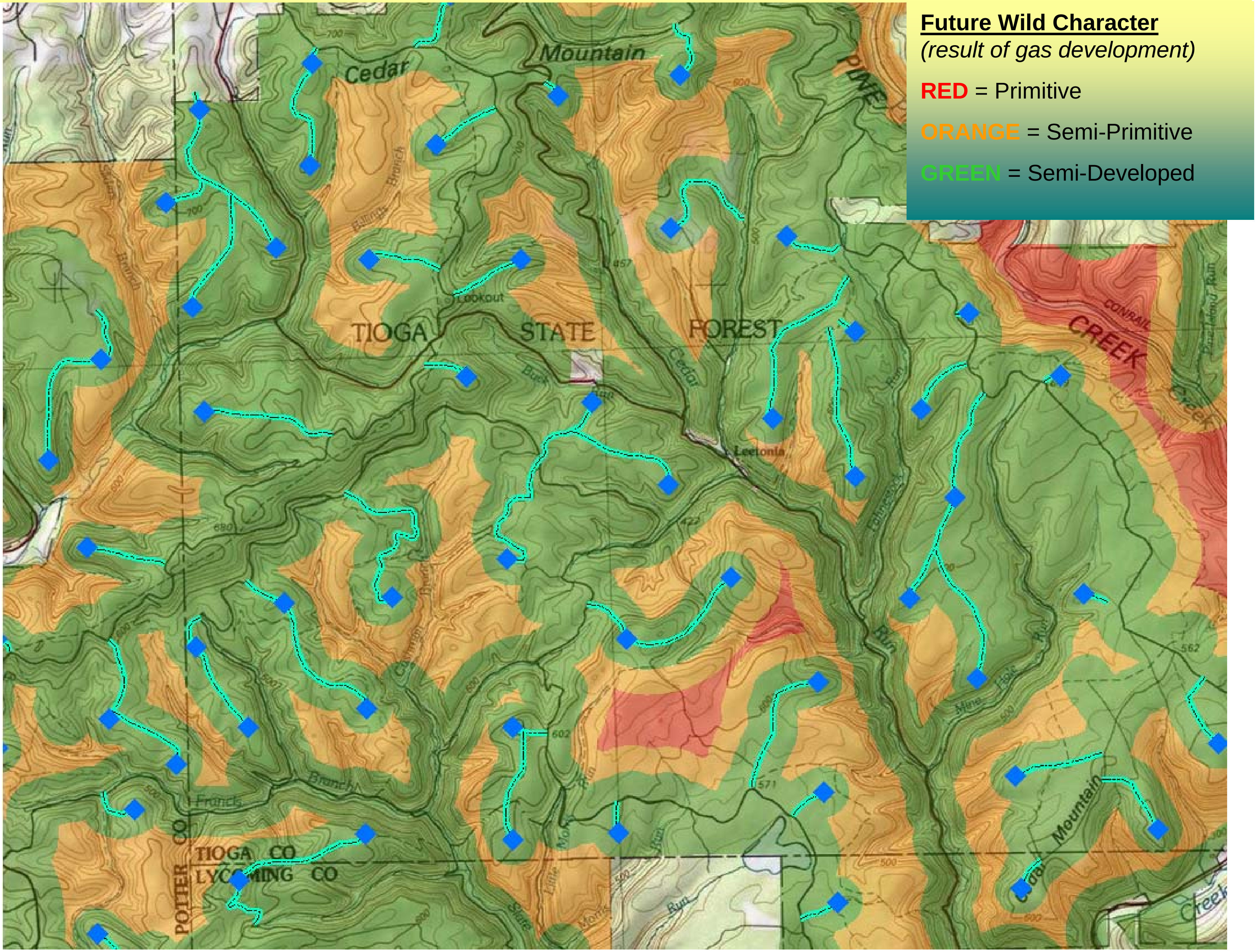
GREEN = Semi-Developed

New Access Roads Required



New Roads to Access Well Pads

Forest’s Wild Character with New Well Pads



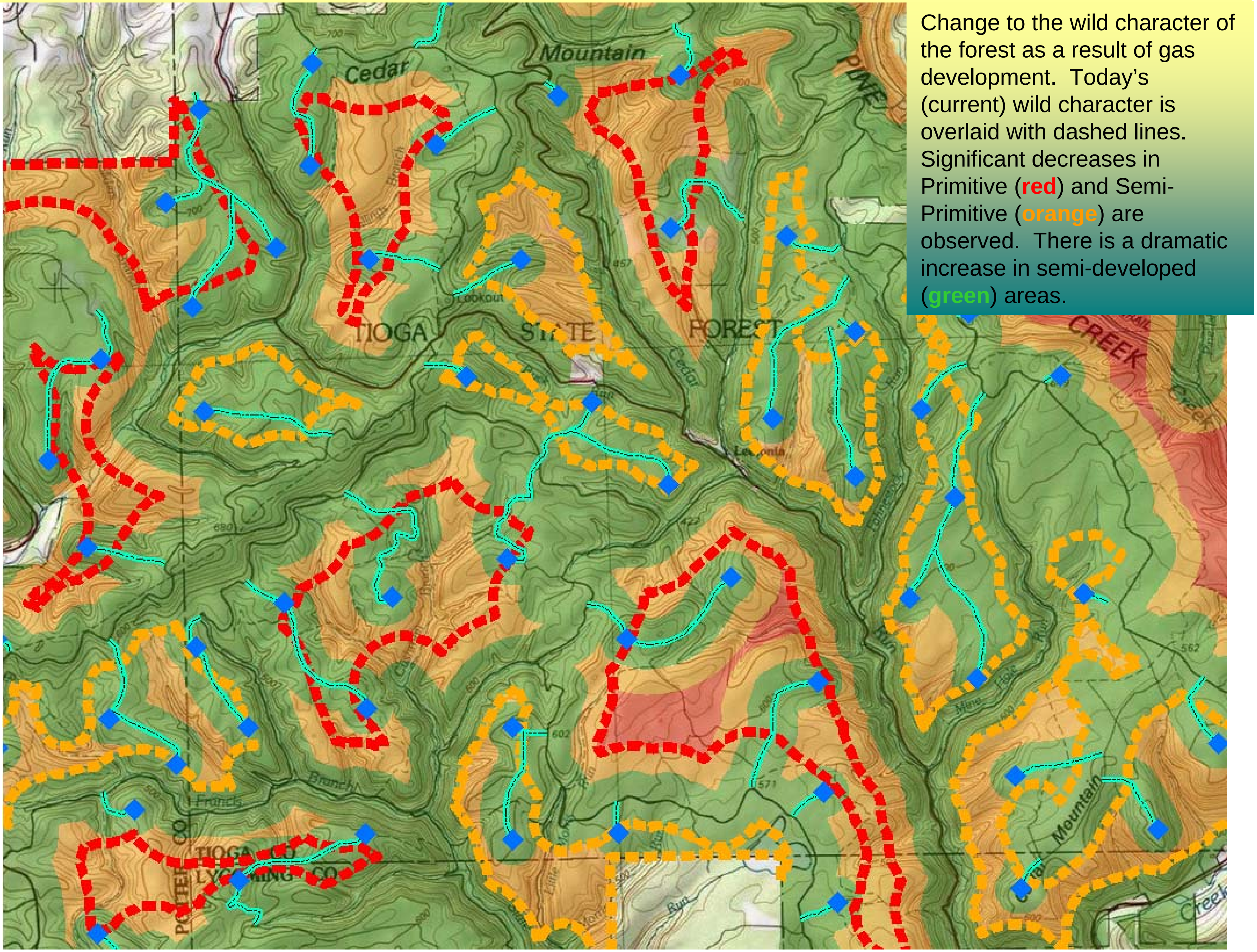
Future Wild Character
(result of gas development)

RED = Primitive

ORANGE = Semi-Primitive

GREEN = Semi-Developed

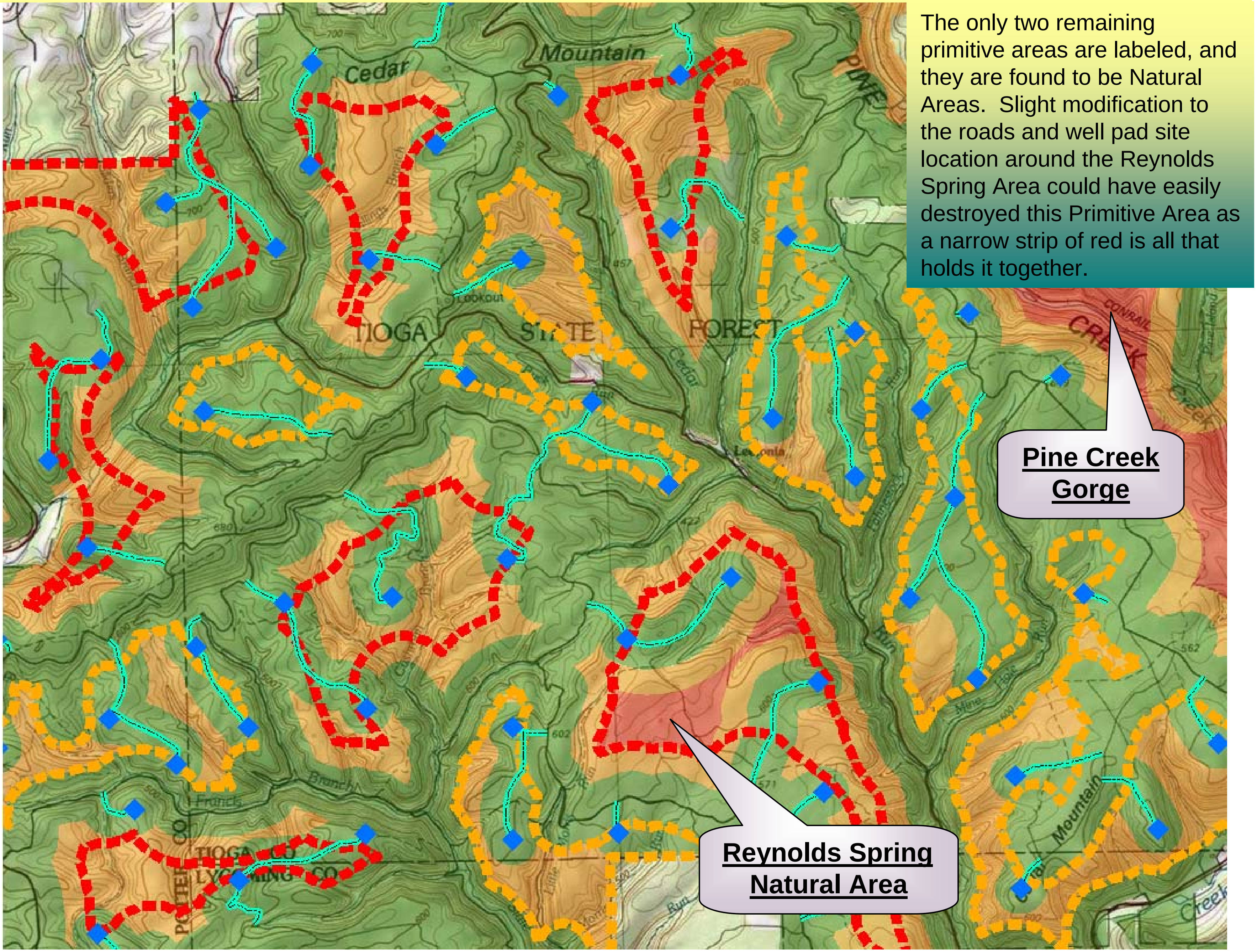
Impact on the Forest's Wild Character



Change to the wild character of the forest as a result of gas development. Today's (current) wild character is overlaid with dashed lines. Significant decreases in Primitive (red) and Semi-Primitive (orange) are observed. There is a dramatic increase in semi-developed (green) areas.

Impact on the Forest's Wild Character

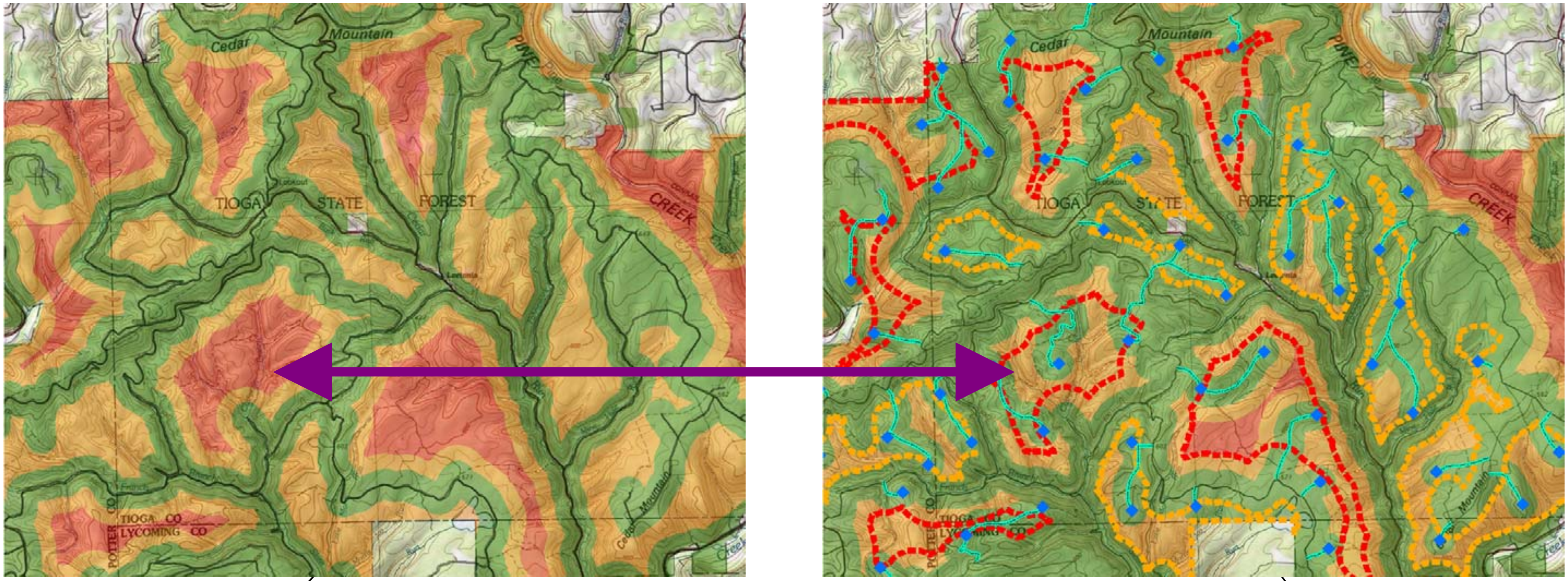
The only two remaining primitive areas are labeled, and they are found to be Natural Areas. Slight modification to the roads and well pad site location around the Reynolds Spring Area could have easily destroyed this Primitive Area as a narrow strip of red is all that holds it together.

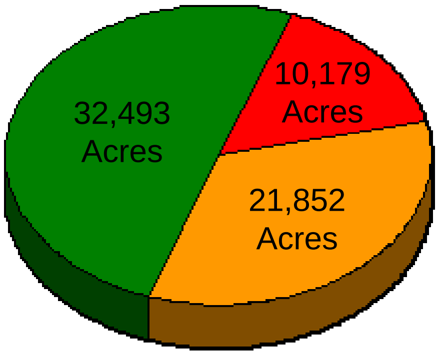


Change in the Forest's Wild Character

Before

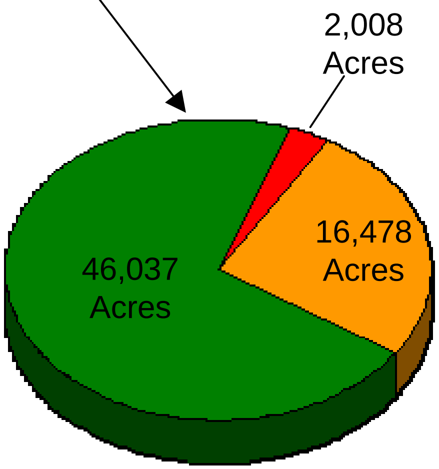
After



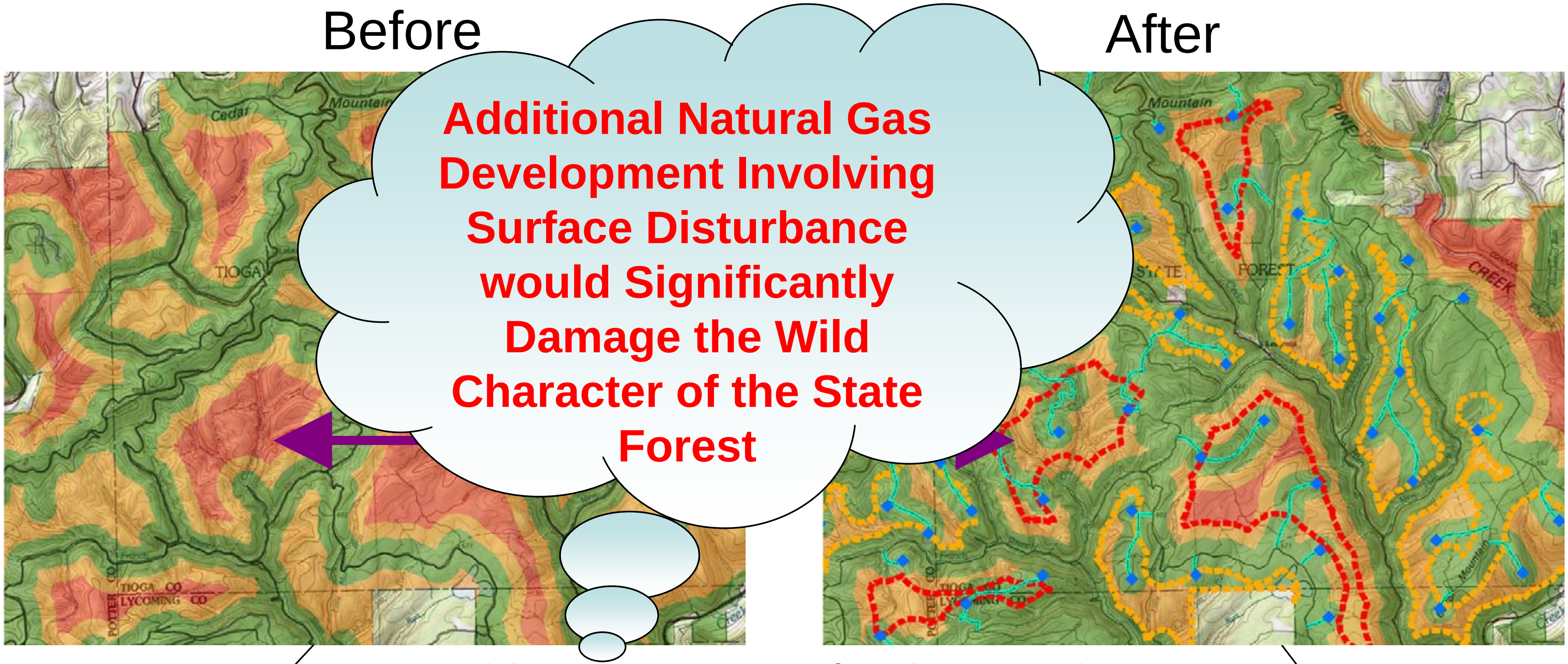


In this ~65,000 acre landscape view, with 54 new well pads…

Zone	Net Gain/Loss
🟥 Primitive	-8,171
🟧 Semi-Primitive	-5,374
🟩 Semi-Developed	13,545

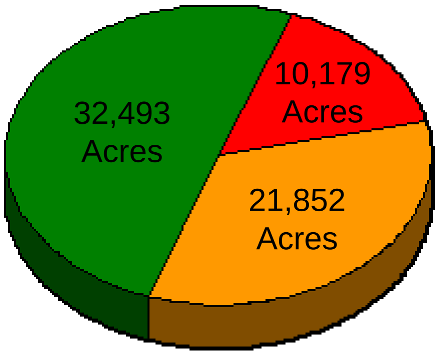


Modeling Change in the Forest's Wild Character



Additional Natural Gas Development Involving Surface Disturbance would Significantly Damage the Wild Character of the State Forest

In this ~65,000 acre landscape view, with 54 new well pads…



Zone	Net Gain/Loss
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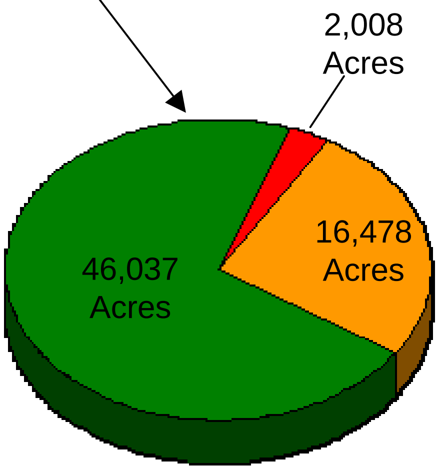
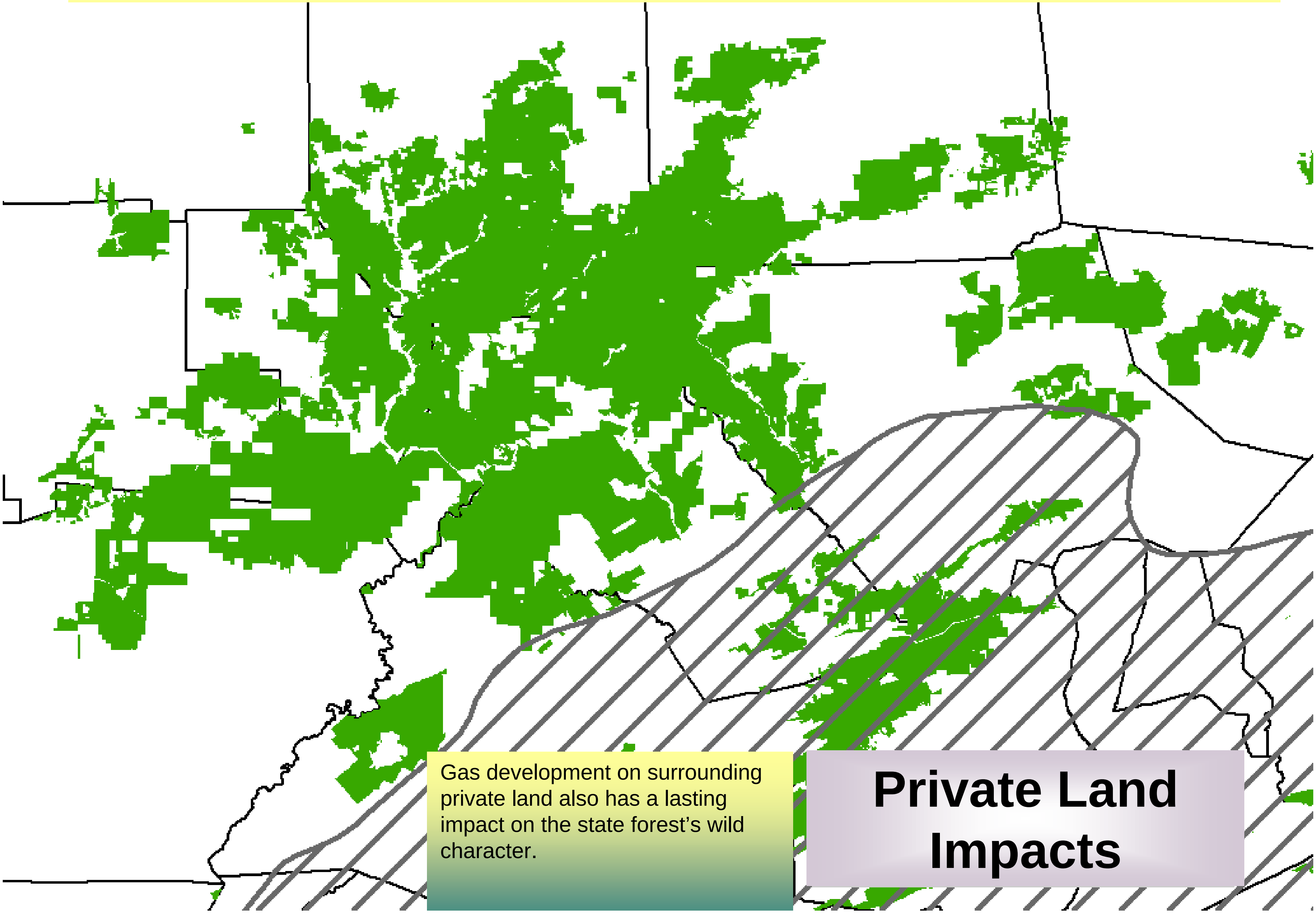


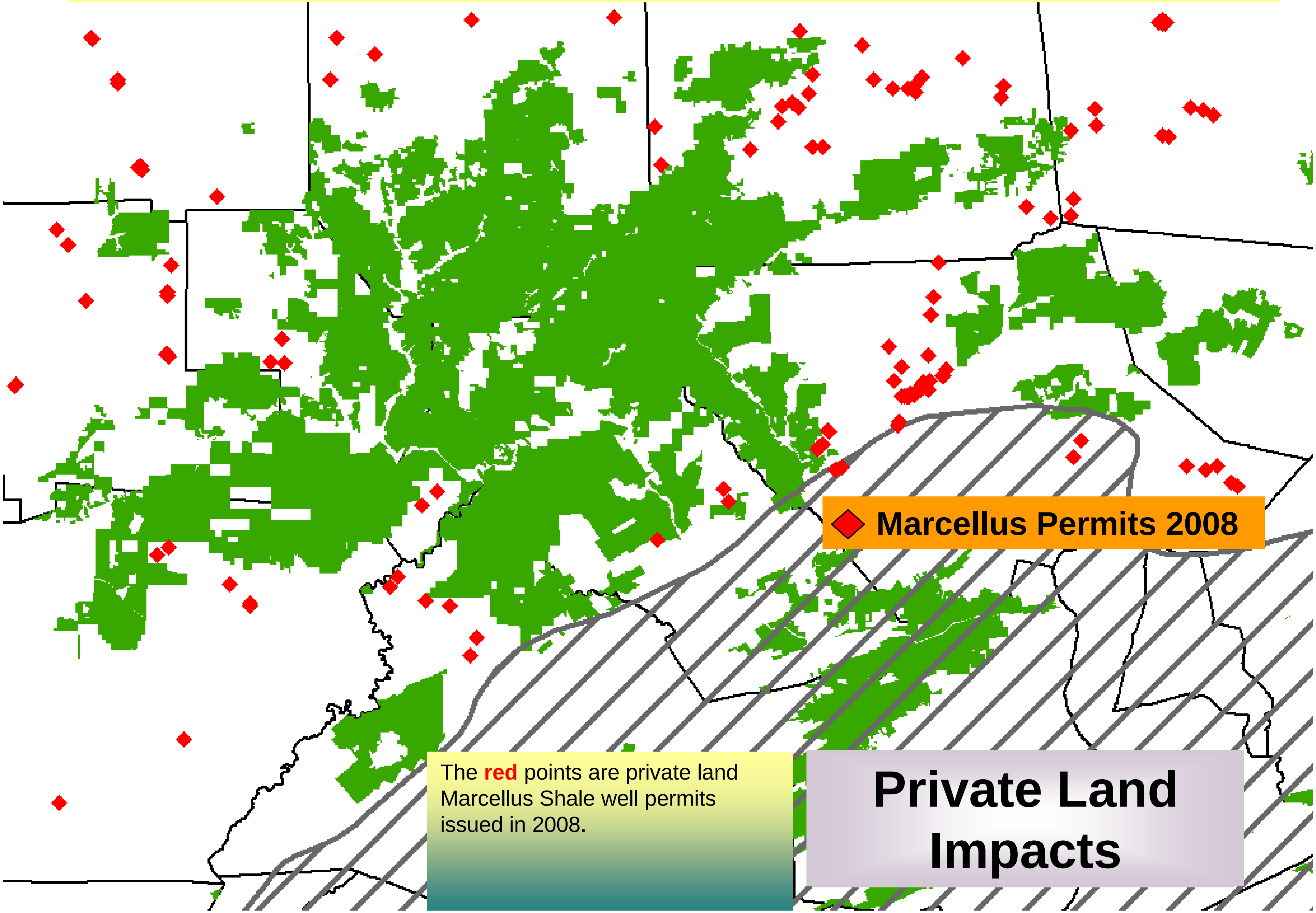
Maintaining the Forest's Wild Character



Gas development on surrounding private land also has a lasting impact on the state forest's wild character.

Private Land Impacts

Maintaining the Forest's Wild Character

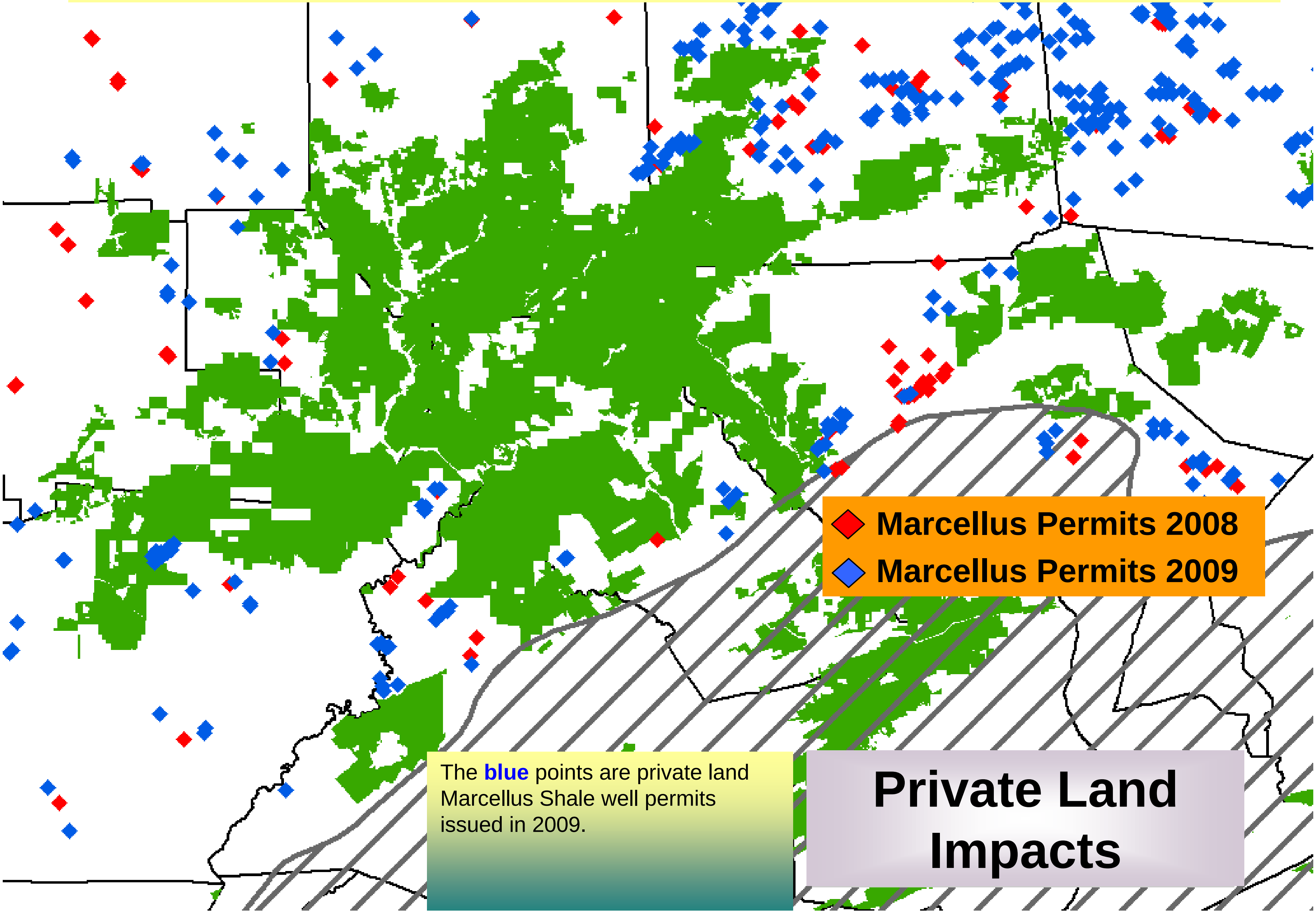


◆ **Marcellus Permits 2008**

The **red** points are private land Marcellus Shale well permits issued in 2008.

Private Land Impacts

Maintaining the Forest's Wild Character

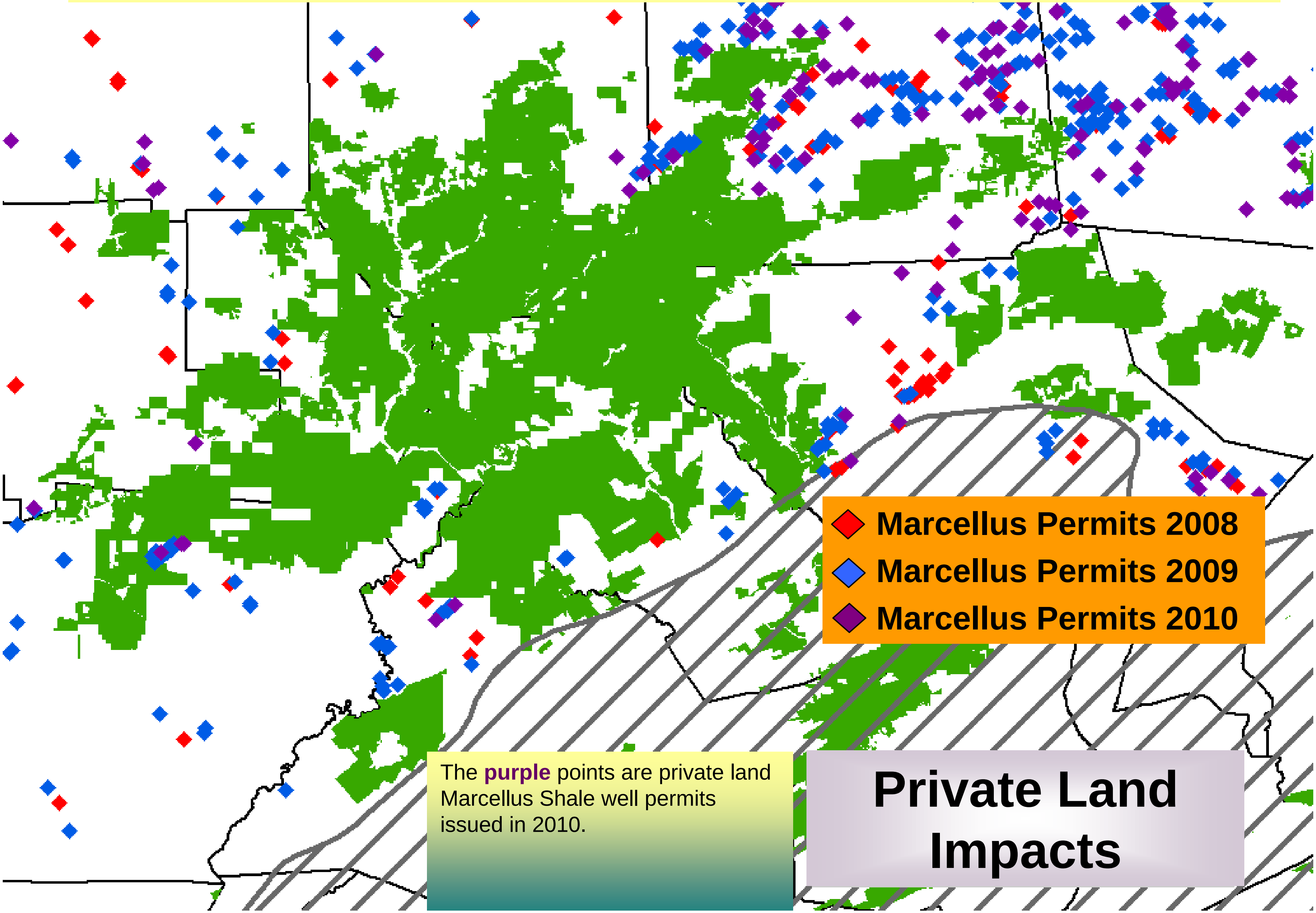


🟥 Marcellus Permits 2008
🟦 Marcellus Permits 2009

The **blue** points are private land Marcellus Shale well permits issued in 2009.

Private Land Impacts

Maintaining the Forest's Wild Character



◆ Marcellus Permits 2008

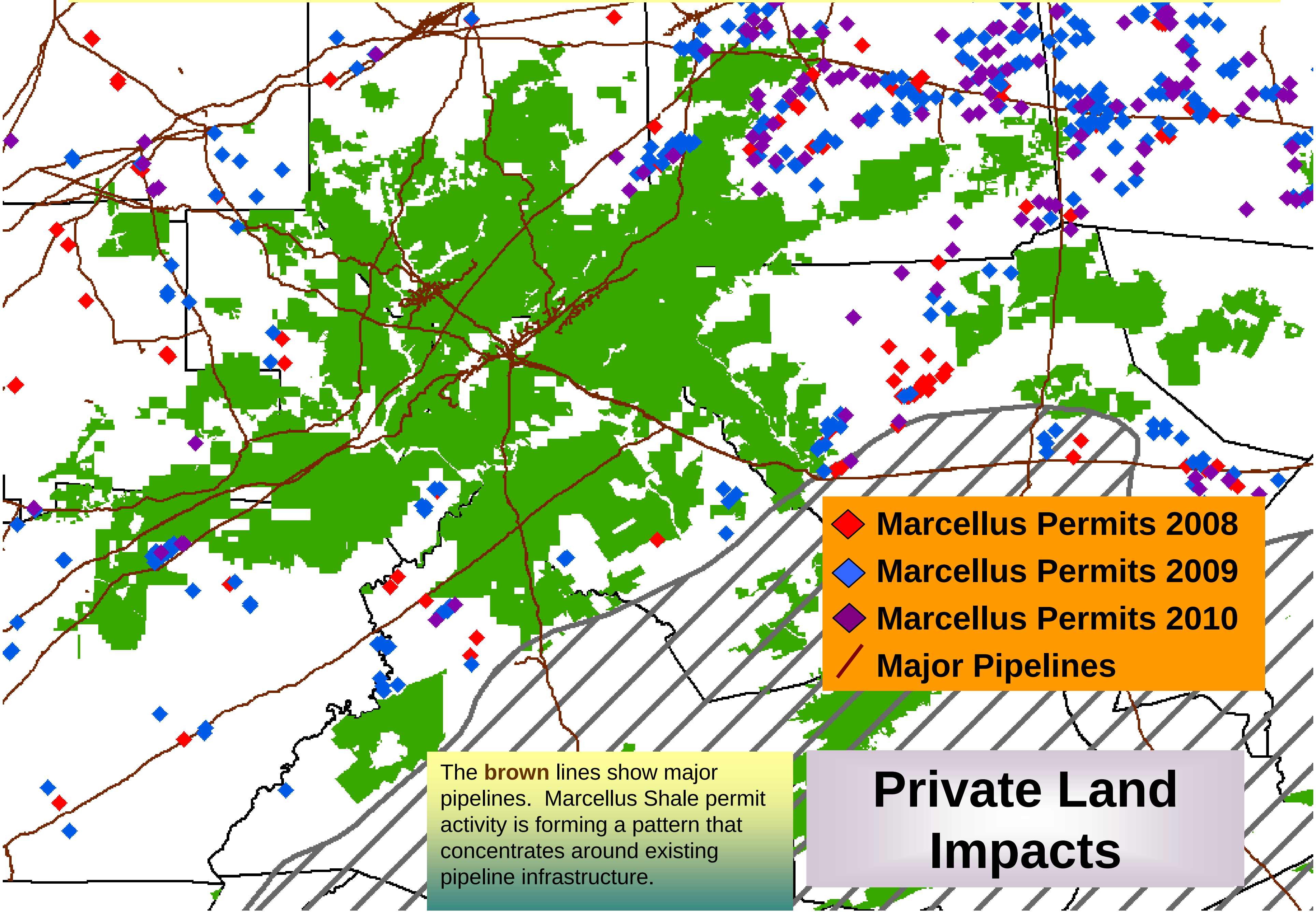
◆ Marcellus Permits 2009

◆ Marcellus Permits 2010

The **purple** points are private land Marcellus Shale well permits issued in 2010.

Private Land Impacts

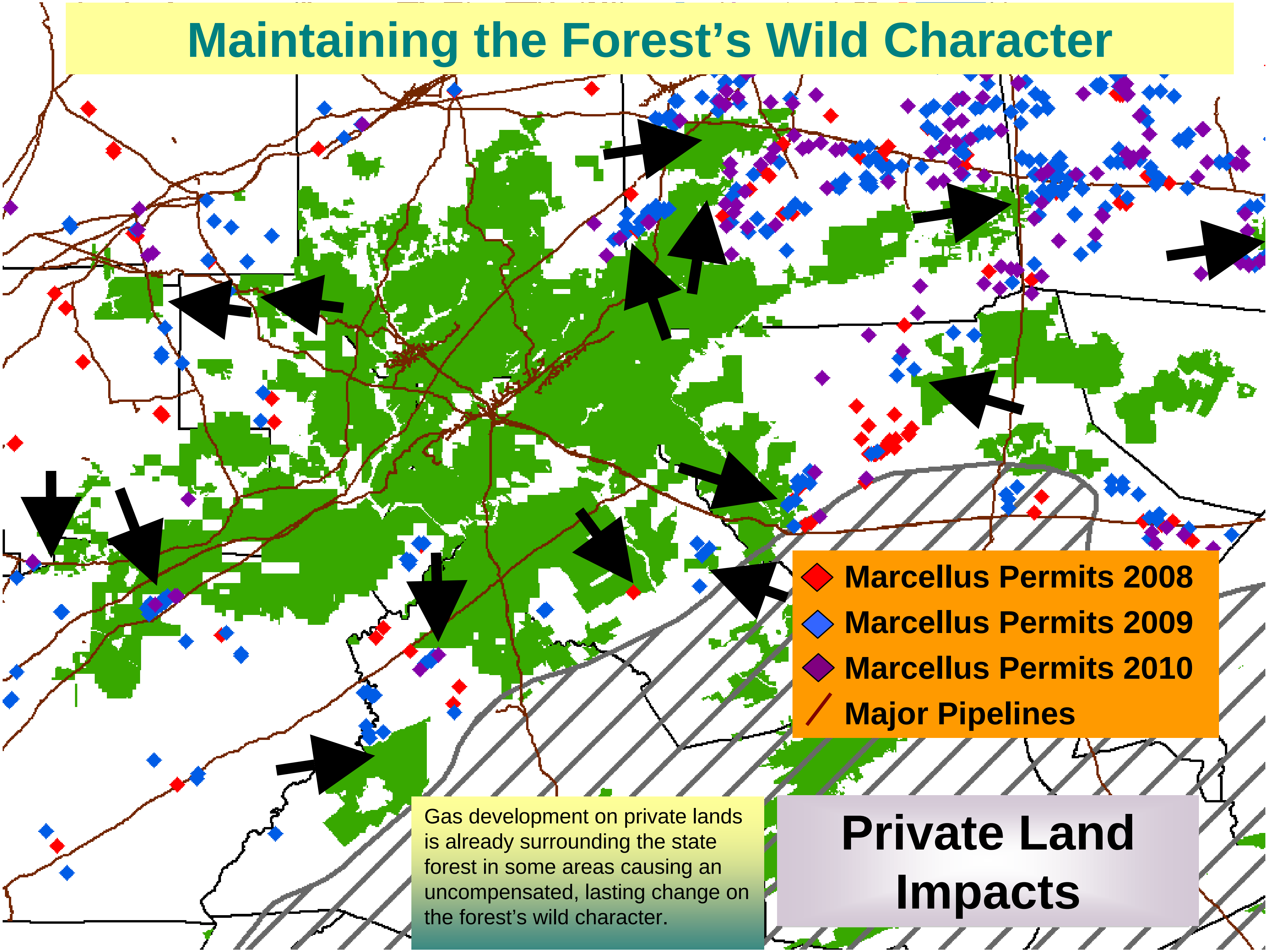
Maintaining the Forest's Wild Character



The **brown** lines show major pipelines. Marcellus Shale permit activity is forming a pattern that concentrates around existing pipeline infrastructure.

Private Land Impacts

Maintaining the Forest's Wild Character

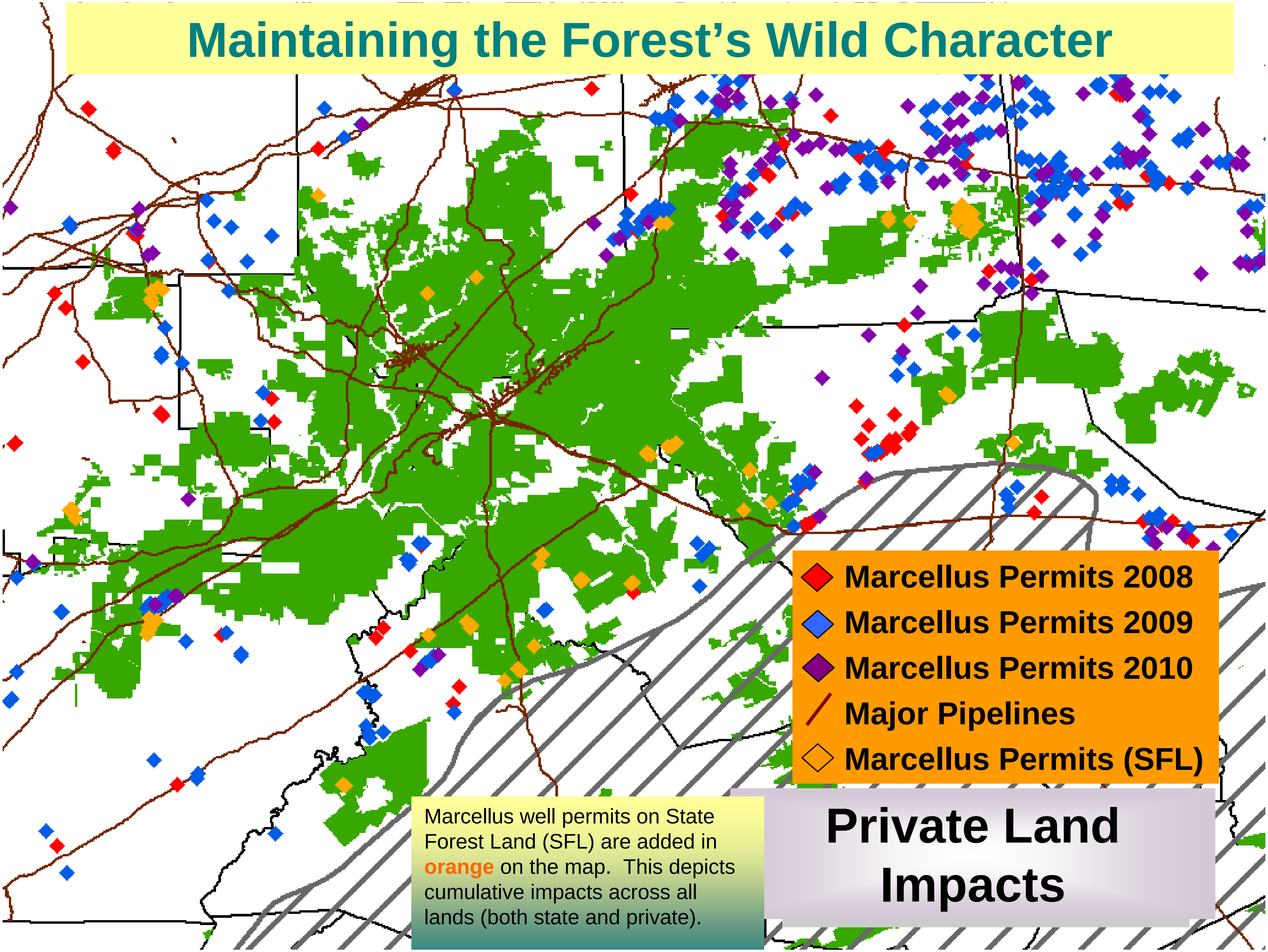


◆ Marcellus Permits 2008
◆ Marcellus Permits 2009
◆ Marcellus Permits 2010
/ Major Pipelines

Gas development on private lands is already surrounding the state forest in some areas causing an uncompensated, lasting change on the forest's wild character.

Private Land Impacts

Maintaining the Forest's Wild Character

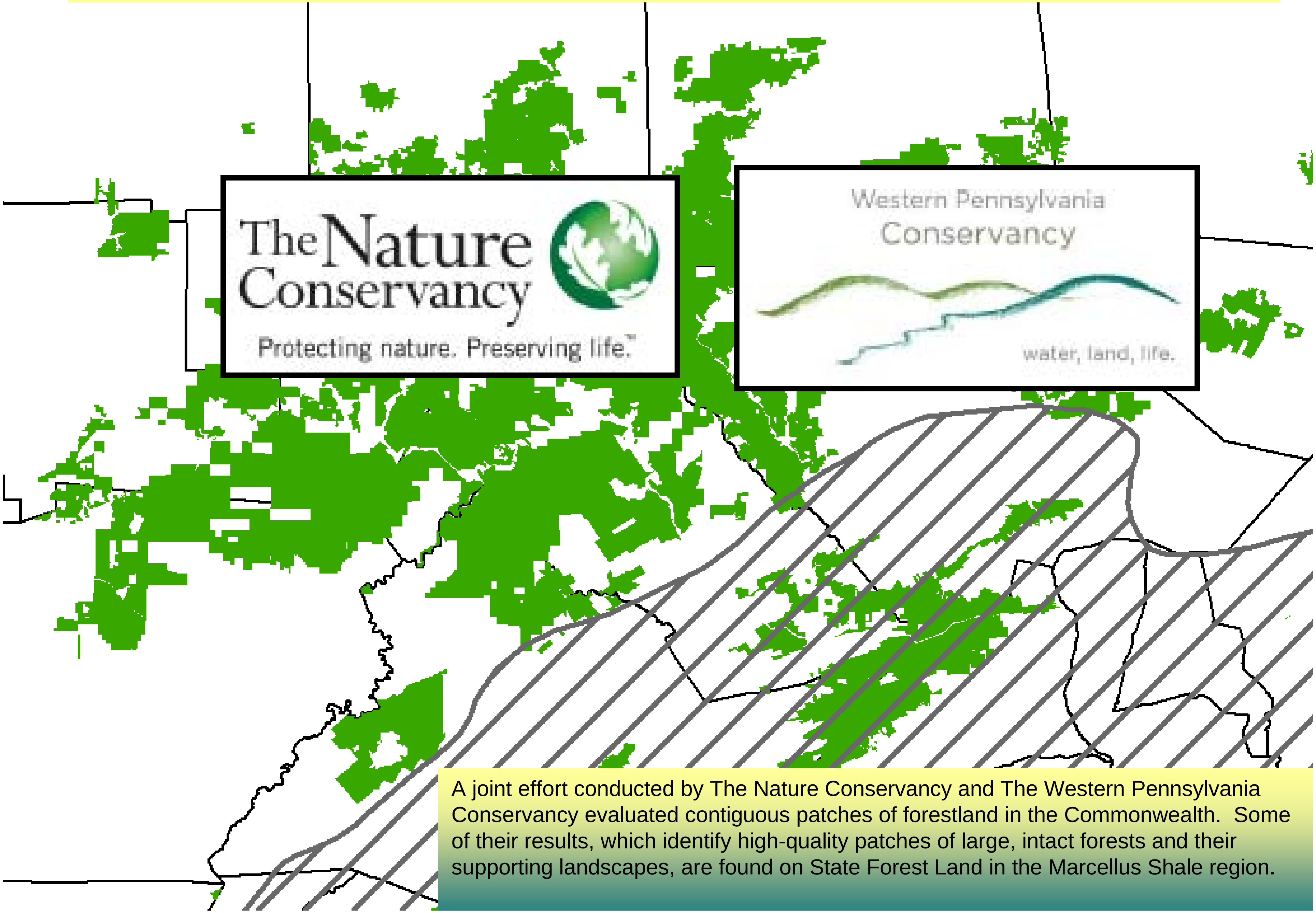


◆ Marcellus Permits 2008
◆ Marcellus Permits 2009
◆ Marcellus Permits 2010
/ Major Pipelines
◇ Marcellus Permits (SFL)

Marcellus well permits on State Forest Land (SFL) are added in **orange** on the map. This depicts cumulative impacts across all lands (both state and private).

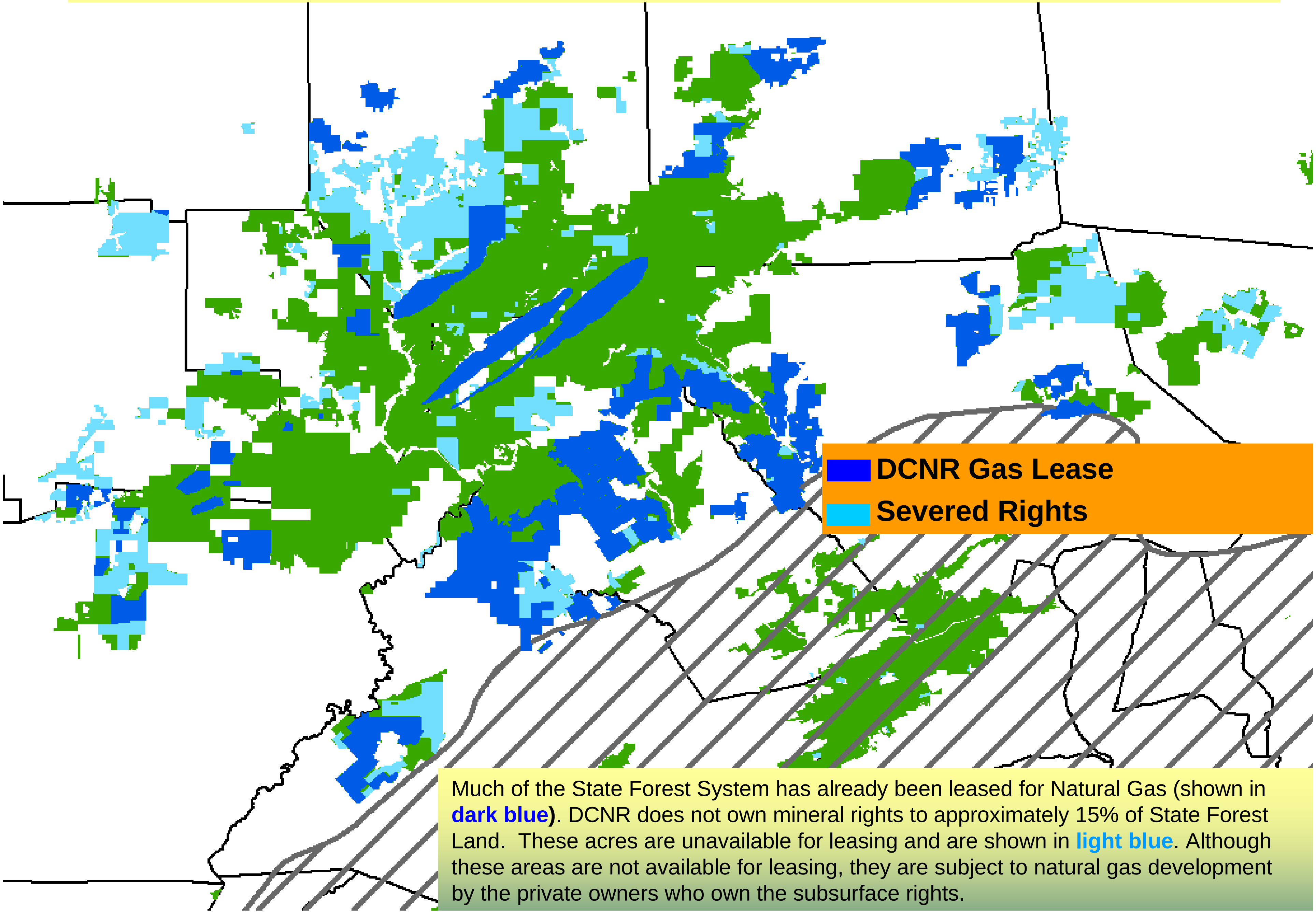
Private Land Impacts

TNC-WPC Priority Forest Patches



A joint effort conducted by The Nature Conservancy and The Western Pennsylvania Conservancy evaluated contiguous patches of forestland in the Commonwealth. Some of their results, which identify high-quality patches of large, intact forests and their supporting landscapes, are found on State Forest Land in the Marcellus Shale region.

TNC-WPC Priority Forest Patches

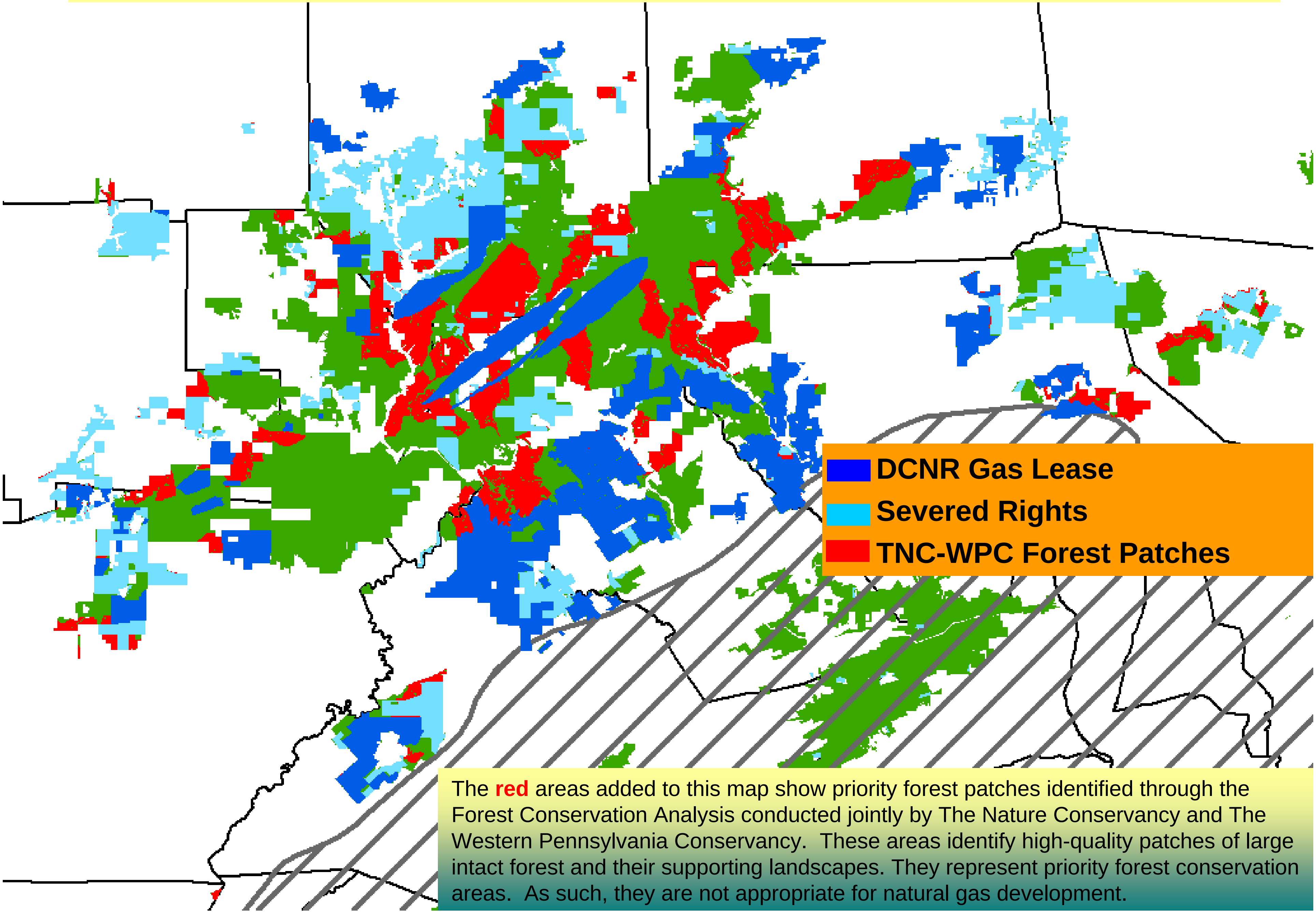


🟦 DCNR Gas Lease

🟦 Severed Rights

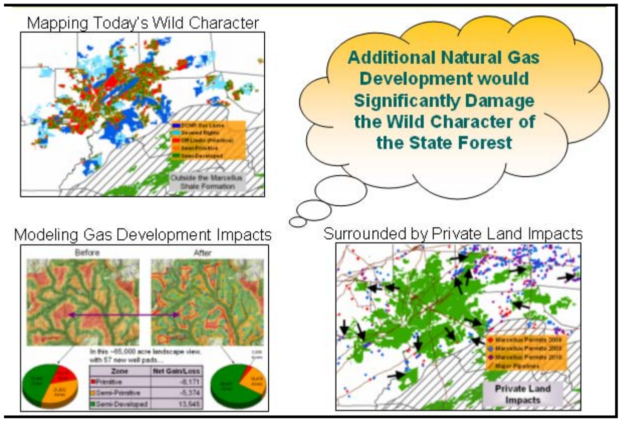
Much of the State Forest System has already been leased for Natural Gas (shown in **dark blue**). DCNR does not own mineral rights to approximately 15% of State Forest Land. These acres are unavailable for leasing and are shown in **light blue**. Although these areas are not available for leasing, they are subject to natural gas development by the private owners who own the subsurface rights.

TNC-WPC Priority Forest Patches



The **red** areas added to this map show priority forest patches identified through the Forest Conservation Analysis conducted jointly by The Nature Conservancy and The Western Pennsylvania Conservancy. These areas identify high-quality patches of large intact forest and their supporting landscapes. They represent priority forest conservation areas. As such, they are not appropriate for natural gas development.

Cumulative Assessment & Impacts


Mapping Today's Wild Character

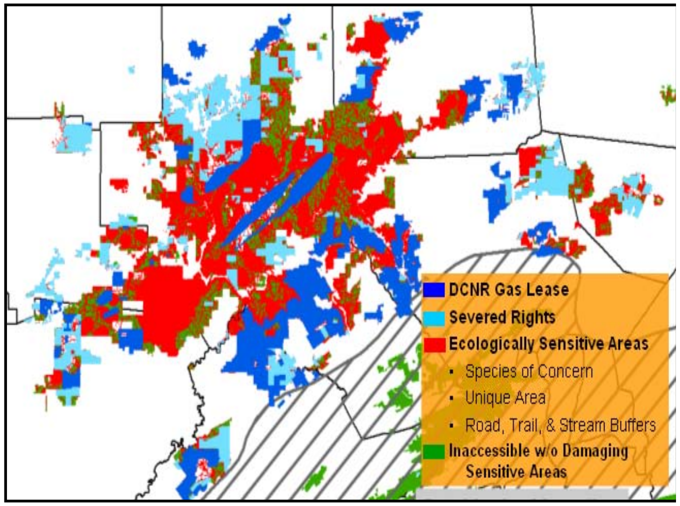
Additional Natural Gas Development would Significantly Damage the Wild Character of the State Forest

Modeling Gas Development Impacts

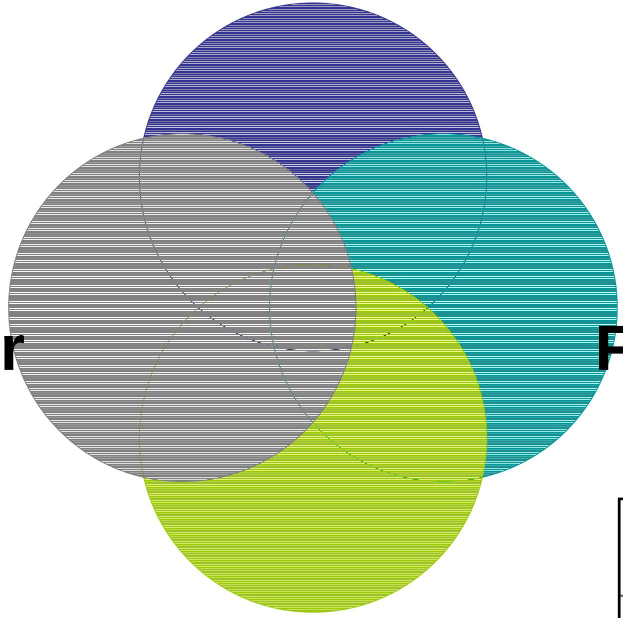
In this ~65,000 acre landscape view, with 57 new well pads...

Zone	Net Gain/Loss
🟥 Primitive	-8,171
🟧 Semi-Primitive	-5,374
🟩 Semi-Developed	13,545

Surrounded by Private Land Impacts



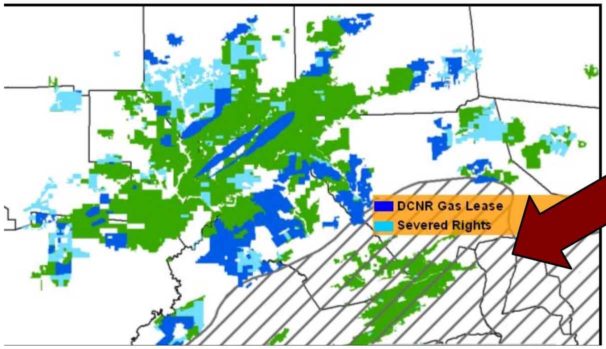
The Forest's Ecological Integrity

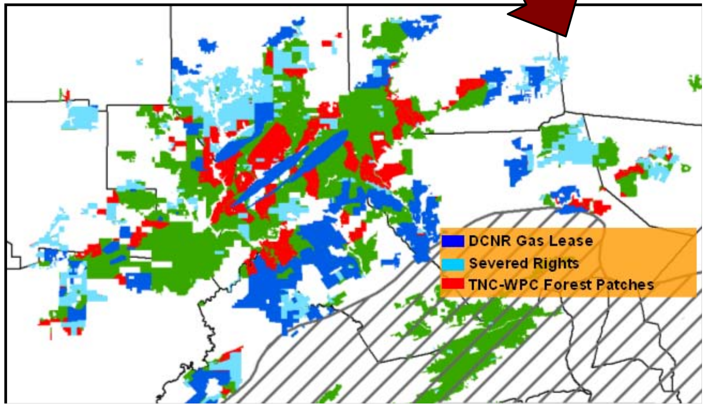


The Forest's Wild Character

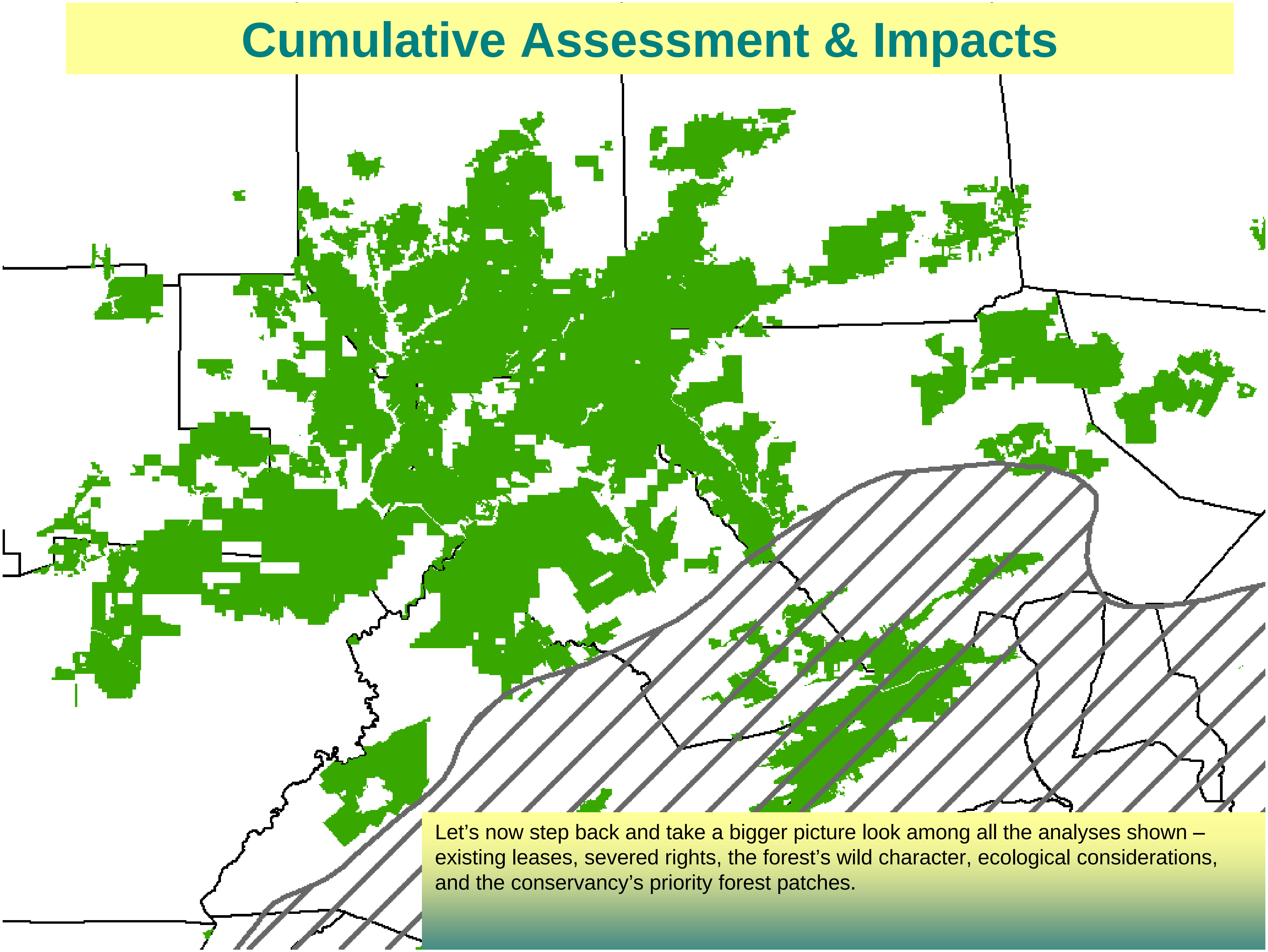
TNC-WPC Forest Patches

Existing Leases & Severed Rights



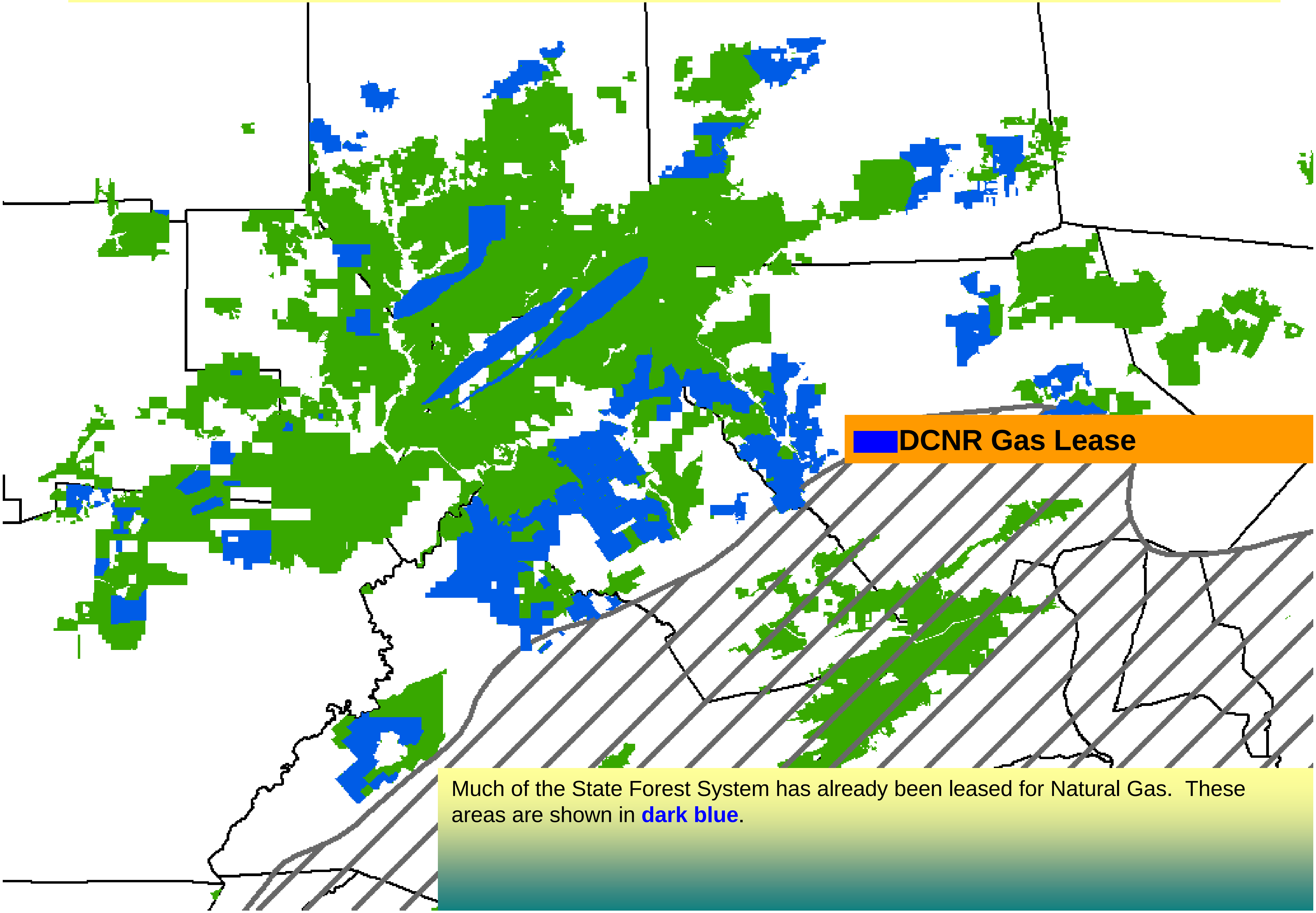


Cumulative Assessment & Impacts



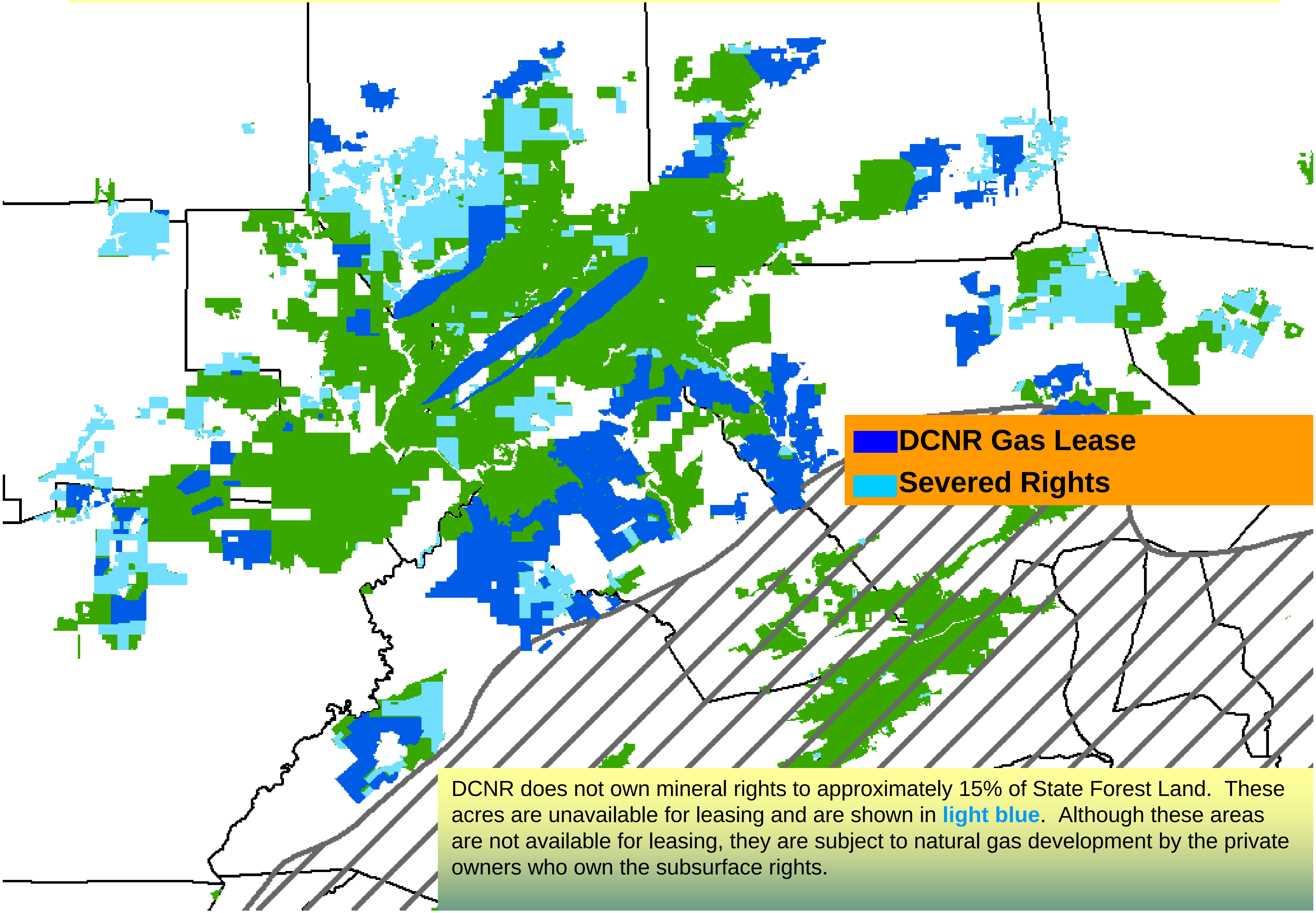
Let's now step back and take a bigger picture look among all the analyses shown – existing leases, severed rights, the forest's wild character, ecological considerations, and the conservancy's priority forest patches.

Cumulative Assessment & Impacts



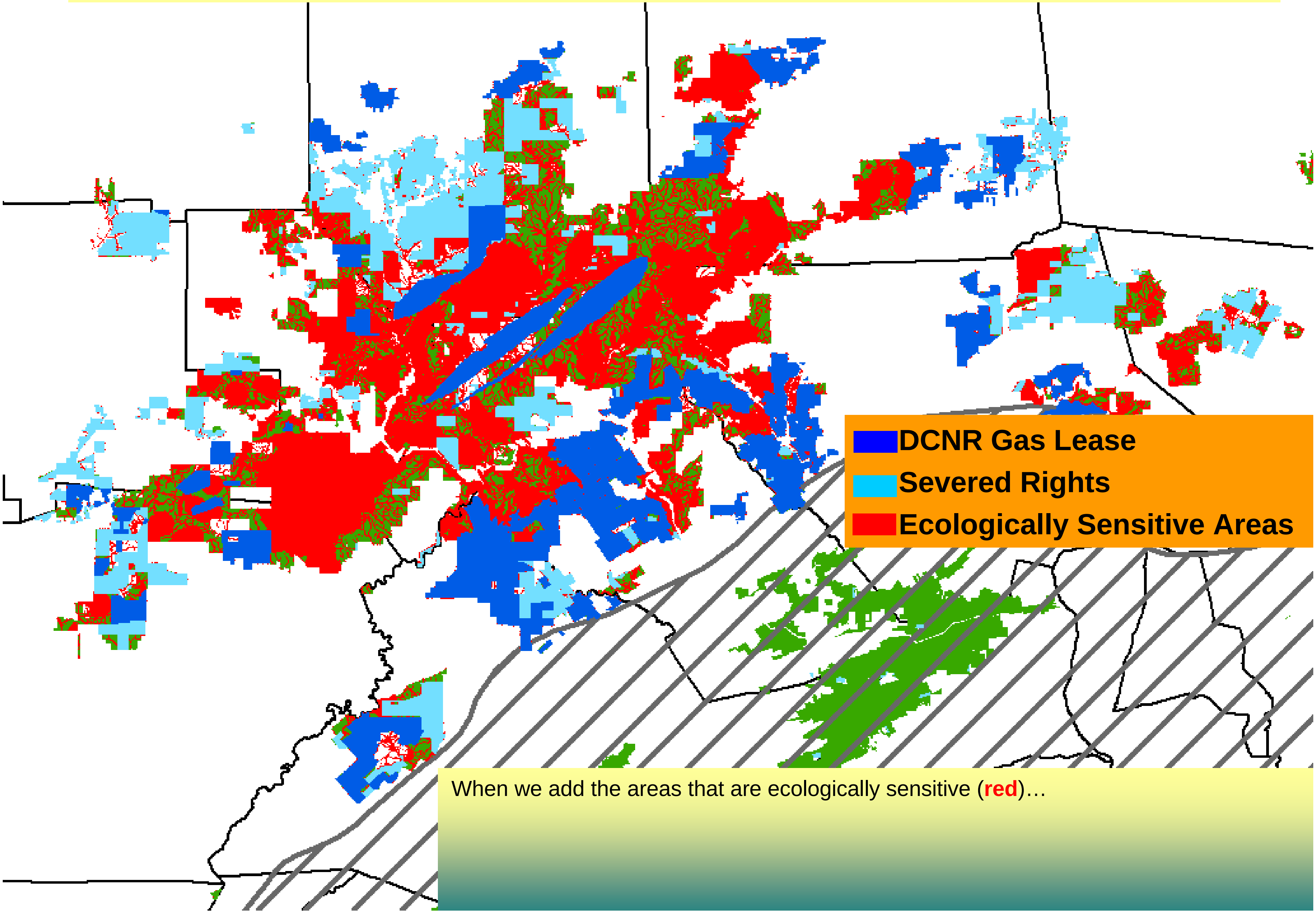
Much of the State Forest System has already been leased for Natural Gas. These areas are shown in **dark blue**.

Cumulative Assessment & Impacts



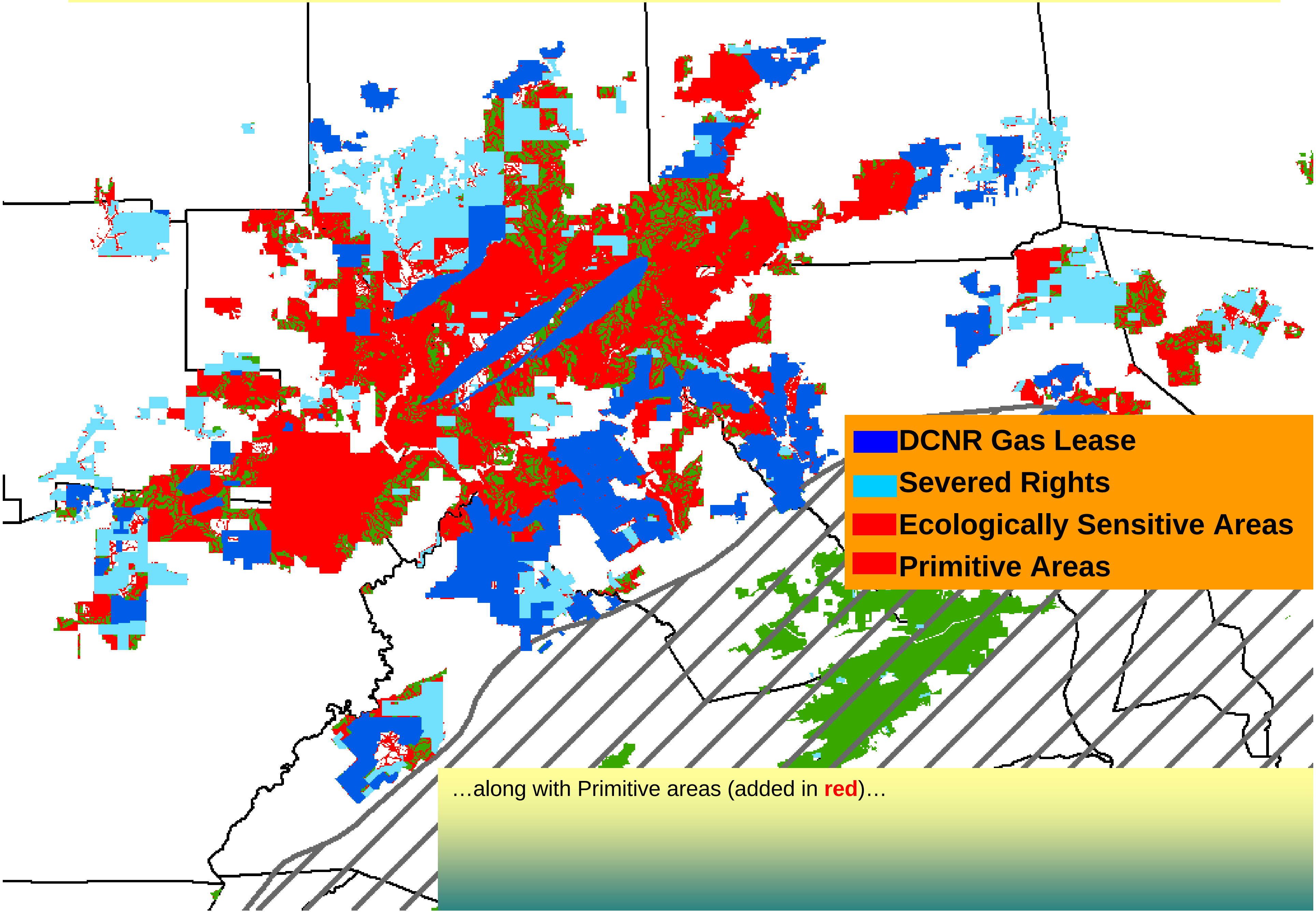
DCNR does not own mineral rights to approximately 15% of State Forest Land. These acres are unavailable for leasing and are shown in **light blue**. Although these areas are not available for leasing, they are subject to natural gas development by the private owners who own the subsurface rights.

Cumulative Assessment & Impacts



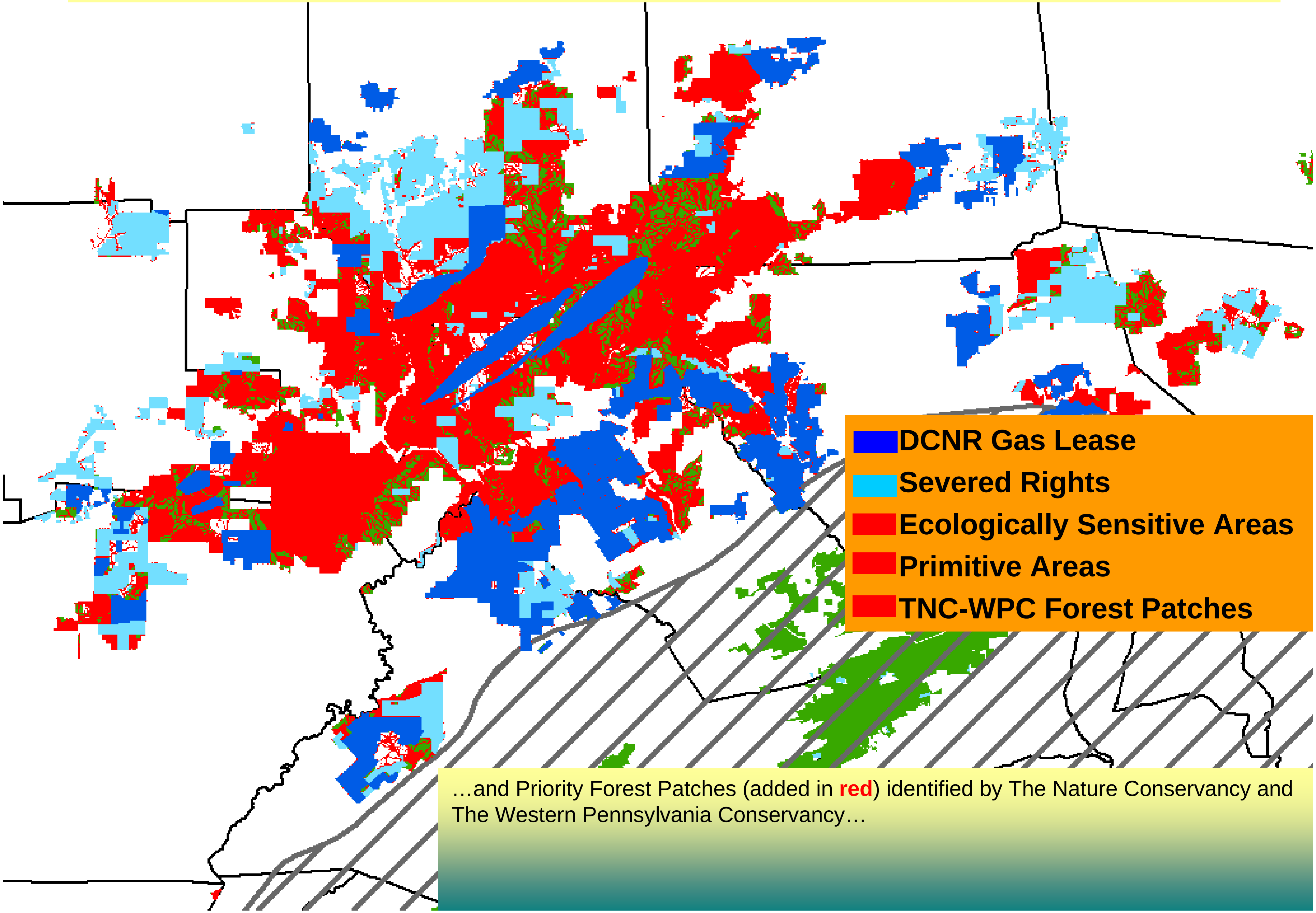
When we add the areas that are ecologically sensitive (**red**)…

Cumulative Assessment & Impacts



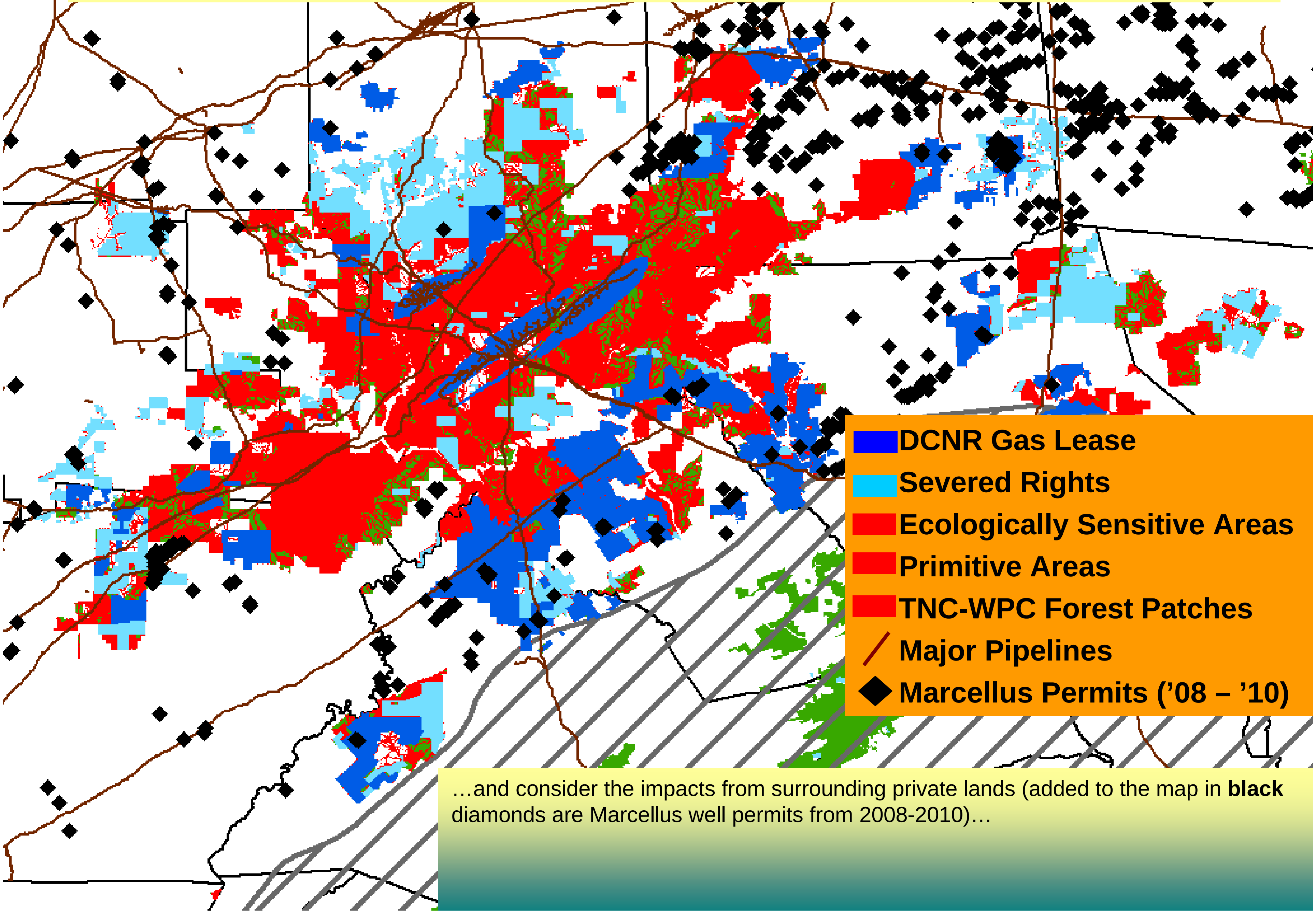
…along with Primitive areas (added in **red**)…

Cumulative Assessment & Impacts



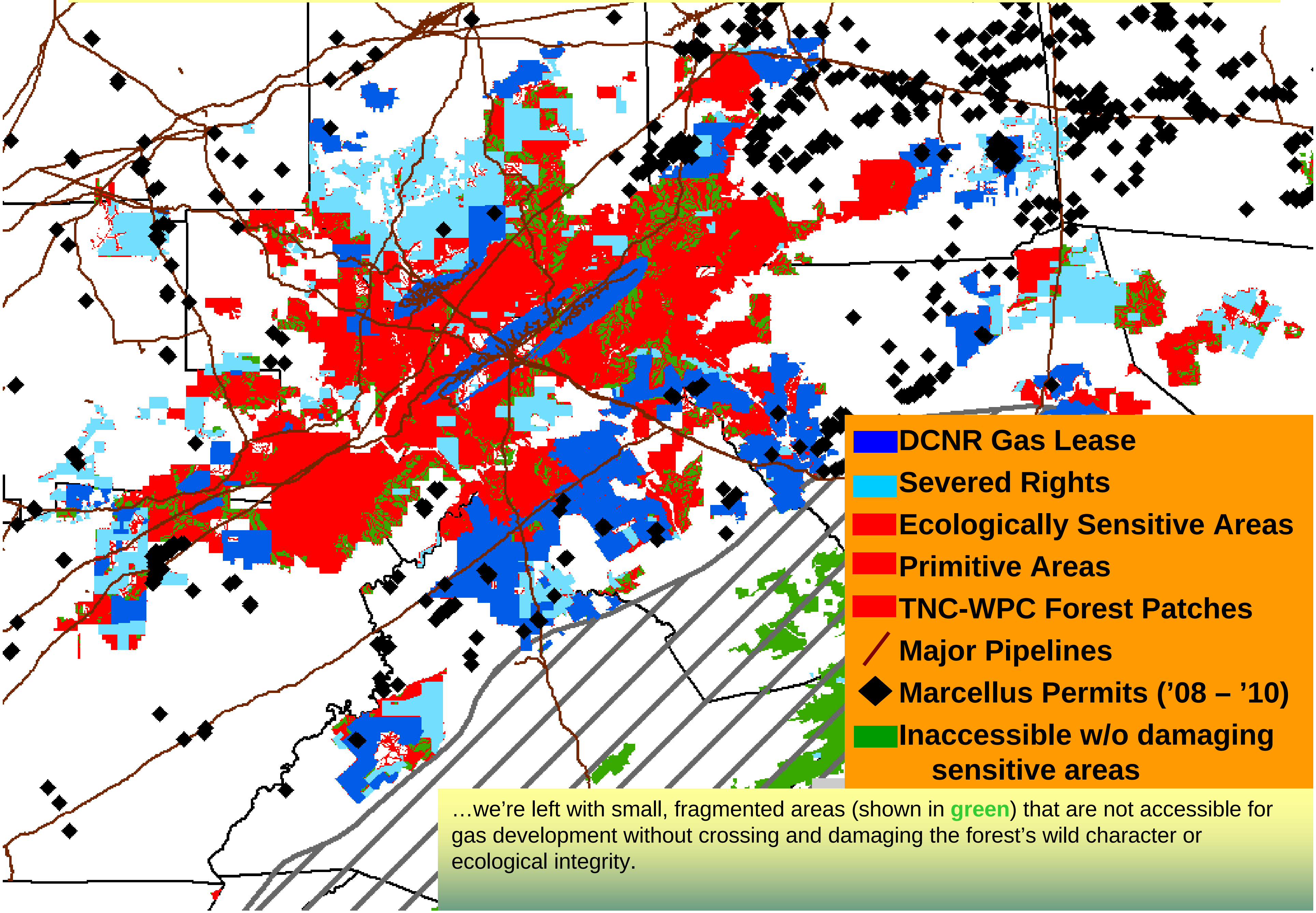
…and Priority Forest Patches (added in **red**) identified by The Nature Conservancy and The Western Pennsylvania Conservancy…

Cumulative Assessment & Impacts



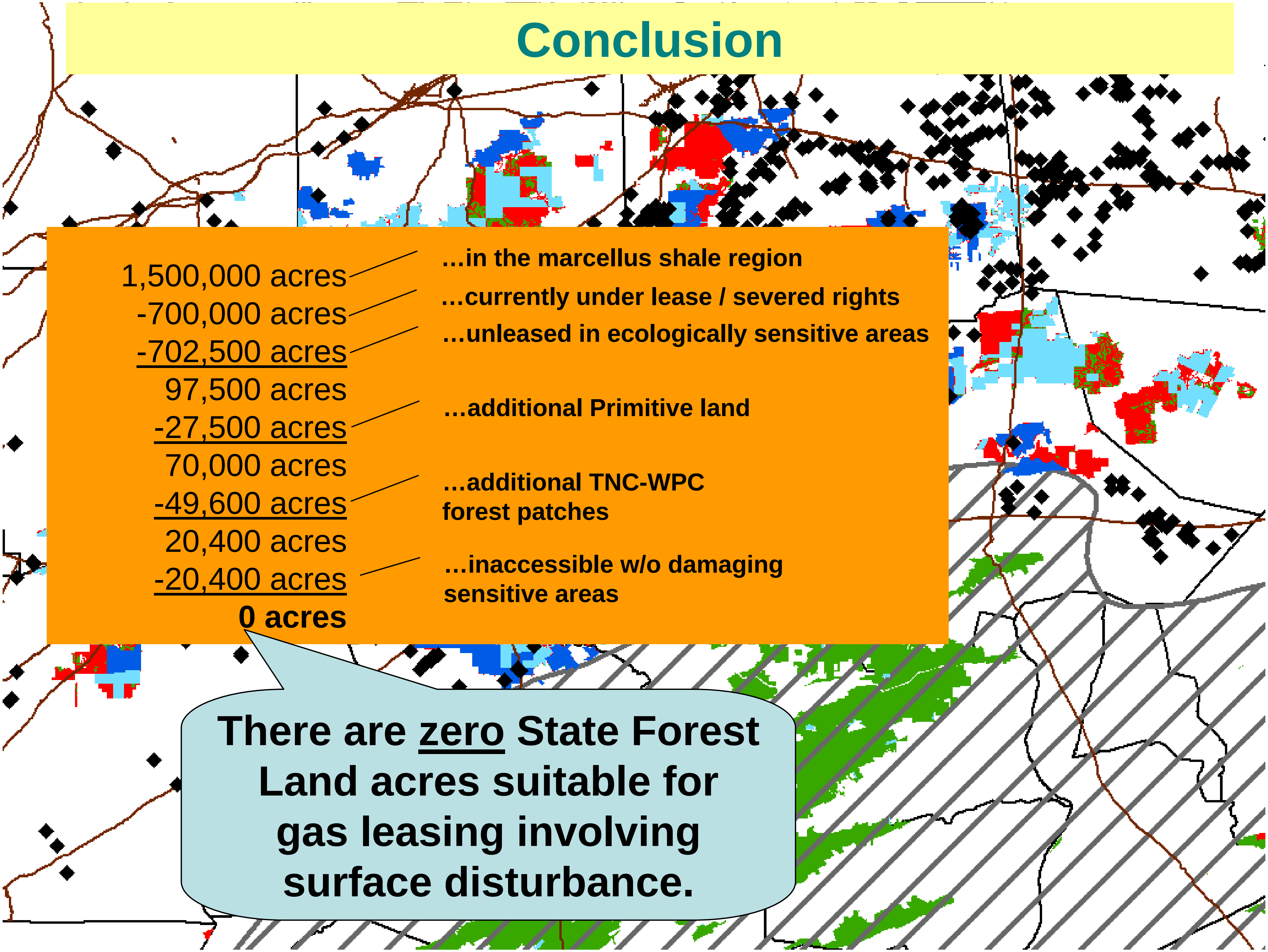
…and consider the impacts from surrounding private lands (added to the map in **black** diamonds are Marcellus well permits from 2008-2010)…

Cumulative Assessment & Impacts



…we're left with small, fragmented areas (shown in green) that are not accessible for gas development without crossing and damaging the forest's wild character or ecological integrity.

Conclusion



1,500,000 acres	…in the marcellus shale region
-700,000 acres	…currently under lease / severed rights
-702,500 acres	…unleased in ecologically sensitive areas
97,500 acres	
-27,500 acres	…additional Primitive land
70,000 acres	
-49,600 acres	…additional TNC-WPC forest patches
20,400 acres	
-20,400 acres	…inaccessible w/o damaging sensitive areas
0 acres	

There are <u>zero</u> State Forest Land acres suitable for gas leasing involving surface disturbance.

CATSKILL MOUNTAINKEEPER
DELAWARE RIVERKEEPER®
EARTHJUSTICE
NRDC
THE EARTH'S BEST DEFENSE
RIVERKEEPER.

January 11, 2012

Attn: dSGEIS Comments
New York State Department of Environmental Conservation
625 Broadway
Albany, NY 12233-6510

Dear Sir or Madam:

Enclosed please find the comments of Catskill Mountainkeeper, Delaware Riverkeeper Network, Earthjustice, the Natural Resources Defense Council and Riverkeeper on the Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Reservoirs, issued September 7, 2011, and draft regulations (Proposed Express Terms 6 NYCRR Parts 52, 190, 550-556, 560, 750.1, and 750.3), issued September 28, 2011.

Sincerely,

Maya k. von Rossum

Wes Gillingham
Catskill Mountainkeeper

Maya van Rossum
the Delaware Riverkeeper, Delaware Riverkeeper Network

Deborah Goldberg

Deborah Goldberg
Earthjustice

Kate Sinding
Natural Resources Defense Council

Kate Hudson
Riverkeeper

THE **Louis Berger Group**, INC.
48 Wall Street, 16th Floor, New York, NY 10005
Tel 212 612 7900 Fax 212 363 4341
www.louisberger.com

Memorandum

TO: Kate Sinding, Natural Resources Defense Council

FROM: Niek Veraart, Louis Berger Group

DATE: January 11, 2012

RE: Technical Comments Summary Report: Expert Team Review of the 2011 Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program and Proposed High-Volume Hydraulic Fracturing Regulations

1.0 Introduction

The Louis Berger Group, Inc. (LBG) is pleased to submit this comment report on the 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas and Solution Mining Regulatory Program and Proposed High Volume Hydraulic Fracturing (HVHF) Regulations to the Natural Resources Defense Council (NRDC) and its partner organizations, Earthjustice, Riverkeeper, Delaware Riverkeeper Network and Catskill Mountainkeeper. This comment report serves two primary purposes: 1) to provide general comments on the RDSGEIS and proposed regulations that are not limited to specific disciplines, and 2) to summarize the discipline-specific technical comments from NRDC's expert review team. The expert review team consisted of Harvey Consulting, LLC, Dr. Tom Myers, Dr. Glenn Miller, Dr. Ralph Seiler, Dr. Susan Christopherson, Meliora Design LLC, LBG, Kevin Heatley, Dr. Kim Knowlton, Dr. Gina Solomon, and Briana Mordick. The detailed technical comments from each author/organization are provided as attachments to this summary report and referenced as appropriate throughout.[1] Table 1 provides a complete list of technical comment attachments and summarizes the major topics areas addressed in each. Resumes for the members of the expert review team are provided in Attachment 12.

2.0 General Comments

2.1 RDSGEIS Fails to Address "Other Low-Permeability Shales"

The final scope and title of the RDSGEIS included other low-permeability shales, in addition to the Marcellus shale. The RDSGEIS makes it clear that development of other shales (including the Utica shale) is not only possible in the future, but is considered likely as evidenced by the inclusion of development of other shales in the Ecology & Environment. Inc. economic impact assessment.[2]

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[1] All references cited and relied upon in the attached reports are hereby incorporated by reference into these comments. Hard and/or electronic copies of all references are available upon request.

[2] See the 11/23/2011 email from Steven Russo (NYSDEC) to Deborah Goldberg (Earthjustice) explaining the assumptions used in developing the scenarios for economic impact assessment include the development of "other shales."

Table 1
Technical Attachments to the Summary Comment Report

Attachment Number	Preparer	Topics Addressed
1	Harvey Consulting, LLC	Scope of SGEIS - Marcellus Shale Only Liquid Hydrocarbon Impacts Water Protection Threshold Well Casing Requirements Permanent Wellbore Plugging &Abandonment Requirements HVHF Design and Monitoring Hydraulic Fracture Treatment Additive Limitations Drilling Mud Composition and Disposal Reserve Pit Use and Drill Cutting Disposal HVHF Flowback Surface Impoundments at Drillsite HVHF Flowback Centralized Surface Impoundments Off-Drillsite Repeat HVHF Treatment Life Cycle Air Pollution Control and Monitoring Surface Setbacks from Sensitive Receptors Naturally Occurring Radioactive Materials Hydrogen Sulfide Chemical Tank, Waste Tank and Fuel Tank Containment Corrosion and Erosion Mitigation and Integrity Monitoring Programs Well Control and Emergency Response Capability Financial Assurance Amount Seismic Data Collection
2	Tom Myers, Ph. D.	Hydrogeology and Contaminant Transport Surface Water Hydrology Groundwater Quality Monitoring Setbacks from aquifers and public water supply wells Acid Rock Drainage
3	Glenn Miller, Ph.D.	Toxicology Hydraulic Fracturing Additives Naturally Occurring Radioactive Materials Contaminants in Flowback water and produced brines Wastewater Treatment issues
4	Ralph Seiler, Ph.D.	Radon in Marcellus Shale Natural Gas Naturally Occurring Radioactive Materials
5	Susan Christopherson, Ph.D.	Socioeconomic Impacts Pace and timing of natural gas development
6	Meliora Design, LLC	Water Quality Stormwater Erosion SPDES General Permit
7	The Louis Berger Group, Inc.	Noise and Vibration Visual impacts Land use Transportation Community character Cultural resources Aquatic Ecology
8[3]	Kevin Heatley, M.EPC LEED AP	Ecosystems and Wildlife
9	Kim Knowlton, DrPH	Climate Change and Public Health
10	Gina Solomon, M.D., M.P.H	Health Impact Assessment
11	Briana Mordick	Induced Seismicity

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[3] Report prepared for and provided courtesy of the Delaware Riverkeeper Network.

The RDSGEIS adds some additional baseline geologic information on the Utica shale, but the environmental impacts specific to the Utica shale have not been addressed. For example, the Utica shale is almost twice as deep as the Marcellus shale, which means wells in the Utica shale will take longer to drill, would create more noise, would require more water, and would generate more waste and truck trips than wells in the Marcellus shale.

In addition to the incomplete study of deeper depth low permeability gas reservoirs, gas reservoirs at shallower depths than the Marcellus shale were not studied at all in the RDSGEIS. These shallower low-permeability shales pose development risks greater than those associated with the Marcellus shale because they are closer to protected water resources. Furthermore, the combined and/or concurrent exploitation of low-permeability shales at multiple depths may result in cumulative impacts not addressed in the RDSGEIS. The absence of the impact analyses of exploitation of shales at depths other than the Marcellus shale renders the RDSGEIS incomplete. NYSDEC should either evaluate additional information and analysis on the impacts of exploring and developing the Utica Shale and other unnamed low-permeability gas reservoirs, or acknowledge that there is insufficient information and analysis to study the impacts of this development. In the latter case, the RDSGEIS should conclude that its examination of impacts and mitigation measures is limited to the Marcellus Shale Gas Reservoir, and therefore any Utica Shale or other unnamed low-permeability gas reservoir development will warrant a site-specific supplemental environmental impact statement review or should be covered under another, future SGEIS process.

For additional detailed information supporting this comment, refer to Chapter 2 of the 2011 Harvey Consulting, LLC report (Attachment 1).

2.2 RDSGEIS and Regulations Fail to Protect the Environment from Non-HVHF Gas Development

While significant gaps remain as identified throughout these comments, the proposed regulatory framework for HVHF includes a number of improvements to NYSDEC's existing regulations to protect the environment from natural gas development. However, most of these improvements apply only to wells meeting the threshold to be classified as HVHF (defined as hydraulic fracturing using greater than 300,000 gallons of water).[4] NYSDEC is using a patchwork approach to regulating HVHF by adding new requirements on top of outdated requirements. A broader reform of the oil and gas development regulations is needed to address deficiencies in the existing regulations. This will ensure that best practice approaches are required for all natural gas wells in New York, including conventional wells and hydraulic fracturing using less than 300,000 gallons of water. Examples of reforms incorporated into the RDSGEIS and/or proposed regulations for HVHF that should apply to all wells include updated well casing requirements, emergency response plans and plans addressing the mitigation of noise, visual, transportation and ecological impacts.

2.3 RDSGEIS Fails to Address Indirect and Cumulative Impacts

The RDSGEIS fails to analyze important indirect and cumulative impacts as required by the State Environmental Quality Review Act (SEQRA). One of the most glaring examples of this is the

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[4] The RDSGEIS arbitrarily increased the threshold for HVHF to 300,000 gal from 80,000 gal, as evaluated in the 1992 GEIS. There is no scientific justification given for the increase, and it effectively leaves all fracturing in the range 80,000-300,000 regulated by the existing rules without NYSDEC ever having conducted an environmental review showing that they are adequate for jobs that big.

RDSGEIS's failure to analyze the impacts of the pipelines and compressor stations that would be required to support the development of HVHF.

The RDSGEIS does not analyze any of the important impacts of pipelines and compressor stations (such as additional habitat fragmentation, noise and air pollutant emissions) based on flawed reasoning that such an analysis is not required because the pipelines would be reviewed under the Public Service Commission's Article VII process. The regulatory review process for pipelines is irrelevant—SEQRA requires state and local agencies to consider indirect "growth inducing" impacts. Pipelines and compressor stations are an indirect effect of the approval of HVHF. Without the approval of HVHF, there would be no reason to construct additional pipelines. Therefore, the pipelines/compressor stations and associated impacts cannot be separated from the environmental impact analysis of the HVHF regulatory program. The separate environmental review of the pipelines is, moreover, a form of segmentation, which is not permissible under SEQRA.[5] The additional natural gas pipelines and related infrastructure could also result in cumulative impacts when their impacts are combined with the impacts of HVHF that were analyzed in the RDSGEIS. The result of these deficiencies in the RDSGEIS is that the true impacts of the approval of HVHF have not been disclosed to the public and the requisite "hard look" under SEQRA has not been taken.

Similar to the treatment of pipeline infrastructure, the RDSGEIS also fails to analyze the cumulative impacts of numerous actions related to HVHF moving forward in New York, including the following:

- **Impacts from wastewater disposal and management**. The wastewater produced during the HVHF process is highly contaminated and could impact water resources if released into groundwater or surface water. While recognizing the problems with management of this water, the RDSGEIS fails to clearly state how this water will be either disposed in a manner that protects human health and the environment, or otherwise treated to remove the contaminants. While the RDSGEIS provides a range of alternatives, the RDSGEIS does not analyze the environmental or human health impacts associated with any of these disposal options. There are four possible treatment options for flowback and produced water discussed in the RDSGEIS: (1) reuse, (2) deep well injection, or (3) treatment in municipal or privately owned treatment facilities. None of these options is properly analyzed in the RDSGEIS, and the potential significant adverse impacts of each are therefore not disclosed nor possible mitigation identified. Further, effectively none of these options is likely to be accomplished in state, and the RDSGEIS implies that virtually all of the wastewater generated in New York will be managed out of state where regulations may be less stringent.

- **Impacts from Centralized Flowback Impoundments.** The RDSGEIS fails to analyze the impacts of centralized flowback impoundments based on statements from industry that they will not be "routinely" proposed. While site-specific SEQRA review would be required for any centralized flowback impoundment, NYSDEC should have addressed the potential for significant adverse cumulative impacts (particular air quality and water resources) arising from centralized flowback impoundments in combination with the other impacts of HVHF discussed in the RDSGEIS.

- **Impacts from seismic data collection.** Seismic data collection has the potential to create

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[5] See 6 § NYCRR (617.2(ag)): "Segmentation means the division of the environmental review of an action such that various activities or stages are addressed under this Part as though they were independent, unrelated activities, needing individual determinations of significance."

habitat fragmentation through the clearing of long linear corridors, among other impacts. Seismic data collection is a reasonably foreseeable part of the development process and should have been considered as an aspect of the cumulative effects assessment in the RDSGEIS.

- **Impacts from liquid petroleum.** The development of the Marcellus shale has the potential to result in wells the encounter liquid hydrocarbons. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drill sites may be proposed to develop those oil resources. Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. None of these impacts were considered in the RDSGEIS.

- **Impacts from land use change**. The RDSGEIS contains some information about potential economic benefits, but does not examine how increase population and employment would change land use. Changes in land use would result in greater demands on the transportation system as well as ecological impacts from new residential and commercial development (above and beyond the direct impacts of the well pad sites themselves).

Fundamentally, the RDSGEIS analyzes only certain elements of HVHF and fails to analyze all elements of the process, both individually and collectively.

2.4 Unenforceable Mitigation under the HVHF Regulatory Framework

As noted throughout the detailed technical review comments, the RDSGEIS includes numerous mitigation commitments that are not enforceable because they are not included in the proposed regulations or supplemental permit conditions.

To provide a consistent regulatory framework for industry and to protect the environment, mitigation measures that would be applied across all HVHF operations should be incorporated into the proposed regulations. Mitigation measures that are site-specific should be incorporated into the supplemental permit conditions. Mitigation measures that are suggested in the RDSGEIS itself that are unenforceable (i.e., not codified through regulatory or other mechanisms) should be acknowledged as such and reduced efficacy of mitigation due to the lack of enforcement should be analyzed and disclosed.

2.5 Setbacks

As a general matter, the setback requirements stipulated by proposed HVHF regulations are inadequate to protect public health and environmental quality. Table 2 provides a summary of the setbacks proposed in the RDSGEIS and/or regulations and the recommended revisions to the setbacks based on the expert reviews conducted for NRDC.

For example, the minimum setback according to the HVHF regulatory framework for a residence is 100-feet. This is inadequate considering the potential for blowouts to eject drilling mud, hydrocarbons, and/or formation water from a well onto adjacent waters and lands. Depending on reservoir pressure, blowout circumstances, and wind speed, these pollutants can be distributed hundreds to thousands of feet away from a well. Other risks to residences and schools within close proximity to HVHF operations include noise levels that damage hearing and, exposure to hazardous gases, chemicals, fuels, and explosive charges.

The potential radius of impact for explosions, fire, and other industrial hazards should be considered in the RDSGEIS and proposed HVHF regulations. For example, Fort Worth Texas uses the International Fire Code as the basis for its minimum 600’ setback from shale gas drilling operations. The figure below shows how the HVHF regulations setback distance requirements are significantly shorter and thus less protective than the requirements in other locations.

Comparison of NYS Setbacks from Homes and Public Buildings to Fort Worth, Texas Setbacks

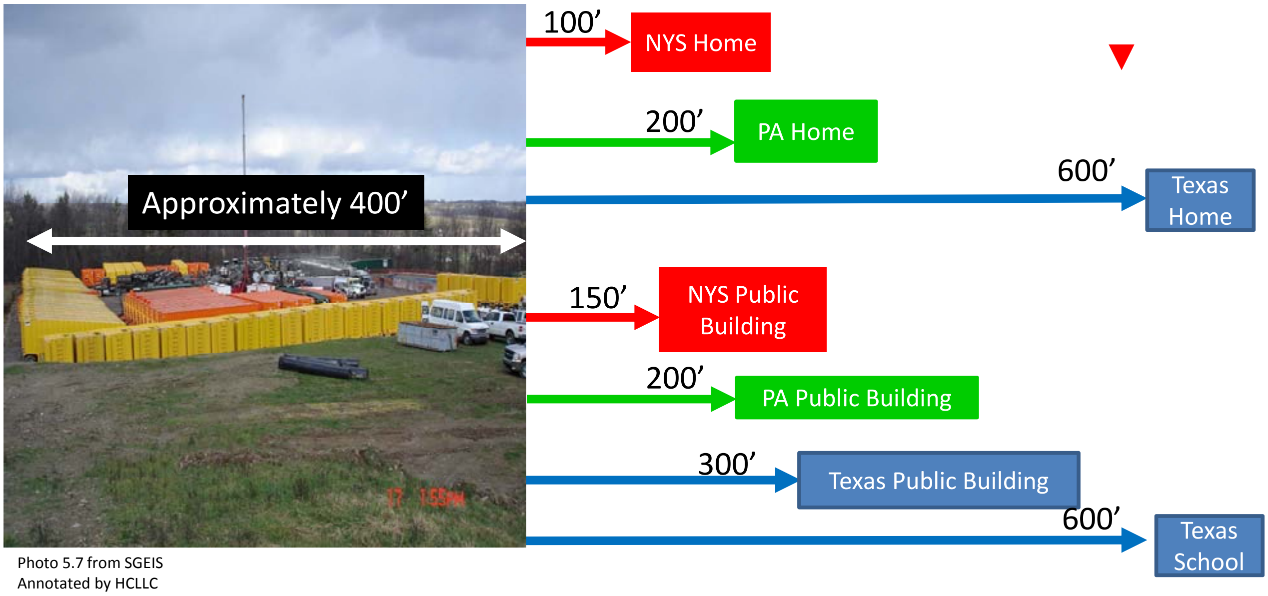

Photo 5.7 from SGEIS
Annotated by HCLLC
Distances shown by arrows drawn to scale

2.6 Insufficient Public Review of HVHF Permit Applications

The RDSGEIS fails to provide a clear and accessible process for public and local government access to site-specific HVHF activity information, while at the same time placing the burden on local government (and not the industry) to provide notice to NYSDEC that a HVHF activity may not be in compliance with local zoning or land use regulations (RDSGEIS pages 8-4 and 8-5). This essentially puts the regulatory burden on local government and at the same time fails to provide local government with access to the necessary information. The burden of demonstrating compliance with local government land use requirements should fall on the industry, not local government and the public. NYSDEC should require public notice of the availability of HVHF permit applications locally through publication of a notice in a newspaper of general circulation and statewide through a centralized website. Permit applicants should be required to provide copies of their application to the affected municipality. The public should have immediate online access to all supporting documentation submitted with each permit application and the public review timeframe should be no less than 30 days. The regulatory framework must incorporate a mechanism for public comments on permit applications to be considered by NYSDEC before the decision to grant or reject a permit application is made.

Table 2
Summary of Setback Recommendations

	Minimum Setback under Existing/Proposed HVHF Regulatory Framework	Recommended Minimum Setback	Rationale/Notes
Residences	100 feet 6 NYCRR § 553.2	1,320 feet	Protects from noise, explosions, fire, and other industrial hazards.
Public Buildings (including schools)	150 feet 6 NYCRR § 553.2		
Primary Aquifers	500 feet 6 NYCRR § 560.4	4,000 feet	The 500 feet setback for primary aquifers should be increased to 4,000 feet (the same setback distance adopted in the RDSGEIS for Filtration Avoidance Determination watersheds), unless a site specific analysis demonstrates there are no fractures connecting the bedrock with the aquifer and there are no obvious surface water pathways.
Principal Aquifers	500 feet in RDSGEIS (page 1-18) but not in the proposed regulations**	4,000 feet	The only difference between a primary and principal aquifer is the number of people potentially using the aquifer. Principal aquifers are thought to be productive enough to be an important source and contamination with fracking fluid or flowback could render them unusable without substantial remediation. Wells near principal aquifers should be subject to the same setback as well near a primary aquifer.
Public Water Supplies	2,000 feet (6 NYCRR § 560.4)	4,000 feet	The setback for public water supplies should be the same as for principal aquifers (4,000 feet) and the operator should identify the capture zone for flow to the well and identify the five year transport distance contour.
Private Drinking Water Wells	500 feet* (6 NYCRR § 560.4)	4,000 feet	Private and public wells should be protected to the same extent. NYSDEC should not allow the owner to waive the private well setback requirement because health and safety are at risk. More than just the "owner" may use the source, and the owner could sell to someone who does not understand the situation.
Stream, Storm Drain, Lake, or Pond	150 feet**	660 feet	The regulations currently contain conflicting and unclear requirements with respect to surface water resource setbacks. The regulations should be revised provide consistent setback requirements that are protective of water sources, including rivers, streams (perennial and intermittent), and lakes.
Filtration Avoidance Determination Watersheds	4,000 feet in RDSGEIS (page 7-56) but not in the proposed regulations	4,000 feet	Incorporate RDSGEIS setback commitment into regulations. In addition, the operator should be required to analyze the local geology to determine whether the groundwater divide would allow transport into the FAD watershed.
Floodplains	Wellpads prohibited in the 100-year floodplain (6 NYCRR § 560.4)	Wellpads prohibited in the 500-year floodplain	For wells that might operate for 30 years, there is a 26% chance of a 100-year flood occurring during the period the well would be operated. Wells should be prohibited within at least the 500 year return interval floodplain, because the damages from significant flooding could be very substantial.

*Setback can be waived by the landowner. The proposed regulations do not address setbacks for domestic use springs

** Setback could be waived based on site-specific analysis.

2.7 Impacts of Well Refracture Not Addressed

The assessments of environmental impacts in the RDSGEIS are all based on a single hydraulic fracturing treatment of each well. The RDSGEIS inappropriately relies on informal statements from industry that refracturing will be rare and does not quantify the number of HVHF treatments possible per well. The RDSGEIS under-predicts both the peak and cumulative impacts by not examining the reasonably foreseeable likelihood that Marcellus, Utica, and other low-permeability shale reservoirs will require more than one HVHF treatment, most likely two or three, over a several-decade long lifecycle. The RDSGEIS should quantify how many times a well may be fracture treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario. Additionally, the RDSGEIS should examine the peak and cumulative impacts of multiple HVHF treatments over a well's life and propose mitigation to offset those reasonably foreseeable impacts. Refer to Chapter 16 of the Harvey Consulting, LLC report (Attachment 1) for more information supporting this comment.

3.0 Summary of Technical Comments

3.1 Liquid Petroleum Impacts

The RDSGEIS describes natural gas exploration and production, but does not address the potential for shale gas wells to also encounter liquid hydrocarbons. Natural gas exploration can identify oil and condensate development opportunities. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drill sites may be needed to develop those oil resources. Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. The risk of oil spills during shale gas exploration has not been analyzed in the RDSGEIS. While blowouts are infrequent, they do occur, and are a reasonably foreseeable consequence of exploratory drilling operations. Blowouts can occur from gas and/or oil wells. They can last for days, weeks, or months until well control is achieved. On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells. Two recent gas well blowouts occurred in Pennsylvania due to Marcellus Shale drilling.

The RDSGEIS should examine the potential for shale gas wells to also encounter liquid hydrocarbons. The RDSGEIS should also examine the incremental risks of oil well blowouts and oil spills, as well as the impacts from the additional wells and drill sites that may be required to develop oil resources identified by shale gas exploration and production activities.

The comments summarized in this section are covered in greater detail in Chapter 3 of the Harvey Consulting, LLC report (Attachment 1).

3.2 Well Casing Requirements

The comments summarized in this section are covered in greater detail in Chapters 5 through 8 of the Harvey Consulting, LLC report (Attachment 1).

3.2.1 Conductor Casing

Conductor casing is the first string of casing in a well and is installed to prevent the top of the well from caving in. The conductor casing requirements listed in the Proposed Supplementary Permit Conditions for HVHF and Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers should be codified in the proposed regulations and should apply to all natural gas wells drilled in NYS, not just HVHF wells. Additionally, NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide a solid structural anchorage. Regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

3.2.2 Surface Casing

Surface casing plays a very important role in protecting groundwater aquifers, providing the structure to support blowout prevention equipment, and providing a conduit for drilling fluids while drilling the next section of the well. Stray gas may impact groundwater and surface water from poor well construction practices. Properly constructed and operated gas wells are critical to mitigating stray gas and thereby protecting water supplies and public safety. If a well is not properly cased and cemented, natural gas in subsurface formations may migrate from the wellbore through bedrock and soil. Stray gas may adversely affect water supplies, accumulate in or adjacent to structures such as residences and water wells, and has the potential to cause a fire or explosion. Instances of improperly constructed wellbores leading to the contamination of drinking water with natural gas are well documented in Pennsylvania and other locations.

The RDSGEIS and proposed regulations include important improvements for surface casing that incorporate many of the comments provided by this working group in 2009. Notable improvements include requirements related to cement quality, casing quality, and installation techniques. Unfortunately, there are a number of inconsistencies between the permit conditions and the proposed regulations that create uncertainty about what will be required. The Harvey Consulting, LLC report provides recommendations for correcting these inconsistencies. Finally, there are a number of new surface casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. These requirements should be included in 6 NYCRR Part 554 (drilling practices for all oil and gas wells), and not just contained in 6 NYCRR Part 560 (drilling practices for HVHF wells).

3.2.3 Intermediate Casing

Intermediate casing provides a transition from the surface casing to the production casing. This casing may be required to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. The RDSGEIS and proposed regulations include important improvements for intermediate casing in comparison to the 2009 DSGEIS. Overall, NYSDEC's intermediate casing requirements for HVHF wells are robust. However, the remaining area for improvement in the proposed regulations is to establish intermediate casing and cementing standards for all wells that will not undergo HVHF treatment, but will require the installation of intermediate casing, on which the proposed regulations are silent. There are also a number of new intermediate casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. Those requirements should be included in 6 NYCRR Part 554 (drilling practices for all oil and gas wells), and not just covered in the new 6 NYCRR Part 560 (drilling practices for HVHF wells).

3.2.4 Production Casing

Production casing is the last string of casing set in the well. It is called “production casing” because it is set across the hydrocarbon-producing zone or, alternatively, it is set just above the hydrocarbon zone. Production casing is used to isolate hydrocarbon zones and to contain formation pressure. Production casing pipe and cement integrity is very important, because it is the piping/cement barrier that is exposed to fracture pressure, acid stimulation treatments, and other workover/stimulation methods used to increase hydrocarbon production.

The RDSGEIS and proposed regulations include substantial improvements for production casing. NYSDEC's proposed production casing requirements for HVHF wells are robust. The most notable improvement to the proposed regulations is that production casing must be set from the well surface through the production zone. This provides an additional protective layer of casing and cementing in the well during HVHF treatments. The RDSGEIS and proposed regulations require production casing to be fully cemented, if intermediate casing is not set. If intermediate casing is set, it requires production casing be tied into the intermediate casing. The proposed regulations also require the cement placement and bond be verified by well logging tools. These requirements are best practice. The Harvey Consulting, LLC report provides minor additional recommendations to improve consistency of the various requirements for production casing and highlights additional best practices that should be considered.

3.3 HVHF Design and Monitoring

Computer modeling is routinely used by industry to design hydraulic fracture treatments. During actual fracture stimulation treatments, data is collected to verify model accuracy, and the model is continually refined to improve its predictive capability. Data collected during drilling, well logging, coring, and other geophysical activities and HVHF implementation can be used to continuously improve the model quality and predictive capability. HVHF modeling is an important way of helping to ensure fracture treatments do not extend outside the target formation. Fracture treatments that propagate outside the shale zone (fracturing out-of-zone) reduce gas recovery and risk pollutant transport.

The RDSGEIS does not require well operators to develop or maintain a hydraulic fracture model. Instead, the RDSGEIS only requires the operator to abide by a 1000' vertical offset from protected aquifers and collect data during the HVHF job to evaluate whether the job was implemented as planned. Knowing whether a job was implemented as planned is only helpful if the initial design is protective of human health and environment. If the job is poorly planned, and is implemented as planned, that only proves that a poor job was actually implemented. Instead, NYSDEC needs to first verify that the operator has engineered a HVHF treatment that is protective of human health and the environment, and then, second, verify that the job was implemented to that protective standard. A rigorous engineering analysis is a critical design step. Proper design and monitoring of HVHF jobs is not only best practice from an environmental and human health perspective; it is also good business because it optimizes gas production and reduces hydraulic fracture treatment cost. Best practices for HVHF design and monitoring should be included as a mitigation measure, and codified in regulations as a minimum standard. These best practices include utilizing hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained in zone.

The comments summarized in this section are covered in greater detail in Chapter 10 of the Harvey Consulting, LLC report (Attachment 1).

3.4 Corrosion and Erosion Mitigation and Integrity Monitoring Programs

Downhole tubing and casing, surface pipelines, pressure vessels, and storage tanks used in gas exploration and production can be subject to internal and external corrosion. Corrosion can be caused by water, corrosive soils, oxygen, corrosive fluids used to treat wells, and the carbon dioxide

(CO_2) and hydrogen sulfide (H_2S) present in gas. High velocity gas contaminated with water and sediment can internally erode pipes, fittings, and valves. HVHF treatments, if improperly designed, can accelerate well corrosion. Additionally, acids used to stimulate well production and remove scale can be corrosive. The RDSGEIS includes a discussion on corrosion inhibitors used by industry in fracture treatments, but does not require them as best practice. Furthermore, the RDSGEIS does not require that facilities be designed to resist corrosion (e.g., material selection and coatings), nor does it require corrosion monitoring, or the repair and replacement of corroded equipment. Best corrosion and erosion mitigation practices and long-term well integrity monitoring should be evaluated and codified in regulations. Operators should be required to design equipment to prevent corrosion and erosion. Corrosion and erosion monitoring, repair, and replacement programs should be instituted.

The comments summarized in this section are covered in greater detail in Chapter 23 of the Harvey Consulting, LLC report (Attachment 1).

3.5 Well Control & Emergency Response Capability

Industrial fires, explosions, blowouts, and spills require specialized emergency response equipment, which may not be available at local fire and emergency services departments. For example, local fire and emergency services departments typically do not have well capping and control systems. The addition of an Emergency Response Plan (ERP) requirement to the RDSGEIS is a substantial improvement over the 2009 DSGEIS, which failed to address this issue. However, it is recommended that NYSDEC include a review, approval, and audit processes to ensure that quality ERPs are developed. Objectives of the ERP should include adequately trained and qualified personnel, and the availability of adequate equipment. If local emergency response resources are relied on in the ERP, operators should ensure they are trained, qualified, and equipped to respond to an industrial accident. Additionally, NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

The comments summarized in this section are covered in greater detail in Chapter 24 the Harvey Consulting, LLC report (Attachment 1).

3.6 Financial Assurance Amount

NYSDEC ignored comments submitted by this working group in 2009 requesting that the SGEIS examine financial assurance requirements to ensure there is funding available to properly plug and abandon wells; remove equipment and contamination; complete surface restoration; and provide adequate insurance to compensate nearby public for adverse impacts (e.g., well contamination). Although changes in financial assurance amounts would require legislative action, the analysis of this issue is necessary to fully disclose the potential adverse environmental impacts that would result in the absence of adequate financial assurances. Moreover, such an analysis would be an appropriate way of bringing this need for legislation to the attention of elected officials as appropriate mitigation for identified significant adverse impacts.

The importance of reevaluating financial assurance requirements is heightened when the inadequacy of the existing requirements is considered. For wells between 2,500’ and 6,000’ in depth, NYSDEC requires only $5,000 financial security per well, with the overall total per operator not to exceed $150,000. For wells drilled more than 6,000’ deep, NYSDEC is proposing a regulatory revision that requires the operator to provide financial security in an amount based solely on the anticipated cost for plugging and abandoning the well (6 NYCRR § 551.6). These requirements are far less than those in other locations. Fort Worth, Texas requires an operator drilling 1-5 wells to provide a blanket bond or letter of credit of at least $150,000, with incremental increases of $50,000 for each additional well. Therefore, under Fort Worth, Texas requirements, an operator drilling 100 wells would be required to hold a bond of $4,900,000, as compared to $150,000 in NYS. In Ohio, an operator is required to obtain liability insurance coverage of at least $1,000,000 and up to $3,000,000 for wells in urban areas.

NYSDEC's financial assurance requirements should not narrowly focus on the costs of plugging and abandoning a well. Instead, NYSDEC's financial assurance requirements should include a combination of bonding and insurance that addresses the costs and risks of long-term monitoring; publicly incurred response and cleanup operations; site remediation and well abandonment; and adequate compensation to the public for adverse impacts (e.g., water well contamination). It is recommended that each operator provide a bond of at least $100,000 per well, with a cap of $5,000,000 for each operator. Additionally, NYSDEC should require Commercial General Liability Insurance, including Excess Insurance, Environmental Pollution Liability Coverage, and a Well Control Policy, of at least $5,000,000. If NYSDEC deviates from these financial assurance requirements, it should be justified with a rigorous economic assessment that is provided to the public for review and comment. Recommendations for financial assurance improvements for Marcellus Shale gas well drilling should be evaluated and included in the proposed regulations.

The comments summarized in this section are covered in greater detail in Chapter 25 of the Harvey Consulting, LLC report (Attachment 1).

3.7 Hydrogeology and Contaminant Transport

The RDSGEIS dismisses the potential for groundwater contamination due to HVHF on the basis of faulty science and unsupported assumptions.

1. The characterization of the hydraulic fracturing process and effects in the RDSGEIS is technically incorrect, leading to important impacts being overlooked.

2. The RDSGEIS assumes that the geologic layers above the Marcellus shale will stop contamination of aquifers without providing sufficient information on these layers, and ignoring the potential for existing faults and fractures to expedite contaminant transport. It also ignores studies which show that hydraulic fracturing has fractured formations as much as 1500 feet above the target shale, thereby providing pathways through the rock which the RDSGEIS relies on for stopping contaminant transport.

3. The RDSGEIS impact analyses are incomplete from a spatial perspective. The analyses focus on *local* impacts and fails to address the *regional* impacts of HVHF on the characteristics of the shale and the environmental implications of these changes. Such changes include increased shale permeability to water flow, which increases the risk of aquifer contamination over time.

4. The RDSGEIS analyses are incomplete from a temporal perspective. The analyses do not address the potential long-term aquifer contamination impacts by focusing on a time period of few days, assuming contamination has not occurred in other locations that lack the monitoring that would be necessary to detect contamination, and not considering evidence of the potential vertical movement of fracking fluid to near-surface aquifers as discovered under comparable conditions elsewhere.

Detailed technical supporting information for the deficiencies noted above is provided in the report prepared by Dr. Tom Myers (Attachment 2). The Myers report also provides a number of important recommendations for:

1. Improving and expanding the characterization of the hydraulic fracturing process and impacts in the RDSGEIS; and
2. Implementing measures as part of the review of specific well site proposals to avoid significant adverse aquifer contamination impacts.

The measures should include the following:

1. Mapping groundwater gradients above the Marcellus shale using existing data.
2. Requiring seismic surveys to locate faults prior to drilling.
3. Implementation of a long-term monitoring plan with wells established to monitor for long-term upward contaminant transport.

The groundwater monitoring at domestic wells proposed in the RDSGEIS is a scientifically improper method of monitoring the location of a contaminant plume because domestic wells are not designed for monitoring. Dedicated monitoring wells are necessary to prevent contamination of water wells by detecting contaminants before they reach the water wells.

3.8 Well Plugging and Abandonment

Wells that are not properly plugged can act as a preferential pathway for surface contaminants to impact groundwater resources. There are 2,114 wells that are at least 47 years old and some more than 87 years old that still have not been properly abandoned in NYS, and 2,026 wells where the age and condition is unknown (and must be assumed improperly abandoned). As a result, there is a risk that improperly planned HVHF wells or fractures could intersect abandoned wells and contaminate groundwater. Key recommendations from Chapter 9 of the Harvey Consulting, LLC report (Attachment 1) related to well plugging and abandonment (P&A) include the following:

- The SGEIS should examine: the number of improperly abandoned or orphaned wells in NYS requiring P&A in close proximity to drinking water sources or in close proximity to areas under consideration for HVHF treatments; whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

- The SGEIS should include maps showing the location and depths of improperly abandoned, orphaned wells in NYS. These maps should correlate the locations and depths to potential foreseeable shale gas development and examine the need to properly P&A these wells before shale gas development occurs nearby. The SGEIS should assess the risk of a HVHF well intersecting a well that is not accurately documented in NYSDEC's Oil & Gas database and whether this poses and unmitigated significant impact to protected groundwater resources.

- The SGEIS requirements with respect to the plugging of improperly abandoned wells nearby proposed HVHF wells should be strengthened and incorporated in the proposed regulations.

3.9 Seismic Data Collection

Seismic surveys are used by industry to target hydrocarbon formations for exploration and appraisal drilling. Typically seismic surveys are conducted using vehicle-mounted vibrator plates that impact the ground or use explosive to create seismic waves which bounce off of subsurface rock strata and geologic formations. The reflected seismic waves are measured at various surface receivers. The rate that seismic energy is transmitted and received through the earth crust provides information on the subsurface geology, because seismic waves reflect at different speeds and intensity off various rock strata and geologic structures. Seismic operations are very labor intensive and require large amounts of equipment, personnel and support systems. Depending on the size of the area under study, and the type of equipment selected, seismic operations can require dozens to hundreds of personnel. In addition to seismic exploration equipment, there is a need for housing, catering, waste management systems, water supplies, medical facilities, equipment maintenance and repair shops, and other logistical support functions.

Significant surface impacts can be caused by extensive tree and vegetation removal to create straight “cutlines” to run seismic equipment (up to 20’-50’ wide). Lines need to be cut to run mechanical vibration equipment or set explosives to generate the seismic waves, and other seismic lines are cleared to set geophones to measure the seismic reflection.

The RDSGEIS does not include any analysis of the potential impacts or mitigation needed for two-dimensional (2D) or three-dimensional (3D) seismic surveys. If 2D or 3D seismic surveys are planned, or are possible in the future, the proposed HVHF regulations should codify a permitting process for these activities and institute mitigating measures in the RDSGEIS to minimize surface impacts and disruptions, and require rehabilitation of impacted areas. In addition, the increased industrial activity (e.g., economic impacts, noise, surface disturbance, wildlife impacts, etc.) associated with 2D and 3D seismic surveys should be examined in the RDSGEIS.

The comments summarized in this section are covered in greater detail in Chapter 26 of the Harvey Consulting, LLC report (Attachment 1).

3.10 Surface Water Hydrology

The RDSGEIS has addressed many of the deficiencies of the 2009 DSGEIS with respect to the treatment of hydrology issues. As discussed in the Myers report (Attachment 2), NYSDEC proposes to use the natural flow regime method (NFRM) for all regions by means of permit conditions. However, NYSDEC should verify the accuracy for the proposed methods for estimating passby flows at ungauged sites. Since NFRM is proposed to be applied everywhere (and not just in a specific case which would justify its use as a permit condition), it would be more appropriate for NYSDEC to include the use of the NFRM as a requirement in the regulations themselves. The following changes should be accounted for in the regulatory framework regarding the avoidance or reduction of potential impacts resulting from water withdrawal:

- NYSDEC should coordinate water withdrawals among operators so their withdrawals do not cumulatively cause flows to drop below the required passby flows at any point along the stream.
- The operator should establish a temporary flow/stage relationship with at least a staff gage that should be monitored.
- Passby flows should be maintained with consideration of the measurement error inherent in the technique. The operator should assume that the measurement method is overestimating

flow and therefore maintain a flow greater than the passby flow by as much as the error estimate.

3.11 Stormwater, Sedimentation and Erosion

All of the comments summarized in this section are covered in greater detail in the Meliora Design, LLC report (Attachment 6).

3.11.1 Cumulative Water Quality Impacts of Land Disturbance Are Not Addressed

The RDSGEIS provides only a very brief generic discussion of the potential land disturbance and associated stormwater and water quality impacts on surface waters from HVHF (and well drilling in general). The RDSGEIS makes no attempt to evaluate the cumulative impacts of HVHF activity on water resources, at either the small (headwater stream) scale, or the larger watershed scale. Even very general cumulative estimates of land disturbance, and its associated water quality impacts, are not provided. Since the original draft of the GEIS nearly twenty years ago, the use of improved geographic information system (GIS) software and modeling tools has expanded the ability of scientists, engineers, and regulators to quantify the scale and impact of proposed activities on water resources. Such analysis has become standard industry practice for watershed planning and the development of TMDL (Total Daily Maximum Load) studies to determine the level of pollutant load (and required pollutant load reduction) to meet water quality standards. The RDSGEIS fails to provide any such analysis, and instead only acknowledges stormwater impacts on water quality in the most general and generic manner, with little industry specific consideration, and no consideration of total or cumulative impacts. A more detailed and comprehensive evaluation of the amount of anticipated land disturbance and associated water quality impacts is essential to a full environmental impact analysis, and to any determinations by NYSDEC on the appropriate regulatory permitting requirements.

3.11.2 Stream Crossing Impacts Are Not Addressed

The RDSGEIS fails to consider the potential surface water impacts of stream crossing activity associated with HVHF well pads, most notably, stream crossings associated with gathering lines and access roads (to both well pads and compressor stations). Stream crossings and the associated water quality impacts are not fully addressed in the RDSGEIS, and are specifically not included in the Draft State Pollutant Discharge Elimination System (SPDES) General Permit. It is unclear how many stream crossings may be anticipated, and of these, how many will essentially be unregulated under current NYSDEC regulations. It is unclear what the anticipated environmental impacts of these stream crossings will be on water quality and aquatic systems. NYSDEC should provide some estimate of the extent of anticipated stream crossings, potential water quality impacts, and proposed requirements to regulate and mitigate these impacts.

3.11.3 Mitigation and SPDES General Permit Do Not Consider Existing Water Quality

With the exception of watersheds that have received Filtration Avoidance Determinations, the RDSGEIS (and associated Draft SPDES HVHF General Permit) do not provide any specific consideration of whether different performance requirements or standards are necessary to protect water quality for higher quality watersheds, impaired streams, or areas of denser well pad development on a watershed basis. There is no documentation to support the adequacy of the proposed setbacks to protect water quality in all situations (i.e., higher quality streams, percent of land disturbance within a watershed, site specific conditions such as steep slopes), and the setbacks discussed in the narrative of Chapter 7 are not clearly coordinated with EAF requirements in Appendices 4, 5, 6 and 10 and the Draft HVHF General Permit mapping and documentation requirements (and the Draft SPDES HVHF General Permit is presumably the regulatory mechanism for compliance). NYSDEC should provide some analysis or justification as to why a single set of performance requirements is applicable in all watersheds and all situations, regardless of stream designation or current levels of impairment or high quality.

3.11.4 SPDES General Permit Flawed

The Draft SPDES General Permit for HVHF is essentially a compilation of the NYSDEC's general permits for both construction activity and industrial activity. The general permit process is essentially "self-regulating," relying on the regulated industry to adhere to certain compliance requirements. It is not clear from the RDSGEIS's very limited discussion of land disturbance and surface water impacts that a general permit process is sufficient to protect water quality. It is also not clear that an industry that is not subject to local government review and approval, unlike virtually all other land disturbance activities addressed by general permits, can be adequately regulated through a general permit process. This is especially important for a heavy industrial activity that will be occurring in areas not zoned or accustomed to heavy industrial activity at the scale that will occur with HVHF. Finally, the general permit process does not provide a timeframe (or process) for public review, comment, and objection to any or all parts of proposed general permit coverage. Essentially, permit coverage is automatically granted to the industry by providing notice to the NYSDEC and meeting minimum performance requirements. The SPDES HVHF General permit should provide a process for public access to all information associated with HVHF land disturbance and water quality impacts, and that a process and timeline be developed to allow for public comment and appeal of general permit coverage for a specific site before general permit coverage is granted. The permit coverage timeline should be adjusted to provide for public comment and appeal.

3.12 Hazardous and Contaminated Materials Management

All of the comments summarized in this section are covered in greater detail in the Harvey Consulting, LLC report (Attachment 1) and the report of Dr. Glenn Miller (Attachment 3).

3.12.1 Disposal of Waste and Equipment Containing NORM

Naturally Occurring Radioactive Materials (NORM) can be brought to the surface in a number of ways during drilling, completion, and production operations:

- **Drilling**: Drill cuttings containing NORM are circulated to the surface.
- **Completion**: Wells stimulated using hydraulic fracture treatments inject water; a portion of that water flows back to the surface ("flowback") and can be contaminated by radioactive materials picked up during subsurface transport.
- **Production**: Subsurface water located in natural gas reservoirs, produced as a waste byproduct, may contain radioactive materials picked up by contact with gas or formations containing NORM (this water is called "produced water'). Equipment used in hydrocarbon production and processing can concentrate radioactive materials in the form of scale and sludge.

The RDSGEIS fails to establish clear cradle-to-grave collection, testing, transportation, treatment, and disposal requirements for all waste containing NORM. The RDSGEIS is improved relative to the 2009 DSGEIS in that it establishes radioactive limitations and testing in some cases, but testing is still not required in all cases (even when data uncertainty exists). Long-term treatment and disposal requirements are not robust for all waste types. Nor is there a process in place to provide the public with information on NORM handling over the project life. For example:

- Radioactivity treatment and disposal threshold levels are established (e.g., for produced water and equipment); however, it is unclear if there is sufficient treatment and disposal capacity in NYS to handle the volume and amount of radioactive waste that may be generated;
- NYSDEC assumes that some waste will not contain significant amounts of radioactivity; yet, this assumption is based on a very limited dataset;
- There is no testing requirement to verify NORM content in drill cuttings before they are sent directly to a landfill; and
- Road spreading of waste is not prohibited; it is deferred to a yet-to-be determined future process outside the SGEIS review.

Detailed collection, testing, transportation, treatment, and disposal methods for each type of drilling and production waste and equipment containing NORM should be included as a mitigation measure and codified in the NYCRR. Where data uncertainty exists, additional testing should be required. The radioactive content of waste should be verified to ensure appropriate transportation, treatment, and disposal methods are selected, and the testing results should be disclosed to the public.

3.12.2 Drilling Mud Composition and Disposal

Drilling muds may contain mercury, metals, Naturally Occurring Radioactive Materials (NORM), oils and other contaminates. The NYSDEC appropriately removed the statement that "*drilling muds are not considered to be polluting fluids"* from the proposed regulations in response to this working group's 2009 comments. This positive change is commendable, but there are two problems related to the regulation of drilling muds that remain:

- The RDSGEIS states that the vertical portion of wells would be "typically" drilled using compressed air or freshwater mud as the drilling fluid. There is no regulatory restriction on industry using toxic additives in drilling mud, with corresponding increases in the risks of water resources contamination during drilling, transport and disposal. NYSDEC should stipulate in the regulations the mandatory use of compressed air or freshwater mud and prohibit the use oil-based muds, synthetic-based muds and the use of toxic additives.
- The proposed regulations do not provide criteria for acceptable drilling mud disposal plans to ensure safe handling and disposal. The proposed regulations should require specific best practices for drilling mud handling and disposal.

3.12.3 Reserve Pit Use and Drill Cuttings Disposal

The RDSGEIS acknowledges the numerous environmental advantages of a closed loop tank system to manage drilling fluids and cuttings rather than reserve pits, but fails to require a closed loop tank system in all circumstances. The closed loop tank system is only required for wells without an acceptable acid rock drainage mitigation plan for onsite disposal and for cuttings that need to be disposed at a landfill because they contain toxic additives. The proposed regulations should prohibit reserve pits and require a closed loop tank system. Reserve pits should only be allowed where the applicant demonstrates that the closed loop tank system would be technically infeasible. The proposed regulations also should include testing of the shale to determine the extent of potentially acid generating material included in the cutting.

The RDSGEIS states that onsite disposal of water-based muds is permissible, despite the fact that these muds may contain mercury, metals and other contaminates. These contaminated muds would be put in direct contact with soils and groundwater, resulting in the potential for significant adverse environmental impacts not addressed in the RDSGEIS. Some portions of the RDSGEIS and proposed regulations vaguely reference a requirement for consultation with the NYSDEC Division of Materials Management prior to disposal of cuttings from water-based mud drilling, but this "consultation" improperly circumvents the proper public review that would be provided by reaching a decision on the disposal requirements for water-based mud and associated cuttings through the environmental review process.

3.12.4 Hydraulic Fracture Additive Limitations

The RDSGEIS and proposed regulations continue to rely solely on the drilling operators to (1) regulate themselves, and (2) select the lowest toxicity chemicals for use in fracture treatment additives.

The proposed regulations require documentation that the additives exhibit "reduced aquatic toxicity" and "lower risk to water resources" compared to alternate additives or documentation that alternatives are not equally effective or feasible. There are no specific criteria for determining what is an acceptable reduction in toxicity or an acceptable reduction in risk. Operators would still be allowed to use harmful chemicals merely by stating to NYSDEC that these are the only chemicals that would be "effective" or by showing that the chemicals they propose are slightly less toxic than the most toxic alternatives.

To address this problem, the RDSGEIS and proposed regulations should identify the type, volume and concentrations of fracture treatment additives that are protective of human health and the environment; include a list of prohibited additives; and require the use of non-toxic materials to the greatest extent possible.

NYSDEC should develop the list of prohibited fracture treatment additives based on the known list of chemicals currently used in hydraulic fracturing. The list of prohibited fracture treatment additives should apply to all hydraulic fracture treatments, not just HVHF treatments. NYSDEC should also develop a process to evaluate newly proposed hydraulic fracturing chemical additives to determine whether they should be added to the prohibited list. No chemical should be used until NYSDEC and/or the New York State Department of Health (NYSDOH) has assessed whether it is protective of human health and the environment, and has determined whether or not it warrants inclusion on the list of prohibited hydraulic fracturing chemical additives for NYS. The burden of proof should be on industry to demonstrate, via scientific and technical data and analysis, and risk assessment work, that the chemical is safe. Fracture treatment additive prohibitions should be included in the RDSGEIS as a mitigation measure and codified in the proposed regulations.

3.12.5 Centralized Surface Impoundments for HVHF Flowback Off-Drillsite

The 2009 DSGEIS disclosed significant adverse air quality impacts associated with centralized surface impoundments for HVHF flowback, which were found to emit over 32.5 tons of air toxics per year. However, this important impact information was removed from the RDSGEIS. Instead, NYSDEC improperly declined to analyze centralized surface impoundments based on statements by the industry that they would not "routinely propose" to use centralized flowback impoundments. The proposed regulations do not prohibit centralized surface impoundments, which would be appropriate mitigation for the significant adverse impact identified in the 2009 DSGEIS, and instead a separate site-specific SEQRA review would be required for them.

3.12.6 Chemical and Waste Tank Secondary Containment

NYSDEC appropriately codified a requirement for secondary containment for chemical and waste handling tanks in the proposed regulations. However, the proposed regulations do not specifically address secondary containment for chemical and waste transport, mixing and pumping equipment. The regulations should be revised to address secondary containment for transport, mixing and pumping equipment in order to minimize potential soil and water resource impacts from chemical spills. There are several other minor modifications to the proposed regulations for secondary containment detailed in Chapter 21 of the Harvey Consulting, LLC report (Attachment 1) to eliminate inconsistencies between various regulatory requirements.

3.12.7 Fuel Tank Containment

NYSDEC appropriately included a requirement for fuel tank secondary containment in the Proposed Supplementary Permit Conditions. However, this requirement is confused by inconsistent statements in the RDSGEIS that secondary containment is not required for *temporary* fuel tanks (page 7-34). In addition to correcting this inconsistency, the proposed regulatory framework for fuel tank containment should be substantively improved to be more protective of the environment through adoption of the following changes:

- Define clear criteria for adequate containment (e.g., using coated or lined materials that are chemically compatible with the environment and the substances to be contained; providing adequate freeboard; protecting containment from heavy vehicle or equipment traffic; and having a volume of at least 110 percent of the largest storage tank within the containment area).
- Include mandatory minimum setbacks from surface water features, homes and public buildings. The proposed regulations contain a setback for surface water resources, but only “to the extent practical.”
- Explain how NYSDEC’s requirements for fuel tank containment interface with federal requirements (40 CFR Part 112).
- Require tank inspections, spill prevention and spill alarm systems.
- Clarify whether vaulted, self-diking, and double-walled portable tanks will be allowed in cases where secondary containment is impractical, and codify the requirements for the use of those tanks, including inspections and spill prevention alarm systems.

3.13 Toxicology

This section addresses the toxicology-related issues associated with Naturally Occurring Radioactive Materials (NORM), hydraulic fracturing additives and waste disposal. For supporting technical information for these comments, refer to the technical reports of Dr. Glenn Miller (Attachment 3) and Dr. Ralph Seiler (Attachment 4).

3.13.1 Naturally Occurring Radioactive Materials

The Marcellus Shale is known to contain NORM concentrations at higher levels than surrounding rock formations. The primary environmental contamination risk associated with NORM is in production brines. Appendix 13 of the RDSGEIS presented some information on radioactivity characteristics of vertical wells in the Marcellus Shale in New York. However, the data in Appendix 13 identifies only 14-24% of the gross alpha radiation sources in the water samples. The sources of the other 75%+ of alpha radiation are not identified. The RDSGEIS explicitly acknowledges that the scientific understanding of NORM in production brine is incomplete.[6] NYSDEC should have obtained more information on the radiation sources in production brine as part of the SGEIS process because it is essential to NYSDEC's decision-making process and for NYSDEC to ensure that adequate regulations are in place before widespread HVHF occurs in New York. Even if the information could not have been reasonably obtained (which is not the case here), the proper approach for SEQRA compliance would have been to disclose the unavailable information in accordance with NYCRR §617.9 (b) (6)[7]:

One possible source of the unspecified alpha levels in production brines is polonium. Polonium-210 is 5,000 times more radioactive than radium and is highly toxic.[8] Polonium-210 is difficult and expensive to remove from drinking water and bioaccumulates in the environment. Before completing the SEQRA process, NYSDEC should determine if polonium is a significant component of alpha emission in formation waters and identify appropriate regulations that address polonium-contaminated wastewater to prevent water resource impacts. Specific technical recommendations regarding the analyses that should be conducted to determine the presence of polonium are provided in Attachment 4. Attachment 4 also addresses the potential for Polonium-210 exposure via build-up in natural gas delivery pipes.

3.13.2 Radon Exposure via Natural Gas Combustion

Radon is a cancer-causing, radioactive gas. Radon is known to be present in natural gas and will be delivered with the natural gas to consumers. The quantity of radon in natural gas is highly variable and has not been studied by NYSDEC in the Marcellus Shale. While normal natural gas use in properly ventilated burners are unlikely to contribute to radon concentrations in a closed space, poorly vented areas may well be a problem, and certain scenarios (e.g., high use of natural gas for industrial applications, restaurants that use gas burners) need to be subjected to risk assessment. At the very least, substantially more radon measurements need to be made. The risk is likely to be greatest in those areas that already have elevated radon in air, and that risk may be enhanced by the natural gas contribution. Any increase in radon exposure in the Southern Tier is of particular concern in terms of cumulative impacts given that the NYSDOH estimates the majority of homes in

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[6] 2011 RDSGEIS Page 5-142: "The data indicate the need to collect additional samples of production brine to assess the need for mitigation and to require appropriate handling and treatment options…."

[7] *In addition to the analysis of significant adverse impacts required in subparagraph 617.9(b) (5) (iii) of this section, if information about reasonably foreseeable catastrophic impacts to the environment is unavailable because the cost to obtain it is exorbitant, or the means to obtain it are unknown, or there is uncertainty about its validity, and such information is essential to an agency's SEQR findings, the EIS must:*

(i) identify the nature and relevance of unavailable or uncertain information;
(ii) provide a summary of existing credible scientific evidence, if available; and
(iii) assess the likelihood of occurrence, even if the probability of occurrence is low, and the consequences of the potential impact, using theoretical approaches or research methods generally accepted in the scientific community.

This analysis would likely occur in the review of such actions as an oil supertanker port, a liquid propane gas/liquid natural gas facility, or the siting of a hazardous waste treatment facility. It does not apply in the review of such actions as shopping malls, residential subdivisions or office facilities.

[8] http://www.who.int/ionizing_radiation/pub_meet/polonium210/en/index.html

the region have existing basement radon levels above the EPA "action level" of 4 pCi/L. Between 20 and 40 percent of homes in the several Marcellus Shale counties have long-term exposure to radon levels above the EPA limit in their living areas.[9] Before completing the SEQRA process, NYSDEC should analyze the cumulative health risk posed by additional radon exposure from Marcellus Shale natural gas combustion so that appropriate mitigation measures can be identified to address the issue.

3.13.3 Hydraulic Fracturing Additives

The RDSGEIS does not present sufficient information to analyze the toxicology risks posed by hydraulic fracturing additives. It does not address the toxicology risks generically or at the site level. The proposed regulations do not require permit applicants to provide sufficient information for the risks of these additives to be considered at the site level. The RDSGEIS provides a long list of potential additives (Tables 5.4 and 5.5), but does not analyze their potential environmental impacts. The list of additives is almost certainly incomplete, specific information on the chemicals is lacking, and the specific rate of usage is not offered. Thus, not knowing the composition of the specific additives nor the amounts in which they would be used during the HVHF process there is no basis for estimating the risk of these components with regard to their presence in the produced flowback or produced water.

The RDSGEIS misrepresents the presence of hydraulic fracturing additives in flowback. Table 6.1 of the RDSGEIS states that no non-naturally occurring additives were detected. However, most of these additives cannot be detected through standard methods. Table 6.1 should be revised to indicate which additives were actually capable of being detected by the analytical methods selected and the associated detection limits. This is a customary practice and standard. The proposed regulations should require testing of flowback water for acrylonitrile, a non-naturally occurring chemical that if detected provides a clear indication of off-site contamination by hydraulic fracturing.

3.13.4 Disposal of Contaminated Wastewater

The water that flows back immediately following hydraulic fracturing is heavily contaminated, primarily with the Marcellus formation contaminants, and represents the most problematic chemical contamination potential, due to the large volumes of contaminated water generated. The produced brines that are released during production generally have higher concentrations of naturally occurring contaminants than flowback waster (although lower volumes) and similarly represent a serious chemical contamination potential. Four problematic components of the flowback water and produced brines are present: the radioactive component (NORM); the inorganic salts, metals and metalloids; the organic substances (from the hydrocarbon formation) and the hydraulic fracturing additives. While recognizing the problems with management of this water, the RDSGEIS fails to clearly state how this water will be either disposed in a manner that protects human health and the environment, or otherwise treated to remove the contaminants. While the RDSGEIS provides a range of alternatives, the RDSGEIS does not analyze the environmental or human health impacts associated with any of these disposal options. Further, effectively none of these options is likely to be accomplished in state, and the RDSGEIS implies that virtually all of the wastewater generated in New York will be managed out of state where regulations may be less stringent.

There are four possible treatment options for flowback and produced water discussed in the RDSGEIS: (1) reuse, (2) deep well injection, or (3) treatment in municipal or privately owned treatment facilities. None of these options is properly analyzed in the RDSGEIS. Reuse is not a

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[9] http://www.wadsworth.org/radon/

complete disposal option because residual salts and other contaminants must still be managed. Beyond reuse, the disposal options considered in the RDSGEIS only included injection wells, municipal sewage treatment facilities (of which there are currently none that are permitted to accept flowback and produced water) and private treatment plants (of which none currently exist in New York). The RDSGEIS did not consider whether there are other, less environmentally harmful, options that exist for flowback and produced water. More importantly, the RDSGEIS fails to evaluate the potentially significant adverse environmental impacts and human health risks associated with these disposal options.

3.14 Air Quality and Odors

For supporting technical information for the comments provided in this section, refer to Chapters 17 and 20 of the Harvey Consulting, LLC report (Attachment 1).

3.14.1 Air Quality Modeling Assumptions

The air quality analysis in the RDSGEIS contains some substantial improvements compared to the DSGEIS, but the assumptions used still warrant additional review and justification. For example, the RDSGEIS did not consider the reasonable worst case scenario air impacts resulting from simultaneous operations of spatially proximate well sites. In addition, the mobile source impact assessment under-predicts the number of miles that will be driven by heavy equipment to transport supplies to and haul wastes away from drillsites, especially wastewater that is hauled out of state to treatment and disposal facilities. Modeling for mobile source air impacts resulting from wastewater transport must be consistent with reasonable worst case scenario forecasts of wastewater volume (which impacts the number of truck trips needed per well site) as well as forecasted in and out of state disposal options (which impacts distance traveled per disposal). Limitations used in the modeling assumptions must all be translated into SGEIS mitigation measures and codified in the proposed regulations to ensure that the National Ambient Air Quality Standards will not be exceeded.

3.14.2 Air Quality Monitoring Program

The RDSGEIS includes a commitment to develop a regional air quality monitoring program to address the potential for significant adverse air quality impacts. However, more information is needed to understand the scope and duration of NYSDEC's proposed air monitoring program. A more rigorous monitoring program proposal is needed that identifies: the scope of the monitoring program; the location of the monitoring sites; the amount of equipment and personnel needed to run each site; the duration of monitoring proposed at each site; along with the cost. It is anticipated that a program used to assess both regional and local impacts will require long term monitoring stations placed in key locations, not just infrequent and unrepresentative sampling. The SGEIS should require the monitoring program to commence prior to Marcellus Shale gas development to verify background levels and continue until NYSDEC can scientifically justify that data collection is no longer warranted, in consultation with EPA. The obligation to fund the air monitoring program needs to be clearly tied to a permit condition requirement.

3.14.3 Greenhouse Gas Emissions Mitigation Plan

The RDSGEIS took a step in the right direction with the inclusion of a requirement for greenhouse gas emissions (GHG) impact mitigation plans. However, this requirement needs to be further defined. NYSDEC should require a GHG Mitigation Plan that provides for measureable emissions reductions and includes enforceable requirements. The GHG Impacts Mitigation Plan should list all Natural Gas STAR Program best management technologies and practices that have been determined by EPA to be technically and economically feasible, and operators should select and use the emission control(s) that will achieve the greatest emissions reductions. The GHG Impacts Mitigation Plan should be submitted and approved prior to drillsite construction, GHG controls should be installed at the time of well construction, and NYSDEC should conduct periodic reviews to ensure that GHG Impacts Mitigation Plans include state of the art emission control technologies. Further, the extent of compliance with adopted emission mitigation control plans should be documented throughout the well's potential to emit GHGs. The GHG Impacts Mitigation Plan requirement should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.4 Flare and Venting of Gas Emissions

Flares may be used during well drilling, completion, and testing to combust hydrocarbon gases that cannot be collected because gas processing and pipeline systems have not been installed. During production operations, high pressure gas buildup may require gas venting via a pressure release valve, or gas may need to be routed to a flare during an equipment malfunction. Reducing gas flaring and venting is widely considered best practice for reducing air quality impacts of natural gas development. The RDSGEIS air quality analyses of flaring assumed it would be limited to three days based on statements from industry, even though the actual duration should be longer. Planned flaring should be limited to no more than three days. In all other cases flaring should be limited to safety purposes only. If NYSDEC finds there is an operational necessity to flare an exploration well for more than a three-day period, the SGEIS impact analysis should evaluate the air pollutant impact, particularly the potential for relatively high short-term emission impacts, from longer flaring events, before approving such operations. The SGEIS should provide justification for allowing a maximum of 5 MMscf of vented gas and 120 MMscf of flared gas at a drillsite during any consecutive 12-month period. The RDSGEIS does not contain information to show that these limits are equivalent to the lowest levels of venting and flaring that can be achieved through used of best practices, and it is unclear if these rates were used in the modeling assessment. Flaring and venting restrictions should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.5 Reduced Emission Completions

Reduced Emission Completions (RECs, also known as "green completions") control methane and other GHG emissions following HVHF operations. RECs also reduce nitrogen oxide (NOx) pollution, which otherwise would be generated by flaring gas wells, and hazardous air pollutants (HAPs) and volatile organic compounds (VOCs) emissions, which otherwise would be released when gas is vented directly into the atmosphere. The RDSGEIS requires RECs where an existing gathering line is located near the well in question, which allows the gas to be collected and routed for sale. While the addition of this requirement represents a substantial improvement that protects air quality and increases the efficiency and productivity of wellsites, NYSDEC should consider expanding its REC requirements to more categories of wells—i.e., wells that are drilled prior to construction of gathering lines. Under the current proposal, a large number of wells could be exempt from the REC requirement, resulting in the flaring or venting of a significant amount of gas that could, instead, be captured for sale. Furthermore, NYSDEC proposes to postpone making a decision on the number of wells that can be drilled on a pad without the use of RECs until two years after the first HVHF permit is issued. NYSDEC should not defer the decision to implement RECs for two more years. The requirement to use RECs in all practicable situations should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.6 Gas Dehydrators

Dehydrator units remove water moisture from the gas stream. Dehydrator units typically use triethylene glycol (TEG) to remove the water; the TEG absorbs methane, VOCs, and HAPs. Gas dehydration units can emit significant amounts of HAPs and VOCs, and it is best practice to use control devices with gas dehydration units to mitigate HAP and VOC emissions. The 2011 RDSGEIS requires emissions modeling, using the EPA approved and industry standard model GRI-GlyCalc, and the installation of emission controls for dehydrator units emitting more than one ton per year of benzene. This is an important and substantial improvement. In addition to this requirement, natural gas operators should be required to evaluate the technical and economic feasibility of installing methane emission controls on gas dehydrators; installation should be mandatory unless an infeasibility determination is made. This requirement should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.7 Diesel Engine Emissions Control

NRDC's 2009 comments recommended limiting diesel engines to Tier 2 or higher. The RDSGEIS takes a step in the right direction by prohibiting "Tier 0" engines and requiring Tier 2 engines in most cases. To further strengthen air quality protection from diesel emissions SGEIS should examine whether it is possible to eliminate Tier 1 engine use altogether.

3.14.8 Leak Detection and Control

Unmitigated gas leaks pose a risk of fire and explosion, and contribute to GHG, VOC, and HAP emissions, that could otherwise be avoided by routine detection and repair programs. NYSDEC's proposed Leak Detection and Repair Program should be revised to require: a drillsite Leak Detection and Repair inspection at start-up; quarterly testing with an infrared camera with additional follow-up testing and repair if a leak is indicated; testing of all equipment located on the drillsite up to and including the gas meter outlet which is connected to the pipeline inlet. These requirements should be included in the SGEIS as mitigation measures and codified in the proposed regulations, and be required for all natural gas operations, not just HVHF operations.

3.14.9 Cleaner Power and Fuel Supply Options

The RDSGEIS did not examine cleaner power and fuel supply options as was requested in NRDC's 2009 comments. In suburban and urban areas of NYS, where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable, eliminating the local diesel exhaust from those engines. In rural areas, where highline power is not readily available, an operator should be required to evaluate whether there is a natural gas supply that could be used as fuel; if so, use of the natural gas supply should be mandatory to the extent practicable. Cleaner power and fuel selection requirements should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. These requirements should apply to all natural gas operations, not just HVHF operations.

3.14.10 Hydrogen Sulfide (H_2S) (“Sour Gas”) Emissions

In addition to air quality risks associated with emissions of criteria pollutants and air toxics resulting from natural gas development, additional air quality risks can occur as a result of the release of hydrogen sulfide (H_2S) or sour gas. H_2S gas produces a malodorous smell of rotten eggs at low concentrations, can cause very serious health symptoms, and can be deadly at the higher concentrations found in some oil and gas wells.

Therefore, proper handling of H_2S is important from both a quality-of-life and human-safety standpoint for workers and nearby public. The RDSGEIS does not analyze H_2S impacts based on the argument (supported by limited evidence) that to date H_2S has not been detected in high concentrations in HVHF operations in Pennsylvania. However, the early experience in Pennsylvania does not mean that there is no potential for H_2S issues to develop over time in New York.

A supplemental permit condition proposed in the RDSGEIS appropriately requires monitoring for H_2S during the drilling phase. However, a requirement should be added to the HVHF regulations to ensure that periodic monitoring occurs throughout production as gas fields age and sour. H_2S monitoring requirements should apply to all wells and therefore should be addressed through regulations, rather than through permit conditions that can be altered without public review. The regulations should stipulate that when monitoring detects H_2S, nearby neighbors, local authorities and public facilities should be notified of the risk of H_2S gas. They should be provided information on safety and control measures that the operator will be required to undertake to protect human health and safety. In cases where elevated H_2S levels are present, audible alarms should be installed to alert the public when immediate evacuation procedures are warranted.

3.15 Socioeconomics

This section addresses the socioeconomic impacts of HVHF. For supporting technical information for these comments, refer to the technical report from Dr. Susan Christopherson (Attachment 5).

3.15.1 NYSDEC’s Socioeconomic Impact Analysis

Although NYSDEC has included more information on the social and economic impacts of gas development using HVHF in the RDSGEIS than it did in the 2009 draft, the RDSGEIS still does not effectively assess those impacts or provide appropriate mitigation strategies. There are a number of substantive concerns raised by the discussion of socioeconomic impacts presented in the RDSGEIS and by the Economic Assessment Report (EAR) prepared by NYSDEC’s consultant, Environment and Ecology, on which that discussion is based.

1. The assessment of economic benefits (jobs and taxes) relies on questionable assumptions about the amount of gas extractable in the New York portion of the Marcellus Shale. The range of estimates for extractable gas appears to be skewed to the high end, leading to an overestimation of economic benefits.

2. The model used in the RDSGEIS to assess social and economic impacts presents natural gas development as a gradual, predictable process beginning with a “ramp-up” period and then proceeding through a regular pattern of well development over time. This model is misleading, and because many of the negative social and economic impacts of HVHF gas extraction (such as housing shortages followed by excess supply) are a consequence of unpredictable development, the model cannot appropriately assess those impacts.

3. The RDSGEIS does not assess public costs associated with natural gas development. A fiscal impact analysis of the base costs to the state and localities that will occur with any amount of HVHF gas development is required, along with an estimate of how costs will increase and accumulate as development expands.

4. The long-term economic consequences of HVHF gas development for the regions where production occurs are not addressed despite a widely recognized literature indicating that such regions have poor economic outcomes when resource extraction ends.

5. Mitigation of enumerated negative social and economic impacts of HVHF gas development is presumed to occur by means of phased development and regulation of the industry, but no evidence or information is provided to indicate whether, and if so how, that would occur.

3.15.2 Uncertainty and Volatility of Natural Gas Production and its Socioeconomic Impacts

The EAR's projections concerning population, jobs, housing, and revenue are predicated on the assumption of a regular, predictable roll-out of the exploratory, drilling, and production phases of the natural gas development process, rather than the irregular pattern typically associated with such development.

Natural gas drilling is a speculative venture and the commercially extractable gas from any particular well is uncertain. This central feature of natural gas development has critical implications for the economies of natural gas development regions. As production fluctuates, they may experience short- and medium-term volatility in population, jobs, revenues, and housing vacancies. The model used in the RDSGEIS to project socioeconomic impacts ignores those issues, however, and assumes instead that the HVHF natural gas development in New York will have a different pattern than that historically associated with such development. Rather than occurring in irregularly recurring waves (or "boom-bust cycles"), development in New York is assumed to be steady and predictable. Many of the economic benefits that the RDSGEIS and EAR associate with natural gas development are predicated on this unlikely gradual, regular development scenario, raising doubts about the projection of economic benefits based on that model.

The spatial distribution of impacts is also uneven. Some wells will have long production phases; others will have dramatic declines in productivity after a relatively short period. The uncertainties in the geographic extent of drilling and the potential for intensive development in "hot spots" have implications for social and economic impacts. If drilling is concentrated in particular locations rather than rolled out uniformly across sub-regions of the landscape (as was modeled in the RDSGEIS), wealth effects and tax revenues also will be concentrated in particular localities. The social and economic costs of spatially concentrated drilling, however, will be experienced across a much wider geographic area, because public services will be required in areas without HVHF development (and therefore not receiving tax revenues from drilling), but close enough to serve the transient population associated with the industry.

Contrary to the RDSGEIS' contention that the regularized development model "does not significantly affect the socioeconomic analysis," smoothing out the unpredictability and unevenness of development covers up many of the negative cumulative social and economic impacts that arise from the unpredictability of shale gas development. Finally, the RDSGEIS does not sufficiently model the resource depletion phase of the exploration, drilling, production, and resource depletion cycle and its implications for local and regional economies.

3.15.3 Economic Impact Study Fails to Address Costs

The 2011 RDSGEIS analyzes potential *economic benefits* of HVHF, but fails to provide the same level of analysis of the potential *costs* of HVHF. A central component of the EAR is use of a Regional Industrial Multiplier System (RIMS) model. This type of model is useful for comparing different types of investments and for examining inter-industry linkages, but it has a significant drawback as the central model for the RDSGEIS analysis of socioeconomic impacts because it can only project economic benefits. It cannot measure or assess the costs of proposed gas development using HVHF.

The RDSGEIS assumes, based on the RIMS model, that economic benefits from HVHF gas development, presumably including benefits to revenue, will be substantial, but there is no fiscal impact analysis or cost-benefit analysis to substantiate that assumption. A fiscal impact analysis is required, given that:

(1) Many purchases by drilling companies are tax exempt.

(2) Costs to the state that will reduce or offset tax revenues are not calculated.

(3) Substantial negative fiscal impacts are detailed in the EAR that are not quantified or fully acknowledged in the RDSGEIS, including public costs associated with the increased demand for community social services, police and fire departments, first responders, schools, etc., as well as costs associated with monitoring and inspection and infrastructure maintenance. Although experience in other shale gas plays demonstrates that these costs are likely, the RDSGEIS makes no attempt to calculate the costs and consider them in the context of a fiscal impact assessment.

(4) There is no analysis of the expected 2-3 year lag between immediate costs and anticipated revenues, during which communities will be faced with significant public service costs.

Given the inability of the EAR input-output model to address the costs of gas development and the significance of local and state costs to decisions about shale gas drilling in the state, revised EAR findings regarding costs must be prepared and an opportunity for public review and comment on the revised EAR afforded before the SGEIS is finalized.

3.15.4 Impacts on Other Industries

HVHF has the potential to have significant adverse effects on the viability of other industries in New York, particularly tourism and agriculture. In contrast with the pages of projected benefits from gas development, the RDSGEIS offers no detailed description and no quantitative analysis of the effects of HVHF development on existing industries and the associated impact on the state of New York's economy. This omission is particularly important for the counties defined in the EAR as "representative" because industries, including agriculture and tourism, are significant employers in those counties and are important to the overall economy of the State. There is no analysis of how the "crowding out" of existing industries may impact the regional or statewide economy or of the implications of the loss of industrial diversity to the long-term prospects for regional economic sustainability.

The inadequate assessment of the impacts on existing industries in the region that will be affected by HVHF gas development is problematic not only because the state does not have adequate information to assess costs and benefits of HVHF gas development, but also because negative impacts on industries such as tourism and agriculture, including dairies and wineries, will undermine state investments intended to support those industries. Given the importance of these industries in the state and regional economy, the evidence that they will be negatively affected by HVHF gas development should have been analyzed in detail and quantified when possible.

3.15.5 Housing and Property Value Impacts

The potential impacts of HVHF on the housing supply, housing costs, and housing financing are inadequately addressed in the EAR. In addition, the social and economic impacts of unpredictable shortfalls in housing followed by periods in which there is an excess supply are not addressed.

The report assumes that the current housing stock would be used to house any workers who move to the production region on a "permanent" (more than one year) basis. However, given the quality and age of the housing stock in the region, evidence from Pennsylvania indicates that it is likely that there will be a demand for new single-family housing. This new housing stock will create new and additional construction jobs, increasing population pressure, accelerating the "boomtown" phenomenon. This housing may also contribute to sprawl around urban population centers such as Binghamton. When drilling ceases, either or temporarily or permanently, the value of this new housing is likely to plummet. The social and economic impacts of unpredictable shortfalls in housing followed by periods in which there is an excess supply are not addressed. These impacts pose environmental justice concerns and require mitigation strategies.

With respect to impacts on property value, the EAR authors found that having a well on a property was associated with a 22% <u>reduction</u> in the value of the property; that having a well within 550 feet of a property increased its value; and that having a well located between 551 feet and 2,600 feet from a property had a negative impact on a property's value. Thus, "…residential properties located in close proximity to the new gas wells would likely see some downward pressure on price. This downward pressure would be particularly acute for residential properties that do not own the subsurface mineral rights." (EAR, 4-114). The EAR's assumption of recovering property values after the completion of HVHF gas development does not take into account the potential for re-fracturing of wells to increase their productivity or the effects of waves of development in which drilling moves in and out of an area. The prospect of industrial activity is what drives down investment in regions open to boom-bust development and also negatively impacts property values. A more definitive analysis of impacts of on property values, including mortgage availability, in regions affected by drilling is needed.

3.15.6 Effects on Employment

The oil and gas industry is not likely to be a major source of jobs in New York, because of the project-based nature of the drilling phase of natural gas production (rigs and crews move from one place to another and activities are carried out at each well) and because of its capital intensity (labor is a small portion of total production costs). The emerging information on actual employment created in Pennsylvania in conjunction with Marcellus drilling shows much smaller numbers than industry-sponsored input-output models projected.

Although the industry points to years of drilling experience in New York, the oil and gas industry employed only 362 people in New York State in 2009 (0.01% of the state's total employment). 43% of those workers (157) were employed in Region C, the region where vertical natural gas drilling is most significant in New York. Wages for these workers constituted 0.04% of the wages in the two-county region with almost 4,000 active gas wells.

In contrast, nearly 674,000 New York jobs were sustained by tourism activity last year, representing

7.9% of New York State employment, either directly or indirectly. New York State tourism generated a total income of $26.5 billion, and $6.5 billion in state and local taxes in 2010. In the Southern Tier alone, the tourism and travel sector accounted for 3,335 direct jobs and nearly $66 million in labor income in 2008. When indirect and induced employment is considered, the tourism sector was responsible for 4,691 jobs and $113.5 million in labor income. In addition, the travel and tourism sector generated nearly $16 million in state taxes and $15 million in local taxes, for a total of almost $31 million in tax revenue.

The RDSGEIS assumes that as the industry "matures" in the region, local residents will be trained and hired for drilling jobs. If, as has been the case with vertical drilling in New York State and in the Western US shale plays, development follows a more irregular pattern, then the higher paid technical jobs are less likely to evolve into stable local employment. In addition, the jobs in ancillary industries (retail and services) are likely to disappear and reappear as rigs leave and re-enter the region at unpredictable intervals.

In addition, many of the highest paid jobs associated with HVHF will not be filled locally. Occupational employment statistics geographical analysis of petroleum engineers, one of the most common occupations in the oil and gas industry, indicates that the states with the highest employment in this occupation are Texas, Oklahoma, and Louisiana. This data suggests that the rural areas of New York that are likely to experience the most intensive gas development will not see an increase in highly skilled and highly paid jobs in petroleum engineering.

The creation of high-paying jobs as a result of expenditures in industries outside the extraction industry is also likely to occur <u>outside</u> the production region. This is important because regions where natural resource extraction takes place (and especially rural regions with little economic diversity) have been found to end up with poorer economies at the end of the resource extraction process. Although the EAR asserts that as the natural gas industry grows, more of the suppliers would locate to the representative regions and less of the indirect and induced economic impacts would leave the regions, no evidence is presented to substantiate this assumption. The more likely outcome is indicated by a study of the impact of gas drilling on Western State economies, which found that natural gas drilling may have positive fiscal impacts at the state level, but negative fiscal impacts for the regions in which it occurs.

3.15.7 Regional Plan of Development Approach to Mitigating Socioeconomic Impacts

The mitigation chapter of the RDSGEIS implies that negative impacts will be mitigated through the permitting process and a secondary level of review triggered by the operator's identification of inconsistencies with comprehensive land use plans. The measures are only advisory. The RDSGEIS proposes no requirements to mitigate adverse socioeconomic impacts in this process.

Mitigation measures should be developed that would require operating companies to submit plans for exploration and development in a county or counties to county planning offices for review of cumulative impacts and mitigation (for example truck traffic routing), a model used in Western U.S. drilling regions. Because the RDSGEIS acknowledges that the pace and scale of development are difficult to ascertain until exploration and production begin to proceed, it is critical that a permit and regional Plan of Development (POD) review process be set up that alerts local officials to the need for long term planning for land use, schools, public safety and public health. The POD, outlining the pace, scale, and general location in which development will occur enables local government to anticipate and develop strategies to mitigate cumulative impacts. The near-term projections of development activity should include all secondary facilities (e.g., water extraction, waste disposal, pipeline construction) in the area to be affected. A POD would allow communities in that region to prepare for the disruption and negotiate the least disruptive and damaging development plan.

To further assist communities in planning for socioeconomic impacts, a series of reporting requirements should be incorporated into the RDSGEIS and regulations. As development activities begin and progress, the information provided in initial projections should be confirmed or revised on a semiannual basis. This information is critical to forecasting and meeting housing and service demands.

In addition, mitigation strategies need to be developed and described in the RDSGEIS that address long term costs to affected regions and the impacts of the resource depletion phase of the exploration, drilling, and development process, when population and jobs leave the region and tax revenues may be insufficient to pay for the capital investments made to serve the population influx during the drilling and production phases of development. Finally, mitigation strategies should include policies to prevent negative impacts on existing industries, including agriculture, tourism and manufacturing.

3.16 Traffic and Transportation

While the RDSGEIS improves upon the 2009 DSGEIS regarding estimates truck trip generation, the impact of HVHF on roadway congestion and safety has not been adequately addressed in the RDSGEIS.

The impacts of a typical multi-well development on congestion and safety should be analyzed in detail; such analysis should include a cumulative traffic effects analysis using a reasonable worst case development scenario. The reasonable worst case development scenario for regional traffic impacts should include indirect traffic generation associated with increased economic development and population growth attributable to natural gas extraction and related economic activity.

The LBG technical memo (Attachment 7) details the specific analyses that should be undertaken and describes how the transportation mitigation commitments described in the RDSGEIS should be incorporated into regulations or permit conditions to ensure they are enforceable. The transportation plan requirement in the RDSGEIS is a good first step, but additional detail is needed on the transportation plan including required contents, methodologies and impact criteria to make this mitigation measure meaningful.

3.17 Noise and Vibration

The construction and operation phase noise impact assessments presented in RDSGEIS are improved over the 2009 DSGEIS, but still contain important flaws that understate the impacts.

For example, the drilling and fracturing impact assessment presented is for one well, ignoring the cumulative impact of multiple wells being developed at the same time. Even using the analysis for a single well, the sound levels associated with the fracturing process are so extreme that hearing damage could result from exposure for 8-hours at a distance of 500 feet from the well pad.

Transportation-related noise impacts are not quantified in the RDSGEIS. Potential noise effects on wildlife are not evaluated, even though the noise of a single well and even more so the combination of noise of multiple wells could affect wildlife (especially sensitive bird species). The cumulative effects of noise on wildlife habitat and fragmentation effects of almost continual disturbance are not evaluated.

Vibration impacts and low-frequency noise impacts (which are associated with health impacts) are similarly not addressed in the RDSGEIS. The LBG technical memo details the specific analyses that should be undertaken and describes how the noise mitigation commitments described in the RDSGEIS should be incorporated into regulations or permit conditions to ensure they are enforceable.

Similar to the transportation plan requirement mentioned above, the noise mitigation plan requirement lacks specificity regarding the analyses required and the thresholds that trigger the need for mitigation. A best practice template for NYSDEC to consider adopting to specify the requirements for noise impact analysis and mitigation plans is the Alberta Energy Resources Conservation Board (ERCB) Noise Control Directive (#38).

3.18 Visual Resources

The RDSGEIS describes in very broad terms the potential direct and cumulative impacts of various phases of natural gas development on NYSDEC-designated visually sensitive resources. This assessment should incorporate best practices for analyzing visual impacts, such as identifying the relevant view groups, landscape zones and photo simulations of well development in various contexts.

The RDSGEIS mitigation section for visual resources suggests that mitigation measures would only be considered when designated significant visual resources (parks, historic resources, scenic rivers, etc.) are present *and* within the viewshed of proposed wells. This approach fails to consider visual impacts on nearby residences or tourists in areas where a significant visual resource is not present. In these situations, no mitigation would be required for individual wells to be consistent with the RDSGEIS. NYSDEC should make basic and low-cost mitigation measures mandatory for all well development sites (such as keeping lighting levels at the minimum level required and directing lights downward to minimize light pollution), regardless of whether or not state designated significant visual resources are present. For more information on the adequacy of the proposed mitigation measures and suggested changes, refer to the LBG technical memorandum (Attachment 7).

3.19 Land Use

The RDSGEIS fails to provide any analysis of the reasonably foreseeable cumulative land use impacts that would result if HVHF development goes forward in New York. This should be corrected by providing information on existing land use patterns and analyzing the impact of the level of development anticipated in the economic impact study on land use change. The RDSGEIS fails to provide any discussion of mitigation measures for land use impacts. Mitigation measures such as buffer distances for incompatible land uses should be described and incorporated into enforceable regulations or supplemental permit conditions, as appropriate. For more information on the adequacy of the proposed mitigation measures and suggested changes, refer to the LBG technical memorandum (Attachment 7).

3.20 Community Character

Community character is an amalgam of various elements that give communities their distinct "personality." These elements include a community's land use, architecture, visual resources, historic resources, socioeconomics, traffic, and noise.[10] The community character impact assessment portion of the RDSGEIS lists some of the community character impacts that could be expected (focused on demographic and economic impacts), but does not analyze the significance of these impacts or draw conclusions on how HVHF would affect community character in the short-term and long-term. The impact assessment does not mention the contribution of visual, land use or historic resource impacts to community character. The discussion of traffic and noise impacts is superficial (two sentences each). A complete community character impact assessment is needed (including regional cumulative impacts) to ensure appropriate mitigation measures are included in the HVHF regulatory framework.

3.21 Cultural Resources

In addition to the ecological effects of the massive ground disturbance and industrial development that will occur with HVHF in New York, the integrity of historic architectural resources, archaeological sites and culturally significant areas to Native Americans is also threatened. The RDSGEIS does not address comments provided by New York Archaeological Council during scoping in 2008 on cultural resource issues and does not adequately address this important resource topic. There is no section of the RDSGEIS specifically devoted to the direct, indirect and cumulative impacts of HVHF on cultural resource or any discussion of mitigation measures (except for impacts related to visual resources). The reliance on the 1992 GEIS for protection of cultural resources is not sufficient given the significantly different type and scale of impacts that could occur with HVHF and the length of time that passed since the 1992 GEIS was prepared. The role of the New York State Office of Parks, Recreation and Historic Preservation (OPRHP) in the review of individual permit applications is not clear in the RDSGEIS. In addition, the RDSGEIS does not explained how tribal consultation regarding impacts to cultural resources will be accomplished in a manner consistent with NYSDEC's own 2009 policy *Contact, Cooperation, and Consultation with Indian Nations*. Cultural resource impacts, mitigation measures and project-level review requirements must be addressed before HVHF is approved. Refer to the LBG technical memorandum for more information supporting these comments (Attachment 7).

3.22 Ecosystems and Wildlife

The ecological effects of HVHF and related infrastructure development include direct losses of habitat, fragmentation of existing habitats and indirect "edge effects" such as the spread of invasive species and noise disturbance of wildlife. The RDSGEIS qualitatively acknowledges these impacts and summarizes the findings of studies conducted in other locations, but does not provide build-out analyses that could quantify the range of cumulative habitat loss and fragmentation effects in New York. As evidenced by The Nature Conservancy's build-out analysis of Tioga County, such an analysis is readily achievable with existing GIS tools and datasets available to NYSDEC.[11] The RDSGEIS should include quantitative build-out analysis of habitat fragmentation and edge effects using estimates of development potential consistent with those developed for the RDSGEIS economic impact assessment and include the impacts from reasonably foreseeable infrastructure such as pipelines and compressor stations. Based on the results of the build-out analysis, NYSDEC should also analyze the potential diminution of critical ecosystem services associated with the disruption of forest cover and soils (carbon sequestration and storage, air filtration, watershed flow rates and volume, surface water quality and thermal condition).

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[10] New York City Mayor's Office of Environmental Coordination. 2010. City Environmental Review Technical Manual.

[11] The Nature Conservancy. 2011 . "An Assessment of the Potential Impacts of High Volume Hydraulic Fracturing on Forest Resources."

The RDSGEIS characterizes the ecological impacts of HVHF as “unavoidable” and fails to consider alternative mitigation approaches that could lessen significant adverse environmental impacts. The site-specific ecological assessments and mitigation measures required by the RDSGEIS for well pads in grasslands greater than 30 acres and forest patches greater than 150 acres is a fragmented approach. It does not address the importance of landscape connectivity between habitat patches, which is essential to the movement and long-term viability of numerous species. A preferable methodology would be to set limits on deforestation, fragmentation and increases in impervious surface cover based upon ecological planning units such as the sub watershed. The SGEIS process should consider an alternative where rather than the current spacing unit requirements (which are intended to maximize production), land disturbance would be restricted region wide based on ecological carrying capacity. An ecologically oriented planning framework could significantly lessen the adverse impacts of HVHF development on terrestrial and aquatic systems.

In addition, consideration should be given to cumulative changes to land use within each watershed that could lead to detrimental changes in the affected stream to support critical species habitat. Limiting the percent increase in impervious area to less than five percent (inclusive of existing uses) in trout supporting watersheds, including upstream tributaries, would reduce the potential for adverse impacts to sensitive aquatic organisms and the loss of a waters best use designation.

The RDSGEIS fails to provide any meaningful guidance regarding the ultimate restoration of well pads, pipeline right-of-ways and access roads to full ecosystem functionality upon decommissioning. Effective restoration requires a comprehensive, site-level assessment of the existing plant community prior to disturbance and the use of local reference ecosystems as templates for restoration. Ecological restoration is based upon the concept of rebuilding degraded areas such that they are structurally and functionally similar to pre-disturbance conditions. Reclamation is not restoration. Grassy fields neither function in a biologically similar manner as a forest nor supply the ecosystem benefits of a forest system. The replacement of a decades-old, complex assemblage of woodland species with a simple mix of grasses is not “restoration”. It may retard erosion but it does not replace the original functionality and structure of the displaced ecosystem.

For supporting technical information for these comments and additional comments on ecological impacts and mitigation measures, refer to the technical report from Kevin Heatley (Attachment 8) and LBG (Attachment 7).

3.23 Climate Change

The RDSGEIS ignores the real possibility that climate change impacts will undermine the safety of HVHF operations, frustrate mitigation efforts proposed by NYSDEC, and therefore exacerbate adverse impacts to the environment and human health resulting from HVHF operations. Increases in extreme weather events, such as floods, pose considerable obstacles to the safety of HVHF operations and infrastructure in and around low-lying coastal areas and floodplains. Precipitation changes coupled with enormous surface and groundwater withdrawals may result in modified groundwater flow patterns, which may cause unexpected groundwater contamination that jeopardizes drinking water supplies. Increased temperatures can volatilize dangerous chemical compounds at drill sites, exposing workers and nearby residents to airborne carcinogens at a rate greater than would be expected by modeling baseline temperatures without climate change. Remarkably, the effect of climate change on the availability of water resources is ignored in the section on the cumulative impact of water withdrawals, and no provision is made for situations where HVHF operations and public needs may conflict over water usage. Underscoring these concerns is the notable failure of NYSDEC to conduct a comprehensive Health Impact Assessment, despite the real possibility that climate change impacts confluent with HVHF operations can pose serious human health problems. Reliable reports on the effect of climate change on New York abound, including some produced within the last year by New York governmental bodies. The RDSGEIS fails to include current information relevant to climate change's potential effects on New York State, which may pose potentially significant adverse environmental and public health threats in conjunction with HVHF operations that should be identified and mitigated to the maximum extent possible.

For supporting technical information regarding these comments, refer to the technical report from Dr. Kim Knowlton (Attachment 9).

3.24 Health Impact Assessment

Numerous health concerns have been associated with natural gas development using hydraulic fracturing, and while the RDSGEIS addresses some aspects of a subset of these health issues, it fails to address other important health risks. The RDSGEIS not only omits several issues, but also it only addresses only some aspects of other issues such as air, water quality, and heightened traffic without fully considering health impacts in those areas. Lastly, it doesn't consider health issues as a group in a formal Health Impact Assessment (HIA), including interactive effects on the health of local residents and communities. A full HIA as part of the RDSGEIS is a necessary component, as there are already numerous reports of health complaints including dizziness, sinus disorders, depression, anxiety, difficulty concentrating, and many others, among people who live near natural gas drilling and fracturing operations in other states. Without a full assessment and mitigation of the impacts of the risks, the health of New York State residents and communities is likely to suffer.

For supporting technical information regarding these comments, refer to the technical report from Dr. Gina Solomon (Attachment 10).

3.25 Induced Seismicity

The RDSGEIS fails to require operators of HVHF wells to consider the risk of induced seismicity when siting wells and designing hydraulic fracture treatments. The justification provided is that high volume hydraulic fracturing is not expected to cause induced seismicity that will result in adverse impacts. Since the RDSGEIS was written, hydraulic fracturing has been confirmed to have caused induced seismicity strong enough to be felt at the surface. The RSDGEIS assumes that operators will manage seismic risks voluntarily and makes statements regarding the frequency of use of seismic monitoring techniques that are internally contradictory. It also fails to recognize the potential significance of unmapped faults and relies too heavily on the occurrence of natural seismicity as a future predictor of the potential for induced seismicity. Finally, it underestimates the potential adverse consequences of induced seismicity, which include risks to drinking water, well integrity, private and public property, and New York City drinking water supply infrastructure. The RSDGEIS provides insufficient analysis and scientific evidence to support its conclusion that regulations to reduce the risk of induced seismicity from hydraulic fracturing are not necessary. The RSDGEIS must require operators to evaluate and manage the risk of induced seismicity from hydraulic fracturing through proper site characterization and hydraulic fracture treatment design.

For supporting technical information regarding these comments, refer to the technical report from Briana Mordick (Attachment 11).

Attachment 1

Harvey Consulting, LLC.

2011 NYS RDSGEIS

Revised Draft Supplemental Generic
Environmental Impact Statement
On the Oil, Gas & Solution Mining Regulatory Program

Well Permit Issuance for Horizontal Drilling
and High-Volume Hydraulic Fracturing to
Develop the Marcellus Shale and Other
Low-Permeability Gas Reservoirs
and

Proposed Revisions to the New York Code of Rules and Regulations

Best Technology and Practice Recommendations

Report to:

Natural Resources Defense Council (NRDC)

Prepared by:

HARVEY
CONSULTING, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

January 9, 2011

Contents

1. Introduction

This report responds to the Natural Resources Defense Council's (NRDC), and its partner organizations Earthjustice, Inc., Riverkeeper, Inc., Catksill Mountainkeeper and Delaware Riverkeeper Network, request for a review of the New York State (NYS) 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas & Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs and proposed revisions to the New York Code of Rules and Regulations (NYCRR).

NRDC, and its partners, requested a technical review of the RDSGEIS and the proposed revisions to the NYCRR to determine if best technology and practices were included. NRDC has also commissioned additional experts; therefore, this list of recommendations is not exhaustive and is complementary to the work assigned to other experts. A complete list of expert recommendations can be found in the summary cover letter submitted by The Louis Berger Group, Inc., on behalf of NRDC, to the New York State Department of Environmental Conservation (NYSDEC) during the RDSGEIS public comment period.

This report makes recommendations for improving the SGEIS and the proposed revisions to the NYCRR. Overall, HCLLC found that NYSDEC made a number of significant improvements in both the RDSGEIS and the proposed revisions to the NYCRR. HCLLC commends NYSDEC for integrating a number of new best practices and technology alternatives into its 2011 RDSGEIS and proposed regulations.

This report highlights the RDSGEIS areas of improvement and reinforces the importance of retaining those improvements in the final SGEIS and the proposed NYCRR revisions. However, there remain significant areas for improvement. This report provides additional technical justification and scientific support for best practices and technology that warrant further NYSDEC consideration. It also recommends area of further study. Recommendations are highlighted in blue text boxes throughout the document.

A systemic problem persists in the 2011 RDSGEIS, where NYSDEC proposes to build on the existing 1992 Generic Environmental Impact Statement (GEIS) for oil and gas drilling in NYS by providing additional information on the Marcellus Shale reservoir and high-volume hydraulic fracturing without addressing the fact that the technology and practices required by the 1992 GEIS are over two decades old.

Since 1992, numerous best technology and best management practice improvements have been made in the oil and gas industry. By relying on 1992-vintage decisions and technology as the foundation for Marcellus Shale development, NYS' RDSGEIS starts with an unstable foundation. This problem is magnified in the proposed revisions to the NYCRR where NYSDEC proposes to retain, with little revision, antiquated technology and practices for all oil and gas development in NYS, while proposing that new technology and practices only apply to HVHF operations. This creates a technically and scientifically unsupported two-tiered system for oil and gas regulation in NYS.

Accordingly, the first and most logical step in the State Environmental Quality Review Act (SEQRA) analysis is to examine the 1992 GEIS foundation and identify new best technology and best practice improvements have been made since 1992 that warrant adoption. Then, and only then, can NYS build a well-supported incremental analysis that examines the impact of new techniques such as horizontal drilling and high-volume fracture treatments.

2. Scope of SGEIS – Marcellus Only

Background: In 2009, NYSDEC proposed that the SGEIS cover all horizontal drilling and HVHF in low-permeability gas reservoirs, at all depths. However, only the Marcellus Shale Gas Reservoir was studied in any detail. The DSGEIS was incomplete for all other low-permeability gas reservoirs.

In 2009, HCLLC recommended that NYSDEC either include additional information and analysis on the impacts of exploring and developing other low-permeability gas reservoirs or limit the scope of the SGEIS to the Marcellus Shale Gas Reservoir.

NYSDEC's consultant, Alpha Geoscience, disagreed with HCLLC's recommendation to limit the SGEIS scope to the Marcellus Shale, stating that the time to modify the scope had lapsed.[1] Alpha Geoscience concluded that it would be best for NYSDEC to determine at a future date, once a specific application was before them, whether the SGEIS covered High-Volume Hydraulic Fracturing (HVHF) operations in other low-permeability reservoirs.

HCLLC disagrees with Alpha Geoscience's recommendation, because it lacks technical and scientific basis and misconstrues HCLLC's recommendation. HCLLC did not recommend that other low-permeability gas reservoirs be excluded from the analysis because they should not be studied at all. On the contrary, HCCLC recommended that if low-permeability gas reservoirs were included in the SGEIS, they should be thoroughly studied. The 2009 DSGEIS should have included a complete assessment of the Marcellus and all other low-permeability gas reservoirs in NYS; however, it did not. Unfortunately, the 2011 RDSGEIS suffers from the same lack of data on other low-permeability gas reservoirs.

Consequently, there is a technical and scientific choice that needs to be made in declaring whether the SGEIS content satisfies its title. Either the SGEIS had to be revised to cover all low-permeability gas formations in NYS, or the SGEIS had to conclude that NYSDEC has insufficient data and/or resources to examine anything more than the Marcellus Shale at this time, and limit the scope of the SGEIS.

HCLLC's 2009 recommendation was made to ensure the SGEIS document title matches its content. The title of the SGEIS purports to provide an environmental impact analysis on all low-permeability gas reservoirs, yet, as explained in HCLLC's 2009 comments, the SGEIS did not provide sufficient analysis of the Utica Shale, and provided no analysis of the other Lower Paleozoic, Devonian (other than Marcellus), and Middle to Upper Paleozoic low-permeability gas reservoirs.[2,3] If NYSDEC has additional information to support a complete SGEIS for the Marcellus and all other low-permeability gas reservoirs, it should certainly include that complete assessment.

Unfortunately, the 2011 RDSGEIS suffers from the same narrow focus on the Marcellus shale. There was little additional work completed to advance NYSDEC's understanding of exploration and development impacts from the Utica Shale and other low-permeability gas reservoirs.

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[1] Alpha Geoscience, Review of the DSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA on January 20, 2011, Page 3.

[2] Ryder, R.T., 2008, Assessment of Appalachian Basin Oil and Gas Resources: Utica-Lower Paleozoic Total Petroleum System: U.S. Geological Survey Open-File Report 2008–1287.

[3] Milici, R.C., and Swezey, C.S., 2006, Assessment of Appalachian Basin Oil and Gas Resources: Devonian Shale-Middle and Upper Paleozoic Total Petroleum System: U.S. Geological Survey Open-File Report 2006-1237.

2011 RDSGEIS: The 2011 RDSGEIS provides some additional information on the Utica Shale Gas Reservoir, mostly in the form of geologic assessment. However, the RDSGEIS does not examine the peak or cumulative impacts of Utica Shale development.

No additional information is provided in the 2011 RDSGEIS on other low-permeability gas reservoirs in the region. The 2011 RDSGEIS states that industry's main focus in the near term is the Marcellus and Utica Shales; however, NYSDEC wants to cover all other low-permeability formations in the SGEIS because it may receive applications in the future for those formations:

> *The Department of Environmental Conservation (Department) has received applications for permits to drill horizontal wells to evaluate and develop the Marcellus and Utica Shales for natural gas production…* *<u>Other shale and low-permeability formations in New York may also be targeted for future application of horizontal drilling and high-volume hydraulic fracturing</u> [emphasis added].*[4]

Chapter 4 provides a geologic description of the Marcellus and Utica shale gas reservoirs; however, no other low-permeability gas reservoirs are studied. Yet, it is well known that most unconventional reservoirs vary in mineralogy, permeability, rock mechanics, and natural fracture parameters (length, orthogonal spacing, connectivity, anisotropy) and that there will be differences between formations that could lead to different drilling, stimulation, and development techniques.

Chapters 5 and 6 provide an analysis of drilling, fracturing, and development approaches in the Marcellus Shale Gas Reservoir. Chapters 5 and 6 are essentially silent on how the Utica Shale Gas Reservoir would be developed. No other low-permeability gas reservoirs are examined.

A search of the 1537 page electronic version of the RDSGEIS for the term "low-permeability gas reservoirs" shows that the term is only used a few times in the entire document. This term is used twice in the Executive Summary, where NYSDEC concludes that it has effectively studied "low-permeability gas reservoir" air quality impacts; yet, as further explained in Chapter 17 of this report there is insufficient information in the RDSGEIS to support that conclusion. The next occurrence of the term "low-permeability gas reservoirs" is not found until page 618 in the Air Quality Section, where again, NYSDEC states that it has included the impacts of "low-permeability gas reservoirs" in the air quality analysis; yet, there is insufficient information in the RDSGEIS to support that conclusion. The next occurrence, after the Air Quality Section, is found at page 1008, where NYSDEC defends exclusion of pipeline and compressor stations. A few minor references to this term are found at page 1071 in Chapter 9 (Alternative Actions). More simply put, the RDSGEIS contents do not match the title, and that there is insufficient information contained in the RDGSEIS to support development of all unnamed, unanalyzed low-permeability gas reservoirs in NYS. NYS has not developed a technical or scientific case to justify that the impacts described for the Marcellus Shale are representative of the peak or cumulative impact that would result from development of all unnamed, unanalyzed low-permeability gas reservoirs in NYS.

The 2011 RDSGEIS does not include a complete list of the formation names that it considers fit under the umbrella term of "low-permeability" formations. The only place that the term "low-permeability" formation is defined is in the Glossary at the end of the document:

> *Gas bearing rocks (which may or may not contain natural fractures) which exhibit in-situ gas permeability of less than 0.10 milidarcies.*[5]

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[4] 2011 NYSDEC, RDSGEIS, Page 1-1.

[5] 2011 NYSDEC, RDSGEIS, Glossary.

Using this definition, a low-permeability formation could include a shale, sandstone, limestone or other formation that is gas bearing with a permeability of less than 0.10 milidarcies. The RDSGEIS does not address the scope of the formations that could be encompassed by this definition.

Figure 4.2 of the RDSGEIS[6] includes a stratigraphic section showing existing known oil and gas intervals above the Marcellus and Utica Shales, including numerous shale and other low-permeability formations that are known to exist, that were not examined in the SGEIS.

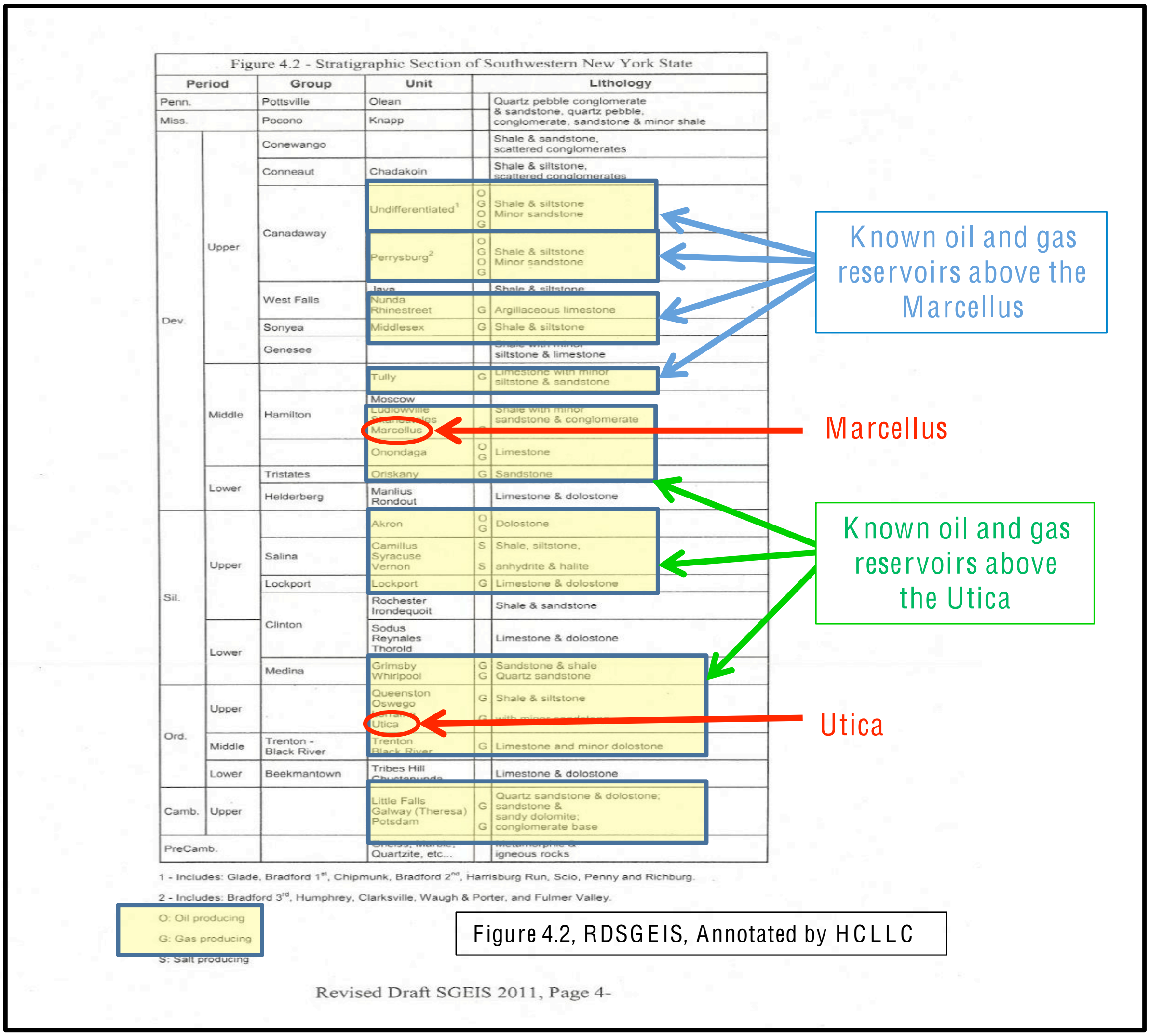

Figure 4.2 - Stratigraphic Section of Southwestern New York State

Period		Group	Unit		Lithology
Penn.		Pottsville	Olean		Quartz pebble conglomerate & sandstone, quartz pebble, conglomerate, sandstone & minor shale
Miss.		Pocono	Knapp		
Dev.	Upper	Conewango			Shale & sandstone, scattered conglomerates
		Conneaut	Chadakoin		Shale & siltstone, scattered conglomerates
		Canadaway	Undifferentiated[1]	O G O G	Shale & siltstone Minor sandstone
			Perrysburg[2]	O G O G	Shale & siltstone Minor sandstone
		West Falls	Java		Shale & siltstone
			Nunda Rhinestreet	G	Argillaceous limestone
		Sonyea	Middlesex	G	Shale & siltstone
		Genesee			Shale with minor siltstone & limestone
	Middle		Tully	G	Limestone with minor siltstone & sandstone
		Hamilton	Moscow Ludlowville Skaneateles Marcellus	G	Shale with minor sandstone & conglomerate
			Onondaga	O G	Limestone
	Lower	Tristates	Oriskany	G	Sandstone
		Helderberg	Manlius Rondout		Limestone & dolostone
Sil.	Upper		Akron	O G	Dolostone
		Salina	Camillus Syracuse Vernon	S S	Shale, siltstone, anhydrite & halite
		Lockport	Lockport	G	Limestone & dolostone
		Clinton	Rochester Irondequoit		Shale & sandstone
	Lower		Sodus Reynales Thorold		Limestone & dolostone
		Medina	Grimsby Whirlpool	G G	Sandstone & shale Quartz sandstone
Ord.	Upper		Queenston Oswego Lorraine Utica	G G	Shale & siltstone with minor sandstone
	Middle	Trenton - Black River	Trenton Black River	G	Limestone and minor dolostone
	Lower	Beekmantown	Tribes Hill Chuctanunda		Limestone & dolostone
Camb.	Upper		Little Falls Galway (Theresa) Potsdam	G G	Quartz sandstone & dolostone; sandstone & sandy dolomite; conglomerate base
PreCamb.			Gneiss, Marble, Quartzite, etc...		Metamorphic & igneous rocks

1 - Includes: Glade, Bradford 1st, Chipmunk, Bradford 2nd, Harrisburg Run, Scio, Penny and Richburg.

2 - Includes: Bradford 3rd, Humphrey, Clarksville, Waugh & Porter, and Fulmer Valley.

O: Oil producing
G: Gas producing
S: Salt producing

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Figure 4.2, RDSGEIS, Annotated by HCLLC

On the next page is a table summarizing historical oil and gas production data from 1967 to 2010 in NYS.[7] This table shows that there is numerous gas zones present both above and below the Marcellus Shale that have been producing gas. Some of these reservoirs are low-permeability reservoirs that may be further developed using horizontal drilling and hydraulic fracturing techniques. Additionally, this table shows that there has been no Utica Shale production in NYS from 1967 to 2010; therefore, little is known about its productivity or how it may be developed.

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[6] 2011 NYSDEC, RDSGEIS, Page 4-7.

[7] NYS Oil & Gas Data Summary 1967-2010, compiled by Briana Mordick, NRDC, December 2011, using NYS data found at http://www.dec.ny.gov/energy/1601.html. 1967-1999 data came from summary production history files. 2000-2010 data came from oil and gas production files.

NYS Oil & Gas Data Summary 1967-2010

		Formation	Oil (bbl)	Gas (mcf)		Oil (bbl)	Gas (mcf)
Devonian	Upper	DEVONIAN SHALE	12,274	323,975			
		UPPER DEVONIAN	364,054	881,848	DEVONIAN SHALE	376,328	1,208,697
		UPPER DEVONIAN SHALE	-	2,874			
		Canadaway Undifferentiated					
		GLADE	1,392,255	449,124			
		BRADFORD	7,665,427	1,639,511			
		BRADFORD 1ST & 2ND	21	-			
		BRADFORD & CHIPMUNK	416,357	676,506			
		Bradford 1st & Chipmunk	6,609	2,497			
		CHIPMUNK, BRADFORD 1ST & 2ND	44,943	10,217			
		CHIPMUNK	7,369,293	1,012,975			
		CHIPMUNK & BRADFORD 2ND	2,454,948	16,415			
		BRADFORD SECOND	21,724	2,520			
		CHIPMUNK, BRADFORD 2ND & 3RD	237,195	162,809	CANADAWAY UNDIFFERENTIATED	23,945,472	7,271,139
		Chipmunk, Bradford 1st,2nd,3rd	9,719	8,321			
		BRADFORD 2ND & 3RD	37,780	9,353			
		CHIPMUNK & BRADFORD 3RD	33,186	34,858			
		Chipmunk & Harrisburg	2,442	1,026			
		Harrisburg	1,682	-			
		SCIO	137,258	2,520			
		PENNY	13,232	46,567			
		PENNY & FULMER VALLEY	42,660	71,003			
		RICHBURG	4,057,637	3,121,677			
		RICHBURG-WAUGH & PORTER	1,104	3,240			
		Canadaway PERRYSBURG	-	395			
		BRADFORD THIRD	228,582	112,002			
		CLARKSVILLE	39,387	36,864	PERRYSBURG	2,055,287	4,746,392
		WAUGH & PORTER	42,100	247,245			
		FULMER VALLEY	1,745,218	4,349,886			
		Nunda	-	-			
		RHINESTREET	-	3,409			
	Middle	TULLY	1,108	275,643	TULLY	1,108	275,643
		HAMILTON	-	20,416	HAMILTON	-	20,416
		MARCELLUS	-	747,399	MARCELLUS	-	747,399
		ONONDAGA	647,251	25,843,114	ONONDAGA	647,251	25,843,114
		ONONDAGA-ORISKANY	-	223,157			
	Lower	ORISKANY	10,582	31,738,725	ORISKANY	10,582	31,961,882
		HELDERBERG	-	10,230,425	HELDERBERG	-	10,230,425
		ONONDAGA-BASS ISLAND	532,310	3,118,389			
Silurian	Upper	BASS ISLAND	1,021,802	5,739,620	BASS ISLAND	1,580,509	9,416,091
		BASS ISLAND/MEDINA	26,397	558,082			
		AKRON	1,577	1,729,358	AKRON	1,577	1,729,358
		SALINA	1,278	5,778			
		CAMILLUS	-	60			
		SYRACUSE	570	2,338			
		VERNON	-	358,405			
		CLINTON	-	87,231			
		LOCKPORT	-	69,528			
		ROCHESTER SHALE	-	70,693			
		SAUQUOIT	-	210			
	Lower	SODUS SHALE	-	164,071			
		MEDINA	213,688	514,545,705			
		GRIMSBY	-	1,501,854	MEDINA	213,688	521,205,687
		WHIRLPOOL	-	893,326			
		MEDINA-QUEENSTON	-	4,264,802			
		HERKIMER	-	5,849,567			
		HERKIMER-ONEIDA	-	1,178,375			
		ONEIDA	-	1,024,647	HERKIMER-ONEIDA-OSWEGO	-	9,169,025
		ONEIDA-OSWEGO	-	1,094,384			
Ordovician	Upper	QUEENSTON	-	56,439,648	QUEENSTON	-	56,439,648
		OSWEGO	-	22,052			
		UTICA	**-**	**-**			
	Middle	TRENTON	-	485,477	TRENTON	-	485,477
		BLACK RIVER	-	318,316,063	BLACK RIVER	-	318,316,063
Cambrian	Upper	LITTLE FALLS	-	501,440	LITTLE FALLS	-	501,440
		THERESA	-	3,588,222	THERESA	-	3,588,222
		POTSDAM	-	-			

NYS Oil & Gas Data Summary 1967-2010, compiled by Briana Mordick, NRDC, December 2011.

Using the Marcellus Shale impact assessment and proposed mitigation measures as a surrogate for peak and cumulative impact assessment in the Utica and all other unnamed low-permeability formations is an inadequate approach.

For example, the Utica Shale Gas Reservoir is almost twice as deep as the Marcellus Shale Gas Reservoir. The Utica Shale dips to 9,000' deep,[8] while the Marcellus Shale is approximately 5,000' deep.[9] Utica Shale wells will take longer to drill than Marcellus Shale wells, generating more air pollution and drilling waste, HVHF waste and resulting in longer duration surface impacts (e.g. noise, light, fuel and chemical storage periods, etc.). Additionally, waste generated translates into additional transportation and surface use impacts. Utica Shale development will also require more resources and equipment. Deeper shale gas formations will have higher reservoir pressure, and will penetrate more known oil and gas zones before reaching the Utica Shale, meaning increased blowout risk. Higher reservoir pressure will require additional combustion equipment to meet higher pump pressure and energy demands. Deeper wells can have more complex well construction designs. Fully cemented casing strings will be more difficult to complete at deeper depths and higher temperature cement mixtures will be required if subsurface temperatures exceed 200 ^{0}F. Therefore, the maximum impact assessment for a Marcellus Shale well is not sufficient to examine the maximum impact of a Utica Shale well.

Additionally, there is little information in Petroleum Engineering technical literature on the Utica Shale, and how it may be effectively developed. The 2011 RDSGEIS assumes that the Utica Shale will be developed using the same exact techniques as the Marcellus Shale; however, this may not be the case. For example, a 2007 a paper prepared by Universal Well Services Inc., CESI Chemical A Flotek Industries Co., in collaboration with the State University of New York noted some significant differences in the Utica Shale, and the likelihood for a unique stimulation method:

> *The primary purpose of stimulating fractured shale reservoirs is the extension of the drainage radius via creation of a long fracture sand pack that interconnects with natural fractures thereby establishing a flow channel network to the wellbore. However, there is limited understanding of a successful method capable of stimulating Utica Shale reservoirs. Indeed most attempts to data have yielded undesirable results. This could be due to several factors, including formation composition, entry pressure, and premature pad fluid leak-off. Furthermore, stimulation of Utica shale reservoirs with acid alone has not been successful. This treatment method leads to a fracture length and drainage radius less than expected resulting in poor well productivity [emphasis added].*[10]
>
> *...several recently drilled Utica shale wells have not responded well to the normal shale fracturing practices. An understanding of Utica shale mineralogy and rock mechanics is necessary before a stimulation method and fluid are selected [emphasis added].*[11]

Additionally, the authors point out that the Utica, unlike the Marcellus, contains a high percentage of acid soluble carbonate and dolomite that may require chemical treatment (e.g. acids) to treat the carbonates and dolomite to reduce entry pressures. They suggest that an acid stimulation treatment could potentially be the main stimulation method instead of a HVHF, or alternatively be added as an additional pre-

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[8] 2009 NYSDEC, DSGEIS, Page 4-5.

[9] 2009 NYSDEC, DSGEIS, Page 4-14.

[10] Paktinat, J., Pinkhouse, J.A., and Fontaine, J., (Universal Well Services Inc.), Lash, G. G., State University of New York College at Fredonia, Penny, G.S., CESI Chemical A Flotek Industries Co., Investigation of Methods to Improve Utica Shale Hydraulic Fracturing in the Appalachian Basin, Society of Petroleum Engineers, SPE Paper 111063, 2007, Page 1.

[11] Paktinat, J., Pinkhouse, J.A., and Fontaine, J., (Universal Well Services Inc.), Lash, G. G., State University of New York College at Fredonia, Penny, G.S., CESI Chemical A Flotek Industries Co., Investigation of Methods to Improve Utica Shale Hydraulic Fracturing in the Appalachian Basin, Society of Petroleum Engineers, SPE Paper 111063, 2007, Page 2.

treatment to a HVHF. The Utica also contains a higher percentage of clays than the Marcellus, and has the potential to generate both siliceous and organic fines that may require additional chemical treatment.

Moreover, there are low-permeability gas reservoirs that are present at depths shallower than the Marcellus Shale, which were not studied at all. Those unnamed, unanalyzed low-permeability reservoirs are in closer proximity to protected water resources, and warrant a complete technical and scientific assessment. Most importantly, HVHF modeling and fracture design requirements should be established to ensure that man-made induced fractures in these shallower reservoirs do not propagate in a manner that pollutes protected groundwater resources. Man-made induced fractures in shallower formations will tend to propagate on the horizontal plane; however, the size of that horizontal fracture must be constrained so that it does not intersect with existing improperly constructed or improperly abandoned wells or transmissive faults and fractures that can provide a direct pollution pathway to protected groundwater resources.

Best technology and best practices and cumulative impacts, in many cases, are reservoir specific. Because the RDSGEIS does not contain information on the depth, type, activity, or equipment requirements for the general category called "*other low-permeability gas reservoirs,*" it is not possible to determine if the maximum impact assessment for a Marcellus Shale well sufficiently covers the maximum impact from "*other low-permeability gas reservoirs.*" Nor is it possible to determine whether best technology and best practices developed for the Marcellus Shale would apply to the Utica Shale since there is very little information and understanding of the optimal Utica Shale stimulation method at this time.

Recommendation No. 1: The SGEIS should either include additional information and analysis on the impacts of exploring and developing the Utica Shale and other unnamed low-permeability gas reservoirs, or acknowledge that there is insufficient information and analysis to study the impacts of this development. In the latter case, the SGEIS should conclude that its examination of impacts and mitigation measures is limited to the Marcellus Shale Gas Reservoir, and therefore any Utica Shale or other unnamed low-permeability gas reservoir development will warrant a site-specific supplemental environmental impact statement review or should be covered under another, future SGEIS process.

3. Liquid Hydrocarbon Impacts (Oil and Condensate)

Background: NYS 2009 Annual Oil and Gas Report[12] show that NYS produced 323,536 barrels of oil in 2009, primarily from the western counties of:

Cattaraugus	201,688 barrels
Allegany	47,421 barrels
Chautauqua	40,187 barrels
Steuben	9,992 barrels

NYSDEC did not separately report the amount of condensate or natural gas liquids production.

Chapter 2 of this report includes a table summarizing oil and gas production from 1967 to 2010 in NYS, showing that oil gas been produced from above the Marcellus and Utica Shale formations, verifying the potential to encounter liquid hydrocarbons while drilling into the Marcellus and Utica formations.

2011 RDSGEIS: The 2011 RDSGEIS describes natural gas exploration and production, but does not address the potential for shale gas wells to also encounter liquid hydrocarbons. Natural gas exploration can identify oil and condensate development opportunities. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drillsites may be needed to develop those oil resources.

Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. The risk of oil spills during shale gas exploration has not been analyzed in the RDSGEIS. While blowouts are infrequent, they do occur, and are a reasonably foreseeable consequence of exploratory drilling operations. Blowouts can occur from gas and/or oil wells. They can last for days, weeks, or months until well control is achieved. On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells. [13] Two recent gas well blowouts occurred in Pennsylvania due to Marcellus Shale drilling.[14,15]

The 2011 RDSGEIS provided several useful maps and a stratigraphic section that aid in understanding the overlap of NYS' oil and gas production intervals. Figure 4.2 includes a Stratigraphic Section of Southwestern NYS that shows oil is produced from the Upper Devonian, at shallower depths than the Marcellus Shale, meaning that wells drilled in this region may encounter oil before penetrating the Marcellus. An annotated version of Figure 4.2 is also shown in Chapter 2 of this report. Figures 4.8 and 4.9 indicate that there is an overlap of current oil production with possible Marcellus Shale development in Cattaraugus, Allegany, Chautauqua, and Steuben counties.

Oil is also found below the Marcellus Shale and above the Utica Shale in the Upper Silurian. Therefore wells drilled into the Utica Shale may encounter oil before penetrating the Utica. Figure 4.6 indicates that there is an overlap of current oil production with possible Utica Shale development in Steuben County.

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[12] New York State Oil, Gas and Mineral Resources, 26th Annual Report for Year 2009 and Appendices, Prepared by NYSDEC, 2009.

[13] Rana, S., Environmental Risks- Oil and Gas Operations Reducing Compliance Cost Using Smarter Technologies, Society of Petroleum Engineering Paper 121595-MS, Asia Pacific Health, Safety, Security and Environment Conference, 4-6 August 2009, Jakarta, Indonesia, 2009.

[14] Blowout Occurs at Pennsylvania Gas Well, Wall Street Journal, June 4, 2010.

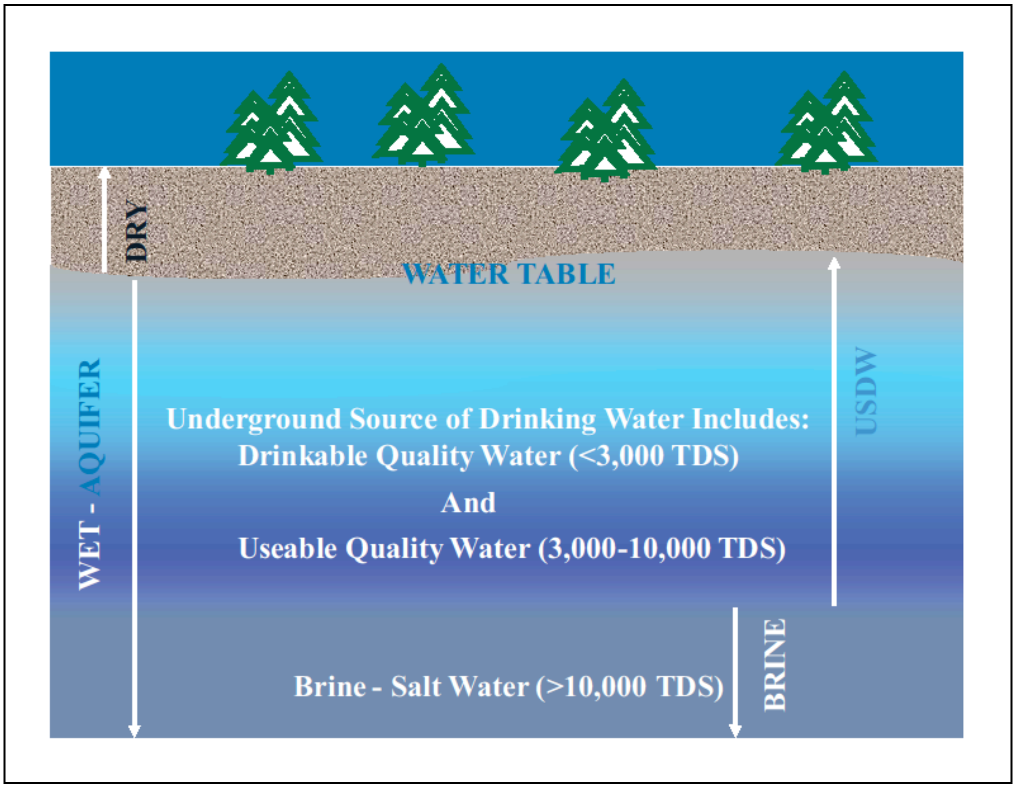
[15] Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid, The Huffington Post, April 20, 2011.

There are low-permeability gas reservoirs that are present at depths both shallower and deeper than the Marcellus Shale, which were not studied in detail in the RDSGEIS. Absent geologic maps for these unnamed, unanalyzed low-permeability reservoirs, it is not clear where oil development and shale gas development overlap for these reservoirs may occur.

Recommendation No. 2: The SGEIS should examine the potential for shale gas wells to also encounter liquid hydrocarbons. The SGEIS should also examine the incremental risks of oil well blowouts and oil spills, as well as the impacts from the additional wells and drillsites that may be required to develop oil resources identified by shale gas exploration and production activities.

4. Water Protection Threshold

Background: The regulations promulgated under the federal Safe Drinking Water Act (SDWA) define an Underground Source of Drinking Water (USDW) as an aquifer or part of an aquifer, which is not exempted (per 40 CFR § 146.4), and: (1) which supplies a public water system; or (2) which contains a sufficient quantity of groundwater to supply a public water system and either supplies drinking water for human consumption or contains fewer than 10,000 milligrams/liter of Total Dissolved Solids (TDS) [10,000 ppm TDS]. 40 CFR § 144.3. An EPA diagram depicting a USDW is shown below.[16]



The 2011 RDSGEIS: The 2011 RDSGEIS is based on the protection of potable water as defined as water containing less than 250 ppm of sodium chloride or 1,000 ppm TDS. The RDSGEIS states:

> *For oil and gas regulatory purposes, potable fresh water is defined as water containing less than 250 ppm of sodium chloride or 1,000 ppm TDS and salt water is defined as containing more than 250 ppm sodium chloride or 1,000 ppm TDS [emphasis added].*[17]

The RDSGEIS identifies 850' as the depth where 250 ppm of sodium chloride or 1,000 ppm TDS is typically reached, however the RDSGEIS notes that in some cases potable water is found deeper than 850'.

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[16] USEPA, Karen Johnson, Chief Ground Water & Enforcement Branch, 2010 PowerPoint Presentation, EPA's Underground Injection Control Program, Regulation of Disposal Wells in Pennsylvania.

[17] 2011 NYSDEC, RDSGEIS, Page 2-23.

> *Groundwater from sources below approximately 850 feet in New York typically is too saline for use as a potable water supply; however, there are isolated wells deeper than 850 feet that produce potable water and wells less than 850 feet that produce salt water. A depth of 850 feet to the base of potable water is commonly used as a practical generalization for the maximum depth of potable water; however, a variety of conditions affect water quality, and the maximum depth of potable water in an area should be determined based on the best available data [emphasis added].*[18]

By comparison, USDWs are based on a TDS cutoff of 10,000 ppm. The RDSGEIS has not explained why it proposes, and NYS regulations rely on, a 1,000 ppm TDS threshold instead of the federally required USDW threshold of 10,000 ppm TDS.

Ohio issued updated Oil and Gas Well Construction Rules on October 28, 2011, that require surface casing and intermediate casing to be set to protect the deepest underground source of drinking water (USDW); Ohio's rules are based on the 10,000 ppm federal TDS threshold.[19]

Recommendation No. 3: The SGEIS and the NYCRR should require wells to be constructed to protect Underground Sources of Drinking Water (USDWs), as defined by the Safe Drinking Water Act.

NYS' use of a 1,000 ppm TDS cut-off instead of the USDW threshold of 10,000 ppm TSD is a two-fold problem: First, the RDSGEIS states that surface casing ("water protection piping") setting depths will be 925' if no other data is available.[20] The 925' surface casing setting depth is based on an 850' base plus 75'[21], where NYSDEC has assumed that TDS will exceed 1,000 ppm at deeper than 850'. The 925' casing setting depth does not take into account the fact that drinking water, under the SDWA definition of a USDW, could exist at depths below 850'. Therefore the RDSGEIS has not provided scientific justification for the default 925' casing setting depth, nor has it explained how such a proposal comports with federal law.

Second, the entire RDSGEIS is premised on the conclusion that a HVHF well initiated at a depth of 2,000' would be safe, because NYSDEC assumes that NYS does not have any drinking water resources deeper than 850' deep. However, the RDSGEIS does not indicate that any examination of the depth of 10,000 ppm TDS water or of the availability of drinking water resources below 850' has been or will be conducted and, therefore, cannot support its 850' assumption.

Additionally, the RDSGEIS states that potable water is found deeper than 850'. Therefore, the 2,000' threshold depth for initiating a HVHF under this SGEIS requires re-evaluation. And as explained in Chapter 10 of this report, HCLLC is recommending that initial drilling and completions occur below 4,000', while site-specific data is gathered in NYS to justify safe drilling at shallower depths.

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[18] 2011 NYSDEC, RDSGEIS, Page 2-23.

[19] Proposed Ohio Oil and Gas Well Construction Rules, October 28, 2011, currently under public review and comment.

[20] 2011 NYSDEC, RDSGEIS, Page 7-50.

[21] See Chapter 6 of this report, where a 100' buffer is recommended, instead of 75'.

Recommendation No. 4: The SGEIS should re-examine the 925' casing default setting and the 2000' HVHF cut-off, and justify how these proposed thresholds will protect USDW sources. Protecting to a 10,000 ppm TDS standard will likely increase both depths.

The SGEIS should include data on the location of Underground Sources of Drinking Water (USDWs), as defined by the Safe Drinking Water Act, across NYS. The SGEIS should include USDW maps for all areas that will be affected by the proposed scope of the SGEIS. This data will be an important tool for industry and the public alike to ensure USDWs are protected.

NYCRR Proposed Revisions: Well construction regulations at 6 NYCRR § 550-559 instruct operators to construct oil and gas wells in a manner that protects potable fresh water, i.e., only water containing less than 250 ppm of sodium chloride or less than 1,000 ppm of TDS. 6 NYCRR § 550.3 (ai).

The NYCRR does not protect, under its definition of "potable fresh water," water resources with less than 10,000 ppm TDS but greater than 1,000 ppm TDS, which could qualify as USDWs under the Safe Drinking Water Act. See 40 CFR §§ 144.3, 146.4.

Regulations at 6 NYCRR § 554.1 require operators to prevent pollution to "surface or ground fresh water"; however, this term is not defined by the NYCRR, so it is unclear what additional groundwater beyond "potable fresh water" would be protected or how.

Recommendation No. 5: The NYCRR should be consistent with federal law [Underground Sources of Drinking Water (USDWs)] or NYSDEC should propose more protective standards for NYS if needed to protect NYS' future water supply needs, if the federal threshold is found insufficient.

5. Conductor Casing

Background: In 2009, HCLLC recommended the NYCRR and the SGEIS be revised to include conductor casing construction standards. While a number of changes were made to improve conduct casing requirements in the RDSGEIS, the proposed revisions to the NYCRR do not include conductor casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on conductor casing and the technical basis for HCLCC's recommendations.

Conductor casing construction standards are only partially addressed in the 2011 RDSGEIS, under Appendix 10, Proposed Supplementary Permit Conditions for HVHF, and Appendix 9, Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers.

2011 RDSGEIS: The 2011 RDSGEIS Appendix 9, Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers, includes a conductor casing requirement that limits drilling fluid types. The requirement excludes synthetic muds and oil based muds from being used while drilling shallow sections of the wellbore.

> *Any hole drilled for conductor or surface casing (i.e., "water string") must be drilled on air, fresh water, or fresh water mud. For any holes drilled with mud, techniques for removal of filter cake (e.g., spacers, additional cement, appropriate flow regimes) must be considered when designing any primary cement job on conductor and surface casing.*

Excluding synthetic muds and oil based muds from being used while drilling shallow sections of the wellbore is a best practice.

Appendix 9 also includes procedures for ensuring conductor pipe is cemented from top to bottom, and firmly affixed in a central location in the wellbore, with a continuous, equally thick layer of cement around the pipe.

> *If conductor pipe is used, it must be run in a drilled hole and it must be cemented back to surface by circulation down the inside of the pipe and up the annulus, or installed by another procedure approved by this office. Lost circulation materials must be added to the cement to ensure satisfactory results.*
>
> *Additionally, at least two centralizers must be run with one each at the shoe and at the middle of the string. In the event that cement circulation is not achieved, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. In lieu of or in combination with such grouting or squeezing from the surface, this office may require perforation of the conductor casing and squeeze cementing of perforations. This office must be notified _______ hours prior to cementing operations and cementing cannot commence until a state inspector is present.*

The 2011 RDSGEIS Appendix 10, Proposed Supplementary Permit Conditions for HVHF, includes a conductor casing condition that states:

> *When drive pipe (conductor casing) is left in the ground, a pad of cement shall be placed around the well bore to block the downward migration of surface pollutants. The pad shall be three feet square or, if circular, three feet in diameter and shall be crowned up to the drive pipe (conductor casing), unless otherwise approved by the Department.*

NYCRR Proposed Revisions: In summary, NYSDEC has included important conductor casing construction guidelines in the 2011 RDSGEIS for wells drilled in primary and principal aquifer areas and HVHF wells, but has not proposed to codify those changes in the NYCRR.

The conductor casing construction guidelines listed in the 2011 RDSGEIS should apply to all wells in NYS, and should not just be limited to wells drilled in primary and principal aquifer areas and HVHF wells. These are best practices for construction of all oil and gas wells.

NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide solid structural anchorage. Also, the regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

Recommendation No. 6: Conductor casing requirements listed in the Proposed Supplementary Permit Conditions for HVHF and Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers should be codified in the NYCRR and should apply to all wells drilled in NYS, not just HVHF wells. Additionally, NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide a solid structural anchorage. Regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

6. Surface Casing

Background: In 2009, HCLLC recommended the NYCRR be revised to include additional surface casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on surface casing the technical basis for HCLCC's recommendations.

Surface casing plays a very important role in protecting groundwater aquifers, providing the structure to support blowout prevention equipment, and providing a conduit for drilling fluids while drilling the next section of the well.

The drilling engineer determines the depth of surface casing installation with these key factors in mind: surface casing should stop above any significant pressure or hydrocarbon zone, ensuring the blowout preventer can be installed prior to drilling into a pressure or hydrocarbon zone, and surface casing should provide a protective barrier to prevent hydrocarbons from contaminating aquifers when the well is drilled deeper (below the surface casing) into hydrocarbon bearing zones.

Stray gas may impact ground water and surface water from poor well construction practices. Properly constructed and operated oil and gas wells are critical to mitigating stray gas and thereby protecting water supplies and public safety. If a well is not properly cased and cemented, natural gas in subsurface formations may migrate from the wellbore through bedrock and soil. Stray gas may adversely affect water supplies, accumulate in or adjacent to structures such as residences and water wells, and has the potential to cause a fire or explosion.

Instances of improperly constructed wellbores leading to the contamination of drinking water with natural gas are well documented in Pennsylvania.[22] Gas well leaks from improperly constructed gas wells have resulted in contamination of the Susquehanna River and adjacent private water supply wells.[23] A 2011 Duke University study covering Pennsylvania and New York found methane contamination of drinking water associated with shale-gas extraction. Duke University found that methane concentrations were 17 times higher, on average, in drinking water wells in active drilling and extraction areas than in wells in nonactive areas.[24]

The 2011 RDSGEIS and the proposed revisions to the NYCRR include important improvements for surface casing. Overall, NYS' surface casing requirements are fairly robust when the NYCRR, guidance documents, and standard stipulations are combined. NYSDEC proposed a number of substantial improvements in the surface casing requirements, most notably improved cement quality, casing quality, and installation techniques.

This chapter reviews the proposed changes and supports the improvements that have been made. It also makes suggestions for improved regulatory clarity and adds a few additional recommendations for NYSDEC to consider in completing its surface casing regulatory program revision.

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[22] *See, e.g.*, DEP Reaches Agreement with Cabot to Prevent Gas Migration, Restore Water Supplies in Dimock Township, Agreement Requires DEP Approval for Well Casing, Cementing, November 4, 2009, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418& typeid=1.

[23] *See, e.g.*, DEP Monitors Stray Gas Remediation in Bradford County Requires Chesapeake to Eliminate Gas Migration, Chesapeake Commits to Evaluate, Remediate All PA Wells to Conform with Improved Casing Regulations, September 17, 2010, available at http://www.portal.state.pa.us/portal/server.pt/ community/newsroom/14287?id=14274&typeid=1.

[24] Osborn, S.G., A. Vengosh, N.R. Warner, R.B. Jackson, 2011 Methane contamination of drinking water accompanying gas- well drilling and hydraulic fracturing, Proceedings of the National Academy of Sciences, U.S.A.; DOI: 10.1073/pnas.1100682108, Page 2.

The main recommendation in this section is to streamline surface casing regulations by amending the NYCRR to include requirements contained in the 2011 RDSGEIS and standard stipulations. As proposed, NYSDEC has included a number of surface casing requirements in the 2011 RDSGEIS at Appendices 8, 9, and 10 (Proposed Permit Conditions). NYSDEC also included some, but not all, of these requirements in the NYCRR. Unfortunately, there are a number of inconsistencies between the permit conditions and the NYCRR that create uncertainty about what will be required.

Additionally, there are a number of new surface casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. These requirements should be included in the NYCRR Part 554 (drilling practices for all oil and gas wells), and not just contained in NYCRR Part 560 (drilling practices for HVHF wells).

In 2009, HCLLC recommended that improved casing and cementing practices be codified in the NYCRR, rather than through a combined patchwork of permit conditions and regulations. HCLLC's concern was that the proposed requirements, in a number of cases, were inconsistent with existing regulations, and could be more efficiently consolidated into a single, more concise set of regulations.

NYSDEC's consultant Alpha Geoscience disagreed. Alpha Geoscience concluded that it would be more logical to use a patchwork of regulations, add a long list of conditions to each permit, and forgo regulatory revision.

> *Harvey Consulting suggests that NYSDEC revise the NYS oil and gas regulations to specifically address new casing and cementing practices and fresh water aquifer supplementary permit conditions. The purpose of the SGEIS, however, is not to revise regulations. The purpose of the Proposed Supplementary Permit Conditions for shale gas activities is to customize the existing regulations and guideline framework to fit new and changing industry, relieving the need for frequent regulatory changes. Permit conditions must be met by the party seeking a permit for a proposed action, so whether or not the permit conditions are included in the New York State regulations is irrelevant.*[25]

HCLLC disagrees with Alpha Geoscience's recommendation. It is relevant whether new requirements are found in regulation or a permit condition. Foremost, revising the outdated NYCRR provides simplicity and clarity for industry and the public. It provides a concise set of co-located rules. Conversely, layering a complex patchwork of permit conditions on outdated NYCRR creates confusion, inconsistency, and enforcement challenges. Furthermore, permit conditions can be revised and modified by staff, without public review, and can be applied in a more discretionary manner. Regulations are not discretionary, and are not subject to modification without a formal public review process. Therefore, HCLLC recommends that requirements that apply to all wells be codified in the NYCRR, and permit conditions be reserved for site-specific, project-specific requirements. This will improve clarity and certainty for industry and the public alike, and will afford NYSDEC the opportunity to apply site-specific, project specific requirements to address unique project issues.

NYSDEC evidently agreed with HCLLC's recommendation to revise the NYCRR by proposing revisions for public review; however, the regulations have only been partially updated to include new surface casing best practices. Therefore inconsistency remains, and needs resolution.

Recommendation No. 7: The surface casing and cementing requirements should be consistent throughout the SGEIS text and with the NYCRR.

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[25] Alpha Geoscience, Review of the DSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA on January 20, 2011, Page 13.

An analysis of the proposed RDSGEIS conditions found in Appendices 8, 9, and 10 is provided below and compared to the proposed NYCRR revisions. Recommendations are made to improve consistency in the documents and highlight additional best practices that should be considered.

The 2011 RDSGEIS: It appears that NYSDEC's intent is to require that all wells meet the minimum standards found at Appendix 8 (NYSDEC's Casing and Cementing Practices), and then layer on additional requirements for wells drilled in primary and principal aquifers (Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers). It appears that a third layer of requirements will be applied to wells that undergo HVHF stimulation treatments (Appendix 10 Proposed Supplementary Permit Conditions for HVHF).

Therefore, it is assumed that a shale gas well that is drilled in a primary and principal aquifer, and will undergo a HVHF stimulation treatment must meet all the conditions found in Appendices 8, 9, and 10; however, this would not be possible because the permit conditions are discordant. An evaluation of these layered conditions reveals inconsistencies, as explained in the text and summary table below.

The 2011 RDSGEIS Appendix 8: Appendix 8 Casing and Cementing Practices requires: surface casing be set at least 75' below freshwater or at least 75' into bedrock, whichever is deeper; surface casing be set before hydrocarbons are encountered; new pipe be used (or used pipe if tested); and centralizers and cement baskets be used.

> 2. *Surface casing shall extend at least 75 feet beyond the deepest fresh water zone encountered or 75 feet into competent rock (bedrock), whichever is deeper, unless otherwise approved by the Department. However, the surface pipe must be set deeply enough to allow the BOP [blow-out preventer] stack to contain any formation pressures that may be encountered before the next casing is run.*
>
> 3. *Surface casing shall not extend into zones known to contain measurable quantities of shallow gas. In the event that such a zone is encountered before the fresh water is cased off, the operator shall notify the Department and, with the Department's approval, take whatever actions are necessary to protect the fresh water zone(s).*
>
> 4. *All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi), unless otherwise approved. Used casing may be approved for use, but must be pressure tested before drilling out the casing shoe or, if there is no casing shoe, before drilling out the cement in the bottom joint of casing. If plain end pipe is welded together for use, it too must be pressure tested. The minimum pressure for testing used casing or casing joined together by welding, shall be determined by the Department at the time of permit application. The appropriate Regional Mineral Resources office staff will be notified six hours prior to making the test. The results will be entered on the drilling log.*
>
> 5. *Centralizers shall be spaced at least one per every 120 feet; a minimum of two centralizers shall be run on surface casing. Cement baskets shall be installed appropriately above major lost circulation zones.*[26]

Appendix 8 requires the use of: 25% excess cement, spacer fluids between the drilling muds and cement, and lost circulation additives. Appendix 8 also requires that gas flows or lost circulation be addressed and

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[26] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 1.

the hole be conditioned before cementing. NYSDEC reserves the right to require a cement evaluation log if cement does not return to the surface.

> 6. *Prior to cementing any casing strings, all gas flows shall be killed and the operator shall attempt to establish circulation by pumping the calculated volume necessary to circulate. If the hole is dry, the calculated volume would include the pipe volume and 125% of the annular volume. Circulation is deemed to have been established once fluid reaches the surface. A flush, spacer or extra cement shall be used to separate the cement from the bore hole spacer or extra cement shall be used to separate the cement from the bore hole fluids to prevent dilution. If cement returns are not present at the surface, the operator may be required to run a log to determine the top of the cement.*
>
> 7. *The pump and plug method shall be used to cement surface casing, unless approved otherwise by the Department. The amount of cement will be determined on a site-specific basis and a minimum of 25% excess cement shall be used, with appropriate lost circulation materials, unless other amounts of excesses are approved or specified by the Department.*[27]

Appendix 8 requires: the water used in the cement be tested for pH and temperature; the cement be prepared according to manufacturer specifications; and the cement be allowed to harden to a compressive strength of at least 500 psi before being disturbed.

> 8. *The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing ticket.*
>
> 9. *The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement.*
>
> 10. *After the cement is placed and the cementing equipment is disconnected, the operator shall wait until the cement achieves a calculated compressive strength of 500 psi before the casing is disturbed in any way. The waiting-on-cement (WOC) time shall be recorded on the drilling log.*[28]

The 2011 RDSGEIS Appendix 9: Appendix 9, Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers, applies to wells drilled in primary and principal aquifer zones. Appendix 9 includes conditions that require: surface casing to be set at least 100' below the deepest freshwater zone and at least 100' into bedrock; the annulus be at least 1-1/4" wide to optimize cement placement and cement sheath width: the entire annulus be cemented, using at least 50% excess cement; the cement design include additives to control lost circulation; centralizers be run at least every 120'; new pipe be used (or reconditioned tested pipe); and NYSDEC be notified and present for cementing operations.

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[27] 2011 NYSDEC, RDSGEIS, Appendix 8, Pages 1-2.

[28] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 2.

> *A surface casing string must be set at least 100' below the deepest fresh water zone and at least 100' into bedrock. If shallow gas is known to exist or is anticipated in this bedrock interval, the casing setting depth may be adjusted based on site-specific conditions provided it is approved by this office. There must be at least a 2½" difference between the diameters of the hole and the casing (excluding couplings) or the clearance specified in the Department's Casing and Cementing Practices, whichever is greater. Cement must be circulated back to the surface with a minimum calculated 50% excess. Lost circulation materials must be added to the cement to ensure satisfactory results. Additionally, cement baskets and centralizers must be run at appropriate intervals with centralizers run at least every 120'. Pipe must be either new API graded pipe with a minimum internal yield pressure of 1,800 psi or reconditioned pipe that has been tested internally to a minimum of 2,700 psi. If reconditioned pipe is used, an affidavit that the pipe has been tested must be submitted to this office before the pipe is run. This office must be notified _______ hours prior to cementing operations and cementing cannot commence until a state inspector is present.*[29]

Appendix 9 requires the surface hole be drilled using compressed air or Water-Based Muds (WBM), meaning no Synthetic-Based Muds (SBM) or Oil-Based Muds (OBM) may be used.

> *Any hole drilled for conductor or surface casing (i.e., "water string") must be drilled on air, fresh water, or fresh water mud. For any holes drilled with mud, techniques for removal of filter cake (e.g., spacers, additional cement, appropriate flow regimes) must be considered when designing any primary cement job on conductor and surface casing.*[30]

As found in Appendix 9, freshwater zone depths and the potential for shallow gas hazards must be estimated and documented in drilling applications; actual data must be collected during drilling to identify any freshwater zones and shallow gas hazards that require additional NYSDEC review and approval.

> *If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. The permittee must immediately inform this office of the occurrence of any fresh water or shallow gas zones not noted on the permittee's drilling application and prognosis. This office may require changes to the casing and cementing plan in response to unexpected occurrences of fresh water or shallow gas, and may also require the immediate, temporary cessation of operations while such alterations are developed by the permittee and evaluated by the Department for approval.* [31]

Appendix 9 requires cement fill the surface casing annulus, and if cement placement in the annulus is not initially successful, additional cement must be pumped into the annulus until it is filled with cement.

> *In the event that cement circulation is not achieved on any surface casing cement job, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. This office must be notified _______ hours prior to cementing operations and cementing cannot commence until a state inspector is present. In lieu of or in*

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[29] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 1.

[30] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 1.

[31] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

> *combination with such grouting or squeezing from the surface, this office may require perforation of the surface casing and squeeze cementing of perforations.* [32]

In Appendix 9, NYSDEC reserves the right to require the operator to run a cement bond log; however, it does not require one to verify the integrity of all surface casing cement jobs.

> *This office may also require that a cement bond log and/or other logs be run for evaluation purposes. In addition, drilling out of and below surface casing cannot commence if there is any evidence or indication of flow behind the surface casing until remedial action has occurred. Alternative remedial actions from those described above may be approved by this office on a case-by-case basis provided site-specific conditions form the basis for such proposals.*[33]

The 2011 RDSGEIS Appendix 10: Appendix 10 contains Proposed Supplementary Permit Conditions for HVHF operations, including additional surface casing requirements. The 2011 RDSGEIS does not explain why these additional pollution prevention and quality control/quality assurance (QC/QA) requirements do not apply to all oil and gas wells in NYS.

The 2011 RDSGEIS Appendix 10 requires new casing and the use of American Petroleum Institute (API) standards for: casing thread compounds, centralizer placement, and cement composition (including the requirement to use gas-blocking additives).

> *31) With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> > *a) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;*
> >
> > *b) Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);*
> >
> > *c) At least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);*
> >
> > *d) Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive…*[34]

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[32] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

[33] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

[34] 2011 NYSDEC, RDSGEIS, Appendix 10, Pages 5-6.

Appendix 10 also requires: drilling mud be circulated and conditioned prior to cementing; spacer fluid be used to separate the drilling mud from the cement, to avoid drilling mud contamination; and cement be installed using methods that inhibit voids in the cement.

> *e) Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond… The surface casing must be run and cemented immediately after the hole has been adequately circulated and conditioned.*
>
> *f) A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *g) The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus…*[35]

Appendix 10 establishes a specific period of time for the cement to harden, and a compressive strength standard that the cement must achieve before drilling continues deeper in the hole. This avoids disturbing the cement until it has completely set.

> *h) After the cement is pumped, the operator must wait on cement (WOC):*
>
> *1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and*
>
> *2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.*[36]

Appendix 10 requires records be kept for a period of 5 years and be available to NYSDEC upon request.

> *A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.*[37]

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[35] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[36] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[37] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

Appendix 10 reserves the right for NYSDEC to require additional casing strings to be set in the well if the surface casing fails to adequately protect water resources or poses a safety hazard.

> *38) The installation of an additional cemented casing string or strings in the well as deemed necessary by the Department for environmental and/or public safety reasons may be required at any time.*[38]

Appendix 10 requires NYSDEC's Casing and Cementing Practices be followed. NYSDEC's Casing and Cementing Practices are included in the 2011 RDSGEIS as Appendix 8. Yet, a number of the Casing and Cementing Practices found in Appendix 8 conflict with the new requirements in Appendix 10 for wells subject to HVHF.

The RDSGEIS does not provide a rationale or basis for the use of a 75' surface casing setting depth for some wells and a 100' surface casing setting depth for others. NYSDEC determined that a 100' setting depth is best practice for groundwater protection in areas of primary and principal aquifers, but does not explain why a 100' standard would not be best practice for all wells, or at least wells that undergo HVHF.

An analysis of the surface casing permit condition requirements and inconsistencies is provided in table format as Appendix A. Recommendations are listed in the table.

NYCRR Proposed Revisions: A number of the requirements listed in the RDSGEIS Appendices 8, 9, and 10 are not codified in the NYCRR, or conflict with the proposed changes to the NYCRR.

Listed below is an analysis of the proposed NYCRR revisions for surface casing and cementing. Specific recommendations for improving surface casing design, installation, and quality control/ quality assurance requirements are also included.

Surface Casing Setting Depth: 6 NYCRR § 554.1(d) requires that:

> *surface casing shall be run in all wells to extend below the deepest potable fresh water level.*

Neither the 75' nor the 100' setting depths below the deepest protected water zone (described in the RDSGEIS) are specified in regulation. Furthermore, this regulation only protects "potable fresh water." As explained in Chapter 4 of this report, NYSDEC should consider its long-term water needs.

Recommendation No. 8: 6 NYCRR § 554.1(d) should be revised to require the surface casing setting depth to be at least 100' below protected groundwater for all wells, or NYSDEC should provide a technical justification for reducing the setting depth to 75' for some wells.

Surface Casing Definition: 6 NYCRR § 550.3(au) reads:

> *surface casing shall mean casing extending from the surface through the potable fresh water zone.*

This definition requires surface casing be set through only the protected water zone, and does not require the casing be set deeper. This definition, as written, does not include the important requirement for the casing to be set at least 100' below protected groundwater and be cemented in place.

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[38] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 8.

Recommendation No. 9: 6 NYCRR § 550.3(au) should be revised to read: surface casing shall mean casing installed and cemented from the surface, through protected groundwater, to a point at least 100' below the deepest protected groundwater. Protected groundwater should be defined in a way that meets NYS' long-term water needs.

Rotary Tool Drilling Practices: 6 NYCRR § 554.4 should be revised to be consistent with the proposed RDSGEIS surface casing conditions, and remove reference errors. 6 NYCRR § 554.4(a) provides the operator with a choice of installing surface casing in accordance with 6 NYCRR § 554.1(b) (which does not provide specific instruction to the operator) or by cementing the production casing from below the deepest potable fresh water level to the surface (which does not provide specific instruction to the operator).

> *§554.4 Rotary tool drilling practices*
>
> *(a) On all wells where rotary tools are employed, and the subsurface formations and pressures to be encountered have been reasonably well established by prior drilling experience, the operator shall have the option of either running surface casing as provided in section 554.1(b) of this Part or of cementing the production casing from below the deepest potable fresh water level to the surface. In areas where the subsurface formations and pressures to be encountered are unknown or uncertain, surface casing shall be run as provided in section 554.1(b) of this Part.*

6 NYCRR § 554.1(b) does not provide any specific direction on the type or amount of surface casing to be installed; it just says:

> *Pollution of the land and/or of surface or ground freshwater resulting from exploration or drilling is prohibited.*

Nor does 6 NYCRR § 554.4(a) provide any specific direction on the type or amount of surface casing to be installed, other than to say that it must be set below *the deepest potable fresh water level,* but the minimum depth that the casing must be set below the deepest freshwater located is not specified.

Recommendation No. 10: 6 NYCRR § 554.1(d) and 6 NYCRR § 554.4(a) should be combined or at least be consistent to require the surface casing setting depth to be at least 100' below protected groundwater.

NYCRR does not provide the operator with instructions on how to determine protected groundwater depth. The RDSGEIS explains that the depth of potable freshwater in NYS is typically 850' deep, but this depth will vary across the state. Using the 850' benchmark may not sufficiently protect all groundwater covered under the Safe Drinking Water Act. NYCRR should be revised to provide instructions to the operator on how to estimate protected water depth in drilling applications and well construction designs. NYCRR should require that depth be confirmed before setting surface casing.

Recommendation No. 11: NYCRR should require the protected groundwater depth be estimated in the drilling application to aid in well construction design. NYCRR should require the protected water depth be verified with a resistivity log or other sampling method during drilling. If the protected water depth is deeper than estimated, an additional string of intermediate casing should be required. Additionally, the NYCRR needs to be clear on whether its purpose is to protect potable freshwater only, or a broader definition of protected groundwater, which would result in surface casing being set deeper.

6 NYCRR § 554.4(b) correctly requires: cement be placed by the pump and plug or displacement methods; cement be placed in the entire annulus; and a wait on cement time before further drilling. However, 6 NYCRR § 554.4(b) does not include the best practices listed in the permit conditions (Appendices 8 and 9). Additionally, many of the best practices included in Appendix 10 for HVHF wells should be included in regulations for all oil and gas wells.

Recommendation No. 12: 6 NYCRR § 554.4(b) should be revised to be consistent with the proposed Appendices 8 and 9 permit conditions. Also, the best practices listed in Appendix 10 for HVHF should apply to all oil and gas wells and be included in 6 NYCRR § 554.4(b).

Cable Tool Drilling Practices: 6 NYCRR § 554.3 includes requirements for cable tool drilling.

Recommendation No. 13: NYSDEC should verify whether cable tool drilling is still anticipated in NYS. If cable tool drilling is still allowed, 6 NYCRR § 554.3 should be revised to require these wells be constructed to the same quality standards as wells drilled with rotary drilling equipment.

Newly proposed surface casing regulations for HVHF wells at 6 NYCRR § 560.6(c)(10) require casing be run in accordance with the "department's casing and cementing requirements." Presumably this refers to the requirements set out in the RDSGEIS at Appendix 8, but this needs to be clarified. All surface casing requirements for HVHF operations should be codified in NYCRR.

A number of new requirements proposed at 6 NYCRR § 560.6(c)(10) should be applied to all wells in NYS, not just those that will undergo a HVHF treatment. 6 NYCRR § 560.6(c)(10) proposes to add these requirements only to HVHF wells.

> *(10) With respect to all surface, intermediate and production casing run in the well, and in addition to the department's casing and cementing requirements and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *(i) all casings must be new and conform to industry standards specified in the permit to drill;*
>
> *(ii) welded connections are prohibited;*
>
> *(iii) casing thread compound and its use must conform to industry standards specified in the permit to drill;*
>
> *(iv) in addition to centralizers otherwise required by the department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed (except production casing) and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill;*
>
> *(v) cement must conform to industry standards specified in the permit to drill and the cement slurry must be prepared to minimize its free water content in accordance with the industry standards and specifications, and contain a gas-block additive;*
>
> *(vi) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *(vii) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *(viii) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;*

> *(ix) after the cement is pumped, the operator must wait on cement (WOC) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer. The operator may request a waiver from the department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 pounds per square inch gage; and*
>
> *(x) a copy of the cement job log for any cemented casing string in the well must be available to the department at the well site during drilling operations, and thereafter available to the department upon request. The operator must provide such log to the department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title. If the well is located on a multi-well pad, all cementing job logs must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title.*
>
> *(11) The surface casing must be run and cemented as soon as practicable after the hole has been adequately circulated and conditioned.*

The zone of critical cement (e.g. cement placed at bottom of surface casing, typically bottom 300-500') should achieve a 72-hour compressive strength standard of 1,200 psi and the free water separation for the cement should be no more than 6 ml per 250 ml of cement. For example, this requirement is found in the Pennsylvania surface casing code (25 PaCode § 78.85 (b))

An analysis of the proposed Appendices 8, 9, and 10 permit condition requirements and inconsistencies, with comparisons to NYCRR, is provided in table format as Appendix A. Recommendations for improving requirements and addressing inconsistencies are listed in the table.

Recommendation No. 14: The recommendations listed in the Surface Casing Analysis Table (Appendix A to this report) should be considered for the SGEIS and the NYCRR, including:

Surface Casing Setting Depth: NYSDEC should consider a 100' protection for all oil and gas wells. Additionally, NYSDEC needs to clarify whether this setting depth is intended to protect potable freshwater only, or include a broader definition of protected groundwater, which would result in deeper surface casing depths. This requirement should apply to all NYS wells.

Protected Water Depth Verification: The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method. If the actual protected water depth extends beyond the estimated protected water depth, an additional string of intermediate casing should be required. This requirement should apply to all NYS wells.

Cement Sheath Width: A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells.

Amount of Cement in Annulus: The surface casing annulus should be completely filled with cement; this should be clearly specified. There should be no void space in the annulus. This requirement should apply to all NYS wells.

Shallow Gas Hazards: If a shallow gas hazard is encountered, surface hole drilling must stop, and surface casing must be set and cemented, before drilling deeper into hydrocarbon resources. All oil and gas well designs and applications should plan for shallow gas hazards. Any shallow gas hazards encountered while drilling should be recorded. This requirement should apply to all NYS wells.

Excess Cement Requirements: 25% excess cement is standard practice, unless a caliper log is run to more accurately assess hole shape and required cement volume. This requirement should apply to all NYS wells.

Cement Type: The cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) is best practice. These practices should apply to all wells, not just HVHF wells.

Cement Mix Water Temperature and pH Monitoring: Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. This requirement should apply to all NYS wells, not just HVHF wells.

Lost Circulation Control: Lost circulation control is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Spacer Fluids: The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Hole Conditioning: Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Cement Installation and Pump Rate: The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice; this requirement should apply to all oil and gas wells, not just HVHF wells.

Rotation and Reciprocation: Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.

Centralizers: The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API RP 10D-2 (July 2010). This requirement should apply to all NYS wells, not just HVHF wells.

Casing Quality: New casing should be used in all wells. Once installed, surface casing remains in the well for the life of the well, and typically remains in place when the well is plugged and abandoned. It is important that the surface casing piping string (known as "the water protection piping string") is of high quality to maximize the corrosion allowance and life-cycle of the piping. The installation of older, used, thinner pipe, with less remaining corrosion allowance, may be a temporary solution, but not a long-term investment in groundwater protection. Used piping may pass an initial pressure test; however, it will not last as long as new piping, and will not be as protective of water resources in the long-term.

Casing Thread Compound: The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.

Drilling Mud: The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all NYS wells.

Cement Setting Time: Best practice is to have surface casing strings stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells.

NYS Inspectors: Best practice is to have a state inspector on site during cementing operations, to verify surface casing cement is correctly installed, before attaching the blowout preventer and drilling deeper into the formation. This requirement should apply to all NYS wells.

Cement QA/QC: Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only QA/QC check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids, in the cement column. Circulating cement to the surface also may not identify poor cement to casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and temperature survey.

Formation Integrity Test: It is best practice to complete a formation integrity test to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. The test should be conducted after drilling out of the casing shoe, into at least 20 feet, but not more than 50 feet of new formation. The test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill. This requirement should apply to all NYS wells.

BOP Installation: The Appendix 8 requirement is best practice. Additionally, the surface casing should be pressure tested to ensure it can hold the required working pressure of the BOP. This requirement should apply to all NYS wells.

Record Keeping: Best practice is to keep permanent records for each well, even after the well is plugged and abandoned (P&A'd). This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Additional Casing or Repair: NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.

Pressure Testing: Casing and piping should be pressure tested.[39]

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[39] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, p. 109.

7. Intermediate Casing

Background: In 2009, HCLLC recommended the NYCRR be revised to include additional intermediate casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on intermediate casing and the technical basis for HCLCC's recommendations.

Intermediate casing provides a transition from the surface casing to the production casing. This casing may be required to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. A drilling engineer may set hundreds or thousands of feet of intermediate casing to: isolate unstable hole sections (to prevent collapse); isolate high or low pressure zones; isolate geologic "thief" zones prone to robbing mud from the well bore (lost circulation); put gas or saltwater zones behind pipe before drilling into the production zone; or provide additional wellbore structure.

Intermediate casing is set prior to drilling through the hydrocarbon bearing zone, and may be cemented behind the entire casing string from the top of the well to the bottom of the casing shoe, depending on intermediate casing depth. Intermediate casing provides an additional protective barrier across to prevent contamination of protected groundwater zones.

The 2011 RDSGEIS and the proposed revisions to the NYCRR include important improvements for intermediate casing. Overall, NYSDEC's intermediate casing requirements for HVHF wells are robust. NYSDEC proposed a number of substantial improvements in the intermediate casing requirements. The most notable improvement to the RDSGEIS mitigation and the NYCRR is that intermediate casing will be required in wells that undergo HVHF treatments to provide an additional protective layer of casing and cementing in the well. The RDSGEIS and the NYCRR requires intermediate casing be fully cemented, and the cement placement and bond be verified by well logging tools.

However, the remaining area for improvement in the NYCRR is to establish intermediate casing and cementing standards for all wells that will not undergo HVHF treatment, but will require the installation of intermediate casing. The proposed NYCRR is silent on the intermediate casing and cementing standards for wells that will not undergo HVHF treatment. NYS should provide instruction on intermediate casing standards for all wells that require it.

There are a number of new intermediate casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. Those requirements should be included in the NYCRR Part 554 (drilling practices for all oil and gas wells), and not just covered in the new NYCRR Part 560 (drilling practices for HVHF wells).

Recommendation No. 15: The NYCRR should be revised to establish intermediate casing and cementing standards for all wells at NYCRR Part 554 (drilling practices for all oil and gas wells).

This section reviews the proposed changes to intermediate casing requirements and supports the improvements that have been made. It also makes suggestions for improved regulatory clarity and offers recommendations for regulatory program revisions.

An analysis of the proposed RDSGEIS conditions found in Appendices 8, 9, and 10 is provided below, and compared to the proposed NYCRR. Recommendations are made to improve consistency in the documents and highlight additional best practices that should be considered.

The 2011 RDSGEIS: The 2011 RDSGEIS recommends that intermediate casing be required in wells that undergo HVHF treatments, to provide an additional protective layer of casing and cementing in the well. The 2011 RDSGEIS recommends that intermediate casing be fully cemented, and the cement placement and bond be verified by well logging tools. This is an excellent recommendation. The 2011 RDSGEIS states:

> *Current casing and cementing practices attached as conditions to all oil and gas well drilling permits state that intermediate casing string(s) and cementing requirements will be reviewed and approved by the Department on an individual well basis. The Department proposes to require, via permit condition and/or regulation, that for high-volume hydraulic fracturing the installation of intermediate casing in all wells covered under the SGEIS would be required. However, the Department may grant an exception to the intermediate casing requirement when technically justified [emphasis added].*[40]
>
> *The current dSGEIS proposes to require in most cases fully cemented intermediate casing, with the setting depths of both surface and intermediate casing determined by site-specific conditions*[41]
>
> *Requirement for fully cemented production casing or intermediate casing (if used), with the cement bond evaluated by use of a cement bond logging tool; and*[42]
>
> *Fully cemented intermediate casing would be required unless supporting site-specific documentation to waive the requirement is presented. This directly addresses gas migration concerns by providing additional barriers (i.e., steel casing, cement) between aquifers and shallow gas-bearing zones.*[43]
>
> *Depending on the depth of the well and local geologic conditions, there may be one or more intermediate casing string.*[44]
>
> *Use of centralizers to ensure that the cement sheath surrounds the casing strings, including the first joint of surface and intermediate casings.*[45]

The 2011 RDSGEIS proposes a waiver process to exclude intermediate casing under some circumstances:

> *A request to waive the intermediate casing requirement would need to be made in writing with supporting documentation showing that environmental protection and public safety would not be compromised by omission of the intermediate string. An example of circumstances that may warrant consideration of the omission of the intermediate string and granting of the waiver could include: 1) deep set surface casing, 2) relatively shallow total depth of well and 3) absence of fluid and gas in the section between the surface casing and target interval. Such intermediate casing waiver request may also be supported by the inclusion of information on the subsurface and geologic conditions from offsetting wells, if available.*[46]

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[40] 2011 NYSDEC, RDSGEIS, Page 7-52.

[41] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 25.

[42] 2011 NYSDEC, RDSGEIS, Page 1-12.

[43] 2011 NYSDEC, RDSGEIS, Page 1-12.

[44] 2011 NYSDEC, RDSGEIS, Page 5-92.

[45] 2011 NYSDEC, RDSGEIS, Page 7-42.

[46] 2011 NYSDEC, RDSGEIS, Page 7-52.

The proposed waiver process conflicts with the stated intent of requiring intermediate casing for HVHF wells. The RDSGEIS states that the reason intermediate casing is required for a HVHF well is because it:

> *...directly addresses gas migration concerns by providing additional barriers (i.e., steel casing, cement) between aquifers and shallow gas-bearing zones.*[47]

As proposed, NYSDEC would consider a wavier if the surface casing is set "deep" or if the well is "shallow"; however, these depths are not defined. The RDSGEIS does not explain how the use of deep-set surface casing or shallow surface casing provides the same protection to aquifers as installing a second string of intermediate casing and cement.

Additionally, as proposed, NYSDEC would consider a wavier if there is an "*absence of fluid and gas in the section between the surface casing and target interval.*[48]" This requirement is incongruous, because there will always be some type of fluid in the formation between the surface casing and target interval; therefore, the conditions for this waiver to occur would never be realized.

Recommendation No. 16: The SGEIS and NYCRR should be revised to remove the waiver provisions for intermediate casing on HVHF wells, or the SGEIS and NYCRR should be revised to include technical justifications, rationale and thresholds for proposed waivers.

The 2011 RDSGEIS requires that intermediate casing be cemented and evaluated for quality as follows:

> *Intermediate casing would be cemented to the surface and cementing would be by the pump and plug method with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess would suffice.*[49]
>
> *The operator would run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the intermediate casing and the production casing. The quality and effectiveness of the cement job would be evaluated using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of API Guidance Document HF1 (First Edition, October 2009). Remedial cementing would be required if the cement bond is not adequate to drill ahead and isolate hydraulic fracturing operations, respectively.*[50]

The requirements for intermediate casing are listed in Appendices 8, 9, and 10 of the RDSGEIS.

The 2011 RDSGEIS Appendix 8: Appendix 8 Casing and Cementing Practices requires intermediate casing be set only in certain circumstances.

> *Intermediate casing string(s) and the cementing requirements for that casing string(s) will be reviewed and approved by Regional Mineral Resources office staff on an individual well basis.*[51]

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[47] 2011 NYSDEC, RDSGEIS, Page 1-12.

[48] 2011 NYSDEC, RDSGEIS, Page 7-52.

[49] 2011 NYSDEC, RDSGEIS, Page 7-53.

[50] 2011 NYSDEC, RDSGEIS, Page 7-54.

[51] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 2.

The 2011 RDSGEIS Appendix 9: Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers requires intermediate casing be set:

> *If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. The permittee must immediately inform this office of the occurrence of any fresh water or shallow gas zones not noted on the permittee's drilling application and prognosis. This office may require changes to the casing and cementing plan in response to unexpected occurrences of fresh water or shallow gas, and may also require the immediate, temporary cessation of operations while such alterations are developed by the permittee and evaluated by the Department for approval.*[52]

The main problem with the conditions of Appendices 8 and 9 is that there is no specific guidance for intermediate casing and cementing, if the intermediate casing string is required as part of the well construction design.

Recommendation No. 17: The SGEIS (Appendices 8 and 9) and NYCRR should be revised to provide specific intermediate casing and cementing requirements, as explained further in Appendix B.

The 2011 RDSGEIS Appendix 10: Appendix 10 contains Proposed Supplementary Permit Conditions for HVHF operations, including additional intermediate casing requirements.

The 2011 RDSGEIS Appendix 10 requires intermediate casing be set, unless a waiver is granted:

> *Intermediate casing must be installed in the well. The setting depth and design of the casing must consider all applicable drilling, geologic and well control factors. Additionally, the setting depth must consider the cementing requirements for the intermediate casing and the production casing as noted below. Any request to waive the intermediate casing requirement must be made in writing with supporting documentation and is subject to the Department's approval. Information gathered from operations conducted on any single well or the first well drilled on a multi-well pad may serve to form the basis for the Department waiving the intermediate casing requirement on subsequent wells in the vicinity of the single well or subsequent wells on the same multi-well pad.*[53]

The 2011 RDSGEIS Appendix 10 requires intermediate casing be completely cemented and the department be notified of cementing operations:

> *This office must be notified ______ hours prior to intermediate casing cementing operations. Intermediate casing must be fully cemented to surface with excess cement. Cementing must be by the pump and plug method with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess will suffice. (Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*[54]

The 2011 RDSGEIS Appendix 10 requires a cement bond evaluation log:

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[52] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

[53] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[54] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

> *The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the intermediate casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate for drilling ahead (i.e., diversion or shut-in for well control).*[55]

The 2011 RDSGEIS Appendix 10 requires new casing and the use of American Petroleum Institute (API) standards for: casing thread compounds, centralizer placement, and cement composition (including the requirement to use gas-blocking additives).

> *With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *a) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;*
>
> *b) casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);*
>
> *c) at least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);*
>
> *d) cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive…*[56]

Appendix 10 requires: drilling mud be circulated and conditioned prior to cementing; the use of a spacer fluid to separate drilling mud from cement, avoiding drilling mud contamination; and cement installation methods that inhibit voids in the cement.

> *e) Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *f) A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement; and*
>
> *g) The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus…*[57]

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[55] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[56] 2011 NYSDEC, RDSGEIS, Appendix 10, Pages 5-6.

[57] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

Appendix 10 establishes a specific period of time required for the cement to harden and a compressive strength standard that the cement must achieve before drilling continues deeper in the hole. This avoids disturbing the cement until it has completely set.

> *h) After the cement is pumped, the operator must wait on cement (WOC):*
>
> > *1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and*
> >
> > *2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.*[58]

Appendix 10 requires records be kept as follows:

> *i) A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.* [59]

An analysis of the Appendices 8, 9, and 10 permit conditions requirements is provided in table format in Appendix B. Recommendations are listed in the table for improving the requirements and addressing inconsistencies.

NYCRR Proposed Revisions: The existing regulations at 6 NYCRR § 554 do not include specific requirements for intermediate casing, when intermediate casing is part of the well construction design.

A new section of regulations at 6 NYCRR § 560.6(c)(13, 14 and 15) proposes to add intermediate casing requirements for HVHF wells:

> *(13) Intermediate casing must be installed in the well. The setting depth and design of the casing must be determined by taking into account all applicable drilling, geologic and well control factors. Additionally, the setting depth must consider the cementing requirements for the intermediate casing and the production casing as noted below. Any request to waive the intermediate casing requirement must be made in writing with supporting documentation and is subject to the department's approval. Information gathered from operations conducted on any single well or the first well drilled on a multi-well pad may be considered by the department upon a request for a waiver of the intermediate casing requirement on subsequent wells in the vicinity of the single well or subsequent wells on the same multi-well pad.*

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[58] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[59] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

> *(14) As specified on a permit to drill, deepen, plug back and convert, the department must be notified prior to intermediate casing cementing operations. Intermediate casing must be fully cemented to surface with excess cement. Cementing must be by the pump and plug method with a minimum of 25 percent excess cement unless caliper logs are run, in which case 10 percent excess will suffice.*
>
> *(15) The operator must run a radial cement bond evaluation log or other evaluation approved by the department to verify the cement bond on the intermediate casing. Remedial cementing is required if the cement bond is not adequate for drilling ahead (i.e., diversion or shut-in for well control).*

Additional intermediate casing and cementing standards are included at 6 NYCRR § 560.6(c)(10) for HVHF wells:

> *(10) With respect to all surface, intermediate and production casing run in the well, and in addition to the department's casing and cementing requirements and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *(i) all casings must be new and conform to industry standards specified in the permit to drill;*
>
> *(ii) welded connections are prohibited;*
>
> *(iii) casing thread compound and its use must conform to industry standards specified in the permit to drill;*
>
> *(iv) in addition to centralizers otherwise required by the department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed (except production casing) and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill;*
>
> *(v) cement must conform to industry standards specified in the permit to drill and the cement slurry must be prepared to minimize its free water content in accordance with the industry standards and specifications, and contain a gas-block additive;*
>
> *(vi) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *(vii) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *(viii) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;*
>
> *(ix) after the cement is pumped, the operator must wait on cement (WOC) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer. The operator may request a waiver from the department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 pounds per square inch gage; and*
>
> *(x) a copy of the cement job log for any cemented casing string in the well must be available to the department at the well site during drilling operations, and thereafter available to the department upon request. The operator must provide such log to the department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a department permit issued*

> *pursuant to Part 550 of this Title. If the well is located on a multi-well pad, all cementing job logs must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title.*

An analysis of the proposed Appendices 8, 9, and 10 permit conditions requirements and the proposed changes to NYCRR is provided in table format in Appendix B. Recommendations for improving requirements are listed in the table.

Recommendation No. 18: The recommendations listed in the Intermediate Casing Analysis Table (Appendix B to this report) should be considered for the SGEIS and the NYCRR, including:

Waiver Provisions: It is best practice to install intermediate casing on a case-by-case basis for most wells; however, it is best practice to install it on all HVHF wells. The waiver provision proposed in the RDSGEIS to exclude intermediate casing on HVHF wells is not technically justified.

Setting Depth: Best practice is to set intermediate casing at least 100' below the deepest protected groundwater, to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Although intermediate casing setting depth is site specific, there should be criteria for determining that depth. This requirement should apply to all NYS wells.

Protected Water Depth Verification: The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method during drilling, ensuring intermediate casing protects that groundwater. This requirement should apply to all NYS wells where intermediate casing is set.

Cement Sheath Width: A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells where intermediate casing is set.

Amount of Cement in Annulus: It is best practice to fully cement intermediate casing if technically feasible to isolate protected water zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. If the casing cannot be fully cemented, most states require cement to be placed from the casing shoe to a point at least 500-600' above the shoe. This requirement should apply to all wells where intermediate casing is set.

Excess Cement: 25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where intermediate casing is set.

Cement Type: Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). The cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where intermediate casing is installed, not just HVHF wells.

Cement Mix Water Temperature and pH Monitoring: Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where intermediate casing is required, not just HVHF wells.

Lost Circulation Control: Lost circulation control is best practice. This requirement should apply to all NYS wells where intermediate casing is required.

Spacer Fluids: The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where intermediate casing is used, not just HVHF wells.

Hole Conditioning: Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Cement Installation and Pump Rate: The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Rotation and Reciprocation: Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.

Centralizers: The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where intermediate casing is installed.

Casing Quality: The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where intermediate casing is set.

Casing Thread Compound: The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Drilling Mud: The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells during the period when drilling occurs through protected water zones.

Cement Setting Time: Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells, not just HVHF wells.

NYSDEC Inspector: Best practice is to have a state inspector onsite during cementing operations. This requirement should apply to all NYS wells where intermediate casing is installed.

Cement QA/QC: The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where intermediate casing is set.

Record Keeping: Best practice is to keep permanent records for each well, even after the well is plugged and abandoned (P&A'd). This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Additional Casing or Repair: NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.

Pressure Testing: Casing and piping should be pressure tested.[60]

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[60] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, Page 109.

8. Production Casing

Background: In 2009, HCLLC recommended NYCRR be revised to include additional production casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on production casing the technical basis for HCLCC's recommendations.

Production casing is the last string of casing set in the well. It is called "production casing" because it is set across the hydrocarbon-producing zone, or alternatively sets just above the hydrocarbon zone. Production casing can be run all the way from the surface of the well across the hydrocarbon zone (production casing string) or can be hung from the surface or intermediate casing at a point deeper in the well (production liner).

If production casing is set across the hydrocarbon-producing zone, it is called a "cased hole" completion. In this scenario, production casing is lowered into the hole and cemented in place. Explosives are then lowered inside the production casing (perforation guns) to perforate holes through the pipe/cement barrier to allow oil and/or gas to enter the wellbore. In some cases, a drilling engineer may elect not to set production casing. This is called an "open hole" completion.

NYSDEC recommends a full string of production casing be set across the production zone and be run to surface, and that the production casing be cemented in place. This is a best practice for HVHF wells.

Production casing is used to isolate hydrocarbon zones and contain formation pressure. Production casing pipe and cement integrity is very important, because it is the piping/cement barrier that is exposed to fracture pressure, acid stimulation treatments, and other workover/stimulation methods used to increase hydrocarbon production.

The 2011 RDSGEIS and proposed revisions to the NYCRR include substantial improvements for production casing. NYSDEC's proposed production casing requirements for HVHF wells are robust. The most notable improvement to the NYCRR is that production casing must be set from the well surface through the production zone. This provides an additional protective layer of casing and cementing in the well during HVHF treatments. The RDSGEIS and NYCRR requires production casing be fully cemented, if intermediate casing is not set. If intermediate casing is set, it requires production casing be tied into the intermediate casing. NYCRR also requires the cement placement and bond be verified by well logging tools. These requirements are best practice.

NYSDEC's proposed HVHF production casing design prevents pollution of protected groundwater by constraining the HVHF pressurized fluid treatment to the inside of the production casing string as it passes the protected groundwater zone. Additionally, behind the production casing string there are two additional layers of casing and cement installed as a barrier across protected waters (e.g. surface and intermediate casing).

This section reviews the proposed changes to production casing requirements and supports the improvements that have been made. It also makes suggestions for improved regulatory clarity and offers recommendations for regulatory program revisions.

An analysis of the proposed RDSGEIS conditions found in Appendices 8, 9, and 10 is provided below, and compared to the proposed NYCRR. Recommendations are made to improve consistency in the documents and highlight additional best practices that should be considered.

The 2011 RDSGEIS: The 2011 RDSGEIS requires that production casing be installed and fully cemented across the production zone in wells that undergo HVHF treatments. The 2011 RDSGEIS states:

> *Requirement for fully cemented production casing or intermediate casing (if used), with the cement bond evaluated by use of a cement bond logging tool.*[61]
>
> *Anticipated Marcellus Shale fracturing pressures range from 5,000 pounds per square inch (psi) to 10,000 psi, so production casing with a greater internal yield pressure than the anticipated fracturing pressure must be installed.*[62]

The 2011 RDSGEIS Appendix 8: Appendix 8 NYSDEC's Casing and Cementing Practices includes the following production casing requirements for all wells.

> 12. *The production casing cement shall extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less. If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows. The Department may allow the use of a weighted fluid in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem.*
> 13. *Centralizers shall be placed at the base and at the top of the production interval if casing is run and extends through that interval, with one additional centralizer every 300 feet of the cemented interval. A minimum of 25% excess cement shall be used. When caliper logs are run, a 10% excess will suffice. Additional excesses may be required by the Department in certain areas.*
> 14. *The pump and plug method shall be used for all production casing cement jobs deeper than 1500 feet. If the pump and plug technique is not used (less than 1500 feet), the operator shall not displace the cement closer than 35 feet above the bottom of the casing. If plugs are used, the plug catcher shall be placed at the top of the lowest (deepest) full joint of casing.*
> 15. *The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.*
> 16. *Following cementing and removal of cementing equipment, the operator shall wait until a compressive strength of 500 psi is achieved before the casing is disturbed in any way. The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing tickets and/or the drilling log. WOC time shall be adjusted based on the results of the test.*[63]

The 2011 RDSGEIS Appendix 9: Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers does not include any additional requirements for production casing.

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[61] 2011 NYSDEC, RDSGEIS, Page 1-12.

[62] 2011 NYSDEC, RDSGEIS, Page 5-92.

[63] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 2-3.

The 2011 RDSGEIS Appendix 10: Appendix 10 contains Proposed Supplementary Permit Conditions for HVHF operations, including additional production casing requirements.

The 2011 RDSGEIS Appendix 10 requires production casing run the entire length of the wellbore, which is an excellent recommendation. Appendix 10 also requires production casing be tied into intermediate casing with at least 500' of cement:

> *36) Production casing must be run to the surface. This office must be notified _______ hours prior to production casing cementing operations. If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).*[64]

Appendix 10 requires a cement bond evaluation log, which is another excellent recommendation:

> *The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the production casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.*[65]

However, Appendix 10 includes a waiver provision that would exempt an operator from installing production casing cement as described above. This waiver provision is based solely on whether oil and gas might migrate from one pool or stratum to another. It does not address any of the other reasons why production casing cementing is important and required by NYSDEC in HVHF wells.

> *Any request to waive any of the preceding cementing requirements must be made in writing with supporting documentation and is subject to the Department's approval.*
>
> *The Department will only consider a request for a waiver if the open-hole wireline logs including a narrative analysis of such and all other information collected during drilling from the same well pad or offsetting wells verify that migration of oil, gas or other fluids from one pool or stratum to another will be prevented. (Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*[66]

Recommendation No. 19: The production casing cementing waiver should be removed for HVHF wells, or NYSDEC should provide more technical justification and rationale for the waiver. NYSDEC should show how environmental protection and safety objectives can be achieved to the same level with the waiver as without it.

The 2011 RDSGEIS Appendix 10 requires new casing and the use of American Petroleum Institute (API) standards for: casing thread compounds, centralizer placement, and cement composition (including the requirement to use gas-blocking additives).

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[64] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[65] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[66] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

> *31) With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *e) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;*
>
> *f) Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);*
>
> *g) At least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);*
>
> *h) Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive…*[67]

Appendix 10 requires: drilling mud be circulated and conditioned prior to cementing; the use of spacer fluid to separate drilling mud from cement, avoiding drilling mud contamination; and cement installation methods that inhibit voids in the cement.

> *e) Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *f) A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *h) The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus…*[68]

Appendix 10 establishes a specific period of time required for the cement to harden and a compressive strength standard that the cement must achieve before drilling continues deeper in the hole. This avoids disturbing the cement until it has completely set.

> *h) After the cement is pumped, the operator must wait on cement (WOC):*
>
> *1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and*
>
> *2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.*[69]

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[67] 2011 NYSDEC, RDSGEIS, Appendix 10, Pages 5-6.

[68] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[69] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

Appendix 10 requires records be kept as follows:

> *A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.*[70]

An analysis of the Appendices 8, 9, and 10 permit conditions requirements is provided in table format in Appendix C. Recommendations are listed in the table for improving the requirements and addressing inconsistencies.

NYCRR Proposed Revisions: The existing regulations at 6 NYCRR § 554 include requirements for production casing:

> *If it is elected to complete a rotary-drilled well and production casing is run, it shall be cemented by a pump and plug or displacement method with sufficient cement to circulate above the top of the completion zone to a height sufficient to prevent any movement of oil or gas or other fluids around the exterior of the production casing. In such instance, operations shall be suspended until the cement has been permitted to set in accordance with prudent current industry practices.*[71]

A new section of regulations at 6 NYCRR § 560.6(c)(16) proposes to add production casing requirements for HVHF wells.

> *(16) Production casing must be run to the surface. If installation of the intermediate casing is waived by the department, then production casing must be fully cemented to surface. <u>If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 300 feet of cement measured using True Vertical Depth</u>. Any request to waive any of the cementing requirements of this paragraph must be made in writing with supporting documentation and must be approved by the department. The department will only consider a request for a waiver if the open-hole wireline logs including a narrative analysis of such and all other information collected during drilling from the same well pad or offsetting wells verify that migration of oil, gas or other fluids from one pool or stratum to another will otherwise be prevented [emphasis added].*

The proposed regulations at 6 NYCRR § 560.6(c)(16) are inconsistent with the Appendix 10 requirement to cement the production casing with a 500' overlap into the intermediate casing.

> *If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).*[72]

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[70] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[71] 6 NYCRR V.B. §554.4(d)

[72] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

Recommendation No. 20: A production casing 500' cement overlap into the intermediate casing is more protective; 6 NYCRR § 560.6(c)(16) should be revised to match Appendix 10.

A new section of regulations at 6 NYCRR § 560.6(c)(17) requires production casing cement be verified for HVHF wells:

> *(17) The operator must run a radial cement bond evaluation log or other evaluation approved by the department to verify the cement bond on the production casing. Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.*

Additional production casing and cementing standards are included at 6 NYCRR § 560.6(c)(10) for HVHF wells.

> *(10) With respect to all surface, intermediate and production casing run in the well, and in addition to the department's casing and cementing requirements and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *(i) all casings must be new and conform to industry standards specified in the permit to drill;*
>
> *(ii) welded connections are prohibited;*
>
> *(iii) casing thread compound and its use must conform to industry standards specified in the permit to drill;*
>
> *(v) cement must conform to industry standards specified in the permit to drill and the cement slurry must be prepared to minimize its free water content in accordance with the industry standards and specifications, and contain a gas-block additive;*
>
> *(vi) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *(vii) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *(viii) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;*
>
> *(ix) after the cement is pumped, the operator must wait on cement (WOC) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer. The operator may request a waiver from the department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 pounds per square inch gage; and*
>
> *(x) a copy of the cement job log for any cemented casing string in the well must be available to the department at the well site during drilling operations, and thereafter available to the department upon request. The operator must provide such log to the department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title. If the well is located on a multi-well pad, all cementing job logs must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title.*

An analysis of the proposed Appendices 8, 9, and 10 permit conditions requirements and the proposed changes to the NYCRR is provided in table format in Appendix C. Recommendations for improving requirements are listed in the table.

Recommendation No. 21: The recommendations listed in the Production Casing Analysis Table (Appendix C to this report) should be considered for the SGEIS and the NYCRR, including:

Casing Design: For all wells, it is best practice for the productive horizon(s) to be determined by coring, electric log, mud-logging, and/or testing to aide in optimizing final production string design and placement. It is best practice to install production casing on a case-by-case basis for most wells; however, it is best practice to install a full string of production casing on HVHF wells to provide a conduit for the HVHF job and provide an extra layer of casing and cement.

Cement Sheath Width: A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells.

Amount of Cement in Annulus: Cementing production casing to surface if technically feasible (becomes more difficult with increasing depth), or at least 500' into the intermediate casing string is best practice. This requirement should apply to all NYS wells where production casing is set.

Excess Cement Requirements: 25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where production casing is set.

Cement Type: Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where production casing is installed, not just HVHF wells.

Cement Mix Water Temperature and pH Monitoring: Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where production casing is required, not just HVHF wells.

Lost Circulation Control: Lost circulation control is best practice. This requirement should apply to all NYS wells where production casing is required.

Spacer Fluids: The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where production casing is used, not just HVHF wells.

Hole Conditioning: Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Cement Installation and Pump Rate: The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Rotation and Reciprocation: Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This will become more difficult with a deviated wellbore, but should be attempted if achievable. This requirement should apply to all NYS oil and gas wells, not just HVHF wells.

Centralizers: Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where production casing is installed.

Casing Quality: The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where production casing is set.

Casing Thread Compound: The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Cement Setting Time: Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. This requirement should apply to all NYS wells, not just HVHF wells.

NYSDEC Inspector: Best practice is to have a state inspector onsite during cementing operations. This is more typical for surface and intermediate casing, but can be considered for production casing as well.

Cement QA/QC: The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where production casing is set.

Record Keeping: Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Additional Casing or Repair: NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.

Pressure Testing: Casing and piping should be pressure tested.[73]

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[73] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, p. 109.

9. Permanent Wellbore Plugging & Abandonment Requirements

Background: In 2009, HCLLC recommended that NYSDEC establish specific criteria to determine when a well must be permanently plugged and abandoned (P&A'd) and recommended improvements in NYS' well plugging regulations, incorporating best technology and practices.

Several terms are used to describe the condition of oil and gas wells that are not active hydrocarbon producers.

- Temporary Abandonment. This term is used to describe a well that may be temporarily suspended as a production well. The well may be shut-in awaiting repairs, a stimulation treatment, workover (e.g. drilling into a new zone) or a decision to finally P&A the well. A reasonable amount time should be afforded to the operator to complete the well work, or to decide when to P&A the well; however, a well should not be temporarily abandoned for a long period of time, because it poses a risk to the environment, especially if the well is known to have a leak or mechanical malfunction. Leaking or malfunctioning wells should be repaired in a timely manner or the well should be permanently P&A'd.

  In 2003, ICF Consulting produced a report for the New York State Energy Research and Development Authority (NYSERDA) that concluded NYS had 5,900 shut-in or temporarily abandoned wells, 39% of the 15,000 known wells.[74] ICF concluded that more than half the 5,900 wells have been "temporarily" abandoned for more than nine years. ICF concluded that:

  > *NYS is one of the few oil and gas producing states that have no specific regulatory provisions for long-term shut-in wells (more than two years). New York's current regulations allow an initial shut in period of one-year and an extension of up to one year, renewable for additional successive periods…*[75]

  ICF concluded that while operators are required to contact NYS to justify temporary abandonment extensions beyond one year, NYS' lack of resources to oversee the program has resulted in many wells remaining idle and not properly P&A'd for years:

  > *The practical effect is that New York's idle well regulation cannot be adequately enforced due to constraints on manpower and other agency resources, and as a result, New York has a defacto long-term inactive well program. For example New York has approximately 1,379 gas wells and 1440 oil wells with either inactive or unknown status that have no reported production since 1992.*[76]

- Permanent Abandonment. A well that is no longer needed to produce hydrocarbons should be plugged (e.g. cement barriers installed, failed casing removed, mechanical plugs set), surface equipment removed (e.g. wellhead and piping), and permanently abandoned. Operators typically do not monitor well condition once a P&A'd job is complete and approved by an agency.

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[74] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 1. A final version of this report could not be located on the world-wide web.

[75] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 5.

[76] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 36.

- Improperly Abandoned Well. This term describes a well that was P&A'd, but was done so in a manner where the well still poses a risk to the environment (e.g. insufficient barriers or cement used to seal the well). Because operators typically do not monitor the condition of P&A'd wells, improperly abandoned wells often go un-resolved.

  The problem of improperly abandoned wells in NYS may be a significant issue, because NYS' P&A regulations currently only require 15' cement plugs, which NYSDEC now recognizes as deficient. Therefore, most wells in the state were not P&A'd using a quality standard that would be considered best technology and best practice today.

- Orphaned Well. This term describes a well that was orphaned by the well operator (e.g. insolvent, absentee, or non-responsive well owners) and the well was not P&A'd. Because, by definition, an "orphaned well" does not have an operator to monitor its condition, permanent abandonment of these wells typically becomes a government or property owner responsibility. Given limited agency resources, the magnitude of the environmental hazard posed by any particular orphaned well often is unknown. Unless government or property owners make it a priority to fund well monitoring or plug the well, the potential environmental impacts of orphaned wells cannot be ascertained.

In 2003, ICF Consulting, further examined 4,140 of the long-term inactive wells in NYS and concluded that:

- 546 of the 4,140 wells (13%) were drilled and completed before 1924 (over 87 years old now);
- 1,568 of the 4,140 wells (38%) were drilled and completed from 1924-1964 (at least 47 years old now, and possibly up to 87 years old); and
- 2,026 of the 4,140 wells (49%) had no information on the date of complete or condition.[77]

Therefore, there are 2,114 wells that are at least 47 years old and some more than 87 years old that still have not been properly abandoned in NYS, and 2,026 wells where the age and condition is unknown (and must be assumed improperly abandoned).

NYS' 2009 Annual Oil and Gas Report[78] shows improperly abandoned and orphaned wells continue to be a significant problem in NYS. NYSDEC reports:

> *Abandoned, unreported and inactive wells continued to be a problem. In 2009 a total of 450 operators reported 3,043 wells with zero production. This is in addition to over* ***4,100 orphaned and inactive wells in the Department's records****. Enforcement actions have reduced the number of unreported wells yet some operators refused to file their annual reports. The operators that remained out of compliance have been referred to the Office of General Counsel for additional enforcement actions.[emphasis added]*
>
> *DEC has at least partial records on 40,000 wells, but estimates that over 75,000 oil and gas wells have been drilled in the State since the 1820s. Most of the wells date from before New York established a regulatory program. Many of these old wells were never properly plugged or were plugged using older techniques that were less reliable and long-lasting than modern methods. [emphasis added]*

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[77] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 32.

[78] New York State Oil, Gas and Mineral Resources, 26th Annual Report for Year 2009 and Appendices, Prepared by NYSDEC, 2009, pp. 22-23.

> *Every year while conducting scheduled inspections or investigating complaints, DEC staff discover more abandoned wells. Extensive courthouse research is often required to identify a well's previous owners. Many of these cases take several years to resolve as DEC pursues legal action against the responsible parties.*
>
> *New York has an Oil and Gas Account which was created to plug problem abandoned wells. It is funded by a $100 per well permit fee; at the end of 2009 the balance was $208,806. DEC has over 500 wells on its priority plugging list. Since the funds are insufficient to plug all the priority wells, DEC continues to pursue other mechanisms to plug abandoned wells [emphasis added].*

Well construction standards, techniques and technology have improved over time, and it is reasonable to assume that most of these long-term idle wells were not constructed to today's standards, have been subject to mechanical wear and corrosion, and warrant proper abandonment to mitigate risk to protected groundwater resources.

To compound problems, many wells that have not been properly abandoned do not have financial security (e.g. bonds) in place to fund P&A work. ICF reported that, in 2003, NYS had more than 3,500 wells that needed to be P&A'd, but there was no financial security in place (e.g. wells that were grandfathered from NYS bonding requirements). Additionally, ICF reported that 675 of the existing oil and gas wells in NYS have operators that do not comply with the current bonding requirements, and numerous operators that might comply with the existing bonding requirements have plugging liability in amounts that exceed NYS' current bonding requirements, which are too low and do not keep pace with the actual costs of P&A'ing wells today.[79]

The number of temporarily abandoned wells, improperly abandoned wells, and orphaned wells in NYS is a significant issue as shale gas resources are developed, because these old wells could provide a vertical conduit for pollutants to reach protected aquifers. Shale gas wells drilled and fracture stimulated nearby a temporarily abandoned, improperly abandoned, or orphaned well pose a risk. For example, a HVHF treatment can propagate a fracture that, depending on geology, HVHF design, and well depths, could pose a risk of intersection with a nearby well (active producer, abandoned or orphaned well).

Temporarily abandoned wells, improperly abandoned wells, and orphaned wells all pose a risk to the environment. Wellbore infrastructure can corrode and erode, failing over time and creating a potential pollutant pathway for hydrocarbons to move vertically through failed casing or cement to groundwater resources. These wells can either leak gas on their own or provide a vertical pollutant pathway to groundwater resources that can be activated by new well activity nearby.

In 2009, HCLLC recommended that temporary abandonment be limited to no longer than a one-year period, with a wellbore integrity monitoring requirement to ensure that the well is not leaking during temporary abandonment, and a requirement to permanently abandon the well after it is idle for more than a year. HCLLC recommended that NYSDEC carefully examine idle wells that have not been properly P&A'd and that are in close proximity to drinking water sources and in areas under consideration for new HVHF treatments, and require those wells to be P&A'd as a high priority and before shale gas drilling operations commence in those areas.

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[79] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 35-36.

A report documenting specific cases of well pollution caused by NYS' improperly abandoned wells or orphaned wells could not be located; however, neighboring Pennsylvania has completed an analysis of this problem, and it sheds light on the problems NYS may encounter.

Pollution caused by improperly abandoned wells in Pennsylvania is documented in a 2009 report prepared by Pennsylvania Department of Environmental Protection (PADEP). The PADEP report lists 27 cases where improperly abandoned wells have been the source of groundwater contamination.[80] In some of the 27 cases the wells were abandoned according to the standard practices of the time, but now leak and need to be re-abandoned using improved materials and techniques. Some of the cases cited by PADEP include very old well construction techniques, for example, surface casing made out of wood that has rotted away, and wells with no surface casing or cement installed at all. These wells have provided a conduit for gas and other pollutants to reach groundwater through damaged or worn casing, poorly installed cement, or more directly where casing or cement was not initially installed.

PADEP also identified wells that need to be P&A'd, but have not yet been addressed due to the lack of a responsible party and/or on account of PADEP resource limitations.[81]

There were three cases cited by PADEP where fracture stimulations in an operating well communicated with a nearby abandoned well, causing a gas leak in the abandoned well.[82] PADEP's study highlighted the importance of locating orphaned and improperly abandoned wells near new oil and gas developments, and study shows the importance of properly abandoning wells before new development proceeds.

A 2011 Duke University study covering Pennsylvania and New York found methane contamination of drinking water associated with shale-gas extraction. The study found that methane concentrations were 17 times higher, on average, in drinking water wells in active drilling and extraction areas than in wells in nonactive areas.[83] Clearly, the higher incidence rate of methane contamination in drinking water wells in shale gas extraction areas is not a coincidence, but is an indicator of shale gas drilling and completion operations mobilizing gas from the shale gas reservoir into protected aquifers. One of the most likely pathways for leaking of gas mobilized by HVHF is a nearby existing well that either was improperly constructed or improperly plugged. Given their failed cement, corroded casing, or lack of casing or cement, such improperly abandoned wells present vertical pathways to aquifers and drinking water resources.

Mechanical failure, human error, and engineering design flaws do occur in the construction and operation of wells. Indeed, groundwater contamination has been attributed to operational failures at various Marcellus Shale gas development operations in Pennsylvania, including operations by Cabot Oil & Gas Corporation, Catalyst Energy, Inc., and Chesapeake Energy Corporation.

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[80] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009.

[81] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009. Cases include: Independent Valley News Migration, Allegheny County – SWRO – March 2009; Versailles Migration, Versailles, Allegheny County – SWRO – 2007 through 2008; Childers Migration, Washington County – SWRO – June 2005; Groshek Migration, Keating Twp., McKean County – NWRO – 2008; and Skinner Migration, Columbus Twp., Warren County – NWRO.

[82] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009.

[83] Osborn, S.G., A. Vengosh, N.R. Warner, R.B. Jackson, 2011 Methane Contamination of Drinking Water Accompanying Gas Well Drilling and Hydraulic Fracturing, Proceedings of the National Academy of Sciences, U.S.A.; DOI: 10.1073/pnas.1100682108, p.2.

For example, on February 27, 2009, the Pennsylvania Department of Environmental Protection (PADEP) issued a Notice of Violation to Cabot Oil & Gas Corporation for unpermitted discharge of polluting substances and failure to prevent gas from entering fresh groundwater, among other deficiencies, in connection with its drilling activities in Dimock Township.[84] PADEP inspectors "…discovered that the well casings on some of Cabot's natural gas wells were cemented improperly or insufficiently, allowing natural gas to migrate to groundwater...DEP ordered Cabot to cease hydro fracking natural gas wells throughout Susquehanna County."[85] In April 2010, under its consent order and agreement with PADEP, Cabot was required to plug three leaking wells that contaminated the groundwater and drinking water supplies of 14 homes in the region.[86]

In 2011, PADEP issued a cease and desist order to Catalyst Energy, Inc. that prohibited the company from conducting drilling and hydraulic fracturing operations, after a PADEP investigation confirmed that private water supplies serving two homes had been contaminated by natural gas and elevated levels of iron and manganese from Catalyst's operations.[87]

In May 2011, PADEP determined that improper well casing and cementing in Chesapeake Energy Corporation's shallower wells allowed migration into groundwater and caused contaminated 16 families' drinking water supplies in Bradford County.[88]

Pennsylvania has found that significant planning and research is needed to identify orphaned and improperly abandoned wells before drilling nearby wells. At a 2009 Stray Gas Workshop in Pennsylvania, Garrett Velosi, from the National Energy Technology Laboratory, pointed out that one of the main problems with stray gas leaks from abandoned wells is verifying the location of improperly abandoned wells. Records on older wells are often limited or non-existent. Mr. Velosi presented methods for locating unmarked abandoned wells. They include the use of historic photos, ground magnetic surveys, and airborne surveys (equipped with magnetometers and methane detectors).[89]

In January 2011, NYS' consultant Alpha Geoscience agreed that timely well plugging and abandonment requirements are important; however, it recommended that establishing "a specific timeline for plugging and abandonment is neither practical nor necessary."[90] Alpha Geoscience did not examine the large backlog of improperly abandoned wells in NYS or the risk of groundwater contamination from improperly abandoned wells located within the radius of influence of new gas wells and HVHF operations. Alpha Geoscience did not recommend any improved P&A procedures, despite NYCRR's outdated requirements. 6 NYCRR § 555.5 requires only 15' cement plugs, as compared to Texas, Alaska, and Pennsylvania regulations that require a series of 50'-200' cement plugs at various locations within the wellbore.

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[84] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[85] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[86] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=10586&typeid=1.

[87] DEP Orders Catalyst Energy to Stop Operations at Gas Wells in Forest County Village, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=16894&typeid=1.

[88] DEP Fines Chesapeake Energy More Than $1 Million, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=17405&typeid=1.

[89] Veloski, G., National Energy Technology Laboratory, Methods for Locating Wells in Urban Areas – A Summary of Case Studies, Pennsylvania Stray Gas Workshop, November 2009.

[90] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA, January 20, 2011

HCLLC disagrees with Alpha Geoscience's recommendation to NYSDEC. Alpha Geoscience's recommendation also conflicts with prior advice from ICF to NYSERDA. HCLLC finds that it is practical and necessary to properly abandon wells on a reasonable timeline, and recommends that NYCRR be improved to include best practices and techniques for permanent wellbore abandonment.

2011 RDSGEIS: The 2011 RDSGEIS document is inconsistent on its recommendations for P&A'ing wells. In Chapter 5, NYSDEC concludes that no improvements are needed in the NYCRR regulations, but proposes changes to improve the regulations at 6 NYCRR § 555.5. In Chapter 6, NYSDEC concludes that it is not possible for HVHF treatments to intersect improperly abandoned wells; yet, in Chapter 7 NYSDEC proposed mitigation to address this very risk. These inconsistencies are further explained below, with recommendations for resolving them.

Chapter 5 of the RDSGEIS concludes that well plugging procedures and requirements in the existing NYCRR (described in the 1992 GEIS) are sufficient to address the risk of improperly abandoned wells. The 2011 RDSGEIS states:

> *As described in the 1992 GEIS, any unsuccessful well or well whose productive life is over must be properly plugged and abandoned, in accordance with Department-issued plugging permits and under the oversight of Department field inspectors. Proper plugging is critical for the continue protection of groundwater, surface water bodies and soil. Financial security to ensure funds for well plugging is required before the permit to drill is issued, and must be maintained for the life of the well [emphasis added].*[91]
>
> *When a well is plugged, downhole equipment is removed from the wellbore, uncemented casing in critical areas must be either pulled or perforated, and cement must be placed across or squeezed at these intervals to ensure seals between hydrocarbon and water-bearing zones. These downhole cement plugs supplement the cement seal that already exists at least behind the surface (i.e., fresh-water protection) casing and above the completion zone behind production casing.*
>
> *Intervals between plugs must be filled with a heavy mud or other approved fluid. For gas wells, in addition to the downhole cement plugs, a minimum of 50 feet of cement must be placed in the top of the wellbore to prevent any release or escape of hydrocarbons or brine from the wellbore. This plug also serves to prevent wellbore access from the surface, eliminating it as a safety hazard or disposal site. Removal of all surface equipment and full site restoration are required after the well is plugged.*
>
> *The plugging requirements summarized above are described in detail in Chapter 11 of the 1992 GEIS and are enforced as conditions on plugging permits. Issuance of plugging permits is classified as a Type II action under SEQRA. Proper well plugging is a beneficial action with the sole purpose of environmental protection, and constitutes a routine agency action. Horizontal drilling and high-volume hydraulic fracturing do not necessitate any new or different methods for well plugging that require further SEQRA review [emphasis added].* [92]

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[91] 2011 NYSDEC, RDSGEIS, Page 5-143.

[92] 2011 NYSDEC, RDSGEIS, Page 5-144.

While NYSDEC agrees that proper well P&A is critical to the protection of groundwater, surface water, and soil, it concludes that horizontal drilling and HVHF shale gas wells do not require any new or different P&A methods. However, this conclusion is inconsistent with NYSDEC's proposed revisions to the P&A procedures at 6 NYCRR § 555.5, this proposal suggests that the existing regulations do not represent best practices.

> **Recommendation No. 22:** The SGEIS should be revised to state that the existing P&A procedures at 6 NYCRR § 555.5 were determined to be outdated and not best practice and that NYSDEC has proposed revisions. The basis for NYSDEC's proposed revisions should be justified in the SGEIS, and include a review of other states' best practices for P&A.

Chapter 5 of the RDSGEIS does not address: (1) whether NYS has a backlog of wells requiring P&A in close proximity to drinking water sources; (2) whether NYS has a backlog of wells requiring P&A in close proximity to areas under consideration for HVHF treatments; (3) whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and (4) whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

> **Recommendation No. 23:** The SGEIS should examine: the number of improperly abandoned or orphaned wells in NYS requiring P&A in close proximity to drinking water sources or in close proximity to areas under consideration for HVHF treatments; whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

For example, maps showing the location and depth of NYS' temporarily abandoned, improperly abandoned, or orphaned wells could not be located; however, this data is needed to ensure safe development of shale gas resources. The RDSGEIS proposes that operators identify any existing well listed in NYSDEC's Oil & Gas database within one mile of the proposed HVHF well[93]; however, ICF's 2003 report to NYSERDA points out that there are a large number of old wells in NYS where location or well condition data is not available in NYSDEC's Oil & Gas database. If NYSDEC has improved the Oil & Gas database to accurately document all existing wells this information should be included in the SGEIS and maps of the wells should be made available.

> **Recommendation No. 24:** The SGEIS should include maps showing the location and depths of improperly abandoned, orphaned wells in NYS. These maps should correlate the locations and depths to potential foreseeable shale gas development and examine the need to properly P&A these wells before shale gas development occurs nearby. The SGEIS should assess the risk of a HVHF well intersecting a well that is not accurately documented in NYSDEC's Oil & Gas database and whether this poses and unmitigated significant impact to protected groundwater resources.

In Chapter 6 of the RDSGEIS, NYSDEC discounts the risks of new HVHF shale gas wells communicating with nearby abandoned wells. NYSDEC relies on its consultant's (ICF) analysis that concludes it is not possible for HVHF treatments to intersect with improperly abandoned wells.[94] Yet, in Chapter 7, NYSDEC recommends precautionary measures to be taken by operators to ensure that wells

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[93] 2011 NYSDEC, RDSGEIS, Page 3-10 and Page 7-72.

[94] 2011 NYSDEC, RDSGEIS, Page 6-52.

near HVHF operations are properly P&A'd to prevent freshwater contamination. The RDSGEIS is internally inconsistent on this point and the two diametrically opposed conclusions need reconciliation.

Recommendation No. 25: Chapter 6 of the SGEIS should be revised to be consistent with and support the Chapter 7 recommendation for HVHF operators to ensure all nearby wells are properly P&A'd before HVHF operations are conducted to mitigate the risk of HVHF treatments intersecting improperly abandoned wells. This requirement should also be codified in NYCRR.

In 2009 HCLLC recommended that preventative measures be taken to identify and properly abandon existing wells before proceeding with nearby shale gas drilling and HVHF operations. NYSDEC responded favorably to this recommendation by proposing that the operator identify any existing well listed in NYSDEC's Oil & Gas database within one mile of the proposed HVHF well[95] and by proposing that any improperly abandoned wells be plugged within that one-mile radius.[96] While NYS' recommendation is a step in the right direction, additional analysis is needed to justify the one-mile radius selected.

The RDSGEIS does not provide data on the maximum horizontal fracture propagation length that could occur at NYS' proposed 2000' depth cut-off. The RDSGEIS assumes the maximum horizontal well length will be 4000'. However, as highlighted in other sections of this report, current horizontal drilling technology allows for wells to be drilled substantially longer than 4000'. Fractures induced along that horizontal wellbore section can propagate several thousand feet from the well, depending on fracture treatment design parameters. Therefore, the wellbore length and the maximum fracture length combined could result in a radius of influence of more than one mile (5,280').

Recommendation No. 26: The SGEIS should provide technical justification for selecting a one-mile wellbore intersection radius and should explain the maximum horizontal drilling length and horizontal fracture length that corresponds with the proposed one-mile radius. This will be especially important for shallower wells where fractures tend to propagate on a horizontal plane, and where there will be a large number of potential shallow well intersection possibilities.

The SGEIS should examine the potential for longer wellbores and large fracture influence zones to occur now or in the future, and a wellbore intersection radius that corresponds to the largest areas of influence that are reasonably foreseeable should be included in the SGEIS as a mitigation measure and be codified in the NYCRR. Alternatively, if NYSDEC selects a one mile radius, the SGEIS should limit drilling length and horizontal fracture length in the SGEIS as a mitigation measure and in the NYCRR to ensure that the radius of influence does not extend beyond the one-mile impact area proposed.

The RDSGEIS proposes, in Table 11.1, that operators identify and plug wells within a one-mile radius, but this requirement is not translated into a permit condition or codified in NYCRR. Table 11.1 proposes:

> *Operators must identify and characterize any existing wells within the spacing unit and within one mile of proposed well and plug and abandon any well which is open to the target formation or is otherwise and immediate threat to the environment [emphasis added].*[97]

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[95] 2011 NYSDEC, RDSGEIS, Page 3-10 and Page 7-72.

[96] 2011 NYSDEC, RDSGEIS, Table 11.1, Page 11-5.

[97] 2011 NYSDEC, RDSGEIS, Table 11.1, Page 11-5.

Appendix 6, PROPOSED Environmental Assessment Form Addendum requires the operator to complete the one-mile radius of investigation, yet, there is no requirement in Appendix 10 or in the NYCRR requiring the offset wells to be plugged by the HVHF operator if needed.

In direct contrast to the conclusions reached in Chapter 6, Chapter 7 of the RDSGEIS acknowledges the potential risk of HVHF wells intersecting improperly abandoned wells and proposes a process to address these risks:

> *To ensure that abandoned wells do not provide a conduit for contamination of fresh water aquifers, the Department proposes to require that the operator consult the* **Department's Oil and** *Gas database as well as property owners and tenants in the proposed spacing unit to determine whether any abandoned wells are present. If (1) the operator has property access rights, (2) the well is accessible, and (3) it is reasonable to believe based on* **available records and history of drilling in the area that the well's** *total depth may be as deep or deeper than the target formation for high-volume hydraulic fracturing, then the Department would require the operator to enter and evaluate the well, and properly plug it prior to high-volume hydraulic fracturing if the evaluation shows the well is open to the target formation or is otherwise an immediate threat to the environment. If any abandoned well is under the operator's control as owner or lessee of the pertinent mineral rights, then the operator is required to comply with the Department's existing regulations regarding shut-in or temporary abandonment if good cause exists to leave the well unplugged. This would require a demonstration that the well is in satisfactory condition to not pose a threat to the environment, including during nearby high-volume hydraulic fracturing, and a demonstrated intent to complete and/or produce the well within the time frames provided by existing regulations [emphasis added].*[98]

While Chapter 7 correctly acknowledges the need for P&A procedure improvement and review of nearby abandoned wells before HVHF treatments, NYSDEC incongruously proposes to limit P&A due diligence to: 1) wells that are within the HVHF well operator's control and 2) wells that are "accessible." This approach discounts the risks posed by improperly abandoned wells that are owned by another operator, orphaned, or difficult to access.

The inconsistency in P&A improvement recommendations persists in the Appendix 10 HVHF Permit Conditions where the recommended improvements in Chapter 7 are not included. The Chapter 7 recommendations are not included in the revised NYCRR either.

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[98] 2011 NYSDEC, RDSGEIS, Page 7-58.

Recommendation No. 27: If a well was not properly P&A'd to current standards, the operator should be required to work with the well owner or take the initiative itself to ensure the well is properly P&A'd before new drilling begins and before a nearby HVHF treatment occurs. Approval of a HVHF well application should be conditioned on verification that any necessary P&A work is complete. This requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

NYSDEC should consider requiring operators to use a variety of proven methods to locate unmarked, abandoned wells, including: historic photos, ground magnetic surveys, and airborne surveys (equipped with magnetometers and methane detectors).

The proposed mitigation measure, requiring improperly abandoned or orphaned wells to be plugged prior to a HVHF treatment, should be included in Appendix 10, of the SGEIS and codified in the NYCRR.

Additionally, NYSDEC should request ICF to further examine additional technical and scientific questions that were not addressed in its analysis.

Foremost, ICF's report does not indicate that ICF evaluated the difference in reservoir pressure near a new shale gas wellbore, drilled into an un-depleted higher pressure gas reservoir, as compared to the lower reservoir pressure in the drainage radius around a well that previously served or is currently serving as a production well. The reservoir pressure in the drainage radius around a production well will be substantially lower creating a pressure sink around that well. By the laws of physics, gas and fluid will flow from higher pressure regimes to lower pressure regimes. Therefore, if a HVHF treatment intersects the drainage radius around a nearby pressure-depleted reservoir connected to an improperly abandoned well, the HVHF fluid and associated mobilized gas will continue to move towards the improperly abandoned well, not back to the new shale gas well as ICF suggests.

As explained in Chapter 10 of this report, industry data shows that HVHF treatments are propagating well beyond the shale zone into formations located above and sometimes below the shale, meaning that the HVHF treatment can potentially intersect the depleted well drainage area of a well that has produced from a zone above or below the shale.

However, ICF concludes that, once the HVHF treatment pressure ceases, all HVHF fluid will return to the shale gas well, and there is no possibility that HVHF fluid or associated mobilized gas will travel up an improperly abandoned well conduit. This conclusion is based on the assumption that the lowest pressure pathway for HVHF fluids injected into the formation is back to the shale gas well, but such assumption does not account for the possibility that a lower pressure regime at an abandoned or active well site could influence the flow of HVHF fluids and newly mobilized gas. It also discounts the possibility that other lower pressure intervals could be located above or below the shale zone that would preferentially accept HVHF fluids and gas mobilized during the treatment.

In these cases, HVHF fluids and gas would continue towards the improperly abandoned well and up the well conduit until pressure equilibrium is reached or into adjacent lower pressured reservoirs. This could result in HVHF fluids and associated gas that is mobilized during the HVHF treatment contaminating groundwater if an exposure pathway exists in the improperly abandoned well or from an adjacent lower pressure reservoir to a shallower protected water zone.

While it is true that HVHF fluids will flow back to the new shale gas well if such well presents the lowest pressure regime for fluid to flow to, this will not always be the case, as evidenced by the fact that not all the HVHF fluid returns to the well. The RDSGEIS states that:

> *Flowback water recoveries reported from horizontal Marcellus wells in the northern tier of Pennsylvania range between 9 and 35 percent of the fracturing fluid pumped. Flowback water volume, then, could be 216,000 gallons to 2.7 million gallons per well, based on a pumped fluid estimate of 2.4 million to 7.8 million gallons, as presented in Section 5.9.*[99]

Therefore, several million gallons of HVHF treatment fluid remain in the reservoir and will travel to the lowest pressure formation/regime present, including such lower pressure regimes present around nearby existing wells that have previously produced hydrocarbons. An out-of-zone HVHF, as described in Chapter 10 of this report could potentially connect with this lower pressure reservoir, if not properly designed and implemented.

Secondly, ICF's analysis did not examine the maximum horizontal distance a HVHF could travel, nor identify minimum safe separation distances between horizontal fractures and abandoned wells. Thus, ICF did not attempt, to compare the maximum HVHF length to the closest distance that an abandoned well may occur.

Instead, ICF's analysis assumes that the HVHF impact radius would always be less than the distance to a nearby well (which may not be true in all cases, and will depend on reservoir characteristics and job design). ICF concludes, without basis, that a fracture created by a HVHF would never intersect a nearby well, but does not establish the well spacing distance required for this to be true nor does it consider the fact that Marcellus Shale fractures (as shown in Chapter 10 of this report) do routinely propagate out of zone.

Additionally, the Chapter 6 conclusion that it is not possible for a HVHF treatment to intersect an improperly abandoned well is discordant with three cases cited in PADEP's 2009 Report that document situations in which fracture stimulations in operating wells communicated with nearby abandoned wells, causing gas leaks in the abandoned wells.[100] PADEP's cases confirm that fracture stimulations, if improperly designed and executed, can intersect improperly abandoned and orphaned wells.

Recommendation No. 28: The SGEIS and NYCRR should require HVHF well operators to identify previously drilled wells that may be located within the hydraulic radius of the new shale gas well that may be affected during a HVHF treatment. The operator should be required to estimate the maximum horizontal and vertical extent of the fracture length that will be propagated and ensure that there are no abandoned or improperly abandoned wells in that intersection radius. An additional safety factor should be applied in this analysis to account for uncertainty in fracture design and implementation, and the potential for the actual fracture length to be longer than estimated (e.g. a conservative analysis is needed).

The HVHF treatment size should be designed to ensure that it does not intersect with any abandoned or improperly abandoned wells, with an additional margin of safety.

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[99] 2011 NYSDEC, RDSGEIS, Page 5-99.

[100] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009.

Any improperly abandoned wells nearby, and just outside, the intersection radius should be properly abandoned to current standards before new drilling begins and before the HVHF treatment occurs.

NYCRR Proposed Revisions: Despite the 2011 RDSGEIS conclusion that no new P&A requirements are needed, and NYSDEC's consultant's (Alpha Geoscience) recommendation that no improvements are necessary, NYSDEC proposed revisions to its existing well P&A requirements at 6 NYCRR § 555.5, Plugging Methods, Procedures and Reports:

(a) The plugging of a well shall be conducted in accordance with the following sequence of operations[:] . The Division at its discretion may require the tagging of all plugs and require casing and/or cement evaluation logs to be run to determine proper plugging procedures. The following are minimum requirements for plugging and the department may impose additional requirements: [emphasis added]

> *(1) The well bore, whether to remain cased or uncased, shall be filled with cement from total depth to at least [15] 50 feet above the top of the shallowest formation from which the production of oil or gas has ever been obtained in the vicinity. Alternatively, a bridge topped with at least [15] 50 feet of cement shall be placed immediately above each formation from which the production of oil or gas has ever been obtained in the vicinity.*
>
> *(2) [If] For any casing [is to be] left in the ground, a cement plug of at least [15] 100 feet in length shall be placed [at the bottom of such section of casing] 50 feet inside and 50 feet outside of the casing shoe . Uncemented casing must be pulled as deep as practical with a 50-foot plug placed in and above the stub of the casing. If the uncemented casing is unable to be pulled the casing must be ripped or perforated 50 feet below the shoe of the next outer casing and a 100-foot plug placed across that shoe. A [similar] 50 foot plug shall be placed at [the top of such section of casing unless it shall extend to]the surface. [In the latter event, the casing shall be capped in any such manner as will prevent the migration of fluids and not interfere with normal soil cultivation.]*
>
> *(3) If casing extending below the deepest potable fresh water level shall not remain in the ground, a cement plug of at least [15] 50 feet in length shall be placed in the open hole at a position approximately 50 feet below the deepest potable fresh water level.*
>
> *(4) If the conductor casing or surface casing is drawn, a cement plug of at least [15] 50 feet in length shall be placed immediately below the point where the lower end of the conductor or surface casing shall previously have rested. The hole thereabove shall be filled with cement, sand or rock sediment or other suitable material in such a manner as well prevent erosion of the well bore area and not interfere with normal soil cultivation.*
>
> *(5) The interval between all plugs mentioned in paragraphs (1) through (4) of this subdivision shall be filled with [a heavy mud-laden] gelled fluid with a minimum density equal to 8.65 pounds per gallon with a 10 minute gel-shear strength of 15.3 to 23.5 pounds per hundred square feet or other department approved fluid.*

NYSDEC's proposed revisions are a step in the right direction. Overall, NYSDEC proposes to require longer cement plugs, weighted mud, and some additional QA/QC procedures, including tagging the cement plugs and possibly running cement evaluation logs.

NYSDEC's existing P&A regulations require short cement plugs (15'), which are woefully inadequate, compared to current best practices of installing a series of 50'-200' cement plugs within a wellbore, and removing corroded casings to isolate water resources. Unfortunately, this means that most of NYS' abandoned wells, if plugged to NYCRR's existing standards, are not likely to provide adequate groundwater protection. To address this problem, the P&A procedures used in each previously abandoned well, located near a proposed new HVHF well should be carefully examined for adequacy to determine whether the well should be re-abandoned to current, more robust P&A standards.

Recommendation No. 29: P&A procedures used in each previously abandoned well, located near a proposed new HVHF well should be carefully examined for adequacy to determine whether the well should be re-abandoned to current, more robust P&A standards and this requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

NYSDEC's proposed increase to 50' cement plug length is an improvement; however, best practices used in other states such as Texas, Alaska, and Pennsylvania require longer cement plugs. NYSDEC should consider enhancing the regulations to require longer and additional cement barriers to ensure that hydrocarbons and freshwater are confined to their respective indigenous strata, and are prevented from migrating into other strata or to the surface. For example, while NYSDEC has proposed to revise the NYCRR to require a 50' cement barrier, Alaska requires double that protection at 100'.[101] Pennsylvania recently upgraded its P&A requirements from its previous 50' standard to plugs of 50'-100'.[102] Texas requires cement plugs ranging from 50'-200' at numerous locations in the well, and requires cement QA/QC procedures.[103] For example, Texas requires each cement plug to be a minimum of 200' in length and extend at least 100' below and 100' above the top of each hydrocarbon stratum and the base of the deepest protected water stratum, which is a substantial difference from NYS' current requirement for 15' plugs.

Recommendation No. 30: The SGEIS mitigation measures and NYCRR should be revised to clearly specify that:

Plugging a wellbore should be performed in a manner that ensures all hydrocarbons and freshwater are confined to their respective indigenous strata, and prevented from migrating into other strata or to the surface.

All hydrocarbon-bearing strata should be permanently sealed off by installing a cement barrier at least 100 feet below the base to at least 100 feet above the top of all hydrocarbon-bearing strata (200' plug).

The plugging of a well should include effective segregation of uncased and cased portions of the wellbore to prevent the vertical movement of fluid within the wellbore. A continuous cement plug must be placed from at least 100 feet below to at least 100 feet above the casing shoe (200' plug).

The operator should be required to submit records to NYSDEC to demonstrate that the well is P&A'd in compliance with regulations.

NYSDEC should consider specifying the grade of cement required to plug the well. It should also consider requiring the use of gas blocking agents.

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[101] 20 AAC 25.

[102] PA Code, § 78.91.

[103] 16 TAC Part 1, § 3.14.

Revisions to the NYCRR include some improved QA/QC procedures, but these revisions are loosely written and do not specify when QA/QC procedures will be mandatory. For example, it is best practice to tag all cement plugs to verify placement depth; this should not be an optional, discretionary procedure. Also, NYSDEC should specify under what circumstances a cement evaluation tool will be required.

Recommendation No. 31: The SGEIS mitigation measures and NYCRR should be revised to require cement quality standards, including the use of gas blocking cement. The SGEIS and NYCRR should require tagging of all cement plugs and provide instructions on when additional cement evaluation tools must be run.

10. HVHF Design and Monitoring

Background: In 2009, HCLLC recommended that NYSDEC revise its regulations to specify and require best technology and best practices for collecting data, and modeling, designing, implementing, and monitoring a fracture treatment, including:

(a) Collecting additional geophysical and reservoir data to support a reservoir simulation model;

(b) Developing a high-quality Marcellus Shale 3D reservoir model(s) to safely design HVHF treatments;

(c) HVHF modeling prior to each fracture treatment to ensure that the fracture is contained to the Marcellus Shale zone;

(d) Careful monitoring of the fracture treatment, including shutting the treatment down if data indicates casing leaks or out-of-zone fractures;

(e) Starting with smaller fracture treatments in the deepest, thickest sections of the Marcellus Shale to gain data and experience (e.g. 4,000' deep and 150' thick);[104]

(f) Using the experience gained with fracture testing on deeper sections of the Marcellus to design and implement larger treatment volumes over time (potentially allowing increasingly shallower and thinner intervals *only* if technical data supports the safety of this technique); and

(g) Documenting, reporting, and remediating fracture treatment failures to ensure drinking water protection.

In 2009, HCLLC recommended that fracture treatments be carefully monitored and shut down if pressure data indicates casing leaks. HCLLC noted the American Petroleum Institute recommends continuous and careful monitoring of surface injection pressure, slurry rate, proppant concentration, fluid rate, and sand or proppant rate, [105] and that fracture treatments should be immediately shutdown if abnormal pressures indicate a casing leak. The 2011 RDSGEIS now requires the operator to carefully monitor fracture treatments and shut down the treatment if data indicates casing leaks or out-of-zone fractures. This is an important improvement to the SGEIS.

Experts agree that Marcellus Shale gas production can be maximized by: 1) drilling long horizontal wells to increase the drainage area and 2) conducting hydraulic fracture treatments to improve permeability and access to trapped gas. However, successful, safe development requires hydraulic fracture treatments be properly designed and sized to remain within the shale zone. Fracture treatments that propagate outside the shale zone (fracturing out-of-zone) reduce gas recovery and risk pollutant transport. There is extensive industry literature on the importance of hydraulic fracture design, modeling, and field verification to optimize fracture stimulation. Therefore, in 2009 HCLLC recommended that the DSGEIS be improved to provide additional technical and scientific data and require specific mitigation, ensuring that operators are designing jobs that will not fracture out-of-zone.

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[104] Smaller, deeper fracture treatments could be used initially in NYS, the performance examined, the predictive model improved based on that data, and then fracture treatment size and proximity to protected waters and other wellbores could be modified, as confidence increases in the predictive ability of the model to ensure a safe and favorable result.

[105] American Petroleum Institute (API) Guidance Document HF1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines, October 2009.

Pollutant transport and pollutant toxicity issues are addressed in Dr. Tom Myers' and Dr. Glenn Miller's reports to NRDC on the 2009 DSGEIS and the 2011 RDSGEIS. HCLLC's recommendations center on what type of data, analysis, tools, and methods an engineer/operator should have in place and use to ensure that a fracture treatment can be contained within the Marcellus Shale zone.

In 2009, HCLLC observed that NYSDEC and/or operators had not provided sufficient data to demonstrate that a HVHF treatment can be contained to the Marcellus Shale. HCLLC pointed out that the 2009 DSGEIS did not require the operator to demonstrate that it is equipped with sufficient expertise, training, qualifications, and engineering tools to safely design, implement, and assess the performance of HVHF treatments. HCLLC recommended that NYSDEC consider operator qualifications.

HCLLC's recommendations on the 2009 DSGEIS explained that it is best practice in newly developed formations, such as the NYS Marcellus Shale, to build hydraulic fracture models. Fracture models are used by engineers to safely design fracture treatments. During actual fracture stimulation treatments, data are collected to verify model accuracy, and the model is continually refined to improve its predictive capability.

Because fracture treatments may be executed several thousand feet below the surface of the earth, and can only be indirectly observed, it is important for engineers to have a 3D model to guide design. While 3D modeling is not an exact science, the model provides an engineer with an estimating method for predicting both horizontal and vertical fracture length.

As further explained below, data collected during drilling, well logging, coring, and other geophysical activities and HVHF implementation can be used to continuously improve the model quality and predictive capability.

In newly developed areas it is important to conduct initial HVHF treatments in the lowest risk zones, far below protected aquifers and with large horizontal offsets from existing wells. Until the predictive capability of site-specific models improves from the input of actual field data, larger buffer zones should be used. Absent hydraulic fracture modeling in newly developed areas such the NYS Marcellus Shale, engineers would blindly be making decisions on the size, type, and execution of HVHF treatments.

NYS' consultant, Alpha Geoscience, agreed with HCLLC's 2009 recommendations and in January 2011 reported to NYSDEC that:

> *Harvey Consulting's [HCLLC] assessment of the dSGEIS' discussion of hydraulic fracture design and monitoring is thorough…*
>
> *Harvey Consulting has thoroughly documented its discussion of hydraulic fracture design and monitoring, citing professional journal articles, professional conference papers, technical guidance documents, and consultant reports.*[106]

Alpha Geoscience recommended to NYSDEC that HCLLC's 2009 recommendations be included in the SGEIS:

> *Harvey Consulting's ideas should be considered for inclusion in the dSGEIS as possible permit conditions, especially for the first wells drilled in an area.*[107]

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[106] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA, January 20, 2011, Pages 26-27.

[107] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 28.

While Alpha Geoscience's report acknowledges the importance of proper HVHF design and monitoring, it includes several misrepresentations about HCLLC's 2009 comments that require correction.

First, Alpha Geoscience incorrectly contends that HCLLC recommended industry and NYS develop separate hydraulic fracture models; this is not correct. HCLLC recommended that industry develop models, or that joint model funding be implemented as a more cost-effective approach. Typically, companies build their own proprietary models to seek competitive advantage, especially in newly developed areas where the models are used as part of the competitive bidding process. However, it is possible for one or more companies to pool resources to develop a joint model as a cost savings.

Second, Alpha Geoscience incorrectly contends that HCLLC recommended that every operator perform fracture modeling at every location, including locations that have been thoroughly modeled and assessed. Alpha Geoscience concluded that this would be extremely costly compared to the technical value. HCLLC did not recommend HVHF modeling be conducted at locations that have been "thoroughly modeled and assessed." Logically, if this work has already been completed, there is no reason to repeat it.

HCLLC did recommend that NYSDEC require operators to complete modeling prior to each fracture treatment to ensure that the fracture is properly designed and planned to be contained to the Marcellus Shale zone. This is not a significant amount of work per well for experienced operators, with working models. HCLLC also recommended that operators collect data during fracture treatments to further refine hydraulic fracture models. HCLLC pointed out that as NYS shale development is in its infancy, hydraulic fracture model work has not yet been completed, and therefore is needed.

Once a hydraulic fracture model is built and populated with data specific to the NYS Marcellus Shale, running a well-specific HVHF treatment scenario is an efficient process, and an important quality control and quality assurance measure. It does not appear that Alpha Geoscience is familiar with the reservoir simulators used for oil and gas work, because their recommendation to construct a hydraulic fracture model for the Marcellus Shale, and then use it only on the initial wells constructed, is inconsistent with industry practice. Model quality improves over time. As additional data is collected and the model is refined, it becomes an increasingly valuable tool to the operator. High-quality models are an essential tool for designing fracture treatments in challenging circumstances and locations.

In 2009, HCLLC explained that industry agrees there is a high level of uncertainty in NYS Marcellus Shale development; industry recommends engineering and geophysical data work to reduce that uncertainty. HCLLC's recommendations in 2009 stated:

> *Marcellus Experience Very Limited: Marcellus Shale gas development has a high level of uncertainty. Shales by nature are very heterogeneous.*[108] *Industry has limited experience exploiting the Marcellus Shale using horizontal wells and slickwater fracs. The first Appalachian Basin Marcellus Shale gas well stimulation using high-volume slickwater fracture treatments was only recently performed in Southwestern Pennsylvania in 2004.*[109] *Therefore, industry has less than five years of experience developing the Marcellus Shale using the techniques proposed in the dSGEIS.*

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[108] Cipolla, C.L., Lolon, E.P., and Mayerhofer, M.J., Reservoir Modeling and Production Evaluation in Shale-Gas Reservoirs, International Petroleum Technology Conference, Paper 13185, December 2009.

[109] Fontaine, J., Johnson, N., and Schoen, D., Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper 117772, October 2008.

Even NYSDEC's consultants acknowledge that industry literature on and experience with the Marcellus Shale is so limited that most of their analysis was based on development of other shale gas reservoirs, such as the Barnett and Fayetteville. NYSDEC's consultant, ICF, states that:

> "Drilling operations, and especially multi-horizontal wells, are relatively new in Marcellus Shale. While drilling operations are underway in neighboring states as evidenced by over 450 wells in Pennsylvania for example, technical studies have yet to be published that quantify actual drilling operations in Marcellus Shale. For the most part, we have had to make assumptions, where technically appropriate, that drilling operations in other shale formations are representative of expected Marcellus operations [emphasis added].[110]

Lack of Marcellus Shale experience increases the risk of fracturing out-of-zone, unless a conservative, step-wise approach is taken to better understand the Marcellus Shale before large scale development occurs in NYS.

NYS Marcellus Data Set Improvement Needed: Site-specific data, unique to the Marcellus Shale in NYS, must be collected to: better understand the reservoir heterogeneities; develop sophisticated three dimensional (3D) reservoir models to more accurately design fracture treatments; and examine actual fracture performance in the field. Reservoir simulation models are critical engineering design tools. The dSGEIS provides no indication that a model exists for the NYS Marcellus Shale.

Engineers use 3D models to predict fracture height, length, and orientation prior to actually performing the job at the well. The goal is to design a stimulation treatment that optimizes fracture networking and maximizes gas production, while confining fracture growth to within the gas shale target formation.[111]

Engineers examine various parameters (e.g., volume, pressure, treatment placement) to optimize a fracture treatment. Without a high-quality 3D reservoir simulation model to design a fracture treatment, operators cannot demonstrate to NYSDEC that the fracture is predicted to stay in zone.

Typically an operator would start by collecting core analysis, well logs, and other subsurface data in the area it is interested in developing, to populate a site-specific 3D reservoir model. To collect this data, additional exploration and appraisal wells must be drilled (see recommendation No. 2). The limited amount of special core analysis and core data on the Marcellus Shale, as well as overlying intervals, is described in Chapter 4 of the DSGEIS, showing a need for additional data.

Test in Deepest, Thickest Zones First: NYSDEC is proposing to allow high-volume fracture treatments, without requiring the standard of care a petroleum engineer would typically use to collect data, and model, design, and monitor fracture treatments. NYSDEC should require that additional data be collected to support a model, and initially it should only allow a few, small fracture treatments that are conducted with intensive monitoring to verify that they are designed and implemented to stay within the

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[110] 2009 NYSDEC, DSGEIS, ICF Task 2 Report, Page 1.

[111] ALL Consulting, Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale, Presented at The Ground Water Protection Council 2008 Annual Forum, Cincinnati, Ohio, September 21-24, 2008.

> *Marcellus Shale. This data gathering and testing should be conducted in the deepest portions of the Marcellus Shale (below 4,000') and in the thickest section of the shale (over 150') to ensure there are adequate buffer zones to protect the environment during the data gathering and testing process. Operators should start with smaller fracture treatment sizes, collecting field data to better understand fracture performance, and use field data to calibrate that performance in the 3D model.*
>
> *Over time, with careful analysis and a conservative, step-wise approach, larger fracture treatments can be tested and carefully monitored. Over time it may be possible to safely use the treatments on thinner reservoirs and shallower reservoirs, but certainly not as a first step. High-volume fracture treatments should not be conducted until there is a sophisticated data set, model, and monitoring program to verify pre-fracture and post-fracture reservoir properties.*
>
> *Buffer Zones Needed: Vertical fractures that extend above and below the shale zone will decrease gas recovery rates by allowing vertical migration into the overlying strata, or by allowing water influx from aquifers above or below the shale. NYS has a financial incentive to ensure fracture treatments are conducted correctly, because NYS will want to maximize its royalty share and tax revenue.*
>
> *To avoid fracturing out-of-zone, engineers typically design fracture treatments with a buffer zone (an un-fractured zone at the top of the shale layer and at the base of the shale). Buffer zone size should increase with geologic and technical uncertainty. Buffer zone size may decrease as industry gains experience and data quality/quantity improves. The DSGEIS does not contain sufficient information to demonstrate that NYSDEC and/or operators proposing high-volume fracture treatments have developed engineering tools capable of computing a safe buffer zone.*

Third, Alpha Geoscience incorrectly contends that HCLLC recommended that every operator perform a minifracture treatment at every location, including locations that have been thoroughly modeled and assessed. HCLLC did not recommend that a minifracture be conducted at every well. Instead, HCLLC recommended that minifractures be conducted in a few different areas of NYS to further refine hydraulic fracture models. HCLLC's 2009 recommendations stated:

> *Technology is available to assess actual fracture growth including: minifracs,[112] microseismic fracture mapping,[113] tilt surveys, well logging (e.g., tracer and temperature surveys[114]), etc.[115] These technologies can be used to provide more accurate assessments of the locations, geometry, and dimensions of a hydraulic fracture system.[116] This data*

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[112] Minifracs are small fracture treatments conducted in the well to better understand fracture conductivity and flow geometry prior to implementing a large fracture treatment. Minifracs are typically used to optimize the fracture design and calibrate the fracture model. These tests involve periods of intermittent injection followed by intervals of shut-in and/or flowback. Pressure and rate are measured throughout a minifrac and recorded for subsequent analyses.

[113] Microseismic monitoring is a method that measures the seismic wave generated during a fracture treatment to map the fracture extent, and it can be used to make "real-time" changes in the fracture design and implementation program.

[114] After the fracture treatment is completed, an operator can run a temperature log in the well to measure the variation in reservoir temperature resulting from the treatment. The reservoir temperature is hotter than the fracture fluid and proppant. Cooler temperatures will be measured where frac fluid and proppant are placed. Temperature logs will provide insight into fracture location and growth outside the casing.

[115] American Petroleum Institute (API) Guidance Document HF1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines, October 2009.

[116] Schlumberger, Microseismic Hydraulic Fracture Monitoring, http://www.slb.com/content/services/stimulation/stimmap.asp.

> *can be obtained in the Marcellus Shale in a few different areas of NYS to further refine the hydraulic fracture model. Minifractures are particularly helpful in estimating fracture dimensions, fracture efficiency, closure pressure, and leakoff prior to implementing a high-volume, full-scale treatment. NYSDEC should require operators to conduct minifractures to better understand site-specific reservoir characteristics prior to conducting a high-volume fracture treatment [emphasis added].*

HCLLC's 2009 recommendations also noted that:

> ***While NYSDEC's consultant, ICF***[117]*, documents a number of the engineering methods that can be used to model, monitor, and improve fracture treatments, NYSDEC does not require any of these methods in its existing regulations. Absent a regulatory requirement, there is no assurance these methods will be used [emphasis added].*
>
> *Best practice for hydraulic fracture planning includes a detailed understanding of the in-situ conditions present in the reservoir (e.g., shale thickness, reservoir pressure, rock fracture characteristics, and special core analysis). In highly heterogeneous reservoirs, reservoir simulation is often coupled with stochastic methods (e.g. Monte Carlo analysis and geostatistical techniques) to improve the quality of the 3D reservoir model.*[118]
>
> *Data collected on previous fracture treatments in the Marcellus Shale and drilling data will be useful to refine the fracture modeling. Actual fracture treatments must be carefully monitored and implemented to ensure fractures stay within zone. Data collected during each fracture treatment should be used to calibrate the 3D reservoir model to improve future fracture treatment design.*
>
> *Peer-reviewed articles and technical data on Marcellus Shale vertical fracture growth characteristics are sparse. While fracture growth models exist at an industry level, and have been tuned for fracture treatments in the Barnett Shales and other gas reservoirs, considerable technical work is still needed to develop fracture growth models for NYS Marcellus Shale development.*
>
> *A literature review was completed by the author [HCLLC] in search of a Marcellus Shale 3D reservoir model for NYS; none was found in the petroleum engineering published literature. It is not clear if the lack of a Marcellus Shale reservoir model for NYS indicates that one does not exist, or whether industry is holding models proprietary. Yet in other shale gas developments (e.g., Barnett and Fayetteville) there is extensive industry literature on: available reservoir simulation model; completion and fracture design; and performance assessment to compare predicted fracture growth with that achieved in the field. Lack of industry literature is usually a strong indication that additional data gathering and technology development is needed.*
>
> *The data void for* NYS' *Marcellus Shale technical literature reinforces the need for NYSDEC to use a conservative, step-wise approach, rather than launching into a massive drilling and fracturing campaign without the data or tools in place to do a safe and effective job.*

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[117] ICF International, Technical Assistance to NYS on DSGEIS, August 2009.

[118] Schepers, K.C., Gonzalez, R.J., Koperna, G.J., and Oudinot, A.Y., Reservoir Modeling in Support of Shale Gas Exploration, Society of Petroleum Engineers, June 2009.

> *NYSDEC should require additional information be collected by industry to better understand the geological and geophysical properties of the Marcellus Shale zone and the overlying strata between the Marcellus and drinking water aquifers.*
>
> *NYSDEC should require 3D reservoir simulation models be developed to accurately predict hydraulic fracture treatment performance, and to ensure the jobs are well engineered and designed with adequate safety factors to avoid fracturing out-of-zone.*
>
> *The DSGEIS must assure the public that fractures can be contained to the Marcellus Shale zone. The DSGEIS does not provide data sufficient to meet this standard. The DSGEIS does not document the existence of 3D reservoir simulation models for NYS' Marcellus Shale, nor does NYSDEC require engineers to design fracture treatments using 3D models.*
>
> *While Marcellus Shale development in Pennsylvania precedes development in NYS, data collected from the Pennsylvania wells is not applicable to the NYS Marcellus Shale because the depth of burial, thickness, organic content, permeability, and other reservoir properties in NYS differ. Industry experts warn that site-specific data is critical:*
>
> *"<u>By their nature, shales are extremely variable and regional differences in structure, mineralogy and other characteristics should always be considered in treatment design</u>...The wide geographic range [of the Marcellus Shale] has led to numerous different completion schemes being utilized as with the geographic variation comes geologic variability within the formation itself. A primary topic of [industry] discussion has been determining the optimal size and type of stimulation treatment for a given area"[119] [emphasis added].*

Marcellus Shale thickness lessens substantially in western NYS to less than 75' for roughly one-third of the total anticipated development area.[120] HVHF treatments in thin shale zones increases the risk of fracturing out-of-zone, unless a very cautious approach is taken by tailoring the design to the geophysical properties of the shale, taking into account shale thickness, local stress conditions, compressibility, and rigidity.

NYSDEC's consultants point out that a gas operator has no incentive to fracture out of the Marcellus Shale zone, because doing so could result in a loss of gas reserves or an increase in produced water volumes. Yet, NYSDEC's consultant, ICF, also recognizes that fracture design is complicated and it is possible to inadvertently fracture out-of-zone. ICF examined the potential for fracture fluids to propagate vertically and contaminate overlying drinking water aquifers. ICF recommended a 1,000' vertical offset be used.

HCLLC agrees that the use of vertical and horizontal offsets (buffer zones) is a prudent approach. The next step is to determine the size of the offsets. Initially, in new areas, offsets should be large, and then may decrease over time, as field data is obtained and predictive capability is refined.

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[119] Fontaine, J., Johnson, N., and Schoen, D., Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper 117772, October 2008.

[120] 2009 NYSDEC, DSGEIS, Figure 4.9.

In 2009, HCLLC pointed out that the 1,000’ vertical offset proposed by ICF is not technically supported, and a horizontal buffer zone is also needed. HCLLC recommended that vertical and horizontal offsets be based on actual field data, 3D reservoir simulation modeling, and a peer-reviewed hydrological assessment. HCLLC recommended these steps be taken to ensure aquifers are protected and nearby wellbore intersections are avoided.

The 2011 RDSGEIS still does not provide technical justification for the proposed minimum 1,000’ vertical offset, nor does it make a recommendation for a horizontal offset from existing wells.

Instead, the 2011 RDSGEIS provides data that shows HVHF treatments in the Marcellus Shale have propagated vertical fractures up to 1500’ in length, and horizontal fractures can extend hundreds to thousands of feet, as further explained below. These data do not support the proposed buffers.

The 2011 RDSGEIS: The 2011 RDSGEIS agrees that in new areas hydraulic fracture model development and design is important, citing recommendations from the Ground Water Protection Council and its consultant ICF; yet, incongruously the RDSGEIS concludes it is unnecessary for operators to be required do this work in NYS (as a SGEIS mitigation measure or a NYCRR requirement).

> *Service companies design hydraulic fracturing procedures based on the rock properties of the prospective hydrocarbon reservoir. For any given area and formation, hydraulic fracturing design is an iterative process, i.e., it is continually improved and refined as development progresses and more data is collected. In a new area, it may begin with computer modeling to simulate various fracturing designs and their effect on the height, length and orientation of the induced fractures. After the procedure is actually performed, the data gathered can be used to optimize future treatments. Data to define the extent and orientation of fracturing may be gathered during fracturing treatments by use of microseismic fracture mapping, tilt measurements, tracers, or proppant tagging. ICF International, under contract to NYSERDA to provide research assistance for this document, observed that fracture monitoring by these methods is not regularly used because of cost, but is commonly reserved for evaluating new techniques, determining the effectiveness of fracturing in newly developed areas, or calibrating hydraulic fracturing models [emphasis added].*[121]

NYSDEC’s consultants (Alpha Geoscience and ICF), the Ground Water Protection Council, HCLLC, and industry all agree:

- There is a need for computer modeling on new gas shale play areas to simulate various fracturing designs and their effects on the height, length, and orientation of the induced fractures;
- After the HVHF treatment is actually performed, gathered data should be used to optimize future treatments; and
- There is technology available to further refine treatment design, including microseismic fracture mapping, tilt measurements, tracers, and proppant tagging.

However, these points of agreement are not reflected in the RDSGEIS, permit conditions, or NYCRR revisions. Remarkably, the 2011 RDSGEIS only has a few paragraphs in the entire 1,537 page document that discuss the importance of HVHF modeling and post-fracture assessment work (Chapter 5.8), and these recommendations are later disregarded in Chapter 7 proposed mitigation.

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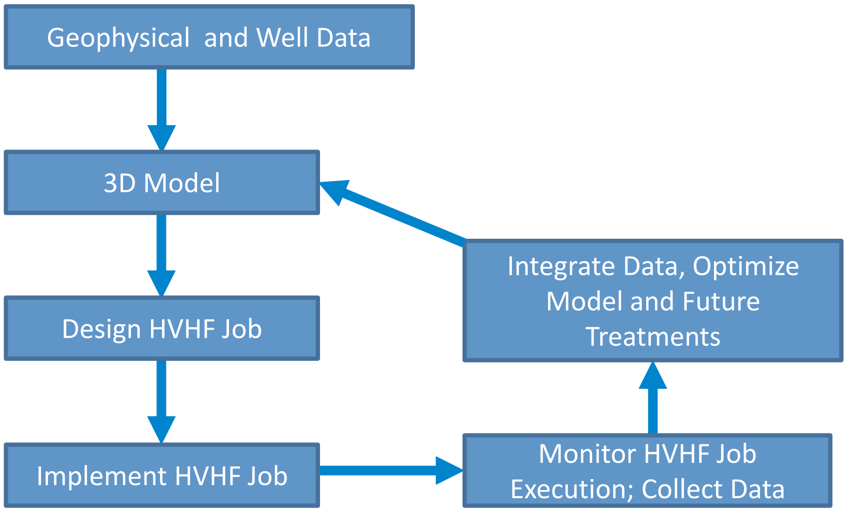
[121] 2011 NYSDEC, RDSGEIS, Page 5-88.

The use of 3D reservoir simulation to more accurately predict vertical and horizontal fracture growth is not new; reservoir simulation models have been used by petroleum engineers for decades. However, computational efficiency and model design have improved considerably, and more sophisticated simulation techniques are now available for shale gas reservoirs.

The basic engineering approach for populating a 3D reservoir simulation model is shown in the simplified flow diagram below, with geophysical data (seismic, well logs, core, samples, etc.) and existing nearby well data serving as the starting point. Once a model is built, it is used to design and optimize a safe and effective HVHF job. Data are gathered while the job is implemented, and those data are used to refine the model and improve future HVHF treatments.



There is abundant industry literature explaining the need for hydraulic fracture modeling and microseismic mapping, especially for new shale play developments, such as in NYS.

NYSDEC should recognize that the use of refined, site-specific models to optimize HVHF jobs is industry best practice. Quality operators with high standards routinely do this work. It should not be considered a burdensome practice, but rather a necessary requirement to protect groundwater and the environment.

Furthermore, it is economically attractive for an operator to use HVHF modeling. Models aid industry in making informed decisions, and prevents fracturing out-of-zone, which maximizes gas recovery rates.

Microseismic mapping has become a key tool for better understanding shale gas heterogeneities, identifying reservoir faults, and measuring actual fracture propagation orientation and length.

A 2010 industry paper[122] written by Rex Energy Corporation and MicroSeismic Inc. explains the importance of microseismic mapping for shale gas engineering:

> *By using microseismic source locations and mechanisms in conjunction with other geological and geophysical knowledge of an area, engineering and completion methods can be quickly corrected and enhanced. Induced fracture height, length, and placement influence the location, orientation and spacing of subsequent wells. Microseismic monitoring allows for identification and characterization of unknown faults which intersect the wellbore and may significantly affect reservoir production and stimulations. Formations with limited exploration with limited exploration data, such as the Marcellus shale, are ideal candidates for microseismic monitoring [emphasis added].*
>
> *In this case study, we will show how the microseismic monitoring of a hydraulic fracture treatment in the Marcellus Shale identified a pre-existing natural fault which intersected the wellbore [emphasis added].*

A 2011 industry paper[123] written by Marquette Exploration (a Marcellus Shale operator) and Schlumberger (an industry contractor), titled "Integrating All Available Data to Improve Production in the Marcellus Shale," emphasizes the importance of HVHF design and monitoring:

> *The operator featured in this paper is a small independent with Marcellus Shale areas of operation spanning across Belmont and Jefferson counties, eastern Ohio (Fig.2). This paper describes the methodology used by the operator to systematically gather the critical data during a pilot program to enhance the knowledge of their reservoir and develop optimized completion strategies and stimulation designs, thereby maximizing the true economic value of their asset.*
>
> *To build realistic property models, input from team members from different disciplines is required; in this study, team members included a geophysicist, geologist, petrophysicist, and reservoir engineer. Once the 3D structural model was completed, individual log measurements and interpreted properties from petrophysical, geomechanical, and image logs were incorporated in the model.*

Marquette Exploration's paper concludes:

- *Delineating a reservoir early on in the play and gathering as much data as possible can improve the drilling and completion design of the initial horizontal wells in the field to reduce the time and cost for an operator to get up the learning curve.*
- *Using all available data can greatly enhance the understanding in a field which, in turn, can improve the lateral design. Core data are imperative to calibrate petrophysical and geomechanical logs to further refine log models in other wells in an area.*
- *Seismic data in conjunction with strategically placed vertical logs can be used to construct a detailed static 3D geological model.*

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[122] Hulsey, B.J., and Cornette, B. (MicroSeismic Inc.), and Pratt, D. (Rex Energy Corporation), Surface Microseismic Mapping Reveals Details of the Marcellus Shale, Society of Petroleum Engineers, SPE Paper 138806, 2010, Page 1.

[123] Ejofodomi, E., Baihly, J., Malpani, R., Altman, R, (Schlumberger), and Huchton, T., Welch, D., and Zieche, J., (Marquette Exploration), Integrating All Available Data to Improve Production in the Marcellus Shale, Society of Petroleum Engineers Paper, SPE 144321, 2011.

- *The thickness, depth, and continuity for shale sub-layers can vary greatly over a small area, so a pilot hole can be imperative to calibrate the geologic model for lateral landing point determination.*
- *The geologic model showed that the reservoir properties varied across the area of interest.*
- *Stochastic modeling can be used to successfully propagate interpreted log properties from a few wells across a large acreage.*
- *A novel reservoir modeling technique, Microseismic Fracture Network (MFN), was developed using microseismic data to properly describe the created complex fracture network.*

A 2010 industry paper[124] written by El Paso Exploration and Production and StrataGen Engineering stresses the importance of HVHF design:

> *…a primary conclusion is that as reservoir permeability decreases, proper well type selection and effective hydraulic fracture stimulation design become much more crucial [emphasis added].*
>
> *Additional modeling with specifics must be performed to evaluate well type, fracture design, and spacing requirement for a specific well or formation [emphasis added].*

A 2011 industry paper[125] written by Schlumberger also stresses the importance of HVHF design and monitoring:

> *The completion strategy and hydraulic fracture stimulation are the keys to economic success in unconventional reservoirs. Therefore, reservoir engineering workflows in unconventional reservoirs need to focus on completion and stimulation optimization as much as they do well placement and spacing. This well-level focus requires the integration of hydraulic fracture modeling software and the ability to utilize measurements specific to unconventional reservoirs [emphasis added].*
>
> *It is very important to properly model hydraulic fracture propagation and hydrocarbon production mechanisms in unconventional reservoirs, a significant departure from conventional reservoir simulation workflows. Seismic-to-simulation workflows in unconventional reservoirs require hydraulic fracture models that properly simulate complex fracture propagation which is common in many unconventional reservoirs, algorithms to automatically develop discrete reservoir simulation grids to rigorously model the hydrocarbon production from complex hydraulic fractures, and the ability to efficiently integrate microseismic measurements with geological and geophysical data. The introduction of complex hydraulic fracture propagation models now allows these workflows to be implemented [emphasis added].*

A 2010 industry paper[126] written by StrataGen Engineering and CMG (industry consultants) again highlights the importance of HVHF design and monitoring:

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[124] Shelley, R.F., Lolon, E., and Dzubin, B. (StrataGen Engineering), and Vennes, M. (El Paso Exploration and Production), Quantifying the Effects of Well Type and Hydraulic Fracture Selection on Recovery for Various Reservoir Permeability Using a Numerical Reservoir Simulator, Society of Petroleum Engineers Paper, SPE 133985, 2010, Pages 1 and 12.

[125] Cipolla, C.L., Fitzpatrick, T., Williams, M.J., and Ganguly, U.K., (Schlumberger), Seismic-to-Simulation for Unconventional Reservoir Development, Society of Petroleum Engineers Paper, SPE 146876, 2011, Page 1.

> *The widespread application of microseismic mapping has significantly improved our understanding of hydraulic fracture growth in unconventional gas reservoirs (primarily shale) and led to better stimulation designs. However, the overall effectiveness of stimulation treatments is difficult to determine from microseismic mapping, as the location of proppant and distribution of conductivity in the fracture network cannot be measured (and are critical parameters that control well performance). Therefore <u>it is important to develop reservoir modeling approaches that properly characterize fluid flow in and the properties of a complex fracture network, tight matrix, and primary hydraulic fracture (if present) to evaluate well performance and understand critical parameters that affect gas recovery</u> [emphasis added].*
>
> *Given the complex nature of hydraulic fracture growth and the very low permeability of the matrix rock in many shale-gas reservoirs combined with the predominance of horizontal completions, <u>reservoir simulation is commonly the preferred method to predict and evaluate well performance</u> [emphasis added].*
>
> *The most rigorous method to model shale-gas reservoirs is to discretely grid the entire reservoir, including the network fractures, hydraulic fracture, matrix blocks, and un-stimulated areas – but this increases computational time. However, with the continual advances in computing power, much more complex numerical models can be efficiently utilized.*

In 2010, Atlas Energy Resources published a Society of Petroleum Engineering Paper that explained the importance of reservoir characterization, modeling, the use of minifracs, and the use of microseismic data. Atlas Energy Resources explained that the use of advanced technology is good business:

> *This paper describes a procedure to enhance production in the Marcellus shale while optimizing economics through integration of minifrac, fracture treatment, microseismic, and production data technologies.*
>
> *Application of this integrated technology approach will help prodvide the operator with a systematic approach for designing, analyzing, and optimizing multi-stage/multi-cluster transverse hydraulic fractures in horizontal wellbores.*[127]

An engineering analysis and modeling prior to a HVHF treatment provides industry, regulators, and the public with confidence that the treatment has been thoroughly evaluated and designed to protect the environment. It is not sufficient for industry and NYSDEC to say this work is being done, while being unwilling to require it. If this work is being done, then creating a formal requirement in the SGEIS and NYCRR does not impose an incremental burden on the operator. Resistance to a formal requirement should signal to NYSDEC that industry best practice is not always followed.

While industry literature explains the need for hydraulic fracture modeling, this does not guarantee it will actually be implemented by all shale gas operators in NYS. Shale gas drilling has attracted numerous small, less experienced operators. Computational modeling requires personnel with expertise in building models, running them, and refining datasets. If the operator does not have sufficient in-house engineering and geophysical expertise, it should be required to hire experts to provide the necessary expertise.

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[126] Cipolla, C.L., Lolon, E.P. (StrataGen Engineering), Erdle, J.C., and Rubin, B. (CMG), Reservoir Modeling in Shale-Gas Reservoirs, Society of Petroleum Engineers Paper, SPE 125530, 2009, Pages 1,3, and 4.

[127] Henry Jacot, R. (Atlas Energy Resources), Bazan, L.W. (Bazan Consulting, Inc.), Meyer, B.R. (Meyer & Associates Inc.), Technology Integration – A Methodology to Enhance Production and Maximize Economics in Horizontal Marcellus Shale Wells, Society of Petroleum Engineers Paper, SPE 135262, 2010, Page 1.

Recommendation No. 32: Best practices for HVHF design and monitoring should be included in the SGEIS as a mitigation measure, and codified in NYCRR as a minimum standard.

Additionally, Alpha Geoscience, ICF, Ground Water Protection Council, HCLLC, and industry all agree that additional technical work is needed to develop new shale gas play areas; yet the 2011 RDSGEIS does not require the operator to develop or maintain a hydraulic fracture model. Instead, the 2011 RDSGEIS only requires the operator to abide by a 1000' vertical offset from protected aquifers and collect data during the HVHF job to evaluate whether the job was implemented as planned.[128]

Knowing whether a job was implemented as planned is only helpful if the initial design is protective of human health and environment. If the job is poorly planned, and is implemented as planned, that only proves that a poor job was actually implemented. This approach would not be in NYS' best interest.

Instead, NYS needs to first verify that the operator has engineered a HVHF treatment that is protective of human health and environment, and then, second, verify that the job was implemented to that protective standard. A rigorous engineering analysis is a critical design step. Proper design and monitoring of HVHF jobs is not only best practice from an environmental and human health perspective, it is also good business because it optimizes gas production and reduces hydraulic fracture treatment costs.

The 2011 RDSGEIS does not require a HVHF design plan.[129] The RDSGEIS does not require the operator to:

(a) Estimate the vertical and horizontal fracture length;

(b) Verify that the proposed HVHF design will not intersect protected groundwater or nearby wells;

(c) Use a site-specific hydraulic fracture model, based on NYS specific shale characteristics and the operational design parameters of the planned HVHF job (volume, pressure, rate, etc.).

Recommendation No. 33: The SGEIS and NYCRR should require the operator to:

(a) Estimate the maximum vertical and horizontal fracture propagation length for each well, and submit technical information (e.g. model output) with its application to support its computations.

(b) Describe in its post-well completion report whether the predicted vertical and horizontal fracture propagation lengths were accurate, or note discrepancies.

(c) Certify that the actual HVHF job was implemented safely, and fracture propagations did not intersect protected aquifers or nearby wells.

Additionally, NYS should reserve the right, and provide funding, to periodically review industry's models and computations to assess quality and verify this work is being completed.

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[128] 2011 NYSDEC, RDSGEIS, Page 5-88.

[129] The operator is only required to verify that the vertical offset of 1000' is achieved and the shale is at least 2000' deep.

The 2011 RDSGEIS assumes that any HVHF job, no matter the volume, no matter the pressure, and no matter the shale thickness, will be safe, as long as it is conducted at a depth below 2,000'. The 2011 RDSGEIS recommends that site-specific SEQRA reviews be limited to wells shallower than 2000' and within 1000' of a protected aquifer.[130] The RDSGEIS lacks technical and scientific data to support the hypothesis that all HVHF treatments, regardless of design, at 2000' or deeper will be safe. Additionally, the RDSGEIS does not address safe horizontal fracture length.

NYSDEC does not provide data on HVHF treatments conducted between 2000' and 5000' deep; yet, NYS proposed to allow shale gas drilling at these depths. Instead, the RDSGEIS relies on limited data collected from Marcellus Shale fractures conducted in other states at depths below 5000'. However, even industry points out that data collected in one part of the Marcellus Shale cannot be applied to the entire shale.

For example, Guardian Exploration and Universal Well Services reports that optimal Marcellus Shale HVHF treatments are still being developed, and that a "one-size-fits-all approach should not be expected. They anticipate that industry will examine the use of higher rates and increased fluid volume and proppant mass in the future resulting in varied fracture lengths from current HVHF jobs:

> *Much work remains to be done in determining the optimal stimulation treatment for the Marcellus shale. Certainly given the extremely large geographic area encompassed by the Marcellus play, it should not be expected that one size will fit all. While the treatment discussed here has been considered successful, future projects will examine the effects of increased rate, increased volumes in terms of both overall fluid volume and proppant mass, the effects of varying the proppant mesh ratios and concentrations, and optimization of flowback/cleanup rates. The utilization of evaluation tools such as microseismic monitoring of fracture growth and horizontal drilling and completions to enhance reservoir development should also prove to be beneficial [emphasis added].*[131]

As HVHF treatment methods continue to evolve, NYSDEC must either set a limit in the SGEIS and NYCRR for the upper bounds of a safe HVHF job, or it must have a process in place for industry to provide site-specific engineering to support each well application to ensure that new HVHF designs are safe.

NYSDEC assumes that 1000' vertical separation between the bottom of the protected groundwater zone and the top of the shale zone where HVHF will occur is sufficiently protective, regardless of shale thickness, HVHF job size, and other subsurface characteristics. However, this approach is not technically supported. The 2011 RDSGEIS concludes:

> *As explained in Section 6.1.5.2, the conclusion that harm from fracturing fluid migration up from the horizontal wellbore is not reasonably anticipated is contingent upon the presence of certain natural conditions, including 1,000 feet of vertical separation between the bottom of a potential aquifer and the top of the target fracture zone. The presence of 1,000 feet of low-permeability rocks between the fracture zone and a drinking water source serves as a natural or inherent mitigation measure that protects against groundwater contamination from hydraulic fracturing [emphasis added].*[132]

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[130] 2011 NYSDEC, RDSGEIS, Page 7-59.

[131] Fontaine, J., and Johnson, N. (Universal Well Services), and Schoen, D. (Guardian Exploration), Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper, SPE 117772, 2008, Page 11.

[132] 2011 NYSDEC, RDSGEIS, Page 7-59.

Neither the 2009 DSGEIS nor the 2011 RDSGEIS contain site-specific NYS Marcellus Shale hydraulic fracture model data to support NYSDEC's conclusion that a 1,000' vertical separation will be protective in all cases in NYS, especially where thinner, shallower shales are present. Furthermore, the 2011 RDSGEIS lacks data on vertical and horizontal fracture propagation in the Marcellus Shale at depths between 2000' and 5000' (depths that NYS proposes to permit).

The behavior of HVHF propagation in NYS is not currently well understood. HCLLC was unable to locate any NYS site-specific hydraulic fracture models for the Marcellus, Utica, or other low-permeability reservoirs. If these models exist, they should be described in the SGEIS, and NYSDEC should explain how it used the data from these models to inform its SGEIS.

Instead, the RDSGEIS currently relies on Marcellus Shale HVHF data from other states that may not be applicable to NYS. For example, NYSDEC points to data collected on 400 Marcellus hydraulic fractures conducted in Pennsylvania, West Virginia, and Ohio. This data was summarized in a three page article in the American Oil & Gas Reporter in July 2010:

> *Four hundred Marcellus hydraulic fracturing stages in Pennsylvania, West Virginia and Ohio have been mapped with respect to vertical growth and distance to the deepest water wells in the corresponding areas. Although many of the hydraulic fracturing stages occurred at depths greater than the depths at which the Marcellus occurs in New York, the results across all depth ranges showed that induced fractures did not approach the depth of drinking water aquifers. In addition, as previously discussed, at the shallow end of the target depth range in New York, fracture growth orientation would change from vertical to horizontal.*[133]

NYSDEC's conclusions rely heavily on the American Oil & Gas Reporter three-page article (Fisher, 2010); yet NYSDEC does not further investigate the origin of the data contained in this article or its implications for shale development in NYS. Fracture growth is a function of type of formations located above and below the Marcellus Shale. Subsurface geology will vary across states and the RDSGEIS does not explain how this data is applicable to NYS. For example, this article:

- Does not provide any information on the maximum HVHF job size (volumes, pressures, rates, etc.) to verify whether the fracture treatments conducted and analyzed are equivalent to the maximum HVHF job size anticipated in NYS;
- Does not provide any information on the Marcellus Shale thickness or geophysical properties present during the HVHF treatments;
- Shows that vertical fractures in excess of 1000' were observed (the plot, which is copied from the Fisher 2010 report and provided below, shows a 1500' vertical fracture propagated at 6300');
- Does not show what the vertical fracture growth height would be in the 2000-5000' Marcellus Shale depth interval that NYS proposes to develop; and,
- Does not show the horizontal distance that a fracture will propagate at the shallower shale depths NYS plans to develop.

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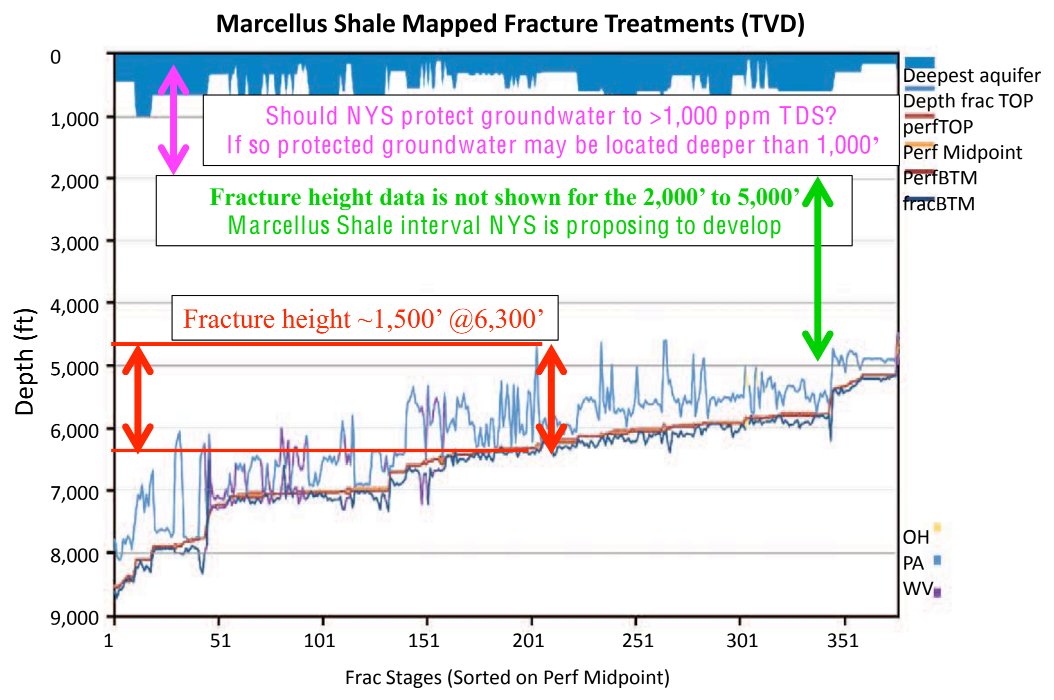
[133] 2011 NYSDEC, RDSGEIS, Page 6-56.

A more in-depth technical paper written by Kevin Fisher (Halliburton) in 2011 appears to be the origin of the data cited in the American Oil & Gas Reporter article. Fisher's 2011 paper[134] concludes that:

> *Fracture lengths can sometimes exceed a thousand feet when contained with a relatively homogeneous layer [emphasis added].*
>
> *At depths deeper than about 2,000 ft, the vertical stress or overburden is generally the largest single stress so the principal fracture orientation is expected to be vertical on deeper wells [emphasis added].*
>
> *At some point on shallow wells, the overburden stress will decrease to a point where it is less than the maximum horizontal stress and, at this point, one would expect the fracture growth to be horizontal and not vertical. As wells get shallower, and the overburden stress lessens, mapped fractures are typically observed exhibiting increasingly larger horizontal components. All of the fractures do not necessarily turn horizontal; they might have significant vertical and horizontal components with more of a T-shaped geometry, but the horizontal components can become significant and could thieve away enough fluid causing a blunting effect, limiting upward fracture-height growth [emphasis added].*

The Marcellus fracture height figure shown in the American Oil & Gas Reporter is provided below; HCLLC annotated it to identify additional evaluation that is needed for NYS.



Plot from Fisher 2010 Cited in 2011 rdSGEIS; annotated by HCLLC with additional red, green, and magenta font information.

The use of vertical offset limits to separate hydrocarbon recovery operations from protected aquifers is a reasonable approach, but it must be scientifically and technical supported. While it is possible that a 1,000' vertical offset may potentially be sufficiently protective; the 2011 RDSGEIS does not provide sufficient scientific data or technical examination to support this recommended threshold.

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[134] Fisher, K. and Warpinski, N., Pinnacle- A Halliburton Service, Hydraulic Fracture-Height Growth: Real Data, Society of Petroleum Engineers Paper, SPE 145949, 2011, Pages 1-2 and 5.

In addition to understanding the maximum vertical fracture propagation height, horizontal fracture propagation distance is an important consideration, especially when developing shallower shale zones. Fractures in shallower formations will tend to propagate on the horizontal plane. HVHF treatments should be designed to prevent fractures from intersecting with existing improperly constructed and improperly abandoned wells, and transmissive faults and fractures, which can provide pollutants a direct pathway to protected groundwater resources.

For example, in 2010 the BC Oil & Gas Commission issued a safety advisory on the risks of fracture treatments intersecting adjacent wells. The advisory specifically notified industry that:

> *A large kick was recently taken on a well being horizontally drilled for unconventional gas production in the Montney formation. The kick was caused by a fracturing operation being conducted on an adjacent horizontal well. Fracture sand was* ***circulated from the drilling wellbore, which was 670m [~2200’] from the wellbore*** *undergoing the fracturing operation. [emphasis added].*[135]

Additionally, the advisory reported 18 known fracture communication incidents in B.C. and one in Western Alberta: five incidents of fracture stimulation communicating with an adjacent well; three incidents of drilling into a hydraulic fracture formed during a previous stimulation on an adjacent well and containing high pressure fluids; 10 incidents of fracture stimulations communicating into adjacent producing wells, and one incident of fracture stimulations communication into an adjacent leg on the same well for a multi-lateral well. Therefore fracture stimulations communication with adjacent wells is a known and reasonably foreseeable risk.

The 2011 RDSGEIS includes a wellbore schematic used in presentations given by the NYSDEC Commissioner. This wellbore schematic, shown below, depicts an example Marcellus Shale well. In the example the base of freshwater is at 500’, the well is drilled to a depth of 4,000’, and the horizontal length of the well is 4,000’.

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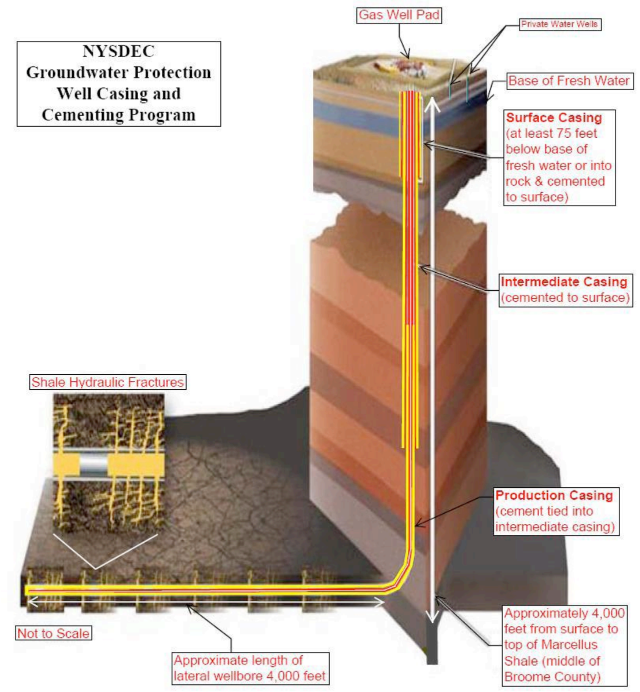
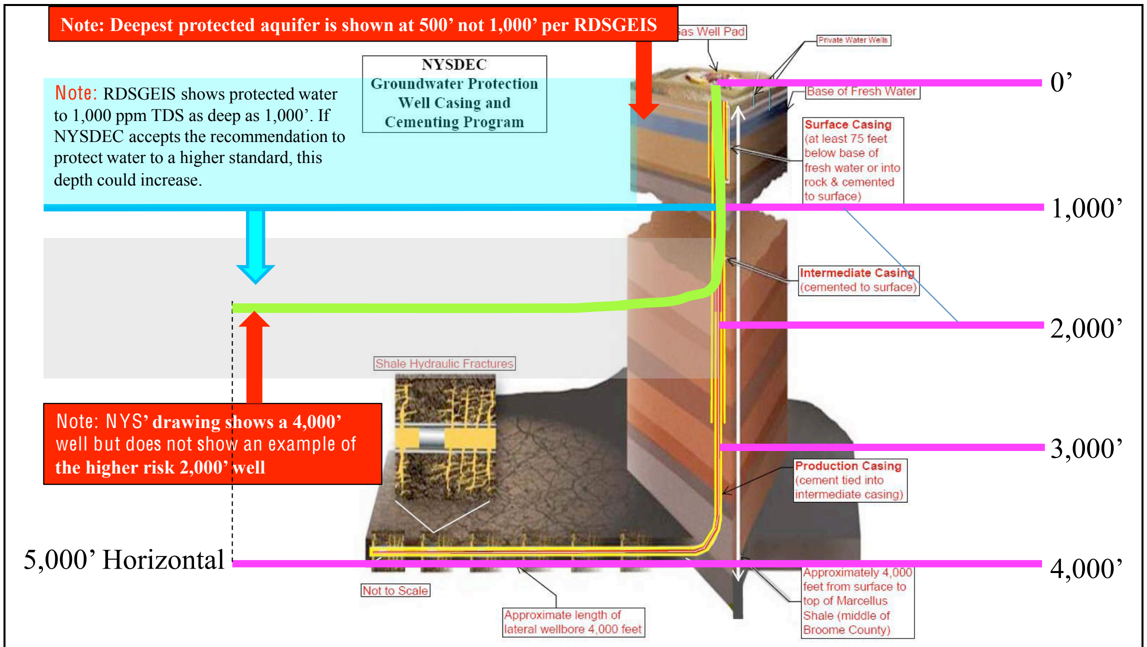
[135] BC Oil & Gas Commission, Safety Advisory 2010-03, Communication During Fracture Stimulation, May 20, 2010.



Drawing from: Presentation by Commissioner Joe Martens NYS Department of Environmental Conservation, 2011 Supplemental Generic Environmental Impact Statement for High-Volume Hydraulic Fracturing showing a 500' freshwater depth and a 4,000' HVHF well.

The drawing does not represent the highest risk wells proposed in the 2011 RDSGEIS. The highest risk wells allowed under the 2011 RDSGEIS would be drilled into a thin section of the Marcellus Shale at a 2,000' depth, with protected water located above at 1,000'. Below is an annotated version of this wellbore schematic, prepared by HCLLC, showing the higher risk wells proposed under the RDSGEIS.



Drawing from: Presentation by Commissioner Joe Martens NYS Department of Environmental Conservation, 2011 Supplemental Generic Environmental Impact Statement for High-Volume Hydraulic Fracturing was annotated by HCLLC to show a HVHF well constructed at 2,000' depth, the base of freshwater at least at 1,000' and a theoretical uncertainty zone associated with vertical and horizontal fracture propagation at 2,000' depth.

As explained in Chapter 9 of this report , if a HVHF treatment intersects with a nearby improperly abandoned well, the potential exists for the improperly abandoned well to become a vertical conduit, and therefore transfer hydraulic fluid and mobilized gas to protected aquifers. Additionally, the pollution risk posed by possible HVHF intersections is not limited to improperly abandoned wells; existing wells that were poorly designed and constructed could also pose a risk.

Physics dictate that fractures form perpendicular to the direction of the least amount of stress. Vertical fracture height will decrease with depth, and horizontal fracture length will increase.

NYSDEC proposes that operators identify wells within a mile radius around the surface location of a HVHF well, to identify wells that might be at risk of intersection with HVHF treatments.[136] However, NYSDEC does not provide technical data to support a mile radius. The 2011 RDSGEIS does not specify a maximum horizontal drilling length. Although NYSDEC's spacing rules may impose some limitation on this length, limitations are not clearly explained in the RDSGEIS.

The RDSGEIS should identify the maximum horizontal fracture propagation distance that could occur in a shallow well to ensure that HVHF treatments do not intersect existing wellbores. This should be included in the SGEIS. Limits on horizontal drilling section lengths and HVHF job size, including a safety zone around each HVHF well, should also be established.

Recommendation No. 34: The SGEIS should provide a basis for the maximum horizontal well drilling limit. The SGEIS should also explain how the operator will verify that the maximum horizontal well drilling limit, plus the maximum predicted horizontal fracture length, will avoid nearby well intersection.

The most logical way forward is to begin by limiting development to the deepest Marcellus Shale intervals, maximizing the vertical separation from drinking water aquifers. Once accurate, field-calibrated 3D reservoir simulation models are available for NYS, development can then move to shallower intervals, as long as technical data shows that treatments will remain in zone.

Recommendation No. 35: The SGEIS should technically justify vertical and horizontal HVHF treatment offsets. Proposed offsets should be supported by hydraulic fracture modeling. Modeling should reflect the maximum HVHF job designs allowed in NYS and shale reservoir characteristics. NYSDEC should provide public access to the scientific data and hydraulic fracture models it uses to develop vertical and horizontal offsets for the purposes of the SGEIS.

Drilling into the deepest, thickest Marcellus Shale intervals (e.g., below 4000') will maximize data collection, affording access to all overlying intervals. Core samples, well logs, and pressure transient data can be obtained, verifying whether there are continuous permeability barriers hydraulically separating the Marcellus Shale and the overlying drinking water aquifers, and geologic barriers that will limit fracture propagation. Initially, smaller fracture treatments should be used as tests. These treatments can be increased in size over time, if data support the conclusion that large fracture treatments can remain in zone. As data are collected, and 3D reservoir models are developed and refined, it may be possible to safely develop the Marcellus at shallower depths and in thinner intervals.

NYSDEC's recommendation to move forward with shale gas development, absent additional engineering data and hydraulic fracture models, is technically unsupported and in direct conflict with the information cited in its 2009 DSGEIS and 2011 RDSGEIS, as well as its own consultants' recommendations.

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[136] 2011 NYSDEC, RDSGEIS, Page 6-56.

Recommendation No. 36: The SGEIS should include a more thorough examination of hydraulic fracture modeling. The SGEIS and NYCRR should require the operator to:

(a) Collect additional geophysical and reservoir data to support a reservoir simulation model;

(b) Develop a high-quality Marcellus Shale 3D reservoir model(s) to safely design fracture treatments;

(c) Maintain and run hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained in zone;

(d) Collect and carefully analyze data from HVHF treatments to optimize future HVHF treatments;

(e) Initially complete HVHF treatments in the deepest, thickest sections of the Marcellus Shale to gain data and experience before proceeding to shallower zones (e.g. 4000' deep and 150' thick, progressively moving shallower as more NYS site-specific information is collected); and

(f) Conduct post-fracture analysis, and provide that analysis to NYS to demonstrate that the HVHF treatment was safely implemented.

NYCRR Proposed Revisions: There are no proposed revisions in the NYCRR. As proposed, the NYCRR do not require operators to:

(a) Submit a HVHF designs to NYS;

(b) Estimate the vertical and horizontal fracture length;

(c) Provide engineering analysis and run HVHF modeling;

(d) Monitor HVHF performance to ensure that HVHF design and actual implementation in the field match; and

(e) Notify NYSDEC if the actual vertical and/or horizontal fracture length greatly exceeds the job design, such that risk may be present to the environment.

11. Hydraulic Fracture Treatment Additive Limitations

Background: In 2009, HCLLC recommended that NYS regulations identify fracture treatment additives that are protective of human health and the environment. HCLLC also recommended that the NYCRR include a list of prohibited chemical additives.

2011 RDSGEIS: The 2011 RDSGEIS includes improvements in the handling and storage of HVHF chemicals by requiring chemicals to be stored in suitable containers placed in secondary containment. Additionally, NYSDEC encourages operators to select the lowest toxicity chemicals. However, neither the 2011 RDSGEIS nor the proposed NYCRR amendments establish a prohibited chemical list, nor do they require an operator to use the lowest toxicity chemicals. Instead, the 2011 RDSGEIS requires only that the operator evaluate alternative products. Ultimately, the operator is allowed to select the final chemicals used with no firm evaluation criteria listed in the NYCRR to rule out harmful chemicals.

NYCRR Proposed Revisions: Proposed regulations at 6 NYCRR § 560.3(c)(1)(v) require only that the operator provide:

> *Documentation that proposed chemical additives exhibit reduced aquatic toxicity and pose a lower potential risk to water resources and the environment than available alternatives; or documentation that available alternative products are not equally effective or feasible.*

The proposed regulation requires the operator to examine chemicals that “exhibit reduced aquatic toxicity” and a “lower risk to water resources,” but the NYCRR does not provide specific criteria for determining what is an acceptable reduction in toxicity or an acceptable reduction in risk.

The 2011 RDSGEIS guides the operator to conduct a five-part analysis:

> *The evaluation criteria should include (1) impact to the environment caused by the additive product if it remains in the environment, (2) the toxicity and mobility of the available alternatives, (3) persistence in the environment, (4) effectiveness of the available alternative to achieve desired results in the engineered fluid system, and (5) feasibility of implementing the alternative.*[137]

However the 2011 RDSGEIS does not instruct the operator on what is required if any part of the five-part analysis has an unacceptable outcome, nor does the NYCRR. For example, if an operator proposes a chemical additive that is known to impact the environment and be persistent if it remains in the environment, but the operator proposes no other alternative, or states that this is the only chemical that will be effective for its planned job, neither the RDSGEIS or the NYCRR prohibit the operator from using this chemical even if it is harmful.

As proposed, the NYCRR would still allow the use of a highly toxic chemical, as long as it was slightly less toxic than the most toxic chemical available. This is not best practice. Best practice would be to use the chemical with the lowest impact and risk, not just a slightly improved risk. Best practice would also be for NYS to develop a list of prohibited chemicals that pose an unacceptable risk to human health and the environment.

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[137] 2011 NYSDEC, RDSGEIS, Page 8-30.

The 2011 RDSGEIS concludes that it is not possible for hydraulic fracturing to contaminate groundwater, erroneously assuming that all wells will be flawlessly constructed and operated, and that no human error is possible that would put hydraulic fracturing additives in contact with groundwater, with the exception of a potential surface spill. The 2011 RDSGEIS concludes:

> *The regulatory discussion in Section 8.4 concludes that adequate well design prevents contact between fracturing fluids and fresh ground water sources, and text in Chapter 6 along with Appendix 11 on subsurface fluid mobility explain why ground water contamination by migration of fracturing fluid is not a reasonably foreseeable impact.*[138]

The 2011 RDSGEIS should be revised to clarify that groundwater contamination by hydraulic fracturing fluids is a reasonably foreseeable impact that requires mitigation. Well construction failures, engineering design flaws, human error, mechanical malfunctions, and chemical spills all are reasonably foreseeable events, and have occurred at Marcellus Shale operations in Pennsylvania.[139] Additionally, Dr. Myers identifies the potential long-term contaminant transport through conductive faults, natural fractures, and advective transport.[140]

Groundwater contamination has been attributed to operational failures at various Marcellus Shale gas development operations in Pennsylvania, including operations by Cabot Oil & Gas Corporation, Catalyst Energy, Inc., and Chesapeake Energy Corporation.

For example, on February 27, 2009, the Pennsylvania Department of Environmental Protection (PADEP) issued a Notice of Violation to Cabot Oil & Gas Corporation for unpermitted discharge of polluting substances and failure to prevent gas from entering fresh groundwater, among other deficiencies, in connection with its drilling activities in Dimock Township.[141] PADEP inspectors *"...discovered that the well casings on some of Cabot's natural gas wells were cemented improperly or insufficiently, allowing natural gas to migrate to groundwater...DEP ordered Cabot to cease hydro fracking natural gas wells throughout Susquehanna County.*"[142] In April 2010, under its consent order and agreement with PADEP, Cabot was required to plug three leaking wells that contaminated the groundwater and drinking water supplies of 14 homes in the region.[143]

In 2011, PADEP issued a cease and desist order to Catalyst Energy, Inc. that prohibited the company from conducting drilling and hydraulic fracturing operations, after a PADEP investigation confirmed that private water supplies serving two homes had been contaminated by natural gas and elevated levels of iron and manganese from Catalyst's operations.[144]

In May 2011, PADEP fined Chesapeake Energy Corporation $1,088,000 for violations related to natural gas drilling activities that contaminated private water supplies in Bradford County. PADEP issued a news release reporting:

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[138] 2011 NYSDEC, RDSGEIS, Page 8-29.

[139] DEP Investigating Lycoming County Fracking Fluid Spill at XTO Energy Marcellus Well, November 22, 2010, available at http://www.portal. state.pa.us/portal/server.pt/community/newsroom/

14287?id=15315&typeid=1

[140] Dr. Tom Myers, Comments Prepared for NRDC on 2011 RDSGEIS, 2012.

[141] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[142] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[143] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=10586&typeid=1.

[144] DEP Orders Catalyst Energy to Stop Operations at Gas Wells in Forest County Village, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=16894&typeid=1.

> *DEP determined that because of improper well casing and cementing in shallow zones, natural gas from non-shale shallow gas formations had experienced localized migration into groundwater and contaminated 16 families' drinking water supplies.*[145]

If HVHF treatments are conducted in poorly constructed wells, there exists a potential for groundwater contamination. Therefore, as NYSDEC recommends, well construction must be robust, and the use of safe HVHF treatment additives provides any extra layer of protection in the event that human error or mechanical malfunction create a pathway for such additives to reach groundwater. Reducing the toxicity of hydraulic fracturing additives by listing prohibited additives mitigates the impact of both surface and groundwater pollution if it occurs.

Recommendation No. 37: NYSDEC should develop a list of prohibited fracture treatment additives based on the known list of chemicals currently used in hydraulic fracturing. The list of prohibited fracture treatment additives should apply to all hydraulic fracture treatments, not just HVHF treatments. NYSDEC should also develop a process to evaluate newly proposed hydraulic fracturing chemical additives to determine whether they should be added to the prohibited list. No chemical should be used until NYSDEC and/or the NYSDOH has assessed whether it is protective of human health and the environment, and has determined whether or not it warrants inclusion on the list of prohibited hydraulic fracturing chemical additives for NYS. The burden of proof should be on industry to demonstrate, via scientific and technical data and analysis, and risk assessment work, that the chemical is safe. Fracture treatment additive prohibitions should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

The 2009 DSGEIS Section 5.3[146] stated that NYSDEC collected compositional information from chemical suppliers and service companies on many of the additives proposed for use in shale fracture treatments. NYSDEC reported partial compositional data on 197 products and complete compositional data on 152 products. Tables 5.3-5.7 provided lists of chemicals proposed for use in fracture treatments, and Section 5.4.3.1 described the potential health impacts of categories of chemicals. Yet the 2009 DSGEIS did not arrive at any recommendation or conclusion about which fracture treatment additives are acceptable for use in NYS and which are not. This problem persists in the 2011 RDSGEIS.

Chapter 5 of the 2011 RDSGEIS explains that NYSDOH reviewed information on 322 unique chemicals present in 235 products proposed for hydraulic fracturing of shale formations in New York and categorized them into chemical classes, but did not develop any recommendations for prohibiting specific HF additives. The 2011 RDSGEIS merely concludes that the 322 unique chemicals studied did not identify any potential exposure situations that are qualitatively different from those addressed in the 1992 GEIS.[147] This conclusion has little significance, since the 1992 GEIS did not establish any criteria for limiting or prohibiting HF chemical additives (i.e., for mitigating potential significant adverse impacts from exposure to these additives). For example, Dr. Miller points out that acrylonitrile and acrylamide are listed, and known to be carcinogenic and quite toxic, but fairly short lived in an aqueous environment.[148] As proposed, NYSDEC would allow these carcinogenic, toxic chemicals to be used, unless industry proposes a less-harmful chemical. The appropriate step for NYS would be to add acrylonitrile and acrylamide, among other chemical that pose a risk to human health or the environment, to the list of prohibited chemicals in NYS.

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[145] DEP Fines Chesapeake Energy More Than $1 Million, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=17405&typeid=1.

[146] 2009 NYSDEC, DSGEIS, Page 5-34.

[147] 2011 NYSDEC, RDSGEIS, Page 8-29.

[148] Dr. Glenn Miller, Comments Prepared for NRDC on 2011 RDSGEIS, 2012.

Although the percentage of hydraulic fracturing fluid that is composed of chemicals may be small—typically 0.5 to 2 percent of the total volume required for a Marcellus Shale hydraulic fracture stimulation—the absolute volume of chemicals used is very large. A typical Marcellus Shale well may require the use of more than five million gallons of freshwater for drilling and hydraulic fracturing. A five million gallon hydraulic fracture treatment would require approximately 25,000 to 100,000 gallons of hydraulic fracturing chemicals per well at a chemical additive dosage of 0.5 to 2 percent. Some of these chemicals are toxic, including known or possible human carcinogens, chemicals regulated under the Safe Drinking Water Act due to their risks to human health, and chemicals regulated under the Clean Air Act as hazardous air pollutants.[149]

Recommendation No. 38: The SGEIS should do more than just list chemicals proposed by industry for HVHF operations and describe their toxicity; the SGEIS should identify chemicals that should be prohibited or used with limitations to protect human health and the environment.

Additionally, the 2011 RDSGEIS includes a process for reviewing chemicals proposed by industry that appears to have little value or scientific rigor.

> *For every well permit application the Department would require, as part of the EAF Addendum, identification of additive products, by product name and purpose/type, and proposed percent by weight of water, proppants and each additive. This would allow the Department to determine whether the proposed fracturing fluid is water-based and generally similar to the fluid represented by Figures 5.3, 5.4, and 5.5.*[150]

Figures 5.3, 5.4, and 5.5 in the 2011 RDSGEIS are merely pie charts showing example compositions from previous Fayetteville and Marcellus Shale HVHF jobs. The 2011 RDSGEIS does not include a scientific analysis of the proposed HVHF compositions to verify if these mixtures are optimal. Therefore, there is little scientific value in having NYSDEC staff compare an operator's proposed HVHF composition to these figures, because NYSDEC has not even completed the fundamental scientific analysis to verify whether these proposed treatment compositions are protective of human health and the environment and whether the figures are a suitable yardstick.

The 2011 RDSGEIS proposes to require industry to submit a Material Safety Data Sheet (MSDS) for every new product that is not currently listed by NYSDEC in Chapter 5 of the 2011 RDSGEIS. NYSDEC explains that the MSDS will provide it with more information on the proposed chemical, but does not institute a plan for taking action to limit or prohibit hazardous chemical use based on a review of that MSDS. Instead, the 2011 RDSGEIS appears to propose that NYSDEC will just collect MSDS information and take no action, other than to accept the chemicals selected by the operator and add the MSDS to NYSDEC's file system.

> *The Department would also require the submittal of an MSDS for every additive product proposed for use, unless the MSDS for a particular product is already on file as a result of the disclosure provided during the preparation process of this SGEIS (as discussed in Chapter 5) or during the application process for a previous well permit. Submittal of product MSDSs would provide the Department with the identities, properties and effects of the hazardous chemical constituents within each additive proposed for use.*[151]

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[149] United States House of Representatives, Committee on Energy and Commerce, Minority Staff, Chemicals Used in Hydraulic Fracturing, April 2011.

[150] 2011 NYSDEC, RDSGEIS, Page 8-30.

[151] 2011 NYSDEC, RDSGEIS, Page 8-30.

The 2011 RDSGEIS goes on to say that NYSDEC staff will verify, by reviewing the well completion form, that the chemicals proposed by industry in a permit application (with no limitations or prohibitions by NYSDEC) were actually the same chemicals used on the HVHF job.

> *In addition to the above requirements for well permit applications, the Department would continue its practice of requiring hydraulic fracturing information, including identification of materials and volumes of materials utilized, on the well completion report which is required, in accordance with 6 NYCRR §554.7, to be submitted to the Department within 30 days after the completion of any well. This requirement can be utilized by Department staff to verify that only those additive products proposed at the time of application, or subsequently proposed and approved prior to use, were utilized in a given high-volume hydraulic fracturing operation.*[152]

The proposed review process holds little scientific or audit value, since NYSDEC is not limiting chemicals in the initial application. It is insufficient to bind industry to use specific chemicals at the tail end of the permitting process, when industry can propose any chemical for use on the front-end.

However, the proposed chemical audit review process would have great value if NYSDEC limited or prohibited chemical use in the initial application. In that case, a post-HVHF review process would be valuable to verify that prohibited chemicals were not used.

There are several international models in place that NYSDEC could consider using to develop a prohibited chemical list, or to develop an approved list of chemical, or both. Below is a short summary of three models that could be considered: (1) the Oslo-Paris Convention (OSPAR) list of environmentally friendly chemicals (chemicals considered to Pose Little Or No Risk (PLONOR) for the oil and gas industry); (2) Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) Offshore Chemical Selection Guidelines for Drilling & Production Activities on Frontier Lands; and (3) the Norwegian Pollution Control Authority chemical coding system for the oil and gas industry. These governmental entities prohibit use of chemicals that have harmful characteristics, such as: low biodegradability; high bioaccumulation potential; high acute toxicity; and detrimental mutagenic or reproductive effects.

OSPAR PLONOR: Certain European governmental entities have developed a list of environmentally friendly chemicals. Under the Oslo-Paris Convention (OSPAR)[153] a list of chemicals that were considered to Pose Little Or No Risk (PLONOR) to the marine environment was developed for use in drilling and stimulation treatments. The PLONOR list was initially developed in early 2000 and has been amended several times to add and de-list chemicals. The PLONOR list has been very effective in reducing chemical pollution from offshore operations, and use of the PLONOR list has expanded to onshore oil and gas operations and to other industrial sectors. HCLCC is not recommending that NYS adopt the PLONOR list without review; instead, HCLLC is recommending that NYSDEC consider a process similar to OSPAR's system to develop a list of hydraulic fracturing treatment additives that would pose little or no risk to human health or the environment if the chemicals spilled, leaked, or were improperly disposed, or, in the alternative, consider developing a list of chemicals to be prohibited from use in hydraulic fracturing operations.

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[152] 2011 NYSDEC, RDSGEIS, Page 8-31.

[153] The Convention for the Protection of the Marine Environment of the North-East Atlantic (the "OSPAR Convention") was opened for signature at the Ministerial Meeting of the former Oslo and Paris Commissions in Paris on 22 September 1992. The Convention entered into force on 25 March 1998. It has been ratified by Belgium, Denmark, Finland, France, Germany, Iceland, Ireland, Luxembourg, Netherlands, Norway, Portugal, Sweden, Switzerland and the United Kingdom and approved by the European Community and Spain.

The OSPAR process is straight forward: the establishment of criteria for inclusion of substances on the PLONOR list. Industry has the burden of proof to provide scientific and technical data to support listing of a chemical as PLONOR—i.e., industry must prove the chemical poses little or no risk. The OSPAR Commission reviews the data and makes the final listing determination. The Commission also can remove chemicals from the PLONOR list if new information comes to light warranting a de-listing. A current list of PLONOR chemicals can be found at the OSPAR website.[154]

C-NLOPB Guidelines: The Canada-Newfoundland and Labrador Offshore Petroleum Board has developed guidelines that industry must follow to select less harmful chemicals used in their offshore oil and gas operations.[155] Industry operators must demonstrate that they have incorporated a chemical selection process in their management system that conforms to the guidelines, and the Board has the ability to audit industry compliance. The guidelines are reviewed at least once every five years to ensure that gains in scientific and technical knowledge are incorporated, and more frequent reviews may be initiated if significant risks are identified. The C-NLOPB Guidelines rely in part on the PLONOR list, but also establish specific requirements for hazard and risk assessment.

The Norwegian Pollution Control Authority has developed a chemical coding system to prohibit use of harmful and toxic chemicals in the Norwegian petroleum industry. The Norwegian Pollution Control Authority system categorizes chemicals by color, using the colors: black, red, yellow and green. Black chemicals are the most hazardous, followed by red, then yellow. Green chemicals are those listed on the PLONOR list.

Black: chemicals on the OSPAR List of Chemicals for Priority Action, chemicals on the Norwegian Pollution Control Authority prioritized list (White Paper No. 21 (2004-2005)), and chemicals in the following categories, characterized by certain ecotoxicological properties:

- Substances that have both a low biodegradability ($BOD_{28}<20\%$) and a high bioaccumulation potential ($\log P_{OW}\bullet 5$);
- Substances that have both a low biodegradability ($BOD_{28}<20\%$) and a high acute toxicity (EC_{50} or $LC_{50}\bullet 10$ mg/l); and
- Substances that are detrimental in a mutagenic or reproductive way.

Red: chemicals in the following categories, characterized by certain ecotoxicological properties:

- Inorganic substances that are acutely toxic (EC_{50} or $LC_{50}\bullet 1$ mg/l);
- Organic substances with a low biodegradability ($BOD_{28}<20\%$);
- Substances that meet two of the three following criteria:
  - Biodegradability equivalent to $BOD_{28}<60\%$;
  - Bioaccumulation potential equivalent to $\log P_{OW}\bullet 3$ and molecular weight < 700; or
  - Acute toxicity of EC_{50} or $LC_{50}\bullet 10$ mg/l.[156]

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[154] OSPAR Convention for the Protection of the Marine Environment of the North-East Atlantic, OSPAR List of Substances/Preparations Used and Discharged Offshore Which Are Considered to Pose Little or No Risk to the Environment (PLONOR), Reference Number: 2004-10, 2008 Update, available at: http://www.klif.no/arbeidsomr/petroleum/dokumenter/plonor2008.pdf

[155] The Canada-Newfoundland and Labrador Offshore Petroleum Board, Offshore Chemical Selection Guidelines for Drilling & Production Activities on Frontier Lands, April 2009, available at http://publications.gc.ca/collections/collection_2009/one-neb/NE23-151-2009E.pdf.

[156] Regulations Relating to Conduct of Activities in the Petroleum Activities (The Activities Regulations), § 56b. The latest update of this list can be found on OSPAR's website under the Offshore Oil and Gas Industry, Decisions, Recommendations and other Agreements.

Green: chemicals on the OSPAR PLONOR list (chemicals considered to Pose Little Or No Risk to the marine environment).

Yellow: chemicals that are not categorized as Green, Black or Red.

Recommendation No. 39: The SGEIS and the NYCRR should include a more rigorous technical and scientific review process to examine newly proposed fracture treatment additives to ensure they are protective of human health and the environment. In addition to a list of prohibited chemicals, NYSDEC should develop a list of recommended/approved fracture treatment additives that have been scientifically and technically reviewed by NYSDEC and NYSDOH and confirmed to pose little or no risk to human health or the environment. This list could be provided to industry for immediate use and would provide industry with a simplified list of chemicals that have already been determined to pose the least risk.

Any chemical not found on this list, or on the list of prohibited chemicals, could be proposed by industry for future use, but would be subject to an in-depth scientific and technical justification and risk assessment review process before being added to the approved chemical list for NYS.

No chemical should be used until NYSDEC and/or the NYSDOH has assessed whether it is protective of human health and the environment. Industry should bear the burden of proof of demonstrating to NYSDEC and NYSDOH that the chemical is safe. The technical and scientific review and approval process to examine newly proposed fracture treatment additives should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This more rigorous technical and scientific review process should apply to all hydraulic fracture treatments, not just HVHF treatments.

12. Drilling Mud Composition and Disposal

Background: In 2009, HCLLC recommended that the NYCRR be revised to: acknowledge and mitigate drilling mud pollution impacts; minimize drilling waste generation; limit heavy metal and NORM content; and establish best practices for the collection, treatment and disposal of drilling waste.

NYCRR Proposed Revisions: NYSDEC proactively responded to scientific and technical information provided through the public input process, revising the NYCRR to recognize that drilling muds are polluting fluids. NYSDEC removed the existing sentence at 6 NYCRR § 554.1(c)(1) that says "drilling muds are not considered to be polluting fluids." This is an important and positive change in the regulations.

However, additional work is still needed in the proposed amendments to the NYCRR to define what types of drilling muds should be used at various depths in constructing a well. NYCRR should also be amended to include best practices for how those drilling muds should be properly handled and disposed.

In January 2011, NYS consultant, Alpha Geoscience complimented HCLLC for its recommendations on drilling mud composition and disposal and agreed that additional mitigation was warranted. Alpha Geoscience wrote: [157]

> *Harvey Consulting has commented on the need for regulation revisions to specifically address drilling mud and drilling waste. The report states "New York State regulations should be revised to acknowledge and mitigate drilling mud pollution impacts, minimize drilling waste generation, limit heavy metal and NORM (Naturally Occurring Radioactive Material) content, and establish best practices for collection, treatment and disposal of drilling waste.*
>
> *Current NYS regulation 6 NYCRR §554.1(c)(1) states that drilling muds are not considered polluting fluids. The 1992 GEIS allows drill cuttings to be buried onsite, and the dSGEIS does not address the potential impact. Drilling muds commonly contain barite which contains mercury (1-10 ppm) (www.fossil.energy.gov) and may also contain cadmium. NYSDEC has not set limits on the heavy metal content of drilling mud, and New York State regulations do not address how to dispose of drill cuttings containing NORM.*
>
> *Harvey Consulting's recommended best management practice for most applications includes a combination of waste minimization, using low impact additives, collecting waste in a closed-loop system, pumping waste to a cuttings reinjection unit, and disposing the waste into a disposal well by deep well injection. Harvey Consulting suggests NYSDEC should thoroughly analyze each situation and location to develop the best site-specific best management practices.*
>
> *Harvey Consulting's comments concerning the composition and handling of drilling mud and drilling waste appear to have some merit. Per 6 NYCRR §554.1 (C)(1) drilling muds are not considered polluting fluids, however the presence of mercury and cadmium in barite composed drilling muds may be cause for concern given the quantity of drilling mud that would be required to drill each well.*

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[157] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Pages 7-9.

> *NYSDEC regulations do not clearly define the treatment or disposal of drilling waste and any best management practices concerning their handling, and/or recycling are not clearly outlined in the dSGEIS as documented by Harvey Consulting. Section 5.13 of the dSGEIS covers waste disposal, however it is general in its scope and does not outline any best management practices concerning the recycling, treatment, or disposal of drilling waste.*
>
> *Harvey Consulting's review recommends that the dSGEIS include best management practices concerning the type and handling of drilling mud and the subsequent waste byproducts. It suggests that NYSDEC should determine which drilling fluid composition and disposal methods are best practices for various scenarios. Alpha agrees that the proposed measures seem reasonable and would serve to protect the public, environment, and the drilling applicant [emphasis added].*

2011 RDSGEIS: The 2011 RDSGEIS explains that drilling operators propose to drill through protected groundwater zones using compressed air or Water-Based Muds (WBM).

> *The vertical portion of each well, including the portion that is drilled through any fresh water aquifers, will typically be drilled using either compressed air or freshwater mud as the drilling fluid.*[158]

The use of compressed air and WBM for drilling though the protected groundwater zones is best practice, as long as NYCRR also sets limits on the type of additives that can be mixed in the WBM formulation. WBM additives used when drilling through the protected groundwater zones should be non-toxic.

The 2011 RDSGEIS' use of the term "typically" indicates that use of compressed air and WBM for drilling though the protected groundwater zones may only occur a portion of the time. This is a best practice that should be implemented each time a well is drilled through protected groundwater zones.

While the 2011 RDSGEIS documents industry's position that it "typically" will use compressed air and WBM for the protection of groundwater, NYSDEC should *require* that practice and ensure that the requirement is codified in NYCRR. The proposed amendments to the NYCRR do not limit the types of drilling muds that can be used while drilling through protected groundwater zones. NYCRR should be revised to clearly prohibit the use of Oil-Based Muds (OBM) and Synthetic-Based Muds (SBM) drilling through protected groundwater zones and to limit additives used in the WBM to those that are non-toxic.

OBM contain diesel fuel or other hydrocarbons. SBM use synthetic oil. SBM are less harmful than OBM, but still contain materials that are toxic, bio-accumulate when discharged into water, and do not biodegrade. For example, European nations prohibit the discharge of SBM to offshore waters, and prohibit their use when drilling through protected waters.[159] SBM are not approved by USEPA or Department of Energy for discharge offshore because they exceed USEPA's effluent limit guidelines.[160] The 2011 RDSGEIS incorrectly describes SBM as *"food-grade"* and *"environmentally friendly."*[161]

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[158] 2011 NYSDEC, RDSGEIS, Page 5-32.

[159] Jonathan Wills, M.A., Ph.D., M.Inst.Pet., for Ekologicheskaya Vahkta Sakhalina, Muddied Waters A Survey of Offshore Oilfield Drilling Wastes and Disposal Techniques to Reduce the Ecological Impact of Sea Dumping, May 25, 2000.

[160] http://web.ead.anl.gov/dwm/techdesc/discharge/index.cfm.

[161] 2011 NYSDEC, RDSGEIS, Page 5-32.

Recommendation No. 40: 6 NYCRR § 554.1(c)(1) should be revised to limit the types of drilling muds that can be used while drilling through subsurface formations that contain protected groundwater. Drilling muds should be limited to Water-Based Muds (WBM) or drilling with air. Any additives required for safe drilling through the protected groundwater interval with WBM should be limited to additives that are bio-degradable, are non-toxic, and do not bio-accumulate. The SGEIS should also include this requirement as a mitigating measure.

Neither the 2011 RDSGEIS nor the proposed amendments to the NYCRR instruct the operator on how to properly dispose of drilling fluids. NYCRR requires a disposal plan and that drilling fluids be removed from the drillsite within 45 days; however, 6 NYCRR § 554.1(c)(1) does not provide specific instructions or criteria for acceptable drilling mud disposal plans. This problem was identified by HCLLC in 2009, and is still unresolved.

This problem is magnified in light of new language in the 2011 RDSGEIS that appears to contemplate allowing drilling muds to be spread on non-active agricultural fields and other soils. The 2011 RDSGEIS includes a discussion on proposed Agricultural District requirements. One of the requirements discussed is for "spent drilling muds to be removed from active agricultural fields." [162] The RDSGEIS is silent on provisions for non-active agricultural fields and other soils, and it is unclear what NYSDEC has planned for drilling mud disposal. NYSDEC should clarify its intentions in regards to spreading drilling muds.

The 2011 RDSGEIS correctly notes that drilling mud can be reconditioned and used at more than one well,[163] but it must eventually be disposed. Drilling muds may contain mercury, metals, NORM, oils, and other contaminates. This is especially true for Marcellus Shale operations where naturally occurring radioactive material is present in the shale drill cuttings and mud mixture. Therefore, drilling muds require proper handling and disposal. [164]

Solid waste management regulations at 6 NYCRR Chapter IV, Subchapter B (Solid Waste) provide the authority by which the state (through the Division of Solid and Hazardous Materials) establishes standards and criteria for solid waste management operations, including landfills and land application. However, the RDSGEIS is unclear on what NYSDEC has deemed to be the best management practices for handling drilling waste. A recent U.S. Department of Energy review of NYSDEC's drilling waste disposal regulations concluded:

> *"The [NYS] DEC has developed no regulations, policies, or guidelines governing slurry injection, subsurface injection, or annular disposal of drilling wastes and reserve-pit wastes [emphasis added]."*[165]

NYSDEC has not established regulations to minimize the generation of drilling waste (e.g. reuse, recycle), or established limits on the heavy metal content of drilling mud additives.

Regulations at 6 NYCRR § 554.1(c)(1) should be revised to provide specific instructions on drilling fluid handling and disposal. Questions that need to be addressed include: Where will drilling waste be taken for treatment and disposal? What tests will be run to characterize the waste stream for proper handling,

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[162] 2011 NYSDEC, RDSGEIS, Page 7-145.

[163] 2011 NYSDEC, RDSGEIS, Page 5-32.

[164] As explained in HCLLC's 2009 report, the mercury content in drilling mud for a Marcellus Shale well drilled to a depth of 5,000' could contain 0.5- 5.0 lbs of mercury per well, depending on barite quality, and drilling muds may also contain the heavy metal cadmium.

[165] U.S. Department of Energy, Drilling Waste Management Information System, http://web.ead.anl.gov/dwm/regs/state/newyork/index.cfm.

treatment, and disposal? Does the treatment capacity exist to handle this incremental waste in NYS? If so, where are the treatment facilities located? What types of treatments will be completed? What is the ultimate disposal location for the treatment byproducts?

Recommendation No. 41: 6 NYCRR § 554.1(c)(1) should be revised to provide specific instructions on the best practices for drilling mud handling and disposal. The SGEIS should also provide specific instructions on the best practices for drilling mud handling and disposal as a mitigating measure. See Chapter 13 of this report for additional recommended disposal solutions.

13. Reserve Pit Use & Drill Cuttings Disposal

Background: In 2009, HCLLC recommended that NYSDEC adopt regulations requiring closed-loop tank systems as best practice, instead of the use of temporary reserve pits to handle and store drill muds and cuttings, unless the operator demonstrates that closed-loop tank systems are not technically feasible. Additionally, HCLLC recommended that if temporary reserve pits are used, NYSDEC should adopt regulations that: require impermeable, chemical resistant liner material; limit the types of chemicals stored to those compatible with the liner material; require wildlife protection design standards; and establish firm removal and restoration requirements when drilling was completed. HCLLC recommended that cuttings not be buried onsite, and that waste be removed from the drilling location and properly disposed at an approved waste disposal facility capable of handling the quantity and type of waste generated.

HCLLC recommended that NYS consider the use of grind-and-inject technology to convert drill cuttings into a slurry that can be injected into a properly designed, approved subsurface disposal well. Additionally, HCLLC recommended that if reserve pits are determined to be the only technically feasible option for temporary waste storage, that storage of drilling waste be limited to un-contaminated drill cuttings, drilled using compressed air or water based-muds with non-toxic additives.

2011 RDSGEIS: The 2011 RDSGEIS recommends closed-loop tank systems as best practice in some circumstances, but in other circumstances defaults to the use of reserve pits, without demonstrating that reserve pits are environmentally preferable.

The RDSGEIS requires a closed-loop tank system for horizontal drilling operations in the Marcellus Shale that do not have an acceptable acid rock drainage (ARD) mitigation plan[166] for on-site cuttings burial; and drill cuttings that are coated with Synthetic-Based Muds (SBM) and Oil-Based Muds (OBM). In all other cases, the RDSGEIS proposes the use of reserve pits.

> *The revised draft SGEIS proposes to require, pursuant to permit conditions and/or regulation, that a closed-loop tank system be used instead of a reserve pit to manage drilling fluids and cuttings for:*
>
> - *Horizontal drilling in the Marcellus Shale without an acceptable acid rock drainage (ARD) mitigation plan for on-site cuttings burial; and*
> - *cuttings that, because of the drilling fluid composition used must be disposed off-site, including at a landfill.*[167]

Appendix 10, Proposed Supplementary Permit Conditions for HVHF, Condition No. 56 requires the operator to provide NYSDEC with an acid rock drainage mitigation plan if NYSDEC requests the plan. However, there is no specific criteria established to define what constitutes and acceptable acid rock drainage mitigation plan.

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[166] 2011 NYSDEC, RDSGEIS, Page 7-67.

[167] 2011 NYSDEC, RDSGEIS, Page 1-13.

Yet, the USGS recommends against onsite disposal because of the potential risk posed:

> *Onsite burial of drill cuttings at shale-gas development sites, which is allowable under the dSGEIS if oil-based drilling mud is not used, should be carefully considered. According to Lash and Engelder (2008), pyrite is abundant in the high-TOC basal intervals of the Marcellus Shale. Oxidation and leaching of pyritic shale produces and acidic, metals-rich discharge commonly referred to as AMD (Acid Mine Discharge). A multi-horizontal well site will generate 100 to 500 times the volume of AMD-producing pyritic shale cutting than that generated at a single-vertical well site. If these pyritic shale drill cuttings are left onsite, the potential for future surface-water and groundwater contamination is significant– removal and disposal of all cuttings at an approved landfill would be the preferred approach [emphasis added].*[168]

The RDSGEIS proposal to use reserve pits is internally inconsistent with the RDSGEIS' conclusion that closed-loop tank systems are environmentally preferable for the following reasons:

> *Depending on the configuration and design of a closed-loop tank system use of such a system can offer the following advantages:*
>
> - *Eliminates the time and expense associated with reserve pit construction and reclamation;*
> - *Reduces the surface disturbance associated with the well pad;*
> - *Reduces the amount of water and mud additives required as a result of re-circulation of drilling mud;*
> - *Lowers mud replacement costs by capturing and re-circulating drilling mud;*
> - *Reduces the wastes associated with drilling by separating additional drilling mud from the cuttings; and*
> - *Reduces expenses and truck traffic associated with transporting drilling waste due to the reduced volume of the waste.*[169]

Additionally, the 2011 RDSGEIS explains the environmental risks of reserve pits:

> *Pit leakage or failure could also involve well fluids. These issues are discussed in Chapters 8 and 9 of the 1992 GEIS, but are acknowledged here with respect to unique aspects of the proposed multi-well development method. The conclusions regarding pit construction standards and liner specifications presented in the 1992 GEIS were largely based upon the short duration of a pit's use. The greater intensity and duration of surface activities associated with well pads with multiple wells increases the potential for an accidental spill, pit leak or pit failure if engineering controls and other mitigation measures are not sufficient. Concerns are heightened if on-site pits for*

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[168] Testimony of John H. Williams, Ground-Water Specialist, U.S. Geological Survey, The Council of the City of New York Committee on Environmental Protection, Public Hearing, Draft Supplemental Generic Environmental Impact Statement Relating to Drilling for Natural Gas in New York State Using Horizontal Drilling and High-Volume Hydraulic Fracturing, October 23, 2009, Page 2.

[169] 2011 NYSDEC, RDSGEIS, Page 5-39.

> *handling drilling fluids are located in primary and principal aquifer areas, or are constructed on the filled portion of a cut-and-filled well pad [emphasis added].*[170]
>
> *As explained in Chapter 5, the total volume of drill cuttings produced from drilling a horizontal well may be about 40% greater than that for a conventional, vertical well to the same target depth. For multi-well pads, cuttings volume would be multiplied by the number of wells on the pad. The potential water resources impact associated with the greater volume of drill cuttings from multiple horizontal well drilling operations would arise from the retention of cuttings during drilling, necessitating a larger reserve pit that may be present for a longer period of time, unless the cuttings are directed into tanks as part of a closed-loop tank system[emphasis added].*[171]

The use of close-loop drilling waste handling system is a best practice. For example, New Mexico requires the use of closed-loop drilling systems.[172]

Recommendation No. 42: The SGEIS and NYCRR should be revised to prohibit reserve pit use for Marcellus Shale drilling operations, and instead require closed-loop tank systems to collect drill cuttings and transport them to waste disposal facilities. NYCRR should make reserve pit use the exception, allowing it only in cases where closed-loop tank systems are determined to be technically infeasible. If reserve pits are determined to be the only technically feasible option, storage of drilling waste should be limited to un-contaminated drill cuttings from the section of the well drilled using compressed air or water based-muds with non-toxic additives. These best practices for drilling waste management should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

Of even greater concern is the RDSGEIS' proposal to allow drill cuttings to be buried onsite in some cases. Marcellus Shale cuttings contain Naturally Occurring Radioactive Materials (NORM) and are coated with drilling muds, including Water-Based Mud (WBM). The Marcellus Shale is considered a "highly radioactive" shale,[173] and its drill cuttings may require special hazardous waste handling and treatment. While the RDSGEIS proposes to allow on-site burial only of drill cuttings that were created by air drilling or WBM drilling operations, WBM may contain mercury, metals, and other contaminants.[174]

> *The Department has determined that drill cuttings are solid wastes, specifically construction and demolition debris, under the State's regulatory system. Therefore, the Department would allow disposal of cuttings from drilling processes which utilize only air and/or water on-site, at construction and demolition (C&D) debris landfills, or at municipal solid waste (MSW) landfills, while cuttings from processes which utilize any oil-based or polymer-based products could only be disposed of at MSW landfills [emphasis added].*[175]

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[170] 2011 NYSDEC, RDSGEIS, Page 6-16.

[171] 2011 NYSDEC, RDSGEIS, Page 6-65.

[172] New Mexico, Energy, Minerals and Natural Resources Department, Oil Conservation Division, Regulations at Title 19, Chapter 15, Part 17.

[173] Hill, D.G., Lombardi, T.E. and Martin, J.P., Fractured Shale Gas Potential in New York, 2002, p.8.

[174] As explained in HCLLC's 2009 report, the mercury content in drilling mud for a Marcellus Shale well drilled to a depth of 5,000' could contain 0.5- 5.0 lbs of mercury per well, depending on barite quality, and drilling muds may also contain the heavy metal cadmium.

[175] 2011 NYSDEC, RDSGEIS, Page 1-13.

The proposed revisions to NYCRR would require the reserve pit liner to be ripped and perforated as part of the onsite burial process (6 NYCRR § 560.7(c)); therefore, contaminated drill cuttings would be in direct contact with soils and surface waters.

While the RDSGEIS generally takes the position that WBM-coated cuttings can be stored in reserve pits and buried onsite, in some cases it waivers. It is not clear what additional limitations may be applied to WBM-coated drill-cuttings disposal. NYSDEC recognizes that onsite burial of chemical additives included in WBM may not be prudent. However, the RDSGEIS does not spell out criteria for determining what types of WBM-coated cuttings may and may not be stored and buried in reserve pits. The RDSGEIS proposes this decision be left to a later NYSDEC consultation process.

An example of how the RDSGEIS deviates from its general position that WBM-coated cuttings can be stored in reserve pits and buried onsite is as follows:

> *Supplementary permit conditions pertaining to the management of drill cuttings from high-volume hydraulic fracturing* **require consultation with the Department's Division** *of Materials Management for the disposal of any cuttings associated with water-based mud-drilling and any pit liner associated with water-based or brine-based mud-drilling where the water-based or brine-based mud contains chemical additives. Supplemental permit conditions also dictate that any cuttings required to be disposed of off-site, including at a landfill, be managed on-site within a closed-loop tank system rather than a reserve pit [emphasis added].*[176]

This uncertain position about what to do with WBM-coated drill cuttings is perpetuated in the proposed revisions to NYCRR at 6 NYCRR § 560.7(c):

> *Consultation with the department's Division of Materials Management (DMM) is required prior to disposal of any cuttings associated with water-based mud-drilling and pit liner associated with water-based mud-drilling where the water-based mud contains chemical additives.*

All WBM contains chemical additives. NYCRR must be clear on which chemical additives would trigger the use of closed-loop tanks and prohibit drill cuttings burial onsite.

Recommendation No. 43: The SGEIS and NYCRR should be clear about how WBM-coated drill cuttings will be handled and should not leave this unresolved. The standards for handling WBM-coated drill cuttings should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

Additionally, it is inefficient from a logistics and energy use standpoint to construct a reserve pit for the temporary storage of drill cuttings, and then remove this pit at a later time. It is substantially more efficient to use a closed-loop tank system to collect the drill cuttings, because the cuttings can be directly transported to a waste handling facility. The RDSGEIS agrees with the efficiencies gained through closed-loop tank systems, but incongruously does not recommend them in all cases.

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[176] 2011 NYSDEC, RDSGEIS, Page 7-67.

> *The 1992 GEIS discusses the use of reserve pits and tanks, either alone or in conjunction with one another, to contain the cuttings and fluids associated with the drilling process. Both systems result in complete capture of the fluids and cuttings; however the use of tanks in closed-loop tank systems facilitates off-site disposal of wastes while more efficiently utilizing drilling fluid and providing additional insurance against environmental releases [emphasis added].*[177]
>
> *The design and configuration of closed-loop tank systems will vary from operator to operator, but all such systems contain drilling fluids and cuttings in a series of containers, thereby eliminating the need for a reserve pit….the objective is to fully contain the cuttings and fluids in such a manner as to prevent direct contact with the ground surface or the need to construct a lined reserve pit.*[178]

NYSDEC's proposal for onsite burial of contaminated drill cuttings becomes even more paradoxical when the RDSGEIS concludes that operators have not proposed onsite burial of drill cuttings.

> *Operators have not proposed on-site burial of mud-drilled cuttings, which would be equivalent to burial or direct ground discharge of the drilling mud itself. Contaminants in the mud or in contact with the liner if buried on-site could adversely impact soil or leach into shallow groundwater [emphasis added].*[179]

A portion of the well drilled will generate cuttings that do not contain NORM. However, as identified in the RDSGEIS, the Marcellus contains NORM and cuttings drilled during this section of the well would require special handling and disposal.

Recommendation No. 44: The SGEIS and NYCRR should prohibit the onsite burial of drill cuttings. If onsite burial is permitted, it should be limited to cuttings that do not have any NORM and are not coated with drill muds containing mercury, heavy metals, and other chemical additives.

Cuttings Reinjection (CRI) Technology, also referred to as "grind-and-inject technology" is commonly used by industry as a best practice to avoid the need for long-term onsite burial of drill cuttings. CRI technology converts drill cuttings into a slurry that can be injected into a subsurface disposal well. CRI also provides a waste disposal method for used drilling mud, because mud can be used in the slurry formulation to reduce supplemental water needs. Currently, NYS does not have sufficient waste disposal wells to handle the anticipated Marcellus Shale drilling waste volume. Either NYS would need to rely on permitted waste handling capacity at wells out of state, or would need to permit and drill wells to meet that need if there are geologically, hydrologically, and otherwise appropriate locations for such wells in NYS.

For example, CRI is commonly used in Alaska as a best practice to avoid use of long-term reserve pit use and surface burial of contaminated drill cuttings. Waste is collected, ground into a slurry, and injected into a subsurface disposal well.[180] If an injection well is not available at a well location, operators have

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[177] 2011 NYSDEC, RDSGEIS, Page 5-37.

[178] 2011 NYSDEC, RDSGEIS, Page 5-37.

[179] 2011 NYSDEC, RDSGEIS, Page 6-66.

[180] BP Exploration (Alaska), Inc., ARCO Alaska, Inc. and ConocoPhillips, Inc. have published numerous technical papers on grind and injection technology, and the success of disposal wells as a pollution prevention measure in the SPE trade journals, and at industry conferences.

collected wastes and transported them back to an injection well location. Operators that do not have their own waste handling facilities or disposal wells typically negotiate an agreement with another operator or a service provider to use its disposal facilities. As a result of this best practice implementation in Alaska, DOE reports there are 58 active Class II-D (disposal) wells and six Class I wells in Alaska.[181]

NYS would need to permit construction of a sufficient number of Class I and Class II injection wells to ensure that there was sufficient capacity for the types and amounts of waste generated.

In addition to the environmental mitigation benefit, CRI technology reduces future liability for industry operators, and has been determined to be an environmentally-appropriate method for handling drilling waste containing NORM by both Shell and Chevron.[182]

Halliburton, an industry service provider, agrees that CRI technology makes business and environmental sense as compared to long-term drilling waste burial at the surface.

> *While it is true that new technology comes with a price tag, and much of the technology used in drilling waste management has been introduced in the last 10 years, many technologies now available to operators <u>are clearly cost effective when the entire well construction cost is evaluated</u>.*
>
> *The cost of making a mistake and having either an expensive remediation project or a potential liability nearly always significantly outweighs the cost of a good preventative drilling waste management program. Further, compliance with current environmental regulations does not always guarantee immunity in the future…*
>
> *Numerous examples exist of industries having to clean up sites that were fully compliant with all regulations at the time the waste was generated and disposed of….*
>
> *The paper demonstrates that the correct application of these technologies combined with a holistic approach to drilling waste management and drilling fluid operations results in a net reduction in well construction costs and a reduction in the potential for environmental liability…*
>
> *… environmental compliance (whether internally or externally driven) is not the only reason to utilize these types of technologies and services [emphasis added].*[183]

International operators report favorable economics for eliminating exploration and production waste by deep well injection. For example, a 2001 Advantek International Corp. report concludes:

> *Downhole disposal of mud and cuttings waste through hydraulic fracturing provides a zero discharge solution and eliminates future cleanup liabilities…This downhole disposal technology has shown success <u>in both onshore and offshore drilling operations</u> and is*

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[181] Puder, M.G., Bryson, B., Veil, J.A, Argonne National Laboratory, "Compendium of Regulatory Requirements Governing Underground Injection of Drilling Wastes," Prepared for the U.S. Department of Energy, February 2003, Page 17.

[182] Okorodudu, A., Akinbodunse, A., Linden, L., Chevron Nigeria Ltd, Anwuri, L., Shell Petroleum Development Co. Nigeria Ltd., Irrechukwu, D.O., Zagi, M.M., Nigeria Department of Petroleum Resources, Guerrero, H., M-I Swaco, "Feasibility Study of Cuttings-Injection Operation: A Case Study of the Niger Delta Basin," SPE Paper 98640, presented at the SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production in Abu Dhabi, U.A.E., April 2006,Page 2.

[183] Browing, K., Seaton, S., Halliburton Fluid Systems, "Drilling Waste Management: Case Histories Demonstrate that Effective Drilling Waste Management Can Reduce Overall Well-Construction Costs," SPE Paper 96775, presented at the 2005 SPE Annual Technical Conference and Exhibition in Dallas Texas, October 2005, Pages 1, 3, & 4

> *becoming a routine disposal option…It also offers favorable economics [emphasis added].*[184]

The U.S. Department of Energy (DOE) also advocates CRI technology:

> *Because wastes are injected deep into the earth below drinking water zones, proper slurry injection operations should pose lower environmental and health risks than more conventional surface disposal methods.*[185]

In 1990, the United States passed the Pollution Prevention Act, establishing a national policy that places priority on pollution prevention and specifies that disposal into the environment should only be allowed as a last resort:

> *The Congress hereby declares it to be the national policy of the United States that pollution should be prevented or reduced at the source whenever feasible; pollution that cannot be prevented should be recycled in an environmentally safe manner, whenever feasible; pollution that cannot be prevented or recycled should be treated in an environmentally safe manner whenever feasible; and disposal or other release into the environment should be employed only as a last resort and should be conducted in an environmentally safe manner[emphasis added].”*[186]

Additionally, the amount of drill-cutting waste generated can be significant. If CRI technology is not used to dispose of this waste by deep well injection, than surface waste disposal sites will need to be utilized to handle this waste. The RDSGEIS estimates the amount of waste generated for each well:

> *For example, a vertical well with surface, intermediate and production casing drilled to a total depth of 7,000 feet produces approximately 154 cubic yards of cuttings, while a horizontally drilled well with the same casing program to the same target depth with an example 4,000-foot lateral section produces a total volume of approximately 217 cubic yards of cuttings (i.e., about 40% more). A multi-well site would produce approximately that volume of cuttings from each well.*[187]

Recommendation No. 45: NYS should consider the use of grind-and-inject technology to convert drill cuttings into a slurry that can be injected into a subsurface disposal well, and work with industry to permit a sufficient number of drilling waste disposal wells to safely meet this need. The use of Cuttings Reinjection (CRI) technology for drilling waste management should be included in the SGEIS as a mitigation measure and codified in the NYCRR, as an environmentally preferable option to onsite-disposal of drilling waste.

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[184] Abou-Sayed, A., SPE, Advantek International, Guo, Q., SPE, Advantek International, “Design Considerations in Drill Cuttings Re-Injection Through Downhole Fracturing,” IADC/SPE Paper 72308, Presented at the IADC/SPE Middle East Drilling Technology Meeting in Bahrain, October 2001, Page 1.

[185] Argonne National Laboratory, “An Introduction to Slurry Injection Technology for Disposal of Drilling Wastes,” Publication prepared for the U.S. Department of Energy, September 2003, Page 2.

[186] Pollution Prevention Act of 1990, U.S. Code, Title 42, Public Health and Welfare, Chapter 133, Pollution Prevention.

[187] 2011 NYSDEC, RDSGEIS, Page 5-34.

14. HVHF Flowback Surface Impoundments at Drillsite

Background: In 2009, HCLLC recommended that the NYCRR require fracture fluid flowback be routed to onsite treatment systems for fracture fluid recycling and/or collected in closed-loop tanks for transportation to offsite treatment systems. Surface impoundments should not be used for fracture fluid flowback.

2011 RDSGEIS: The 2011 RDSGEIS made excellent revisions that address public concerns and are protective of human health and the environment by clearly prohibiting HVHF flowback waste impoundments at drillsites. The 2011 RDSGEIS recommends the use of closed-loop tank systems at the drillsites for collecting waste before transporting it to a treatment location, or recycling it for use on another well:

> *Flowback water stored on-site must use covered watertight tanks within secondary containment and the fluid contained in the tanks must be removed from the site within certain time periods.*[188]
>
> *The Department proposes to require that operators storing flowback water on-site would be required to use watertight tanks located within secondary containment, and remove the fluid from the wellpad within specified time frames.*[189]

NYCRR Proposed Revisions: Proposed regulations at 6 NYCRR § 560.6(c)(27) specifically prohibit HVHF flowback from being directed to or stored in any on-site pit, and require covered watertight tanks to handle flowback at the drillsite. Furthermore, 6 NYCRR § 750-3.4(b) prohibits the issuance of a State Pollutant Discharge Elimination System (SPDES) permit without prior certification that HVHF flowback fluids will be not be directed to or stored in a pit or impoundment. Proposed regulations at 6 NYCRR § 560.3(a)(10)-(11) also require an operator to provide a description of the closed-loop tank system it will use and the number of receiving tanks it will employ for flowback water.

No further recommendations. The RDSGEIS includes the use of closed-loop tank systems, which is best available technology.

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[188] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 25.

[189] 2011 NYSDEC, RDSGEIS, Page 1-12.

15. HVHF Flowback Centralized Surface Impoundments Off-Drillsite

Background: In 2009, HCLLC recommended that the NYCRR prohibit the use of centralized surface impoundments for HVHF flowback. This recommendation was made because it is best technology to eliminate the use of surface impoundments altogether, rather than gathering HVHF flowback into tanks at the drillsite and then moving it by pipeline or truck to be pumped into a larger open impoundment at a centralized location away from drillsites. If flowback is recycled, it should be trucked or piped from tank–to–tank to another drillsite or used at the same drillsite in a different well.

Eliminating use of centralized surface impoundments prevents: large scale surface disturbance that requires multi-year rehabilitation[190]; the potential for leakage to occur through or around the liner, impacting ground water; and the potential to generate substantial amounts of hazardous air pollution.

A centralized surface impoundment photograph in Pennsylvania is shown below.

Bednarski Centralized Waste Impoundment, Pennsylvania, Site Permit PADEP, 798407

The most serious concern with the use of centralized surface impoundments for HVHF flowback is the amount of hazardous air pollution predicted for these centralized surface impoundments. In 2009, NYSDEC estimated that each centralized impoundment would be a major source of hazardous air pollution, emitting more than 32.5 tons of air toxics per year, and it was unclear if NYSDEC's estimate was even a worst-case estimate:

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[190] Surface disturbance is less for temporary tanks than impoundments. Impoundments require surface soil excavation and multi-year rehabilitation. Temporary tanks used at the drillsite use existing gravel space already in place for drilling operations rather that impacting new and additional surface terrain away from the drillsite.

> *Based on an assumed installation of ten wells per wellsite in a given year, an annual methanol air emission [estimate] of 32.5 tons (i.e., "**major" quantity of HAP**) is theoretically possible at a central impoundment*[191] *[emphasis added].*

USEPA classifies a major source of hazardous air pollution as a source that emits more than 25 tons per year. These centralized impoundments have been sited nearby residential homes and community facilities in other states, increasing the amount of hazardous air pollution exposure to nearby humans, including increased exposure to benzene, a known human carcinogen.

In January 2011, NYS' consultant, Alpha Geoscience, complimented HCLLC for its recommendations on flowback impoundments, and supported improved mitigation:

> *Harvey Consulting has thoroughly documented their discussion of surface flowback impoundments and hazardous air pollutants, citing a professional journal article, technical guidance documents, consultant reports, and NYSDEC documents.*[192]

2011 RDSGEIS: The 2011 RDSGEIS states that centralized flowback impoundments are "not contemplated" by industry.[193]

> *The Department was informed in September 2010 that operators would not routinely propose to store flowback water either in reserve pits on the wellpad or in centralized impoundments. Therefore, these practices are not addressed in this revised draft SGEIS and such impoundments would not be approved without site-specific environmental review [emphasis added].*[194]

This industry representation is inconsistent with the actual practice of operators in Pennsylvania. Moreover, neither the RDSGEIS nor the proposed NYCRR amendments prohibit the use of centralized flowback impoundments. This leaves the door open for centralized flowback impoundments to be approved if a site-specific environmental review is conducted.

NYSDEC's requirement to use closed-loop HVHF flowback collection tanks at each drillsite is an efficient collection method, because fluid can be easily transferred to a treatment and disposal location, or taken to another well for reuse. It would not be efficient, or environmentally sound, to collect HVHF waste in a closed-loop flowback tank at the drillsite, and then transfer that waste by temporary piping or truck to a large centralized surface impoundment off of the drillsite location.

Recommendation No. 46: The SGEIS and NYCRR should prohibit the use of centralized surface impoundments for HVHF flowback based on the known impacts examined in the SGEIS process. HVHF flowback waste should be collected at the wellhead and recycled or directly routed to disposal. This prohibition should be described in the SGEIS as a mitigation measure and codified in the NYCRR.

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[191] 2009, NYSDEC, DSGEIS, Page 6-56.

[192] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 31.

[193] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 15.

[194] 2011 NYSDEC, RDSEGIS, Page 1-2.

If NYSDEC does not prohibit the use of centralized impoundments, the SGEIS should analyze the impacts and propose mitigation to protect public health and the environment. The decision to allow centralized flowback impoundments should not be segmented from the SGEIS just because it is known to create significant impacts. Prohibiting the use of centralized impoundments mitigates that known risk.

16. Repeat HVHF Treatment Life Cycle Impacts

Background: In 2009, HCLLC recommended that the DSGEIS disclose how many times a well may be fracture treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario. HCLLC pointed out that the 2009 DSGEIS estimated water use and waste volumes based on a single initial fracture treatment and that this approach does not consider the fact that most shale gas wells require multiple fracture treatments.

2011 RDSGEIS: The 2011 RDSGEIS indicates there may be a potential for repeated HVHF treatments over the life of the well.[195] However, the 2011 RDSGEIS does not quantify the number of HVHF treatments possible per well, nor does it estimate the peak or cumulative impact of these HVHF treatments. Therefore the RDSGEIS under-predicts both the peak and cumulative impacts by not examining the reasonably foreseeable likelihood that Marcellus, Utica, and other low-permeability shale reservoirs will require more than one HVHF treatment, most likely two or three, over a several decade long lifecycle.

NYSDEC does acknowledge that, when Marcellus repeat HVHF treatments are conducted, the impact will be equivalent to the initial treatment. However, its impact assessment does not examine the peak or cumulative impacts that may occur:

> *Regardless of how often it occurs, if the high-volume hydraulic fracturing procedure is repeated it will entail the same type and duration of surface activity at the well pad as the initial procedure [emphasis added].* [196]

For example, NYSDEC estimates 1,600 or more wells to be drilled and completed per year,[197] estimating a 30 year development life cycle,[198] for a total of 48,000 wells. NYSDEC estimates each HVHF treatment to use an average 4,200,000 gallons per well,[199] and that approximately 9-35% of HVHF treatment returns to the well and is produced as waste that requires handling, treatment and/or disposal.[200] A single HVHF treatment in each well, over a thirty year period, could yield a total waste load of 18-71 billion gallons. That waste volume could double or triple if two or three fracture treatments are conducted on each well over a several decade period. Assuming at least two fracture treatments, and possibly three may be implemented, the waste volumes would increase substantially, possibly exceeding 200 billion gallons.

NYSDEC acknowledges the fact that repeated HVHF treatments have been required in the Barnett shale, typically within 5 years from the initial HVHF.[201] However, NYSDEC notes:

> *Marcellus operators with whom the Department has discussed this question have stated their expectation that refracturing will be a rare event.*[202]

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[195] 2011 NYSDEC, RDSGEIS, Page 6-275.

[196] 2011 NYSDEC, RDSGEIS, Page 5-99.

[197] 2011 NYSDEC, RDSGEIS, Page 2-1.

[198] 2011 NYSDEC, RDSGEIS, Page 6-6.

[199] 2011 NYSDEC, RDSGEIS, Page 6-10.

[200] 2011 NYSDEC, RDSGEIS, Page 5-99.

[201] 2011 NYSDEC, RDSGEIS, Page 5-98.

[202] 2011 NYSDEC, RDSGEIS, Page 5-98.

The information NYDEC gathered from a few Marcellus operators, that concludes Marcellus shale re-fracturing will be "rare", is inconsistent with industry literature.

For example, in 2010 Range Resource published a Society of Petroleum Engineering technical paper that describes two successful horizontal shale re-fracture re-stimulations and explains that Marcellus re-fracture stimulations will be used:

> *Based on the success of horizontal re-fracs in other shale plays, re-fracture stimulations in the Marcellus will be an excellent option to maximize fracture complexity and increase the total effective fracture network. ...These re-fracs can be utilized to soften overall field decline in future years…"*[203]

In 2006, Schlumberger, an Oil & Gas Service Company, published a Society of Petroleum Engineering technical paper describing the benefits of re-fracture re-stimulations to increase hydrocarbon production in wells that were initially fractured and where hydrocarbon production had declined to a point that it was economically attractive to repeat the fracture stimulation procedure in that same well:

> *A successful refracturing treatment is one that creates a fracture having higher fracture conductivity and/or penetrating an area of higher pore pressure than the previous fracture.*[204]

Schlumberger explains that re-fracture re-stimulations are likely in wells that have the following characteristics: low productivity relative to other wells with comparable pay; remaining reserves in place; need for fracture reorientation to improve hydrocarbon production; poorly placed initial fracture treatment (e.g. proppant crushing, or proppant flowback, use of incompatible fluids); and reservoir complexity leading to poor hydrocarbon recovery.

A 2010 Apache Corporation, Society of Petroleum Engineering paper, agrees that re-fracture re-stimulations will play an important role in shale stimulation for some time to come. Apache Corporation explains that re-fracture re-stimulations are being used in shale wells to increase gas production, and to make good wells even better gas producers:

> *Refracs of even good wells increased the recovery and re-established near initial production rate. Increasing stimulated reservoir volume should increase both the IP*[205] *and EUR*[206]*. When new areas of the shale are exposed in a refrac, there should also be a gain in reserves (Warpinski, 2008). Increases in stimulated reservoir volume could be accomplished by opening many of the micro-cracks and laminations within the undisturbed matrix blocks in the initial drainage [area] that were left unstimulated by previous fracturing attempts. Re-opening of natural and hydraulic fractures that had closed due to overburden and confining stress created by depletion would re-establish matrix area contact.*[207]

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[203] Curry, M., and Maloney, T., Range Resources Corp., Woodroof, R., and Leonard, R. ProTechnics Division of Core Laboratories, Less Sand May Not Be Enough, Society of Petroleum Engineers Technical Paper, SPE 131783, 2010. Page 12.

[204] Moore, L.P., Ramakrishnan, H,, Schlumberger, Restimulation: Candidate Selection Methodologies and Treatment Optimization, Society of Petroleum Engineers Technical Paper, SPE 102681, 2006. Page 1.

[205] IP= Initial Production.

[206] EUR= Expected Ultimate Recovery.

[207] King, G.E., Apache Corporation, Thirty Years of Gas Shale Fracturing: What Have We Learned?, Society of Petroleum Engineers Technical Paper, SPE 133456, 2010. Page 24.

Re-fracture re-stimulation has been used widely in the Barnett Shale. Many technical papers report successful re-fracture re-stimulations in the Barnett Shale where improved HVHF slickwater fractures were used as a second treatment after the initial cross-linked gel fracture treatment. While the Marcellus and Utica Shales in NYS will start with improved HVHF slickwater fracture treatments, these treatment methods will continue to improve over time, and like the Barnett, repeat fracture treatments will be required to improve hydrocarbon performance as new and improved fracture treatment design supplants existing technology. Apache Corporation explains:

> *Fracturing technology for shales is constantly improving and refracs may slowly fade from common use as the frac designs for shale wells are optimized. Until optimal fracs are achieved and production engineering is optimized, however, refracs will have a place in shale stimulation [emphasis added].*[208]

Additionally, NYSDEC acknowledges the benefits of re-fracture treatment:

> *Several other reasons may develop to repeat the fracturing procedure at a given well. Fracture conductivity may decline due to proppant embedment into the fracture walls, proppant crushing, closure of fractures under increased effective stress as the pore pressure declines, clogging from fines migration, and capillary entrapment of liquid at the fracture and formation boundary. Refracturing can restore the original fracture height and length, and can often extend the fracture length beyond the original fracture dimensions.* [209]

Recommendation No. 47: The SGEIS should quantify how many times a well may be fracture treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario. Additionally, the SGEIS should examine the peak and cumulative impacts of multiple HVHF treatments over a well's life and propose mitigation to offset those reasonably foreseeable impacts.

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[208] King, G.E., Apache Corporation, Thirty Years of Gas Shale Fracturing: What Have We Learned?, Society of Petroleum Engineers Technical Paper, SPE 133456, 2010. Page 24.

[209] 2011 NYSDEC, RDSGEIS, Page 5-98.

17. Air Pollution Control and Monitoring

Air Quality Impact Assessment Modeling Analysis:

In 2009, AKRF's comments on the 2009 DSGEIS (prepared for NRDC) identified a number of shortcomings in the air quality impact assessment modeling analysis. Notably, that emissions from 10 wells per year and simultaneously operating equipment would produce emission impacts that exceed the NAAQS.

The 2011 RDSGEIS: The 2011 RDSGEIS includes a substantial amount of new modeling work and a number of operational restrictions and limitations to ensure that NAAQS are not violated. While the RDSGEIS has been significantly improved in this area, some problems with the analysis persist, and some new problems have developed.

The following assumptions used in the air quality impact assessment modeling analysis warrant further review and justification:

- The modeling analysis assumes that a maximum of four wells per drillsite will be drilled each year.[210] However, NYS ECL § 23-0501 requires development of all infill drilling within three years of the first well drilled, and the RDSGEIS envisions the Marcellus Shale gas reservoir will be developed from a multi-well pad for a 640-acre spacing unit, with 40-acre spacing. At 40-acre spacing density, 16 wells would need to be drilled in three years to fill a 640-acre unit, meaning that a maximum of 5-6 wells could possibly be drilled per year. This conflicts with the 4 wells per year (12 wells for three years) assumption and would generate more significant air quality impacts than contemplated by the RDSGEIS.
- Gas compositional data used in the modeling analysis was based on Marcellus Shale gas only. There was no analysis of Utica Shale gas or gas from any other low-permeability gas reservoir.[211] Modeling should be based on a reasonable worst case scenario that includes analysis of all shale formations with development potential, not just the Marcellus Shale, if the SGEIS proposes to cover more reservoirs.
- The modeling analysis assumed that there will be no emissions of criteria pollutants from venting. However, the RDSGEIS proposes to allow gas venting of up to 5 MMscf during any consecutive 12-month period, including sour gas, as long as it is vented at least 30 feet in the air. This allowance undermines the assumption that no criteria pollutants would be emitted during venting.
- The modeling analysis assumes only three days of gas flaring per well. However, the RDSGEIS states that flaring can occur for up to a month in some cases.[212] Therefore, the modeling understates the potential emissions from flaring.

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[210] 2011 NYSDEC, RDSGEIS, Page 6-104.

[211] 2011 NYSDEC, RDSGEIS, Page 6-115.

[212] 2011 NYSDEC, RDSGEIS, Table 5.29 on Page 5-136 shows that well cleanup and testing can take 12 hours to 30 days. Modeling on Page 6-192 only assumes 3 days of flaring.

- The supplemental 24-hour $PM_{2.5}$ model impacts analysis did not evaluate simultaneous operation of equipment operating on the pad. However, other short-term impact assessment assumed simultaneous operation of one well drilling, one well completion and one well flaring, along with operation of the on-site line heater and off-site compressor for the gas production phase for previously-completed wells.[213] Therefore, the 24-hour $PM_{2.5}$ impact modeling is based on inconsistent assumptions.
- To account for the possibility of simultaneous well operations at nearby pads, a simplified sensitivity analysis was performed in the RDSGEIS to determine the potential contribution of an adjacent pad to the modeled impacts.[214] This modeling assumed a single adjacent pad, located one kilometer away (0.62 miles), with identical equipment and emissions as the modeling target pad.

  The RDSGEIS model only examined the potential for two multi-well drillsites, drilling horizontal wells to be located near each other at a distance of 0.62 miles apart. The modeling analysis assumed that only two drillsites would be operating nearby each other, and that drillsite development in an area would occur in a sequential fashion,[215] which is not always the case (especially when there are multiple operators developing an area).

  The modeling analysis did not evaluate the possibility of more than two multi-well drillsite drilling and completion operations adjacent to each other, nor did it evaluate the possibility of multi-well drillsites operating nearby several single well drilling and completion operations drilled on 40 acre spacing. Nor did the analysis examine the possibility that the surface location of multi-well drillsites could be positioned closer than 0.62 miles apart.

  NYS does not require drillsites to be located over the drilling unit, as long as surface siting approval is authorized. Therefore there is a possibility for drillsites to be located closer than 0.62 miles, a possibility of simultaneous operation of more than two drillsites at a time, and a possibility that more significant overlapping ambient air pollution impacts may occur than modeled. Therefore, the RDSGEIS did not consider the reasonable worst case scenario air impacts resulting from simultaneous operations of spatially proximate well sites. NYSDEC wither needs to examine all possible concurrent operation impacts, or prohibit the possibility.
- Mobile source impact assessment under-predicts the number of miles that will be driven by heavy equipment to transport supplies to and haul wastes away from drillsites, especially wastewater that is hauled out of state to treatment and disposal facilities. Modeling for mobile source air impacts resulting from wastewater transport must be consistent with reasonable worst case scenario forecasts of wastewater volume (which impacts the number of truck trips needed per well site) as well as forecasted in and out of state disposal options (which impacts distance traveled per disposal).

  The RDSGEIS assumes that both light and heavy duty trucks will only travel 20-25 miles[216] one way, yet out-of-state treatment and disposal facilities may be located several hundred miles away. For rural operations, it is unlikely that supplies, equipment, specialty contractors, lodging, and other support equipment and personnel will be located within 20-25 miles of the drillsite.

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[213] 2011 NYSDEC, RDSGEIS, Page 6-124.

[214] 2011 NYSDEC, RDSGEIS, Page 6-127.

[215] 2011 NYSDEC, RDSGEIS, Page 6-136.

[216] 2011 NYSDEC, RDSGEIS, Page 6-176.

- The modeling analysis assumes that there will be no simultaneous operations of well drilling and completion equipment on a drillsite. There is a permit requirement prohibiting simultaneous operations;[217] however, this requirement is not codified in the proposed revisions to NYCRR.[218]

Recommendation No. 48: The RDSGEIS air quality impact assessment modeling analysis assumptions warrant additional review and justification. Limitations used in the modeling assumption must all be translated into SGEIS as mitigation measures and codified in the NYCRR to ensure the assumed impacts will not be exceeded. This was done in some cases, but not all. In the cases where modeling assumptions used cannot be justified, modeling revisions will be needed to examine impacts and identify required mitigation, or operational limits set.

Air Quality Monitoring Program:

In 2009, AKRF recommended improved air dispersion modeling and a region-wide emissions analysis. In response, NYSDEC completed a significant amount of additional work on the air quality section of the RDSGEIS. A major conclusion from this work was that there is insufficient information to understand the consequences of increased regional NO_x and VOC emissions on the resultant levels of ozone and $PM_{2.5}$. As a result of this lack of data, these impacts were not fully quantified by modeling alone. Furthermore, NYSDEC concluded that ambient air quality monitoring program is needed.

While implementation of a ambient air quality monitoring program, is an important improvement in the RDSGEIS, the proposed program needs further definition, a funding commitment, and a formal industry compliance obligation.

The 2011 RDSGEIS: The 2011 RDSGEIS includes a commitment to implement local and regional air quality monitoring:[219]

> *The Department also developed an air monitoring program to fully address potential for adverse air quality impacts beyond those analyzed in the dSGEIS, which are either not fully known at this time or not verifiable by the assessments to date. The air monitoring plan would help determine and distinguish both the background and drilling related concentrations of pertinent pollutants in the ambient air [emphasis added].*[220]
>
> *The dSGEIS identifies additional mitigation measures designed to ensure that emissions associated with high-volume hydraulic fracturing operations do not result in the exceedance of any NAAQS. In addition, the Department has committed to implement local and regional level air quality monitoring at well pads and surrounding areas [emphasis added].*[221]

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[217] 2011 NYSDEC, RDSGEIS, Appendix 10, Attachment A, Condition 2.

[218] 2011 NYSDEC, RDSGEIS, Page 6-115.

[219] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 23.

[220] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 16.

[221] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 23.

Although Section 6.5.4 of the RDSGEIS proposes alternative methods for implementing air quality monitoring, it does not settle on a recommended solution.[222] The RDSGEIS proposes two alternatives: (1) industry-led monitoring with NYSDEC oversight, or (2) NYSDEC monitoring with industry funding. The RDSGEIS identifies NYSDEC monitoring with industry funding as the preferred alternative without making clear how this goal will actually be funded and implemented.

Table 6.24 proposes to: add a single air monitoring trailer and mobile laboratory to monitor ozone, particulate matter, oxides of nitrogen and air toxics; use infrared cameras to monitor gas leaks; and conduct summa canister sampling for BTEX and other VOCs. However, the RDSGEIS does not explain how the addition of a single mobile trailer and lab along with some other intermittent sampling will provide sufficient information to understand the consequences of increased regional NO_x and VOC emissions on the resultant levels of ozone and $PM_{2.5}$.

The RDSGEIS did not evaluate the possibility of installing permanent monitoring locations at numerous locations in NYS, with priority in existing non-attainment areas, and areas that will be heavily impacted by shale gas development. Instead, the RDSGEIS only proposes to examine “regional level” monitoring by collecting data at two sites in NYS.[223] This proposal is insufficient because monitoring regional ambient air quality is not possible with the limited data provided by a two-site program, proposed for an unspecified time period.

More information is needed to understand the scope and duration of NYSDEC’s proposed air monitoring program. A more rigorous monitoring program proposal is needed that identifies: the scope of the monitoring program; the location of the monitoring sites; the amount of equipment and personnel needed to run each site; the duration of monitoring proposed at each site; along with the cost. It is anticipated that a program used to assess both regional and local impacts will require long term monitoring stations placed in key locations, not just infrequent and unrepresentative sampling.

The obligation to fund the air quality monitoring program needs to be clearly tied to a permit condition requirement—for example, the permit to flare or spud a well should require a contribution to an air quality monitoring fund; such a requirement is not set forth in either Appendix 6 or Appendix 10.

Recommendation No. 49: The SGEIS should include a more rigorous air monitoring program to achieve NYSDEC’s goal of regional and local air pollutant impact monitoring. The proposed program should identify: the scope of the monitoring program; the location of the monitoring sites; the amount of equipment and personnel needed to run each site; the duration of monitoring proposed at each site; along with the cost. The SGEIS should require the monitoring program to commence prior to Marcellus Shale gas development to verify background levels and continue until NYSDEC can scientifically justify that data collection is no longer warranted, in consultation with EPA. The obligation to fund the air monitoring program needs to be clearly tied to a permit condition requirement.

The RDSGEIS acknowledges that air monitoring may identify peak or cumulative air pollution impacts that warrant additional emission controls. For example, NYSDEC has identified that:

> *…the consequences of the increased regional NOx and VOC emissions on the resultant levels of ozone and PM2.5 cannot be fully addressed by only modeling at this stage due to the lack of detail on the distribution of the wells and compressor stations. In addition, any potential emissions of certain VOCs at the well sites due to fugitive emissions,*

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[222] 2011 NYSDEC, RDSGEIS, Page 6-180 through 6-184.

[223] 2011 NYSDEC, RDSGEIS, Page 6-181.

> *including possible endogenous level, and from the drilling and gas processing equipment at the compressor station (e.g. glycol dehydrators) are not fully quantifiable.*[224]

However, the RDSGEIS does not explain NYSDEC's plan to collect data, identify the potential for air pollutants to exceed the federal, state or local air pollution control standards, or require these additional emission controls in a timely manner before adverse impacts are realized by humans or the surrounding ecosystem.

Recommendation No. 50: The SGEIS should explain NYSDEC's plan to collect data, identify the potential for pollution problems to exceed the federal, state or local air pollution control standards, and the timely installation of additional emission controls, in order to protect against exceedances of pollution control standards, should be required as an SGEIS mitigation measure and codified in the NYCRR.

GHG Impacts Mitigation Plan:

In 2009, HCLLC and AKRF recommended further analysis of Greenhouse Gas (GHG) impacts and mitigation. In response, NYSDEC acknowledged the potential for GHG emissions impacts and the need for mitigation. While such acknowledgement represents a substantial improvement from the 2009 draft, the proposed mitigation needs improvement to ensure the requirements are clear, measureable and enforceable.

The 2011 RDSGEIS: The 2011 RDSGEIS requires a GHG Impacts Mitigation Plan.[225]

> *The Plan must include: a list of best management practices for GHG emission sources for implementation at the permitted well site; a leak detection and repair program; use of EPA's Natural Gas Star best management practices for any pertinent equipment; use of reduced emission completions that provide for the recovery of methane instead of flaring whenever a gas sales line and interconnecting gathering line are available; and a statement that the operator would provide the Department with a copy of the report filed with EPA to meet the GHG Reporting Rule.*[226]

The GHG Impacts Mitigation Plan requires the operator to implement a Leak Detection and Repair Program,[227] use Reduced Emission Completions,[228] use EPA Natural Gas STAR program recommendations, and identify other best management practices.

The requirement that a GHG Impacts Mitigation Plan be prepared and include the use of best management practices for GHG control is a step in the right direction; however, given the variety of best management practices under EPA's voluntary Natural Gas STAR program, NYSDEC should require that well operators select and install the controls that will achieve the greatest emissions reductions possible. In addition, such emissions reductions should be made enforceable, as permit conditions or in the NYCRR.

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[224] 2011 NYSDEC, RDSGEIS, Page 6-181.

[225] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 24.

[226] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 24.

[227] See also HCLLC recommendations on LDAR Program in this section of the report.

[228] See also HCLLC recommendations on Reduced Emission Completions in this section of the report.

For example, the Natural Gas STAR Program data shows that it is both technically feasible and economically attractive to use "low-bleed" or "no-bleed pneumatic controllers and plunger lift systems;[229] however, it is not clear whether an operator would be required under the GHG Impacts Mitigation Plan to use this technology, or how NYSDEC would enforce its use if an operator chose not to select it.

NYSDEC should require operators to use Natural Gas STAR Program best management technologies and practices that will optimize emissions reductions.

The RDSGEIS does not make clear whether or how new technologies or practices would be required (e.g. technologies or practices identified by the Natural Gas STAR Program after drillsite construction has been completed). It is not clear if an operator will be required to implement GHG emission controls only at the time of construction, or if there will be an ongoing obligation to implement additional controls as they are identified by the Natural Gas STAR Program and developed.

The plan should include a list of emission controls that will be installed at the time of construction and best management practices, and a process for periodically reviewing new technologies and installing them as new control solutions are developed over time.

Recommendation No. 51: NYSDEC should require a GHG Mitigation Plan that provides for measureable emissions reductions and includes enforceable requirements. The GHG Impacts Mitigation Plan should list all Natural Gas STAR Program best management technologies and practices that have been determined by EPA to be technically and economically feasible, and operators should select and use the emission control(s) that will achieve the greatest emissions reductions.

The GHG Impacts Mitigation Plan should be submitted and approved prior to drillsite construction, GHG controls should be installed at the time of well construction, and NYSDEC should conduct periodic reviews to ensure that GHG Impacts Mitigation Plans include state of the art emission control technologies. Further, the extent of compliance with adopted emission mitigation control plans should be documented throughout the well's potential to emit GHGs.

The GHG Impacts Mitigation Plan requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

Flare and Venting of Gas Emissions:

In 2009, HCLLC recommended that flaring and venting be limited to the lowest level technically feasible and safe. Reducing gas flaring and venting is widely considered best practice. Both federal and state governments have taken steps over the past two decades to enact regulations that limit flaring and venting of natural gas.[230] Initially the motive was to conserve hydrocarbon resources to maximize federal and

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[229] Older gas wells stop flowing when liquids (water and condensate) accumulate inside the wellbore creating backpressure on the hydrocarbon formation. This will be a future problem in NYS, as gas wells age. Methane gas is emitted when companies open wells to vent gas to the atmosphere to unload wellbore liquids (water and condensate that accumulate in the bottom of the well) in order to resume gas flow. The industry typically refers to this process as "blowing down the well" or a "well blowdown." Eventually, even a well's own gas pressure becomes insufficient to flow accumulated liquids to the surface and the well is either shut-in as uneconomic, or some form of artificial lift (e.g. plunger lifts) is installed to transport the liquids to the surface.

[230] Global Gas Flaring Reduction Partnership (GGFR), Guidance on Upstream Flaring and Venting Policy and Regulation, Washington D.C., March 2009.

state revenue and gas supply. More recently, focus on GHG, VOC and HAPs emission reduction has prompted additional innovation to further reduce flaring and venting.

Flares may be used during well drilling, completion, and testing to combust hydrocarbon gases that cannot be collected because gas processing and pipeline systems have not been installed. If gas processing equipment and pipeline systems are in place, gas flaring can be avoided in all cases except in the event of equipment malfunction. During the drilling and completion phase of the first well on a well pad, a gas pipeline might not be installed. Gas pipelines are typically not installed until it is confirmed that an economic gas supply has been found. Therefore, gas from the first well is often flared or vented during drilling and completion activities because there is not a pipeline to which it can be routed. The RDSGEIS proposes to require Reduced Emission Completions for all wells where a pipeline is installed, which will reduce the need to flare or vent gas.

During production operations, high pressure gas buildup may require gas venting via a pressure release valve, or gas may need to be routed to a flare during an equipment malfunction. At natural gas facilities, continuous flaring or venting may be associated with the disposal of waste streams[231] and gaseous by-product streams[232] that are uneconomical to conserve. Venting or flaring may also occur during manual or instrumented depressurization events, compressor engine starts, equipment maintenance and inspection, pipeline tie-ins, pigging, sampling activities, and pipeline repair.[233]

Best practices for planned[234] flaring and venting during gas production should limit flaring and venting to the smallest amount possible and only for purposes of for safety. Gas should be collected for sale, and used as fuel unless it is proven to be technically and economically unfeasible.

The 2011 RDSGEIS: The 2011 RDSGEIS limits planned gas flaring to flowback operations for wells where a gas sales line has not been installed which is a significant improvement.[235]

However, when flaring or venting does occur, there is the potential for relatively high short-term VOC and CO emission impacts that need to be considered.[236] The RDSGEIS states that industry only plans to flare for a maximum of three days, and NYSDEC only modeled a 3-day impact; yet, the RDSGEIS states that flaring can occur for up to a month (30 days) in some cases. [237]

> *A flaring period of 3 days was considered for this analysis for the vertical and horizontal wells respectively although the actual period could be either shorter or longer [emphasis added].*[238]

Modeling needs to represent a reasonable worst case scenario. Because only a three day flaring period was considered in the RDSGEIS modeling, planned flaring should be limited to no more than three days.

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[231] For example, acid gas from the gas sweetening process and still-column overheads from glycol dehydrators.

[232] For example: instrument vent gas; stabilizer overheads and process flash gas.

[233] The Global Gas Flaring Reduction partnership (GGFR) and the World Bank, Guidelines on Flare and Vent Measurement, September 2008.

[234] There is a difference between planned flaring and emergency flaring. Emergency flaring is conducted to safely route combustible and potentially toxic (e.g. hydrogen sulfide gas) and in most cases cannot be avoided. Planned flaring can be avoided in most cases.

[235] 2011 NYSDEC, RDSGEIS, Page 5-135.

[236] 2011 NYSDEC, RDSGEIS, Page 6-103.

[237] 2011 NYSDEC, RDSGEIS, Table 5.29 on Page 5-136 shows that well cleanup and testing can take 12 hours to 30 days. Modeling on Page 6-192 only assumes 3 days of flaring.

[238] 2011 NYSDEC, RDSGEIS, Page 6-197.

Alternatively, modeling analysis should be based on the maximum time period that flaring would be allowed.

> **Recommendation No. 52:** Planned flaring should be limited to no more than three days. In all other cases flaring should be limited to safety purposes only. If NYSDEC finds there is an operational necessity to flare an exploration well for more than a three-day period, the SGEIS impact analysis should evaluate the air pollutant impact, particularly the potential for relatively high short-term emission impacts, from longer flaring events, before approving such operations. Flaring restrictions should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

In 2009, HCLLC recommended that NYSDEC should require operators to flare gas as a preferred method over venting. Gas flaring is environmentally preferable over venting because flaring reduces HAP, VOC, and GHG emissions.[239] Proposed revisions to 6 NYCRR § 560.6(c)(28) would require that gas be flared whenever technically feasible instead of vented,[240] which is a significant improvement.

The RDSGEIS limits the amount of flaring and venting that is allowed at a drillsite during any consecutive 12-month period; however, it is unclear how the venting (5 MMscf) or flaring (120 MMscf) thresholds were developed, and such thresholds are not listed in the proposed revisions to the NYCRR.

- *During the flowback phase, the venting of gas from each well pad will be limited to a maximum of 5 MMscf during any consecutive 12-month period. If "sour" gas is encountered with detected hydrogen sulfide emissions, the height at which the gas will be vented will be a minimum of 30 feet (9.1m);*
- *During the flowback phase, flaring of gas at each well pad will be limited to a maximum of 120 MMscf during any consecutive 12-month period [emphasis added].*[241]

> **Recommendation No. 53:** The SGEIS should provide justification for allowing a maximum of 5 MMscf of vented gas and 120 MMscf of flared gas at a drillsite during any consecutive 12-month period. The RDSGEIS does not contain information to show that these limits are equivalent to the lowest levels of venting and flaring that can be achieved through used of best practices, and it is unclear if these rates were used in the modeling assessment. Flaring and venting limits, once justified, should be included in the SGEIS as a mitigation measure, codified in the NYCRR, and should apply to all natural gas operations, not just HVHF operations.

In 2009, HCLLC recommended that NYSDEC require that well operators follow best practices for construction and operation of flares used for safety. The RDSGEIS requires self-igniting flares,[242] which is an improvement; however, the RDSGEIS does not require that:

- Flare pilot blowout risk be minimized by installing a reliable flare system;
- Low/intermittent velocity flare streams have sufficient exit velocity or wind guards;
- A reliable ignition system is used;

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[239] Fugitive and Vented methane has 21 times the global warming potential as combusted methane gas. Methanetomarkets.org, epa.gov/gasstar.

[240] 2011 NYSDEC, RDSGEIS, Page 7-117.

[241] 2011 NYSDEC, RDSGEIS, Page 7-108.

[242] 2011 NYSDEC, RDSGEIS, Page 7-117.

- Liquid carry over and entrainment in the gas flare stream is minimized by ensuring a suitable liquid separation system is in place; or
- Combustion efficiency is maximized by proper control and optimization of flare fuel/air/steam flow rates.

Recommendation No. 54: The SGEIS should require flare systems to be designed in a manner that optimizes reliability, safety, and combustion efficiency, including requirements to: minimize the risk of flare pilot blowout by installing a reliable flare system; ensure sufficient exit velocity or provide wind guards for low/intermittent velocity flare streams; ensure use of a reliable ignition system; minimize liquid carry over and entrainment in the gas flare stream by ensuring a suitable liquid separation system is in place; and maximize combustion efficiency by proper control and optimization of flare fuel/air/steam flow rates. Flare design requirements should be included in the SGEIS as a mitigation measure and codified in the NYCRR. These requirements should apply to all natural gas operations, not just HVHF operations.

Reduced Emission Completions:

In 2009, HCLLC recommended the use of Reduced Emission Completions (RECs, also known as “green completions”) to control methane and other greenhouse gas (GHG) emissions following HVHF operations. RECs also reduce nitrogen oxide (NO_x) pollution, which otherwise would be generated by flaring gas wells, and hazardous air pollutants (HAPs) and volatile organic compounds (VOCs) emissions, which otherwise would be released when gas is vented directly into the atmosphere.

EPA estimates that, on average, an REC can capture 7,700 Mcf/well workover for an unconventional gas well. If, for example, 2,000 wells are exempted during the first few years of Marcellus Shale gas development in NYS before pipeline infrastructure is more broadly developed, that could result in 15.3 Bcf (6.2 $MMTCO_2e$) of methane gas vented to the atmosphere.

To put the significance of 15.3 Bcf of methane gas (6.2 $MMTCO_2e$) into perspective, it is equivalent to the GHG emissions from:

- Over 1,100,000 passenger vehicles; or
- The electric use of approximately 700,000 homes for one year; or
- 13,000,000 barrels of oil consumed.[243]

The 2011 RDSGEIS requires RECs where an existing gathering line is located near the well in question, which allows the gas to be collected and routed for sale. While the addition of this requirement represents a substantial improvement that protects air quality and increases the efficiency and productivity of well-sites, NYSDEC should consider expanding its REC requirements to more categories of wells—i.e., wells that are drilled prior to construction of gathering lines. Under the current proposal, a large number of wells could be exempt from the REC requirement, resulting in the flaring or venting of a significant amount of gas that could, instead, be captured for sale.

Furthermore, NYSDEC proposes to postpone making a decision on the number of wells that can be drilled on a pad without the use of RECs until two years after the first HVHF permit is issued.

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[243] EPA Greenhouse Gas Equivalencies Calculator, http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results

> *Reduced Emissions Completion (REC) would be required whenever a gathering line is already constructed. In addition, two years after issuance of the first permit for high volume hydraulic fracturing, the Department would evaluate whether the number of wells that can be drilled on a pad without REC should be limited [emphasis added].*[244]

NYSDEC should not defer the implementation of this known best practice, because it could result in the exemption of several thousand wells from this control technology requirement, leading to unmitigated air quality impacts from uncontrolled venting. HCLLC agrees that RECs are not an option for single exploration wells with no offset wells or pipeline infrastructure nearby. In addition, RECs may not be possible if well pressure is too low. Regulations should make exceptions only for these situations in which emission control is truly infeasible. However, RECs should be required in all other circumstances.

Once an exploration well is drilled and hydrocarbons are located, additional drilling and well completion operations on that same drillsite should be coordinated with gas line installation, enabling RECs for all subsequent wells. High-volume hydraulic fracturing can be completed at any time after a well is drilled and gas is found. The well can be temporarily suspended, and the HVHF be conducted once a gas line is in place. In a newly explored area, it may be reasonable to drill an exploration well, and conduct a HVHF treatment to test gas productivity before drilling additional production wells. However, once a commercial source of gas is identified and tested with that initial exploration well, there is no reason to vent or flare gas using the HVHF flowback process and test wells prior to a gas line installation.

In natural gas fields, gas from the first well is often flared or vented during drilling and completion activities, because natural gas pipelines are typically not installed until it is confirmed that an economical gas supply has been found. However, once a pipeline is installed, subsequent wells drilled on that same pad would be in a position to implement REC techniques.

Operators often point to the lack of pipeline infrastructure as a primary reason REC may not be possible. However, there are also alternatives to piping methane, such as using it onsite to generate power, re-injecting it to improve well performance, or providing it to local residents as an affordable power supply. Therefore, RECs do not need to rely solely on the installation of a nearby pipeline.

RECs are technically feasible and economically attractive, and are a commercially available emission control option. Appendix 25 of the RDSGEIS, Reduced Emission Completions Executive Summary, summarizes the economic benefits, making a clear case for requiring this technology on all NYS wells, with few exceptions. RECs provide an immediate revenue stream by routing gas (methane and gas condensates) to a gas sales line that would otherwise be vented into the atmosphere or flared.. Alternatively, captured gas can be used for fuel, offsetting operating costs, or re-injected to improve well performance. Industry has demonstrated that RECs are both an environmental best practice and profitable.

In addition to being economically attractive for the operator, there are a number of other benefits of RECs:

- The collection of potentially explosive gas vapors, rather than venting them to the atmosphere. This improves well site safety, reduces worker exposure to harmful vapors, and limits overall corporate liability.
- The reduction in emissions, noises, odors, and citizen complaints associated with venting or flaring.
- The reduction in disposal costs, as a result of gas and condensate capture and sale.

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[244] 2011 NYSDEC, RDSGEIS, Page 1-116.

- The elimination of the need to secure flare permits and provide flaring notifications.[245]
- The reduction of VOCs and HAPs. Unprocessed natural gas contains VOCs and HAPs, along with methane. Flaring, an alternative control device, can reduce VOCs and HAPs. However, flaring generates NO_X and particulate matter (PM), as well as other combustible byproducts. Many areas with significant oil and gas development have challenges achieving ozone and regional haze standards. Therefore, REC technology is a preferred alternative.
- Wells flow back to portable separation units for longer periods than would be allowed with direct venting into the atmosphere or flaring, providing improved well cleanup and enhanced well productivity.
- Fewer wells are drilled as more methane is kept in the system and sent to market, thereby reducing a range of environmental impacts.

While some operators report the voluntary use of RECs, many wells in the United States are still drilled without REC. And, even for companies that have announced the use of RECs, it is not clear how extensively RECs are implemented. Thus, many states have put REC requirements into effect.

The commercial availability of REC equipment has become so widespread that it is now required in several states. For instance, Colorado requires RECs on all oil and gas wells unless they are not technically and economically feasible.[246] Fort Worth, Texas requires RECs.[247] Wyoming has required RECs in the Jonah-Pinedale Anticline Development Area (JPAD) since 2007, and more recently, Wyoming has expanded this requirement to all Concentrated Development Areas (CDAs) of oil and gas in the state.[248]

In 2005, EPA estimated that an average of 7,000 Mcf of natural gas can be recovered during each REC.[249] In 2011, EPA increased the emission recovery estimate and created two distinct categories of wells that are major contributors to methane emissions: Unconventional Gas Wells (7,700 Mcf/well workover) and Low Pressure Gas Well Cleanup (1,400 Mcf/well/year). For each unconventional gas well completion, there is an opportunity to generate about $31,000 in gross revenue, creating a very short payout period if the operator invests in its own equipment.[250]

Investment in REC equipment is extremely profitable, with a conservative average investment cost of $10,000 per REC.[251] The payout occurs quickly if a contractor is hired and the operator only pays a per well REC equipment rental charge. As long as the gas that is captured and sold exceeds the equipment rental charge, the payout is immediate.

Oil and gas operators that have a sufficient number of wells to amortize the cost of REC equipment are finding it more economically attractive to invest in their own technology. Most of the companies that have gone this route report a one- to two-year payout, and substantial profitability thereafter, depending on the gas and condensate recovery rate.[252] For smaller operators, it is possible, and maybe more

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[245] Flaring is not always practicable near populated areas or areas of high forest fire risk.

[246] Colorado Oil and Gas Conservation Commission, Rule § 805(b)(3)

[247] Fort Worth Texas, Ordinance No. 18449-02-2009.

[248] Wyoming Oil and Gas Production Facilities, Chapter 6, Section 2, Permitting Guidance, March 2010.

[249] United States Environmental Protection Agency, Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers, Journal of Petroleum Technology, June 2005.

[250] (7,700 Mcf)($4/Mcf)= $30,800

[251] EPA's Green Completion PRO FACT Sheet No.703 estimates the cost between $1K and $10K; a $10K per completion cost estimate is conservative.

[252] EPA Natural Gas STAR, Green Completions, PRO Fact Sheet No. 703, September 2004.

financially feasible, to rent REC equipment from a contractor. The profitability math is simple. In 2005, the EPA estimated that, on average, 7,000 Mcf/well of natural gas could be captured, yielding a profit of $14K per well, with a payback of less than one year.[253] However, it is important to note that EPA's 2005 profitability calculations were based on lower gas prices ($3/Mcf) than the current market rate ($4+/Mcf). Using the EPA's new 2011 estimate of 7,700 Mcf/well and a gas price of $4/Mcf, each well, on average, has the potential to generate $31,000 in gross revenue. A portion of that revenue stream must be allocated to purchasing or renting the required REC equipment, but unless that cost is greater than $31,000 per well, a REC is a profitable endeavor. Profitability will vary based on the market price for gas and the cost of carrying out the REC.

The EPA has found that RECs are a major contributor to methane reductions on a national scale. In 2008, 50 percent of the EPA's Natural Gas STAR Program's annual total reductions for the oil and gas production sector was attributed to REC s.[254] Therefore, requiring this technology will be very important to NYS' and EPA's GHG emission reduction goals.

Recommendation No. 55: Drilling and well completion operations should be coordinated with gas line installation, enabling RECs for all wells drilled subsequent to the initial exploration well. Alternatively, methane gas should be used onsite to generate power, re-injected to improve well performance, or provided to local residents as an affordable fuel supply. NYSDEC should not defer the decision to implement RECs for two more years. The requirement to use RECs in all practicable situations should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

Wastewater Impoundments:

In 2009, HCLLC pointed out that centralized wastewater impoundments have the potential to be a major source of HAPs—EPA lists facilities that release 10 tons of a single HAP per year as major sources. The 2009 DSGEIS estimated 32.5 tons of methanol[255] per year—more than three times the HAP major source threshold—could be emitted from centralized wastewater impoundments.[256] This large amount of hazardous air pollution was identified as an unmitigated significant impact.

In 2009, HCLLC recommended the use of closed loop collection and tank systems, rather than wastewater impoundments, as a best practice. The 2011 RDSGEIS prohibits the use of wastewater impoundments at the drillsite, requiring closed loop collection and tank systems. This is a substantial improvement. However, the RDSGEIS does not prohibit centralized flowback impoundments at locations

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[253] EPA Natural Gas STAR, Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas, November 1, 2005.

[254] 2009 EPA Natural Gas STAR Program Accomplishments, available online at http://www.epa.gov/gasstar/documents/ngstar_accomplishments_2009.pdf. Total sector reductions (2008) = 89.3 Bcf of which 50 percent are the result of RECs (50% of 89.3 Bcf = 45 Bcf).

[255] EPA lists methanol as a hazardous air pollutant, but has not yet classified it with respect to carcinogenicity. The reproductive and developmental effect of methanol on humans is not yet understood. http://www.epa.gov/ttn/atw/hlthef/methanol.html. Testing in rats has yielded skeletal, cardiovascular, urinary system, and central nervous system malformations. American Conference of Governmental Industrial Hygienists (ACGIH), TLVs and BEIs, Threshold Limit Values for Chemical Substances and Physical Agents, Biological Exposure Indices, Cincinnati, OH, 1999. In humans, chronic inhalation or oral exposure may result in headaches, dizziness, giddiness, insomnia, nausea, gastric disturbances, conjunctivitis, blurred vision, and blindness. Neurological damage, specifically permanent motor dysfunction, may also be a result. The Merck Index. An Encyclopedia of Chemicals, Drugs, and Biologicals. 11th ed. Ed. S. Budavari. Merck and Co. Inc., Rahway, NJ. 1989.

[256] 2009 NYSDEC, DSGEIS, Page 6-57.

away from the drillsite and fails to analyze the impacts of such centralization. This represents impermissible segmentation. It is recommended that centralized flowback impoundments be prohibited, however, if this recommendation is not adopted a new draft should be prepared analyzing the potential impacts posed by the reliance on centralized impoundments to store and treat HVHF wastewater and made available for public comment; such a significant analysis cannot be deferred until future site-specific review.

Despite the RDSGEIS's reliance on representations by industry that centralized flowback impoundments are not contemplated at this time, recent experience in Pennsylvania, and other states, reveals that industry's use of centralized flowback impoundments has become common practice. The RDSGEIS either needs to clearly prohibit the use of centralized flowback impoundments in NYS or analyze the potential environmental impacts, including human health impacts, posed by such use and develop ways to avoid or mitigate such impacts.

While industry may not presently intend to build centralized flowback impoundments in NYS, that could change in the future. Based on the use of centralized flowback impoundments as a common industry practice, this is a reasonably foreseeable impact, and unless prohibited is an unmitigated significant impact.

As proposed, there would be no limitations in place for these types of impoundments:

> *Since September 2009 industry has provided information that: (1) simultaneous drilling and completion operations at a single pad would not occur; (2) the maximum number of wells to be drilled at a pad in a year would be four in a 12-month period; and (3) centralized flowback impoundments, which are large volume, lined ponds that function as fluid collection points for multiple wells, are not contemplated [emphasis added].*[257]

Recommendation No. 56: The use of centralized impoundments to collect waste should be prohibited because these impoundments are a major source of air pollution. This prohibition should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

If centralized flowback impoundments are not prohibited, the potential adverse impacts to human health and the environment must be analyzed fully by NYSDEC. Given that the RDSGEIS includes no analysis whatsoever of the impacts of centralized flowback impoundments, a new draft must be prepared and made available for public comment in order to satisfy the requirements of SEQRA; deferring such analysis for later review would constitute impermissible segmentation. Moreover, mitigation measures to address the potential significant impacts must be included in the SGEIS and codified in the NYCRR.

Gas Dehydrators:

In 2009, HCLLC pointed out that gas dehydration units can emit significant amounts of HAPs and VOCs, and it is best practice to use control devices with gas dehydration units to mitigate HAP and VOC emissions.

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[257] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 15-16, and Page 6-111.

Dehydrator units remove water moisture from the gas stream. Dehydrator units typically use triethylene glycol (TEG) to remove the water; the TEG absorbs methane, VOCs, and HAPs. These gases are vented to atmosphere unless pollution controls are installed. Best technology for dehydration units includes the installation of flash-tank separators to recover gas pollutants. Alternatively, pollutants can be routed to a vapor collection/destruction unit, or desiccant dehydrators can be used. Desiccant dehydrators have shown to cost less than flash-tank separators, have lower operating and maintenance costs, and control 99% of HAPs.[258]

The 2011 RDSGEIS requires emissions modeling, using the EPA approved and industry standard model GRI-GlyCalc, and the installation of emission controls for dehydrator units emitting more than one ton per year of benzene. This is an important and substantial improvement.

Appendix 10, Proposed Supplementary Permit Conditions for HVHF, requires:

> *The emissions of benzene at any glycol dehydrator to be used at the well pad will be limited to one ton/year as determined by calculations with the GRI-GlyCalc program. If wet gas is encountered, the dehydrator will have a minimum stack height of 30 feet (9.1m) and will be equipped with a control device to limit the benzene emissions to one ton/year;*[259]

The 2011 RDSGEIS also requires a GHG impacts mitigation plan[260] that includes an evaluation of EPA Natural Gas STAR Best Practices for methane and other GHG emissions. However, it does not make GHG emission controls for gas dehydrators mandatory.

NYSDEC's requirement to control emissions from all dehydrators emitting more than one ton per year of benzene will result in emission control on a number of NYS dehydration units. However, smaller dehydration units that do not fall under this requirement may still have economical methane emission control opportunities.

In 2011, the EPA estimated that approximately 8 Bcf of methane is emitted from gas dehydration systems annually. Most of this methane is emitted from smaller glycol dehydration units currently fall below federal regulatory thresholds for emission control. That methane could instead be captured for sale or use as fuel.[261] While the EPA requires a number of large glycol dehydrators to install emission controls, under the federal Maximum Achievable Control Technology (MACT) standards at 40 CFR Part 63, Subpart HH, small glycol dehydrators are typically exempt. Many small operating glycol dehydrator units do not have flash tank separators, condensers, electric pumps, or vapor recovery installed.

There are four straightforward solutions readily available to control methane emissions from TEG dehydrator units, including: installing a flash tank separator; optimizing the glycol circulation rate; rerouting the skimmer gas; and installing an electric pump to replace the natural gas driven energy exchange pump.

A typical glycol dehydration system includes the following components:

- **Glycol Contactor**: Wet gas enters the glycol contactor. Glycol removes moisture from the gas by the process of physical absorption. Along with removing moisture, the glycol also absorbs methane,

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[258] Fernandez, R., Petrusak, R., Robinson, D., Zavadil, D., Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers, Journal of Petroleum Technology, June 2005.

[259] 2011 NYSDEC, RDSGEIS, Page 7-108 and 7-109, and Appendix 10, Attachment A.

[260] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 24.

[261] USEPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks; (1990-2009), April 15, 2011.

VOCs, and HAPs. Dry gas exits the glycol contactor absorption column and is either routed to a pipeline or a gas plant.

The glycol contactor unit plays the primary role in dehydrating gas to pipeline specifications; the rest of the glycol dehydration system is required to convert the now moisture rich glycol back into a lean product that can be re-used to dehydrate more incoming gas. Therefore, the next step in the process is to route the moisture rich glycol to “regenerator” and “reboiler” units.

- **Glycol Regenerator & Reboiler:** Glycol loaded with moisture, methane, VOCs, and HAPs (“rich glycol”) exits the bottom of the glycol contactor unit and is routed to the glycol regenerator and reboiler units, where the absorbed components are removed and “lean” glycol is created. If emission controls are not installed, methane, VOCs, HAPs, and water are boiled off and vented to atmosphere from the regenerator and reboiler units.

  One way to limit the amount of methane, VOCs, and HAPs emitted to the atmosphere from the regenerator and reboiler units is to install a flash tank separator.

- **Flash Tank Separator:** The installation of a flash tank separator between the glycol contactor and the glycol regenerator/reboiler units creates a pressure drop in the system, allowing methane and some VOCs and HAPs to flash out of (separate from) the glycol. The amount of pressure drop that can be created is a function of the fuel gas system pressure or compressor suction pressure, because methane gas flashed-off at the flash tank separator is then sent to be used as fuel in the TEG reboiler or compressor engine. Simply put, the pressure can only be dropped to a pressure that still exceeds the fuel gas pressure, allowing the collected methane gas to flow into the fuel system. Flash tank separators typically recover 90 percent of the total methane and approximately 10 to 40 percent of the total VOCs that would otherwise be vented to atmosphere. Methane emissions can also be controlled by taking the simple step of adjusting the rate that glycol is circulated in the system.

  In 2005, the EPA estimated that the installation of a flash tank separator, on average, resulted in 10 Mcfd (3,650 Mcf/yr) of methane gas captured for sale or use as fuel for each TEG dehydrator (typically a 90 percent reduction in methane emissions). And in 2009, the EPA reported that flash tank separators are installed on *only*: 15 percent of the dehydration units processing less than 1 MMcfd; 40 percent of units processing 1 to 5 MMcfd; and between 65 and 70 percent of units processing more than 5 MMcfd.[262] Therefore, an emission control target still exists, especially for small dehydration units.

  The installation of a flash tank separator also improves the efficiency of downstream components (e.g. condensers) and reduces fuel costs by providing a fuel source to the TEG reboiler or compressor engine.[263]

- **Glycol Recirculation Pump:** Methane emissions are directly proportional to the glycol circulation rate. Circulating glycol at a rate that exceeds the operational need for removing water content from gas unnecessarily increases methane emissions. Glycol circulation rates are typically set at the maximum to account for peak throughput. Gas pressure and flow rate decline over time, requiring the glycol circulation rate to be adjusted to meet operational need. Optimizing the glycol circulation merely requires an engineering assessment and a field operating adjustment. If the glycol dehydration unit includes a condenser, methane emissions can be collected and used for fuel or destroyed, rather than being vented to atmosphere.

  In 2005, the EPA estimated that optimizing the glycol circulation rate could result in a wide range of methane capture from 1 to 100Mcfd (18,250 Mcf/yr using a median estimate of 50 Mcfd). [264]

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[262] USEPA Natural Gas STAR, Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators, 2009.

[263] USEPA Natural Gas STAR, Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators, 2009.

- **Condensers**: Some glycol reboilers have condensers to recover natural gas liquids and reduce VOCs and HAPs. However, condensers do not capture methane (because it is a non-condensable gas); therefore, the addition of a condenser does not reduce methane emissions. When condensers are installed, methane gas is typically vented to atmosphere. Alternatively, this methane gas (called "skimmer gas") can be routed to the reboiler firebox or other low-pressure fuel gas systems.[265] In 2005, the EPA estimated that rerouting glycol skimmer gas could result in an average methane capture of 21 Mcfd (7,665 Mcf/yr). [266]
- **Electric Pump vs. Energy-Exchange Pumps**: Historically, gas-assisted glycol pumps have been used. Where there is an electric supply, the gas-assisted glycol pumps can be replaced with an electric pump. Gas-assisted pumps are driven by the expansion of the high-pressure gas entrained in the rich glycol that leaves the contactor, supplemented by the addition of untreated high-pressure wet (methane rich) natural gas. The high-pressure gas drives pneumatic pumps. Much like pneumatically operated valves, pneumatically operated pumps vent methane.

  In 2007, the EPA estimated that between 360 and 36,000 Mcf/yr in methane emission reductions could be achieved by installing an electric pump to replace the natural gas driven glycol energy exchange pump; the wide range in methane emission reductions is a function of the large variation in equipment sizes.[267]

In 2007, EPA estimated the total potential emission reductions at any given glycol dehydration unit is a function of how many emission control solutions are installed. The total may range from 3,700-35,000 Mcf/year ($14.8K-$140K worth of gas leakage). In 2011, EPA estimated 38,000 Mcf/year ($152K).[268] Therefore, controlling methane emissions and other GHG emissions from dehydration units is good business.

However, despite the clear environmental and financial benefits, not all members of the oil and gas industry voluntarily invest in methane control options. Therefore, it is recommended that NYSDEC require operators to evaluate the technical and economic feasibility of installing methane emission controls on gas dehydrators; installation should be mandatory unless an infeasibility determination is made.

Recommendation No. 57: Natural gas operators should be required to evaluate the technical and economic feasibility of installing methane emission controls on gas dehydrators; installation should be mandatory unless an infeasibility determination is made. This requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

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[264] The wide range in methane capture opportunity is a function of the dehydrator size, and how efficiently the operator previously optimized the glycol circulation rate.

[265] USEPA Natural Gas STAR, Reroute Glycol Skimmer Gas, PRO Fact Sheet No. 201, 2004.

[266] EPA Natural Gas STAR, Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas, November 1, 2005.

[267] EPA Natural Gas STAR, Natural Gas Dehydration, Producers Technology Transfer Workshop, Durango Colorado, September 13, 2007.

[268] USEPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks; (1990-2009), April 15, 2011.

Diesel Engine Emission Control:

In 2009 AKRF recommended that diesel engines should be Tier 2 or higher. AKRF pointed out that "Tier 0" engines could be used, unless NYSDEC limited engines by certification type. Uncertified engines have extremely high emission rates for criteria pollutants such as particulate matter.

Additionally, AKRF recommended that diesel particle filters be installed on diesel engines to reduce particulate matter that has shown to aggravate respiratory systems and is known to be carcinogenic. More specifically AKRF recommended that all engines with a power output of 50 horsepower or greater be equipped with a diesel particle filter, either by the original engine manufacturer or by retrofit.

The 2011 RDSGEIS, Appendix 10 Proposed Supplementary Permit Conditions for HVHF, addressed most of AKRF's recommendations, by prohibiting Tier 0 engines, requiring Tier 2 engines in most cases, and requiring both Tier 1 and Tier 2 engines to install emission controls. NYSDEC proposes that:

- *No uncertified (i.e., EPA Tier 0) drilling or hydraulic fracturing engines will be used for any activity at the well sites;*
- *The drilling engines and drilling air compressors will be limited to EPA Tier 2 or newer equipment. If Tier 1 drilling equipment is to be used, these will be equipped with both particulate traps (CRDPF [Continuously Regenerating Diesel Particulate Filters]) and SCR [Selective Catalytic Reduction] controls. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from the control requirements or proposes alternate mitigation and/or control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence; and*
- *The completion equipment engines will be limited to EPA Tier 2 or newer equipment. Particulate traps will be required for all Tier 2 engines. SCR control will be required on all completion equipment engines regardless of the emission Tier. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from this requirement or proposes mitigation and/or alternate control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence [emphasis added].*[269]

NYSDEC estimates that 25% of the engines may be Tier 1 engines, and to ensure compliance with National Ambient Air Quality Standards (NAAQS) it requires the engine to be equipped with both CRDPFs and Selective Catalytic Reduction controls.

While NYSDEC has proposed a number of improvements for diesel engine emission control, the RDSGEIS did not assess whether Tier 1 engines could be eliminated altogether.

Recommendation No. 58: The SGEIS should examine whether it is possible to eliminate Tier 1 engine use. Further examination of AKRF's recommendation to prohibit Tier 1 engine use is warranted.

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[269] 2011 NYSDEC, RDSGEIS, Page 7-108 and 7-109 and Appendix 10, Attachment A, Condition 9-11.

Leak Detection & Repair Program:

In 2009 HCLLC recommended that NYSDEC require Leak Detection and Repair (LDAR) programs including acoustic detectors and infrared technology to detect odorless and colorless leaks. Unmitigated gas leaks pose a risk of fire and explosion, and contribute to GHG, VOC, and HAP emissions, that could otherwise be avoided by routine detection and repair programs.

Methane gas leaks can occur from numerous locations at gas facilities—valves, drains, pumps, threaded and flanged connections, pressure relief devices, open-ended valves and lines, and sample points—as gas moves through equipment under pressure. These leaks are called “fugitive emissions.”

Fugitive emissions from equipment leaks are unintentional losses of methane gas that may occur due to normal wear and tear, improper or incomplete assembly of components, inadequate material specifications, manufacturing defects, damage during installation or use, corrosion, or fouling.[270]

Because methane is a colorless, odorless gas, leaks often go unnoticed. Historically, leak checks were only performed on equipment components when they were first installed, using a soap bubble test or hand held sensor, to ensure the installation was leak tight. After installation leaks were not typically monitored or repaired unless they became a significant safety hazard. For example, a significant gas leak would be repaired if area, building, or employee monitors set off alarms or if olfactory, audible, or visual indicators observed by facility employees identified the leak. Under these circumstances, the leaks had usually become an obvious safety concern. As a result, methane leaks at outdoor facilities and unmanned facilities often went undetected for long periods of time.

Fugitive emission control is a two-part process that includes: (1) a monitoring program to identify leaks and (2) a repair program to fix the leak. Monitoring program type and frequency is a function of the type of component, and how the component is put to use. In most cases, monitoring programs can be intermittently scheduled at a certain frequency (e.g. monthly or quarterly) to identify leaking equipment. However, permanent leak sensors may be required to detect chronic leakers.[271]

There are many different monitoring tools that can be used to identify leaks, including electronic gas detectors, acoustic detectors, ultrasound detectors, flame ionization detectors, calibrated bagging, high volume sampler, end-of-pipe flow measurement, and infrared leak detection. Once leaks are identified, the operator can evaluate what is causing the leak and develop a replacement or repair program to mitigate the leak.

For example, a hand held infrared camera can be used as a screening tool to detect emissions that are not visible to the naked eye. An infrared camera produces images of gas leaks in real-time. [272] It is capable of identifying methane leaks, but cannot quantify the amount of the leak. Infrared cameras produce photos that show methane gas leaks.

Once a leak is identified, and a more quantitative leak flow rate determination is needed, other measurement devices such as Hi-Flow Samplers, Vent-Bag Methods, and Anemometers may be used.[273] Hi-Flow Samplers capture the entire leak, measuring the leak rate directly for leaks up to 10 cubic feet per

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[270] USEPA, Methane’s Role in Promoting Sustainable Development in the Oil and Natural Gas Industry, 2009.

[271] Squarek, J. (Canadian Association of Petroleum Producers), Layer, M. (Environment Canada) and Picard, D. (Clearstone Engineering Ltd.), Development of a Best Management Practice in Canada for Controlling Fugitive Emissions at Upstream Oil and Gas Facilities, 2005.

[272] Snider, P., Advanced Well Completion Technology to Reduce Methane Emissions and Use of Infared Cameras for Leak Detection, Global Forum on Flaring and Venting Reduction and Natural Gas Utilisation, 2008.

[273] Heath, M.W., Leak Detection and Quantification of Fugitive Methane Emissions at Natural Gas Facilities, 2009.

minute (cfm), providing leak flow rate and concentration data.[274] Toxic Vapor Analyzers and acoustic leak detection systems are other methods to identify methane leaks.[275]

Fugitive emissions management is an ongoing commitment, not a one-time initiative. The potential for fugitive equipment leaks will increase as facilities age. Successful fugitive emission control plans require trained personnel, emissions testing equipment, and performance tracking systems.

In 2009, the EPA examined the profitability of repairing equipment leaks at oil and gas facilities and found that leak repair is not only an important air pollution control and safety measure, but also is a profitable investment.[276] EPA reports that fugitive emissions control provides numerous benefits including: reduced maintenance costs and downtime, improved process efficiency, a safer work environment, a cleaner environment, and resource conservation.

The 2011 RDSGEIS acknowledges the potential impact of gas leaks, and requires a Leak Detection and Repair Program to be included in the operator's GHG Mitigation Plan.

> *Because the production phase is the greatest contributor of GHGs and in an effort to mitigate VOC and methane leaks during this phase, the Department proposes to require, via permit condition and/or regulation, a Leak Detection and Repair Program would* ***include as part of the operator's greenhouse gas emissions impacts mitigation plan*** *which is required for any well subject to permit issuance under the SGEIS [emphasis added].*[277]

The 2011 RDSGEIS specifies the minimum requirements for a Leak Detection and Repair Program.

> *The Leak Detection and Repair Program within the greenhouse gas emissions impacts mitigation plan would contain the following minimum requirements.*
>
> - *There would be an ongoing site inspection for readily detected leaks by sight and sound whenever company personnel or other personnel under the direction of the company are on site. Anytime a leak is detected by sight or sound, an attempt at repair should be made. If the leak is associated with mandated worker safety concerns, it should be so noted in follow-up reports;*
> - *Within 30 days of a well being placed into production and at least annually thereafter, all wellhead and production equipment, surface lines and metering devices at each well and/or well pad including and from the wellhead leading up to the onsite separator's outlet would be inspected for VOC, methane and other gaseous or liquid leaks. Leak detection would be conducted by visible and audible inspection and through the use of at least one of the following: 1) electronic instrument such as a forward looking infrared camera, 2) toxic vapor analyzer, 3) organic vapor analyzer, or 4) other instrument approved by the department;*
> - *All components noted above that are possible sources of leaks would be included in the inspection and repair program. These components include but are not limited to: line heaters, separators, dehydrators, meters, instruments, pressure relief valves,*

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[274] http://www.heathus.com/_hc/index.cfm/about-us/vision

[275] Methane to Markets, Reducing Methane Emissions through Directed Inspection and Maintenance (DI&M), Oil & Gas Subcommittee Technology Transfer Workshop, 2009.

[276] Methane to Markets, Reducing Methane Emissions Through Directed Inspection and Maintenance (DI&M), Oil & Gas Subcommittee Technology Transfer Workshop, 2009.

[277] 2011 NYSDEC, RDSGEIS, Page 7-114 .

> *vents, connectors, flanges, open-ended lines, pumps and valves from and including the wellhead up to the onsite separator's outlet;*
>
> - *For each detected leak, if practical and safe an initial attempt at repair would be made at the time of the inspection, however, any leak that is not able to be repaired during the inspection may be repaired at any time up to 15 days from the date of detection provided it does not pose a threat to on-site personnel or public safety. All leaking components which cannot be repaired at detection would be identified for such repair by tagging. All repaired components would be re-inspected within 15 days from the date of the initial repair and/or re-repair to confirm, using one of the approved leak detection instruments, the adequacy of the repair and to check for leaks. The department may extend the period allowed for the repair(s) based on site-specific circumstances or it may require early well or well pad shutdown to make the repair(s) or other appropriate action based on the number and severity of tagged leaks awaiting repair; and*
> - *Site inspection records would be maintained for a minimum period of 5 years. These records would include the date and location of the inspection, identification of each leaking component, the date of the initial attempt at repair, the date(s) and result(s) of any re-inspection and the date of the successful repair if different from initial attempt [emphasis added].*[278]

The RDSGEIS proposal to require an LDAR Program is a substantial improvement; however, a few changes to the proposed program are recommended:

- An LDAR inspection should be conducted at well/drillsite start-up, not 30 days after. It is best practice to construct and install equipment and test for leaks prior to operation. Equipment should not be operated for 30 days without completing this minimum standard of care.
- Quarterly testing with an infrared camera (as a screening method) should be required, instead of annual testing, as a minimum standard. If the infrared camera screening indicates a leak, the leak location, if clearly pin pointed, should be repaired. Or additional testing should be conducted using more sophisticated tools (described above) to pin-point the leak location, followed by a repair.
- Testing should include all equipment located on the drillsite. As proposed, the RSGEIS suggests the LDAR Program end at the separator's outlet. Equipment will be located downstream of the separator outlet, and prior to the connection the gas transit line that could potentially leak gas. Therefore, it is recommended that the LDAR Program be implemented for all equipment on the drillsite up to and including the gas meter outlet which is connected to the pipeline inlet.

Recommendation No. 59: The proposed LDAR Program should be revised to require: a drillsite LDAR inspection at start-up; quarterly testing with an infrared camera with additional follow-up testing and repair if a leak is indicated; testing of all equipment located on the drillsite up to and including the gas meter outlet which is connected to the pipeline inlet. These requirements should be included in the SGEIS as mitigation measures and codified in the NYCRR, and be required for all natural gas operations, not just HVHF operations.

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[278] 2011 NYSDEC, RDSGEIS, Page 7-115 and 7-116.

Cleaner Power and Fuel Supply Options:

In 2009, HCLLC and AKRF recommended that the SGEIS evaluate the use of cleaner engines and fuels.

In suburban and urban areas of NYS, where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable, thus eliminating local diesel exhaust. This alternative would be particularly beneficial where operations are planned near sensitive receptors and in areas that already suffer from high air pollutant loading. Electric engines have the added benefit of quieter operation and less noise impact in urban and suburban settings.

In rural areas, where high-line power is not readily available, an operator should be required to evaluate whether there is a natural gas supply that could be used as fuel. Natural gas fired engines produce less air pollution that diesel engines. A natural gas supply should be available for all wells drilled on a multi-well drillsite, except the first well. Once the first well is drilled using diesel, subsequent wells can be drilled using the natural gas produced by that well to generate power. Smaller temporary gas processing units are available to process wellhead gas to the quality required for equipment use. The use of dual fuel engines would enable switching from diesel to natural gas once it is available.

The use of electric and natural gas engines would result in reduced local pollutant emissions and overall GHG emissions (both grid power and natural gas have a lower carbon footprint than diesel) and generally would have associated cost savings given the reduced fuel transportation and storage needs (e.g. double-wall tanks) and the reduced risk of tank leakage and cleanup associated with the use of fuel gas produced on-site or electric power.

The 2011 RDSGEIS: The 2011 RDSGEIS did not examine cleaner power and fuel supply options. The RDSGEIS only briefly mentioned that electric engines and cleaner fuel options were recommended[279] but disregarded the recommendations as “unlikely to be practically implemented to any extent” due to the remote nature of the drillsites. This analysis is incomplete and fails to consider viable alternatives for mitigating air pollution.

Foremost, electric power is available in all suburban and urban areas of NYS, and is currently located in many rural areas as well to supply power to homes, farms and businesses.

Secondly, the use of natural gas-fired engines on a multi-well drillsite is a commonly used mitigation measure. While diesel engines are often used as the prime mover of power supply for rotary well drilling, natural gas or dual fuel (diesel/gas) engines are available to take advantage of cleaner fuel supplies.[280] EnCana, a gas producer, reports that natural gas-fired rigs reduce air pollution by 90% compared to diesel fired rigs.[281] Power can also be supplied to the drilling rig by a natural gas-powered reciprocating turbine that can generate electricity on site.

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[279] 2011 NYSDEC, RDSGEIS, Page 6-144.

[280] www.naturalgas.org.

[281] EnCana 2005 Annual Report.

Recommendation No. 60: In suburban and urban areas of NYS, where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable, eliminating the local diesel exhaust from those engines. In rural areas, where high-line power is not readily available, an operator should be required to evaluate whether there is a natural gas supply that could be used as fuel; if so, use of the natural gas supply should be mandatory to the extent practicable. Cleaner power and fuel selection requirements should be included in the SGEIS as a mitigation measure and codified in the NYCRR. These requirements should apply to all natural gas operations, not just HVHF operations.

18. Surface Setbacks from Sensitive Receptors

Background: The 2009 DSGEIS did not propose sufficient safety or quality-of-life surface setbacks from sensitive human and environment resource receptors. This problem persists in the 2011 RDSGEIS. Noise, traffic, odor, air, and water pollution impacts to sensitive receptors will be significant if the small setbacks proposed in the RDSGEIS are adopted.

Surface setbacks should be increased to mitigate significant impacts and to create a safe environment for the affected public. For example:

- Blowouts can eject drilling mud, hydrocarbons, and/or formation water from a well onto adjacent waters and lands. Depending on reservoir pressure, blowout circumstances, and wind speed, these pollutants can be distributed hundreds to thousands of feet away from a well. These pollutants can then be further transported in the subsurface or on the surface, creating a large area of contamination in a very short amount of time.
- Chemicals, fuels, and explosive charges (e.g. perforating guns) may be located at the drillsite and may pose hazards to the public, in addition to the flammable, explosive, and hazardous gases (e.g. hydrogen sulfide gas, benzene) that are produced from the well and associated equipment.
- The potential radius of impact for explosions, fire, and other industrial hazards should be considered. For example, the city of Forth Worth, Texas uses the International Fire Code as the basis for its minimum 600' setback from Barnett shale gas drilling operations.[282] Whereas, NYCRR only provides for a 100' setback from a home. 6 NYCRR § 553.2.
- High pressure hose leaks can spray industrial fluids off the drilling pad and onto surrounding properties or waters. The radius of contamination will depend on system pressure, shut-down reaction timing, wind speed, and other factors.

For example, in September 2009, 1,300 gallons of well chemicals were leaked during a hydraulic fracture treatment at the Cabot Heitsman 4H well located in Susquehanna Country, Pennsylvania, and flowed into the nearby Steven's Creek located more than 100 feet away, despite protections in place under the operator's required Pennsylvania PPC plan.[283]

Recommendation No. 61: The SGEIS should provide scientific and technical justification for each setback distance proposed to demonstrate how that distance is protective of the nearby sensitive receptor. A hazard identification analysis should be completed to assess the safe distance from human and sensitive environmental receptors to proposed shale gas drilling and HVHF operations. The analysis should assess blowout radius, spill trajectory, explosion hazards, other industrial hazards, fire code compliance, human health, agricultural health, and quality-of-life factors. Improved setbacks as a result of this analysis should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

While statewide minimum setbacks to protect human health, provide safe buffers, and protect the environment should be established, both the RDSGEIS and NYCRR should include a provision to allow local communities to establish more protective setbacks than statewide regulations to address unique and site-specific local concerns and community characteristics.

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[282] Fort Worth Gas Drilling Regulations Presentation, Barnett Shale EXPO, March 11, 2009.

[283] Cabot Oil & Gas Corporation, Engineering Study, for submittal to PADEP, In Response to Order dated September 24, 2009, prepared by URS Corporation for Cabot, October 9, 2009.

Recommendation No. 62: The SGEIS and NYCRR should allow local zoning authorities to establish more protective setbacks than statewide regulations to address unique and site-specific local concerns and community characteristics. The ability to improve local setbacks should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

The 2011 RDSGEIS: The 2011 RDSGEIS proposes additional setbacks from aquifers, wells, and water bodies for HVHF operations, but does not establish additional setbacks from homes or public buildings.

NYSDEC does not provide scientific or technical justification in the RDSGEIS for the setback distances it has selected. Setbacks ranging from 150’ to 2,000’ are included in the RDSGEIS without justification for how or why those particular distances were selected or determined to be adequate to protect water resources.

The 2011 RDSGEIS proposes the following setbacks:

- **500’ setback from primary and principal aquifers**. However, for principal aquifers, drilling and HVHF operations can occur within that 500’ buffer with additional review, and for both primary and principal aquifers the setback distance will be reconsidered in two years in a yet to be determined process.

  > *Well pads for high-volume hydraulic fracturing would be prohibited within 500 feet of primary aquifers (subject to reconsideration 2 years after issuance of the first permit for high-volume hydraulic fracturing).*[284]

  > *For at least two years from issuance of the first permit for high-volume hydraulic fracturing, proposals for high-volume hydraulic fracturing at any well pad within 500 feet of principal aquifers, would require (1) site-specific SEQRA determinations of significance and (2) individual State Pollutant Discharge Elimination System (SPDES) permits for stormwater discharges. The Department would re-evaluate the necessity of this approach after two years of experience issuing permits in areas outside of the 500-foot boundary.*[285]

- **2,000’ setback from a public water supply**, unless a shale gas well is located within 1000’ of a subsurface water supply designated by the New York City Department of Environmental Protection (NYCDEP). However, these setbacks will be reconsidered in three years in a yet to be determined process.

  > *The Department will not issue well permits for high-volume hydraulic fracturing at the following locations…any proposed well pad within 2,000 feet of public water supply wells, river or stream intakes and reservoirs (subject to reconsideration 3 years after issuance of the first permit for high-volume hydraulic fracturing).*[286]

  > *The Department proposes that site-specific environmental assessments and SEQRA determinations of significance be required for … any proposed well location determined by NYCDEP to be within 1,000 feet of its subsurface water supply infrastructure.*[287]

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[284] 2011 NYSDEC, RDSGEIS, Page 1-17.

[285] 2011 NYSDEC, RDSGEIS, Page 1-18.

[286] 2011 NYSDEC, RDSGEIS, Page 3-15.

[286] 2011 NYSDEC, RDSGEIS, Page 3-16.

[287] 2011 NYSDEC, RDSGEIS, Page 3-15.

Recommendation No. 63: The process for revising the 500’ setback from primary and principal aquifers and the 2,000’ setback from a public water supply in two and three years, respectfully, is unclear. NYSDEC should clarify the review process, including an explanation of its plans for public review and comment. NYSDEC should revise its regulations at 6 NYCRR § 617.4(b) to provide that the siting of any oil or gas well within 500’ of a primary aquifer or within 2,000 of a public water supply is a Type I action.

- **500’ setback from a private water well**.

> *The Department will not issue well permits for high-volume hydraulic fracturing at the following locations…any proposed well pad within 500 feet of private drinking water wells or domestic uses springs, unless waived by the owner.*[288]

The RDSGEIS provides no rationale as to why a public water supply would be afforded a 2,000’ setback, while a private water well would only be afforded at 500’ setback.

Recommendation No. 64: The SGEIS should examine whether waivers to the 500’ private water well setback comport with federal law and the requirement to protect Underground Sources of Drinking Water (USDWs). The SGEIS should provide technical justification for any reduction in this setback, and should not allow a private well owner to reduce the setback such that it poses a risk to its water supply, as well as other user in the area. Private land owners should not be allowed to waive setbacks from private water wells and adversely affect the water quality of neighboring wells.

- **150’ setback from a stream, storm drain, lake, or pond**.

> *Based on the above information and mitigating factors, the Department proposes that site specific SEQRA review be required for projects involving any proposed well pad where the closest edge is located within 150 feet of a perennial or intermittent stream, storm drain, lake or pond.*[289]

The 150’ setback language conflicts with the 2,000’ setback language above, because it allows a closer setback from lakes, rivers and streams than from a public water supply. It is not clear which lakes, rivers, and streams would be protected by the 150’ setback, and which would be protected by a 2,000’ setback.

On October 3, 2011 Pennsylvania Governor Corbett announced plans to implement the Marcellus Shale Advisory Commission recommendation to increase the setback distance for wells near streams, rivers, ponds and other bodies of water to at least 300’.[290] An increased set back to at least 300’ should also be considered by NYS.

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[288] 2011 NYSDEC, RDSGEIS, Page 7-76.

[289] 2011 NYSDEC, RDSGEIS, Page 7-76.

[290] Pennsylvania Office of the Governor, News Release, Governor Corbett Announces Plans to Implement Key Recommendations of Marcellus Shale Advisory Commission, October 3, 2011.

Recommendation No. 65: The conflicting language between the 150' setback requirement and 2,000' setback requirement for lakes, rivers, and streams needs to be resolved in both the SGEIS and the NYCRR. As drafted, neither the RDSGEIS nor the NYCRR are clear which lakes, rivers, and streams would be protected by the 150' setback, and which would be protected by a 2,000' setback. NYSDEC should indicate whether it intends to apply the 150' setback only to surface water resources that are not actual or potential public drinking water supplies. NYSDEC should also explain whether the 150' set back is sufficient to protect those water resources, or whether this setback should be increased. Improved setbacks as a result of this analysis should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

- **4,000' setback from NYC and Syracuse watersheds**.

  > *Accordingly, the Department recommends that regulations be adopted to prohibit high-volume hydraulic fracturing in both the NYC and Skaneateles Lake watersheds, as well as in a 4,000 -foot buffer area surrounding these watersheds, to provide an adequate margin of safety from the full range of operations related to high-volume hydraulic fracturing that extend away from the well pad. The Department also is presenting this proposal based on its consistency with the principles of source water protection and the "multi-barrier" approach to systematically assuring drinking water quality.*[291]

Recommendation No. 66: The 4,000' setback from NYC and Syracuse watersheds should be added to the proposed regulatory revisions for operations associated with HVHF at 6 NYCRR § 560.4. The SGEIS and NYCRR should also clarify if activities associated with HVHF drilling and completions will be prohibited underneath the watershed as well as on the surface.

NYSDEC has not provided engineering or scientific justification for the setback distances it has selected, other than a brief assessment of the setbacks that are allowed in other states. NYSDEC ultimately selected setbacks that are not as protective as those identified by the agency's consultants. For example, the RDSGEIS, states:

> *The required setbacks from surface water supplies in other states reviewed by Alpha vary between 100 and 350 feet.*[292]

NYSDEC's consultants collected information that shows a more protective 350' setback is in use in other states; however, NYSDEC concludes that only a 150' setback will be required. This is less than half the distance of the most protective standard found by NYSDEC's consultants, and the 150' setback can be further reduced at NYSDEC's discretion based on a site-specific SEQRA review:

> *Based on the above information and mitigating factors, the Department proposes that site specific SEQRA review be required for projects involving any proposed well pad where the closest edge is located within 150 feet of a perennial or intermittent stream, storm drain, lake or pond.*[293]

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[291] 2011 NYSDEC, RDSGEIS, Page 7-56.

[292] 2011 NYSDEC, RDSGEIS, Page 7-76.

[293] 2011 NYSDEC, RDSGEIS, Page 7-76.

Of note, the RDSGEIS does not address setbacks from homes or public buildings. The RDSGEIS merely requires the operator to document the distance from the proposed drilling and HVHF operations to "…any residences, occupied structures or places of assembly within 1,320 feet."[294] However, no new setback is established for homes or public buildings, other than required by current regulations.

NYCRR Proposed Revisions: The new setbacks proposed in the RDSGEIS are codified in regulation at 6 NYCRR §560.4. These setbacks would apply only to wells that undergo HVHF. NYSDEC does not explain why these setbacks would not apply to all oil and gas well drilling in NYS, despite the fact that 6 NYCRR § 553.2 (Well Surface Restrictions) applies to all NYS oil and gas wells. NYSDEC has not justified its limiting of new setback increases to HVHF wells only.

Recommendation No. 67: The setback increases proposed in the RDSGEIS should apply to all oil and gas drilling in NYS and should be codified at 6 NYCRR § 553.2.

The existing NYCRR allows drilling, HVHF operations, and production equipment to be located within 100' from an inhabited private dwelling and within 150' from a public building or area that may be used as a place of "resort, assembly, education, entertainment, lodging, trade, manufacture, repair, storage, traffic or occupancy by the public." The existing NYCRR also allows drilling, HVHF operations, and production equipment to be located within 50' from a public stream, river, or other body of water. There is no required setback from buildings or structures used for agriculture. 6 NYCRR § 553.2.

The proposed revisions to the NYCRR include 500' setbacks from primary aquifers, 2,000' setbacks from public water supplies, and 500' setbacks from private wells. Proposed 6 NYCRR § 560.4. However, these setbacks apply only to wells that undergo HVHF, and do not apply to all wells that undergo hydraulic fracturing operations in NYS.

NYSDEC's setback analysis does not take into account that directional drilling technology enables wells to be drilled to a bottom-hole location at 3-5 miles[295] away from a wellhead. In directional drilling, it is now common for the horizontal displacement of the bottom hole location to be several times the total vertical depth (TVD) of the well. For example, a well with a vertical depth of 5,000' could have a bottom hole horizontal displacement of 10,000-15,000' from the drill site, or more. A well with a vertical depth of 7,000' could have a bottom hole horizontal displacement of 14,000-21,000' from the drill site, or more. For example, in 1997, BP drilled a well to approximately 5,300' achieving a 33,182' horizontal displacement, meaning the wellhead was located over 6 miles away from the hydrocarbon target.[296] In 1997, a 6-mile horizontal displacement was a great feat; now, extended reach drilling (ERD) is commonplace in the industry, and wells are routinely drilled to hydrocarbon targets miles away from the wellhead.

Given the flexibility afforded by the fact that 640-acre spacing units may vary in shape, from square to rectangular, and that surface drillsites need not be located over the spacing unit, well operators utilizing directional drilling technology have a greater ability to select surface drillsite locations that optimize distance from sensitive public and private resources.

As shown in the figure below, the setbacks currently proposed in the RDSGEIS and in the NYCRR are inadequate. Shale drilling and HVHF operations within 100'-150' of homes and public buildings pose a direct safety risk, not to mention the health and quality of life impacts presented. NYSDEC is proposing

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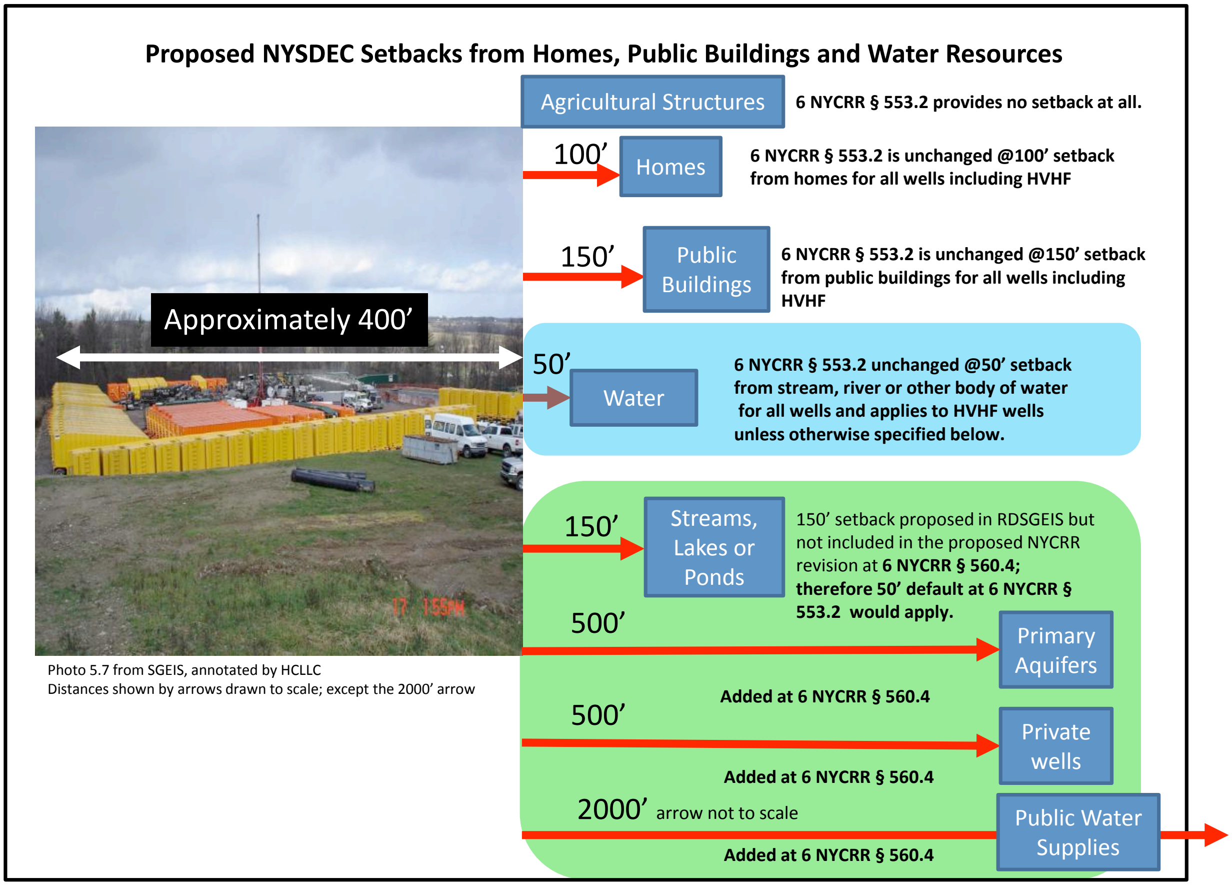
[294] 2011 NYSDEC, RDSGEIS, Page 3-10.

[295] Well step-out distance that can be achieved will depend on well depth.

[296] BP, Extended-Reach Drilling: Breaking the 10-km Barrier, 1997.

to allow shale drilling and HVHF operations to run 24 hours a day, 7 days a week, which will result in significant impacts to human health and quality of life—disrupting sleep, work, schooling, and recreational patterns for nearby residents.



Proposed NYSDEC Setbacks from Homes, Public Buildings and Water Resources

6 NYCRR § 553.2 provides no setback at all.

6 NYCRR § 553.2 is unchanged @100’ setback from homes for all wells including HVHF

6 NYCRR § 553.2 is unchanged @150’ setback from public buildings for all wells including HVHF

6 NYCRR § 553.2 unchanged @50’ setback from stream, river or other body of water for all wells and applies to HVHF wells unless otherwise specified below.

150’ setback proposed in RDSGEIS but not included in the proposed NYCRR revision at **6 NYCRR § 560.4; therefore 50’ default at 6 NYCRR § 553.2 would apply.**

Added at 6 NYCRR § 560.4

Added at 6 NYCRR § 560.4

Added at 6 NYCRR § 560.4

Photo 5.7 from SGEIS, annotated by HCLLC
Distances shown by arrows drawn to scale; except the 2000’ arrow

By comparison, the local zoning setback requirements for Barnett Shale development implemented in the urban area of Fort Worth, Texas are substantially larger than those proposed for NYS.[297] As shown in the figure below, the required setback from a home is six times larger at 600’, as compared to NYS’ 100’ setback. Additionally, Fort Worth, Texas has implemented setbacks of at least 300’ from public buildings and 600’ from schools, which is more than double what is proposed by NYSDEC.[298]

At a state level, Wyoming requires a minimum setback of 350’ from “water supplies, residences, schools, hospitals, and other structures where people are known to congregate.”[299] The below photograph shows the proximity of homes to a well pad in Pennsylvania, where a 200’ minimum setback from homes is required.[300]

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[297] Fort Worth Gas Drilling Regulations Presentation, Barnett Shale EXPO, March 11, 2009; the Code of Ordinances of the City of Forth Worth § 15-36(A).

[298] The Code of Ordinances of the City of Forth Worth § 15-34(N)(7), § 15-36(A).

[299] Wyo. Admin. Code OIL GEN Ch. 3 § 22(b).

[300] Governor’s Marcellus Shale Advisory Commission Report, Prepared for Governor Corbett of Pennsylvania, July 22, 2011.

The photo above shows homes within close proximity to shale drilling operations in Hopewell Township, Washington County, PA.

Comparison of NYS Setbacks from Homes and Public Buildings to Fort Worth, Texas Setbacks

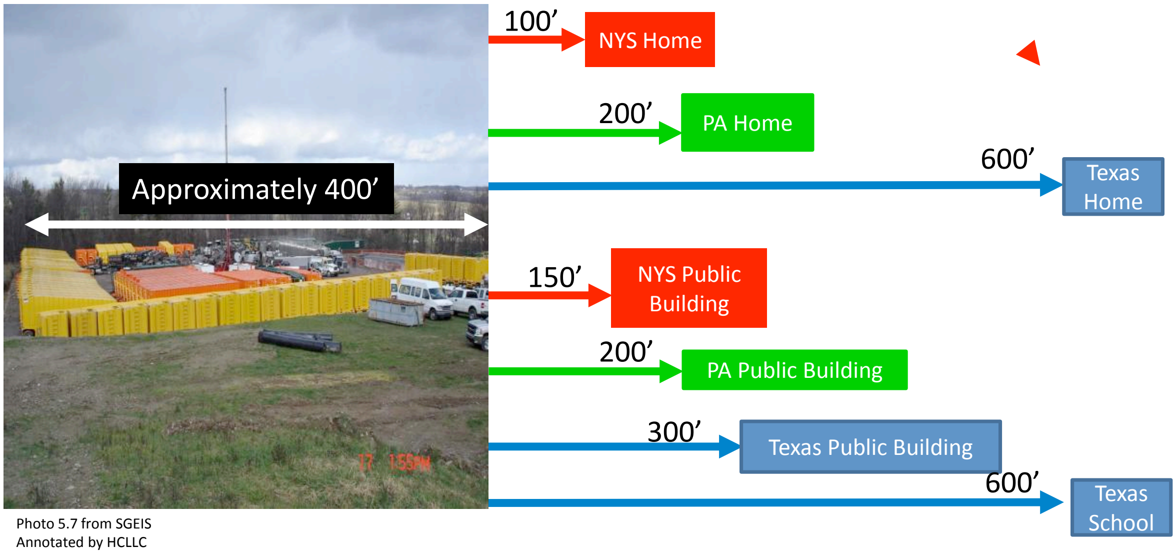

Photo 5.7 from SGEIS
Annotated by HCLLC
Distances shown by arrows drawn to scale

> **Recommendation No. 68:** Improved setbacks should be included in the SGEIS as a mitigation measure and codified in the NYCRR. Specifically, the SGEIS and NYCRR should be revised at 6 NYCRR § 553.2 to include the following minimum setbacks: homes, public buildings, and schools (1,320'; ¼ mile); private and public wells, primary aquifers, and other sensitive water resources (4,000'); and other water resources (660'; 1/8 mile). Additionally, NYSDEC should clarify the authority of local zoning authorities to establish minimum setbacks that are more protective than NYS' minimum standards in order for localities to address unique and site-specific local concerns and community characteristics.

In addition to the inadequate minimum setback requirements, the NYCRR allows an operator to move its surface location by 75' without obtaining a permit amendment. 6 NYCRR § 552.3(b). Absent NYSDEC and public review, a 75' adjustment is very significant, especially when setbacks as low as 50' to 150' are used. The regulations at 6 NYCRR § 552.3 explain that a 75' surface location adjustment is allowed, without any permit amendment process, to account for surface obstructions or topography. However, if an operator's due diligence and site planning during the original permit process include an examination of surface obstructions and topography, later adjustments should not be necessary.

Recommendation No. 69: The NYCRR should be revised at 6 NYCRR § 552.3 to allow the well location to be adjusted by 75' without a permit amendment only if all the statewide and local setback requirements are still preserved.

The proposed regulations that govern HVHF SPDES permits also suffer from inadequate minimum setback requirements. The revisions proposed to 6 NYCRR § 750-3.3 include: a 4,000' setback from an unfiltered water supply; a 500' setback from a primary aquifer; no operations within a 100-year floodplain; and a 2,000' setback from a public water supply, including wells, natural lakes, man-made impoundments, rivers and streams. However, neither the existing regulations nor the proposed revisions to 6 NYCRR § 750-3.3 include setbacks from streams, rivers, or other bodies of water that are not specifically designated as public water supplies. Thus, HVHF operations potentially could be as close as 50' to streams, rivers, or other bodies of water, based on 6 NYCRR § 553.2. Also, the proposed regulations do not require a minimum setback of HVHF operations from private wells.

Further inconsistency is introduced in the proposed revisions to 6 NYCRR § 750-3.21, which prohibit HVHF operations within 100' of a wetland. While this setback requirement is recognized in the RDSGEIS,[301] the proposed revisions to 6 NYCRR § 553.2 and 6 NYCRR § 560.4 do not include a parallel requirement. These sections of the regulations should be revised to include a wetland setback.

Recommendation No. 70: The NYCRR should be revised at 6 NYCRR § 553.2 to include a wetland setback of at least 100' as described in the RDSGEIS.

The proposed revisions to 6 NYCRR § 750-3.21(f)(3) do not authorize the issuance of a SPDES permit for HVHF operations within 150' of storm drains, lakes, ponds, and perennial or intermittent streams, which conflicts with the 50' setback established at 6 NYCRR § 553.2. There remains confusion about which setbacks would be applied to lakes, ponds, and perennial or intermittent streams and rivers.

Recommendation No. 71: The NYCRR should be revised at 6 NYCRR § 750-3.3, 6 NYCRR § 750-3.2, 6 NYCRR § 553.2, and 6 NYCRR § 560.4 to provide consistent setback requirements that are protective of water sources, including rivers, streams, lakes, and private water supplies.

NYCRR should be clear that the intent, as stated in the RDSGEIS, is to measure setbacks from the edge of the drillsite, and to attempt to center wells on the drillsite to maximize the distance from the well to the drillsite edge.

Recommendation No. 72: NYCRR and the SGEIS should clarify that setbacks are measured from the edge of the drillsite. Wells should be centered on the well pad and should be set back at least 100' from the pad edge, to maximize well setbacks from sensitive receptors.

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[301] 2011 NYSDEC, RDSGEIS, Page 2-34.

19. Disposal of Drilling & Production Waste and Equipment Containing Naturally Occurring Radioactive Material (NORM)

Background: In 2009, HCLLC made recommendations to NYSDEC on best practices for disposal of drilling and production waste and equipment containing Naturally Occurring Radioactive Materials (NORM). NORM includes uranium, thorium, radium, and lead-210 and their decay products.[302] Additionally, radon, a component of natural gas, decays into radioactive polonium.

NORM can be brought to the surface in a number of ways during drilling, completion, and production operations:

- Drilling: Drill cuttings containing NORM are circulated to the surface.
- Completion: Wells stimulated using hydraulic fracture treatments inject water; a portion of that water flows back to the surface ("flowback") and can be contaminated by radioactive materials picked up during subsurface transport.
- Production: Subsurface water located in natural gas reservoirs, produced as a waste byproduct, may contain radioactive materials picked up by contact with gas or formations containing NORM (this water is called "produced water'). Equipment used in hydrocarbon production and processing can concentrate radioactive materials in the form of scale and sludge.

In January 2011, NYSDEC's consultant, Alpha Geoscience, agreed that the disposal of waste containing NORM is an important issue that should be addressed in the SGEIS. Alpha Geoscience's review of HCLLC's recommendations on NORM concluded that:

> *Harvey Consulting's recommendation to analyze practices for NORM testing, NORM treatment, and NORM disposal appears to be complete and well-researched. The review presents a concise analysis of practices involving the testing for and the treatment and disposal of NORM.*
>
> *Harvey Consulting's review of the dSGEIS's content regarding NORM is supported by a range of reliable sources. References include the EPA's website, USGS fact sheets, Texas Railroad Commission regulations, and a publication by Argonne National Laboratory.*[303]

Alpha Geoscience recommended that the SGEIS include a detailed analysis of NORM testing, treatment, transportation, and disposal methods:

> *Alpha suggests that **it may be useful to operators if the SGEIS includes NYSDEC's detailed analyses of NORM testing, treatment, transportation, and disposal**. This information may prove useful to the operator for developing handling and disposal plans [emphasis added].*[304]

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[302] USEPA Oil and Gas Production Wastes, NORM, http://www.epa.gov/radiation/tenorm/oilandgas.html.

[303] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Pages 9-11.

[304] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 12.

Yet, Alpha Geoscience recommended against adopting specific regulations to formalize NORM testing, treatment, transportation, and disposal requirements in NYS; instead, Alpha Geoscience recommended that NYSDEC "consider" having "temporary guidelines:"

> *Alpha suggests that NYSDEC consider having temporary guidelines regarding NORM in place, to clarify expectations and requirements for operators prior to the commencement of operations. This also would be helpful to operators for the design of handling and disposal plans [emphasis added].*[305]

HCLLC disagrees with Alpha Geoscience's recommendation for temporary NORM disposal guidelines. The requirements for testing, treatment, transportation, and disposal of NORM should be formalized in NYCRR. The rules should be clear to industry and the public, and enforceable by NYSDEC.

The 2009 DSGEIS acknowledged that drilling and production waste and equipment may contain NORM. NYSDEC reports that the Marcellus Shale contains Uranium-238 and Radium-226, and this NORM may be present in drill cuttings, produced water, and stimulation treatment waste.[306] NYSDEC identified Radium-226 as the most significant NORM of concern, because it is water soluble and has a half-life of 1,600 years.[307] Radiation pathways can include external gamma radiation, ingestion, inhalation of particulates, and radon gas.[308]

In 2009, HCLLC recommended that the SGEIS address the potential for equipment scale and sludge to contain high concentrations of NORM. HCLLC explained that equipment (water lines, flow lines, injection wellheads, vapor recovery units, water storage tanks, heaters/treaters, and separators)[309] used to process natural gas and produced water containing NORM can become coated with radium scale and sludge deposits.[310] Scale precipitates from produced water when it is brought to the surface, cooled to lower temperatures, and subject to lower pressures.[311] The most common form of scale is barium sulfate, which readily incorporates radium in its structure. HCLLC noted that, because E&P waste is exempt from the federal Resource Conservation and Recovery Act (RCRA),[312] it is critical that states establish clear best practice requirements for handling E&P waste, especially for NORM found in equipment scale and sludge. HCLLC pointed out that other oil and gas states, such as Texas and Louisiana, have adopted stringent NORM regulations, including: occupational dose control, surveys; testing and monitoring; record keeping; signs and labeling; and treatment and disposal methods.[313]

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[305] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 11.

[306] 2009 NYSDEC, DSGEIS, Page 4-36.

[307] 2009 NYSDEC, DSGEIS, Page 6-129.

[308] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[309] Argonne National Laboratory, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactive Materials Generated by the Petroleum Industry, Publication ANL/EAD-2, 1996.

[310] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[311] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[312] Environmental Protection Agency, Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations, EPA530-K-01-004, October 2002.

[313] 2009 NYSDEC, DSGEIS, Page 7-101.

The 2011 RDSGEIS: The 2011 RDSGEIS provided some improved data and acknowledged the risk of significant impacts from improperly disposed waste containing NORM. The RDSGEIS concluded that the NORM dataset is limited and there can be significant variability in NORM content. The 2011 RDSGEIS based its conclusions on data collected in other states; this data examined Marcellus Shale cuttings, produced water, and HVHF flowback.

However, the 2011 RDSGEIS still does not establish clear cradle-to-grave collection, testing, transportation, treatment, and disposal requirements for all waste containing NORM. The RDSGEIS is improved in that it establishes radioactive limitations and testing in some cases, but testing is still not required in all cases (even when data uncertainty exists). Long-term treatment and disposal requirements are not robust for all waste types. Nor is there a process in place to provide the public with information on NORM handling over the project life. For example:

- Radioactivity treatment and disposal threshold levels are established (e.g. for produced water and equipment); however, it is unclear if there is sufficient treatment and disposal capacity in NYS to handle the volume and amount of radioactive waste that may be generated;
- NYSDEC assumes that some waste will not contain significant amounts of radioactivity; yet, this assumption is based on a very limited dataset;
- There is no testing requirement to verify NORM content in drill cuttings before they are sent directly to a landfill; and
- Road spreading of waste is not prohibited; it is deferred to a yet-to-be determined future process outside the SGEIS review.

Recommendation No. 73: Detailed collection, testing, transportation, treatment, and disposal methods for each type of drilling and production waste and equipment containing NORM should be included in the SGEIS as a mitigation measure and codified in the NYCRR. Where data uncertainty exists, additional testing should be required. The radioactive content of waste should be verified to ensure appropriate transportation, treatment, and disposal methods are selected, and the testing results should be disclosed to the public.

Equipment Containing NORM: The 2011 RDSGEIS contains substantially improved requirements for equipment containing NORM, including a new radiation testing requirement and a treatment and disposal threshold limit. The RDSGEIS concludes that pipe scale and sludge (NORM buildup in equipment) can result in NORM concentrations that may have a significant adverse impact.

The 2011 RDSGEIS clarifies that NYSDOH will require the well operator to obtain a radioactive materials license for its facility when exposure rate measurements associated with scale accumulation in or on piping, drilling, and brine storage equipment exceeds 50 microR/hr[314] (µR/hr).[315] The RDSGEIS does not explain the origin of the 50 µR/hr limit; however, this limit has been used by a number of oil and gas producing states, including Texas[316] and Louisiana.[317]

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[314] Microroentgens per hour (µR/hr) is a measurement of exposure from x-ray and gamma ray radiation in air.

[315] 2011 NYSDEC, RDSGEIS, Page 5-142.

[316] Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, Economic Regulation, Railroad Commission of Texas, Environmental Protection, Oil and Gas NORM.

[317] Louisiana Administrative Code, Title 33 LAC Part XV, Radiation Protection.

Presumably, equipment containing a radioactive concentration of less than 50 µR/hr would be disposed of in a NYS landfill; however, it is unclear if NYS' landfills are designed to accommodate waste containing radioactivity of up to 50 µR/hr.

Recommendation No. 74: NYSDEC should explain the origin of the 50 µR/hr limit, and explain how NYS determined that this threshold is sufficiently protective for NYS. The SGEIS should explain where equipment containing a radioactive concentration of less than 50 µR/hr would be disposed (e.g. a NYS landfill), and whether this waste disposal method was designed for this waste handling purpose.

The RDSGEIS Chapter 7 (Section 7.7.2) proposes NORM testing (radiation survey) requirements:

> *The Department proposes to require, via permit condition and/or regulation, that radiation surveys be conducted at specified time intervals for Marcellus wells developed by high-volume hydraulic fracturing completion methods on all accessible well piping, tanks, or other equipment that could contain NORM scale buildup. The surveys would be required to be conducted for as long as the facility remains in active use. Once taken out of use no increases in dose rate are to be expected. Therefore, surveys may stop until either the site again becomes active or equipment is planned to be removed from the site. If equipment is to be removed, radiation surveys would be performed to ensure appropriate disposal of the pipes and equipment. All surveys would be conducted in accordance with NYSDOH protocols. The NYSDOH's Radiation Survey Guidelines and a sample Radioactive Materials Handling License are presented in Appendix 27. The Department finds that existing regulations, in conjunction with the proposed requirements for radiation surveys, would fully mitigate any potential significant impacts from NORM [emphasis added].*[318]

NYSDEC's proposal to require NORM testing (radiation surveys) for HVHF wells and equipment is an important improvement. This proposed mitigation measure is effectively translated into a permit condition. Appendix 10, Proposed EAF Addendum Requirements for HVHF, Condition No. 65, requires:

> *65) Periodic radiation surveys must be conducted at specified time intervals during the production phase for Marcellus wells developed by high-volume hydraulic fracturing completion methods. Such surveys must be performed on all accessible well piping, tanks, or equipment that could contain NORM scale buildup. The surveys must be conducted for as long as the facility remains in active use. If piping, tanks, or equipment is to be removed, radiation surveys must be performed to ensure their appropriate disposal. All surveys must be conducted in accordance with NYSDOH protocols [emphasis added].*[319]

However, this permit condition is only applied to HVHF wells and equipment. NORM can accumulate in all oil and gas equipment; therefore, this requirement is better suited for the NYCRR and should be applied to all oil and gas operations.

Additionally, it is recommended that the radiation testing frequency and method be specified. As explained in Dr. Glenn Miller's and Dr. Ralph Seiler's comments on the 2011 RDSGEIS, the test method is an important determinant in quantifying total radioactivity.[320] Furthermore, Dr. Glenn Miller and Dr.

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[318] 2011 NYSDEC, RDSGEIS, Page 7-119.

[319] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 12.

[320] Miller, G. and Seiler, R., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

Ralph Seiler recommended that radiation testing not be limited to radium. For example, Dr. Ralph Seiler points out in his comments that while NYSDEC has identified Radium (Ra) as a contaminant of concern, NYSDEC has overlooked the potential significant unmitigated impact of Polonium 210 (^{210}Po) accumulating in pipe scale as a byproduct of radon decay (natural gas contains radon).[321]

Recommendation No. 75: The requirement for radiation surveys should be codified in the NYCRR and applied to all oil and gas operations, not just HVHF operations. Radiation testing frequency and method should be specified to ensure that all potential radiation impacts are assessed and quantified. The proposed HVHF Permit Condition No. 65 could serve as a starting point for the NYCRR revisions.

Produced Water and Flowback Wastewater NORM: In 2009, HCLLC pointed out that water produced from wells can be rich in chloride, which enhances the solubility of other elements, including the radioactive element radium.[322] HCLLC also noted that flowback wastewater can contain NORM.

In 2009, NYSDEC reported that it had insufficient data on NORM in produced water and flowback wastewater, but acknowledged that NORM is present and is known to be found in elevated levels in produced water.

The Department of Energy (DOE) explains the presence of NORM in produced water:

> *<u>Because the water has been in contact with the hydrocarbon-bearing formation for centuries, it contains some of the chemical characteristics of the formation and the hydrocarbon itself.</u> It may include water from the reservoir, water injected into the formation, and any chemicals added during the production and treatment processes.* *Produced water is also called "brine" and "formation water."* *<u>The major constituents of concern in produced water are</u>:*
>
> - *Salt content (salinity, total dissolved solids, electrical conductivity)*
> - *Oil and grease (this is a measure of the organic chemical compounds*[323]
> - *Various natural inorganic and organic compounds or chemical additives used in drilling and operating the well*
> - *<u>Naturally occurring radioactive material (NORM).</u>*
>
> *The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geological host formation, and the type of hydrocarbon product being produced. Produced water properties and volume can even vary throughout the lifetime of a reservoir [emphasis added].*[324]

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[321] Seiler, R., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

[322] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[323] In addition to the major constituents of concern listed by DOE for produced water, Dr. Glenn Miller notes that both the gasoline and diesel range hydrocarbon fractions should be monitored, since they are more soluble than heavy hydrocarbons.

[324] United States Department of Energy, Produced Water Management Information System, http://www.netl.doe.gov/technologies/pwmis/intropw/index.html.

Since 2009, NYSDEC gathered additional information and improved the 2011 RDSGEIS to acknowledge and quantify the potential adverse impact of produced water radioactivity. Although NYSDEC's research shows that flowback waste may not contain significant concentrations of radioactive material, NYSDEC acknowledges it has a limited dataset, and proposes radiation surveys for both types of wastewater (flowback and produced water).

NYSDEC's proposal to require NORM testing (radiation surveys) for flowback and production brine is a significant improvement to the 2011 RDSGEIS, and this proposed mitigation measure was effectively translated into a permit condition. Appendix 10, Proposed EAF Addendum Requirements for HVHF, Condition No. 64, requires:

> *64) Flowback water recovered after high-volume hydraulic fracturing operations must be tested for NORM prior to removal from the site. Fluids recovered during the production phase (i.e., production brine) must be tested for NORM prior to removal.*[325]

However, this permit condition is only applied to HVHF wells and equipment. NORM can be present in all flowback wastewater, including hydraulic fracture treatments less than 300,000 gallons, and produced water from wells that are not subject to HVHF treatments. Therefore, this requirement is better suited for the NYCRR and should be applied to all oil and gas operations.

Additionally, it is recommended that the NORM testing method and frequency be specified. As explained in Dr. Glenn Miller's and Dr. Ralph Seiler's comments on the 2011 RDSGEIS, the test method is an important determinant in quantifying total radioactivity.[326]

Recommendation No. 76: The requirement to test produced water (production brine) and flowback wastewater (waste from hydraulic fracturing operations) should by codified in the NYCRR and applied to all oil and gas operations. NORM testing frequency and method should be specified. Proposed HVHF Permit Condition No. 64 could serve as a starting point for NYCRR revisions.

The RDSGEIS proposes to allow flowback wastewater and produced water to be disposed of at a Publically Owned Treatment Works (POTW), as long at the influent concentration of radium-226 (as measured prior to admixture with POTW influent) is limited to 15 pCi/L,[327] or 25% of the 60 pCi/L concentration value listed in 6 NYCRR Part 380-11.7.

> *The Department proposes to require, as a permit condition, that the permittee demonstrate that it has a source to treat or otherwise legally dispose of wastewater associated with flowback and production water prior to the issuance of the drilling permit. Disposal and treatment options include publicly owned treatment works, privately owned high volume hydraulic fracturing wastewater treatment and/or reuse facilities, deep-well injection, and out of state disposal.*

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[325] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 12.

[326] Miller, G. and Seiler, R., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

[327] Picocuries per gram (pCi/g) is a measure of the radioactivity in one gram of a material. One picocurie is that quantity of radionuclide(s) that decays at the rate of 3.7 x 10-2 disintegrations per second.

> *Flowback water and production water must be fully characterized prior to acceptance by a POTW for treatment. Note in particular Appendix C. IV of TOGS 1.3.8, Maximum Allowable Headworks Loading. The POTW must perform a MAHW analysis to assure that the flowback water and production water will not cause a violation of the POTW's effluent limits or sludge disposal criteria, allow pass through of unpermitted substances or inhibit the POTW's treatment processes. As a result, the SPDES permits for POTWs that accept this source of wastewater will be modified to include influent and effluent limits for Radium and TDS, if not already included in the existing SPDES permit, as well as for other parameters as necessary to ensure that the permit correctly and completely characterizes the discharge. In the case of NORM, anyone proposing to discharge flowback or production water to a POTW must first determine the concentration of NORM present in those waste streams to determine appropriate treatment and disposal options. POTW operators who accept these waste streams are advised to limit the concentrations of NORM in the influent to their systems to prevent its inadvertent concentration in their sludge. For example, due to the potentially large volumes of these waste waters that could be processed through any given POTW, as well as the current lack of data on the level of NORM concentration that may take place, it will be proposed that POTW influent concentrations of radium-226 (as measured prior to admixture with POTW influent) be limited to 15 pCi/L, or 25% of the 60 pCi/L concentration value listed in 6 NYCRR Part 380-11.7. As more data become available on concentrations in influent vs. sludge it is possible that this concentration limit may be revisited [emphasis added].*[328]

EPA data shows that produced water can contain 0.1 to 9,000 pCi/L of radium-226.[329] Therefore, it is reasonably foreseeable that there will be substantial volumes of wastewater that will exceed the 15 pCi/L POTW influent limit. NYSDEC has not proposed a waste treatment or disposal solution for wastewater that exceeds the 15 pCi/L POTW influent limit.

Recommendation No. 77: The SGEIS should examine treatment and disposal options, and capacity within NYS, for wastewater exceeding 15 pCi/L radiation.

Additionally, it is unclear if NYS' POTWs are designed to treat incoming wastewater with 15 pCi/L radiation. The Federal Safe Drinking Water standard is 5 pCi/L[330] (radium-226 and radium -228 combined).[331] The 5 pCi/L threshold was set because of the increased risk of cancer above this level. Because the RDSGEIS does not examine NYS' POTW's ability to treat incoming wastewater with 15 pCi/L radiation, it does not provide an estimate of the expected radiation level at the POTW effluent. Therefore, it is not clear whether POTW effluent discharge at a level greater than 5 pCi/L could end up in a drinking water supply, or how NYSDEC plans to monitor and ensure that this does not happen.

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[328] 2011 NYSDEC, RDSGEIS, Page 6-58 and 6-59.

[329] USEPA Oil and Gas Production Wastes, Summary Table of Reported Concentrations of Radiation in TENORM, http://www.epa.gov/radiation/tenorm/sources.html#summary-table

[330] Measured as Radium 226 and Radium 228 combined.

[331] USEPA Federal Safe Water Drinking Water Standards for Radionuclides at http://water.epa.gov/drink/contaminants/index.cfm#List.

Recommendation No. 78: The SGEIS should examine whether NYS' POTWs are designed to treat incoming wastewater with 15 pCi/L radiation, and should predict the maximum effluent radiation level. The SGEIS should explain how NYSDEC will ensure that drinking water sources will not exceed 5 pCi/L radiation.

The 2011 RDSGEIS does not prohibit road spreading of waste; it deferred this decision to a yet-to-be determined future process outside the SGEIS review. Yet, other oil and gas producing states, such as Texas, specifically prohibit road spreading of waste containing NORM.[332] A study conducted by Argonne National Lab for the US Department of Interior (DOI) concluded that land spreading of diluted NORM waste presented the highest potential dose of exposure to the general public of all waste disposal methods studied.[333]

Most states dispose of wastewater using deep well injection or use it to enhance hydrocarbon recovery operations. Land disposal is not common for onshore operations. The Department of Energy reports that more than 98% of oil and gas wastewater from onshore operations is injected into underground disposal wells, which are regulated by EPA, or used for enhanced hydrocarbon recovery.[334] The 2009 DSGEIS explored produced water treatment and disposal options (e.g. injection wells, treatment plants, and road spreading),[335] but did not land on a best practice.

The 2011 RDSGEIS concludes there is not enough information available to allow for road spreading under a Beneficial Use Determination (BUD).[336] However, the RDSGEIS does not explicitly state that road spreading for any purpose is prohibited until NYSDEC and NYSDOH agree on exposure standards that will serve as thresholds for BUD determinations, with the proposed exposure standards undergoing a public review and comment period.

Since the current BUD does not require an operator to test for NORM,[337] it is unclear how NORM testing at the well site will be integrated into the BUD process. The level of NORM, if any, that will be allowed in fluids used for road spreading is also unclear. The 2011 RDSGEIS does not examine the cumulative impact of spreading small amounts of NORM repeatedly over the same area. It is recommended that land and road spreading of produced water and other waste containing NORM be **prohibited**. Produced water containing NORM should be returned to the subsurface formation from which it came, or should be handled at an approved waste treatment plant.

Recommendation No. 79: The SGEIS should explicitly state that land and road spreading for any purpose is prohibited until NYSDEC and NYSDOH agree on exposure standards that will serve as thresholds for BUD determinations, with the proposed exposure standards undergoing a public review and comment period.

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[332] Texas Railroad Commission (TXRRC), 16 Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, §4.601 - 4.632. "Disposal of Oil and Gas NORM Waste". The TCEQ has jurisdiction over the disposal of other NORM wastes.

[333] Argonne National Laboratory, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactive Materials Generated by the Petroleum Industry, Publication ANL/EAD-2, 1996.

[334] Argonne National Laboratory, Produced Water Volumes and Management Practices in the United States, Report Prepared for United States Department of Energy, Report No. ANL/EVS/R-09/1, 2009.

[335] 2009 NYSDEC, DSGEIS, Page 5-131.

[336] 2011 NYSDEC, RDSGEIS, Page 7-60.

[337] The example BUD application provided in Appendix 12 requires testing for calcium, sodium, chloride, magnesium, total dissolved solids, pH, iron, barium, lead, sulfate, oil and grease, benzene, ethylbenzene, toluene and xylene, but not NORM.

The Environmental Protection Agency (EPA) identifies produced water pits (brine pits) as an outdated practice in cases where produced water contains NORM. If wastewater pond sediments pose a potential radiological health risk, tank sediments from wastewater stored in tanks also would pose a radiological health risk. EPA reports that:

> *Lined and/or earthen pits were previously used for storing produced water and other nonhazardous oil field wastes, hydrocarbon storage brine, or mining wastes. In this case, TENORM[338] in the water will concentrate in the bottom sludges or residual salts of the ponds. Thus the pond sediments pose a potential radiological health risk....produced waters are now generally reinjected into deep wells…No added radiological risks appear to be associated with this disposal method as long as the radioactive material carried by the produced water is returned in the same or lower concentration to the formations from which it was derived [emphasis added].*[339]

Recommendation No. 80: The SGEIS should address testing of wastewater sediments, and explain the collection, transportation, treatment, and disposal methods for this potential radiological health risk.

Drill Cutting NORM: The 2011 RDSGEIS acknowledges the fact that drill cuttings can contain NORM, but makes a blanket assumption that the level of radiation from cuttings will be low. The RDSGEIS does not require site-specific testing to verify this assumption, nor does it preclude cuttings disposal in existing solid waste landfills. Instead, the RDSGEIS only recommends that the well operator consult with the landfill operator prior to drill cuttings disposal.

> *In New York State the NORM in cuttings is not precluded by regulation from disposal in a solid waste landfill, though well operators should consult with the operators of any landfills they are considering using for disposal regarding the acceptance of Marcellus Shale drill cuttings by that facility [emphasis added].*[340]

The 2011 RDSGEIS is unclear about the environmental and human health protections that would be achieved via the landfill consultation process. Appendix 10, Proposed EAF Addendum Requirements for HVHF, requires the operator to specify where it plans to dispose of cuttings, and requires evidence that the cuttings will go to a Part 360 solid waste landfill. However, the RDSGEIS does not provide scientific or engineering data to demonstrate that existing NYS landfills are properly designed and equipped to safely handle and store drill cuttings containing NORM.

NYSDEC acknowledges significant uncertainty about the NORM content of drill cuttings in Chapter 7, and raises questions as to whether there are sufficient data to fully assess NORM impacts at this time. The 2011 RDSGEIS states:

> *Existing data from drilling in the Marcellus Formation in other States, and from within New York for wells that were not hydraulically fractured, shows significant variability in NORM content. This variability appears to occur both between wells in different portions of the formation and at a given well over time. This makes it important that samples from wells in different locations within New York State are used to assess the extent of this variability.*

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[338] TENORM is Technologically Enhanced Natural Occurring Radioactive Material.

[339] http://www.epa.gov/radiation/tenorm/oilandgas.html#disposalpast.

[340] 2011 NYSDEC, RDSGEIS, Page 5-129 and 5-130.

> *During the initial Marcellus development efforts, sampling and analysis would be undertaken in order to assess this variability. These data would be used to determine whether additional mitigation is necessary to adequately protect workers, the general public, and environment of the State of New York [emphasis added].*[341]

Yet, the 2011 RDSGEIS does not propose NORM mitigation measures. It does not require drill cuttings testing prior to disposal in the landfill, nor does it establish a maximum allowed NORM disposal threshold for safe long-term cuttings disposal in a landfill.

Recommendation No. 81: Drill cuttings should be tested for NORM prior to disposal in a landfill. A maximum allowed NORM threshold for drill cuttings disposal in the landfill should be clearly established and scientifically justified. Testing and threshold requirements should be included in the SGEIS as a mitigation measure and codified in the NYCRR. Waste exceeding the established NORM threshold should be handled under NYS' radioactive waste handling rules.

Chapter 5.2.4.2 of the 2011 RDSGEIS concludes that NORM content in drill cuttings is equivalent to background levels of radiation occurring naturally in the atmosphere. This conclusion is based on Geiger counter and gamma ray spectroscopy sampling methods.

Yet, Dr. Glenn Miller points out in his comments on the 2011 RDSGEIS[342] that gamma ray spectroscopy is insufficient to assess all radioactive constituents (e.g. polonium is radioactive and only a weak gamma ray emitter), and gamma ray measurements do not provide insight into the potential for drill cuttings containing NORM to later oxidize, leach, and concentrate NORM when disposed. Dr. Miller concludes that NYS likely has underestimated the amount of NORM in drill cuttings, and recommends NYS require additional testing methods to verify total radiation levels and better understand the potential for drill cuttings to later oxidize, leach, and concentrate NORM when disposed. Additional work is needed to verify whether the disposal of drill cuttings containing NORM in existing NYS landfills is a best practice.

Recommendation No. 82: The SGEIS should provide scientific and engineering data to demonstrate that existing NYS landfills are properly designed and equipped to safely handle and store drill cuttings containing NORM, including lower concentrations of NORM that could cumulatively have a significant impact when stored in large volumes over long periods of time. The SGEIS should examine the potential for drill cuttings containing NORM to later oxidize, leach, and concentrate radioactive materials within the landfill. If NYSDEC cannot provide scientific and engineering data to demonstrate that existing NYS landfills are properly designed and equipped to safely handle and store drill cuttings containing NORM, it should identify alternative collection, transportation, treatment, and disposal requirements.

NYCRR Proposed Revisions: Proposed Permit Condition No. 53 requires waste fluids be handled in accordance with 6 NYCRR § 554.1(c)(1); yet, this regulation does not specify the best practice for handling hydraulic fracturing fluid and other drilling and completion wastes. Instead, 6 NYCRR § 554.1(c)(1) merely provides a process for the applicant to submit a waste management plan. In 2009, HCLLC recommended revisions to this regulation; yet, none are proposed. The existing regulation states:

> *Prior to the issuance of a well-drilling permit for any operation in which the probability exists that brine, salt water or other polluting fluids will be produced or obtained during drilling operations in sufficient quantities to be deleterious to the surrounding environment, the operator*

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[341] 2011 NYSDEC, RDSGEIS, Page 7-119.

[342] Miller, G., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

> *must submit and receive approval for a plan for the environmentally safe and proper ultimate disposal of such fluids. For purposes of this subdivision, drilling muds are not considered to be polluting fluids. Before requesting a plan for disposal of such fluids, the department will take into consideration the known geology of the area, the sensitivity of the surrounding environment to the polluting fluids and the history of any other drilling operations in the area. Depending on the method of disposal chosen by the applicant, a permit for discharge and/or disposal may be required by the department in addition to the well-drilling permit. An applicant may also be required to submit an acceptable contingency plan, the use of which shall be required if the primary plan is unsafe or impracticable at the time of disposal [emphasis added].*

Terms such as "sufficient quantities" are ambiguous, providing operators and regulators large latitude in how they interpret the regulation. Regulations should specify technically and scientifically based thresholds and management practices.

Under 6 NYCRR § 554.1(c)(1), the waste disposal method is selected by the applicant, with no instruction on how to determine the best waste management practice. While recycling and the reuse of fracturing fluid are discussed in the RDSGEIS, there is no requirement in the proposed permit conditions to use this best practice. Furthermore, NYSDEC does not explain how it will oversee the recycling and reuse processes.

Recommendation No. 83: Revisions are needed to 6 NYCRR § 554.1(c)(1) to require a more robust waste management planning and oversight process, including detailed instructions on collection, testing, transportation, treatment, and disposal of waste.

20. Hydrogen Sulfide

Background: In 2009, HCLLC recommended that the NYCRR require operators to follow American Petroleum Institute Recommended Practice 49 (API RP 49) for Drilling and Well Servicing Operations Involving Hydrogen Sulfide, and API RP 55 for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide, to protect employees and the public.

The 2011 RDSGEIS: The 2011 RDSGEIS reports that Marcellus Shale operations in Pennsylvania have not produced substantial amounts of H_2S.[343] However, this conclusion is based on limited information from wells drilled only in Pennsylvania. These data do not confirm that H_2S will not be present initially or over time in NYS wells.

H_2S gas produces a malodorous smell of rotten eggs at low concentrations, can cause serious health symptoms at elevated concentrations, and can be deadly at the higher concentrations found in some oil and gas wells.

The Occupational Safety and Health Administration (OSHA) recommends close monitoring of H_2S for human health and explosion mitigation:

> *Hydrogen Sulfide or sour gas (H2S) is a flammable, colorless gas that is toxic at extremely low concentrations. It is heavier than air, and may accumulate in low-lying areas. It smells like "rotten eggs" at low concentrations and causes you to quickly lose your sense of smell. Many areas where the gas is found have been identified, but pockets of the gas can occur anywhere.*
>
> *Iron sulfide is a byproduct of many production operations and may spontaneously combust with air.*
>
> *Flaring operations associated with H_2S production will generate Sulfur Dioxide (S02), another toxic gas.*
>
> *Active monitoring for hydrogen sulfide gas and good planning and training programs for workers are the best ways to prevent injury and death.*[344]

The American Conference of Governmental Industrial Hygienists recommends a Threshold Limit Value of 10ppm and a short-term exposure (STEL) limit of 15 ppm, averaged over 15 minutes, for the action level indicating the need for respiratory protection.[345] While workers may be afforded respiratory protection, nearby members of the public do not have routine access to respiratory protection and monitoring systems. Routine, standardized testing should also be in place to ensure public health and safety.

A 300 ppm concentration of H_2S is considered by the American Conference of Governmental Industrial Hygienists as Immediately Dangerous to Life and Health.

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[343] 2011 NYSDEC, RDSGEIS, Page 5-138.

[344] OSHA website at http://www.osha.gov/SLTC/etools/oilandgas/general_safety/h2s_monitoring.html.

[345] OSHA website at http://www.osha.gov/SLTC/etools/oilandgas/general_safety/appendix_a.html.

> *In low concentrations, H_2S sometimes can be detectable by its characteristic odor; however, the smell cannot be relied upon to forewarn of dangerous concentrations (greater than 100ppm) of the gas because it rapidly paralyzes the sense of smell due to paralysis of the olfactory nerve. A longer exposure to the lower concentrations has a similar desensitizing effect on the sense of smell.*
>
> *It should be well understood that the sense of smell will be rendered ineffective by hydrogen sulfide, which can result in an individual failing to recognize the presence of dangerously high concentrations. Exposure to hydrogen sulfide causes death by poisoning the respiratory system at the cellular level.*[346]

Therefore, proper handling of H_2S is important from both a quality-of-life and human-safety standpoint for workers and nearby public.

While H_2S may not be initially present at a drillsite, the operator must remain vigilant in monitoring for H_2S over time, because sulfate reducing bacteria and other forms of acid producing bacteria can generate H_2S in the reservoir, such that H_2S concentrations elevate over time. Increasing levels of H_2S is a common problem in waterflooding operations in oil and gas fields. Biocides are typically used to mitigate bacteria growth; however, sometimes biocides are not successful.

Biocide use and close monitoring of H_2S early in field development is an important mitigation measure, because once elevated H_2S is present it is difficult to control. Industry anticipates H_2S will be a future concern in operations requiring large volumes of water for HVHF treatments, especially where treatment fluid is recycled, as planned in NYS. A 2010 Apache Corporation paper summarizes the problem:

> *One of the most severe threats in recycling waters for fracs is the control of bacteria (Tischler, 2009), including sulfate reducing bacteria (SRBs) and other forms such as acid producing bacteria (APB), iron fixing bacteria and slime formers. SRBs have created souring of some conventional reservoirs from injection of waters, both produced and semi-fresh, which have established a presence in the reservoirs and create H_2S gas and iron sulfide problems. Local well fouling problems are common where SRBs are spiked into the formation from drilling or completion fluids. This type of H_2S occurrence may cause local corrosion…in shale, however, the effect of uncontrolled bacteria is a general unknown, given the extremely large volumes of surface water used for slick water fracturing. For this reason, recycling of the water may seed all waters with bacteria and/or concentrate the bacteria; thus bacterial control is a necessity [emphasis added].*[347]

Due to the potential close proximity of Marcellus Shale operations to the public, a robust initial monitoring program should be instituted to determine H_2S concentrations in Marcellus Shale gas throughout NYS. As described in American Petroleum Institute Recommended Practices 49 and 55, monitoring frequency can be adjusted over time as site-specific information is obtained. Initial sampling should be conducted at each drillsite, with at least monthly sampling thereafter.

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[346] OSHA website at http://www.osha.gov/SLTC/etools/oilandgas/general_safety/appendix_a.html

[347] King, G.E., Apache Corporation, Thirty Years of Gas Shale Fracturing: What Have We Learned?, Society of Petroleum Engineers Technical Paper, SPE 133456, 2010, Page 30.

Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing, Permit Condition No. 25 includes a requirement to conform with API RP 49; however, there is no requirement for operators to conform with API RP 55, which applies after the well is drilled, during production operations.

NYCRR Proposed Revisions: As a control measure, when H_2S is present, the proposed regulations at 6 NYCRR § 560.6(c)(28) require the venting of any gas containing H_2S through a flare stack to combust the dangerous vapors.

Recommendation No. 84: H_2S monitoring and reporting requirements should be included in the RDSGEIS as a mitigation measure and codified in the NYCRR. Operators should be required to follow H_2S detection and handling procedures to protect employees and the public. Initial H_2S testing should be conducted at each drillsite. Subsequent test frequency should be based on the results of initial testing. H_2S levels can increase over time as gas fields age and sour. H_2S requirements should be included in regulation for both drilling and production operations, and should not just be relegated to a drilling permit condition. Additionally, when H_2S is present, nearby neighbors, local authorities, and public facilities should be notified, and provided information on the safety and control measures that the operator will undertake to protect human health and safety. In cases where elevated H_2S levels are present, audible alarms should be installed to alert the public when immediate evacuation procedures are warranted.

21. Chemical & Waste Tank Secondary Containment

Background: In 2009, HCLLC recommended that NYCRR be revised to include secondary containment for chemicals stored on the well pad or, alternatively, require the use of double-wall tanks. Chemicals, especially corrosive chemicals, can result in storage container leaks and spills to the environment. Best practice for permanent chemical storage is to install secondary containment under the storage container, and ensure the containers are not in contact with soil or standing water.[348] Shale gas drilling and HVHF operations include the use of many chemical tanks and waste handling tanks (e.g. flowback tanks) that warrant secondary containment.

2011 RDSGEIS: NYSDEC responded to public comments and made appropriate revisions to the 2011 RDSGEIS with its requirement for 110% secondary containment for all chemical and waste handling tanks. It also requires secondary containment for chemical and waste transport, mixing and pumping equipment. The 2011 RDSGEIS states:

> *Flowback water stored on-site must use covered watertight tanks within secondary containment and the fluid contained in the tanks must be removed from the site within certain time periods.*[349]
>
> *Secondary containment would be required for all fracturing additive containers and additive staging areas. These requirements would be included in supplementary well permit conditions for high-volume hydraulic fracturing.*[350]
>
> *Secondary containment measures may include one or a combination of the following; dikes, liners, pads, curbs, sumps, or other structures or equipment capable of containing the substance. Any such secondary containment would be required to be sufficient to contain 110% of the total capacity of the single largest container or tank within a common containment area.*[351]
>
> *Secondary containment for flowback tanks is required.*[352]
>
> *The Department proposes to require that operators storing flowback water on-site would be required to use watertight tanks located within secondary containment, and remove the fluid from the wellpad within specified time frames.*[353]
>
> *Location of additive containers and transport, mixing and pumping equipment...within secondary containment...[emphasis added]*[354]

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[348] Bureau of Land Management, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, The Gold Book, 2007.

[349] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 25.

[350] 2011 NYSDEC, RDSGEIS, Page 7-38.

[351] 2011 NYSDEC, RDSGEIS, Page 7-38.

[352] 2011 NYSDEC, RDSGEIS, Page 7-40.

[353] 2011 NYSDEC, RDSGEIS, Page 1-12.

[354] 2011 NYSDEC, RDSGEIS, Page 7-29.

Recommendation No. 85: Secondary containment requirements for well site chemicals should be applied as a best practice to all oil and gas development and codified in NYCRR, and should not be limited to shale gas and HVHF operations.

NYCRR Proposed Revisions: Proposed regulations codify the requirement for secondary containment for chemical and waste handling tanks, but do not specifically address secondary containment for chemical and waste transport, mixing and pumping equipment.

Recommendation No. 86: Consistent with the proposed RDSGEIS mitigation, 6 NYCRR § 750-3.11 and 6 NYCRR § 560.6 should be revised to require lined secondary containment for chemical and waste transport, mixing, and pumping equipment.

Proposed regulations at 6 NYCRR § 750-3.11 provide very specific instructions on how to construct adequate secondary containment, including the use of coated or lined materials that are chemically compatible with the environment and the substances they may contain. Regulations also state that the containment structures must have adequate freeboard, be protected from damage, and be able to contain at least 110% of the largest tank volume.

> *750-3.11 Applications of standards, limitations and other requirements*
>
> *(e) The HVHF SWPPP must, at a minimum, include the HVHF SWPPP General Requirements listed in subparagraph (1) below, Structural Best Management Practices (BMPs), Non-structural BMPs, and Activity-Specific SWPPP Requirements.*
>
> *(v) Secondary Containment - To prevent the discharge of hazardous substances, the owner or operator shall provide, implement, and operate secondary containment measures. Such secondary containment shall be: (a) designed and constructed in accordance with good engineering practices, (b) constructed, coated or lined with materials that are chemically compatible with the environment and the substances to be contained, (c) provide adequate freeboard, (d) protected from heavy vehicle or equipment traffic; and have a volume of at least 110 percent of the largest storage tank within the containment area [emphasis added].*

In contrast, proposed regulations at 6 NYCRR § 560.6 offer substantially less instruction on how to construct adequate secondary containment. They do not mandate the use of coated or lined materials that are chemically compatible with the environment and the substances they may contain. They do not require the containment structure have adequate freeboard. Nor do they require that the containment be protected from damage.

> *§560.6 Well Construction and Operation.*
>
> *(c) Drilling, Hydraulic Fracturing and Flowback.*
>
> *(26) Hydraulic fracturing operations must be conducted as follows:*
>
> *(i) secondary containment for fracturing additive containers and additive staging areas, and flowback tanks is required. Secondary containment measures may include, as deemed appropriate by the department, one or a combination of the following: dikes, liners, pads, impoundments, curbs, sumps or other structures or equipment capable of containing the substance. Any such secondary containment must be sufficient to contain*

> *110 percent of the total capacity of the single largest container or tank within a common containment area. No more than one hour before initiating any hydraulic fracturing stage, all secondary containment must be visually inspected to ensure all structures and equipment are in place and in proper working order* *[emphasis added].*

Recommendation No. 87: 6 NYCRR § 560.6 should be revised to include specific secondary containment construction standards that are consistent with 6 NYCRR § 750-3.11.

Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing: Permit conditions have been developed to require secondary containment. However, the permit conditions merely echo proposed regulations at 6 NYCRR § 560.6. They do not provide additional or supplemental requirements to the NYCRR.

Recommendation No. 88: Streamline the Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing contained in the RDSGEIS to remove requirements that are redundant with NYCRR, or if retained, ensure that permit language matches the final codified version of NYCRR and cite the NYCRR requirements.

22. Fuel Tank Containment

Background: In 2009, HCLLC recommended that the NYCRR be revised to require more stringent oil spill prevention measures for temporary fuel tanks associated with drilling and well stimulation activities, and that NYS' regulations be at least as stringent as federal EPA's Spill Prevention Control and Countermeasures (SPCC) Plan. HCLLC recommended that NYSDEC incorporate existing EPA oil spill prevention standards into the NYCRR. EPA standards require secondary containment if a facility stores 1,320 gallons of fuel or more (30 CFR § 112), including portable, temporary fuel tanks.

In 2009, NYSDEC proposed to exempt drilling rig and HVHF fuel tanks (even those as large as 10,000 gallons) from NYS' petroleum bulk storage regulations and tank registration requirements at 6 NYCRR §§ 612-614, citing the fact that the storage tanks are temporary (non-stationary) as the reason for the exemption. This problem persists in the 2011 RDSGEIS.

HCLCC questioned NYSDEC's rationale for exempting drilling rig and HVHF fuel tanks from NYS' spill prevention regulations, as all other tanks 1,100 gallons and larger must register in NYS, install secondary containment, and undergo inspections at 5- and 10-year intervals.

HCLLC pointed out that a temporary fuel tank poses a greater environmental risk than a stationary fuel tank, because temporary fuel tanks are relocated many times during their operating lives, increasing the potential for tank damage during transit and the likelihood of tank appurtenance leakage.

Large temporary fuel tanks should be subject to the same secondary containment requirements as large stationary fuel tanks in NYS, particularly in situations where temporary fuel tanks are installed in one location for a significant period of time (e.g. a multi-well pad where drilling and completion operations could span several years). Alternatively, where secondary containment is not technically feasible, the use of double-walled or vaulted tanks should be considered for portable fuel tanks.

In January 2011, NYS' consultant, Alpha Geoscience, reviewed HCLLC's recommendation and provided NYSDEC with incorrect guidance on EPA's secondary containment requirements for onshore oil drilling workover and mobile equipment and other fuel storage.[355] Alpha Geoscience advised NYSDEC that EPA's SPCC regulations only addressed stationary fuel tanks greater than 1,320 gallons.

Alpha Geoscience's advice was incorrect because EPA's SPCC rules apply to facilities that have an aggregate fuel or hydrocarbon storage of 1,320 gallons or more at a facility, and secondary containment rules are not limited to stationary tanks.[356]

2011 RDSGEIS: NYSDEC's 2011 proposal for fuel tank secondary containment is confusing and inconsistent. The RDSGEIS both recommends and requires fuel tank secondary containment as a best practice, yet also exempts large fuel tanks used for drilling and HVHF operations.

For example, the 2011 RDSGEIS states that secondary containment will be required for fuel tanks and areas where fuel transfers occur:

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[355] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 21.

[356] USEPA, SPCC Guidance for Regional Inspectors Version 1.0, November 28, 2005, Page 2-16.

> *The Department proposes to require, via permit condition and/or new regulation, that operators provide secondary containment around all additive staging areas and fueling tanks, manned fluid/fuel transfers and visible piping and appropriate use of troughs, drip pads or drip pans [emphasis added].*[357]

NYSDEC supports its recommendation for fuel tank secondary containment by pointing out that its consultant has identified it as a best management practice:

> *In addition to its regulatory survey, Alpha also reviewed and discussed best management practices directly observed in the northern tier of Pennsylvania and noted that "[t]he reclamation approach and regulations being applied in PA may be an effective analogue going forward in New York." The best management practices referenced by Alpha* ***include…Secondary containment structures around petroleum storage tanks and lined*** *trenches to direct fluids to lined sumps where spills can be recovered without environmental contamination [emphasis added].*[358]

Yet, the 2011 RDSGEIS exempts large fuel tanks from secondary containment by designating drilling rig and HVHF fuel tanks as "temporary":

> *The diesel tank fueling storage associated with the larger rigs described in Chapter 5 may be larger than 10,000 gallons in capacity and may be in one location on a multi-well pad for the length of time required to drill all of the wells on the pad. However, the tank would be removed along with the rig during any drilling hiatus between wells or after all the wells have been drilled. There are no long-term or permanent operations at a drill pad which require an on-site fueling tank. Therefore, the tank is considered non-* ***stationary and is exempt from the Department's petro****leum bulk storage regulations and tank registration requirements [emphasis added].*[359]

The 2011 RDSGEIS does not explain why a temporary fuel tank would pose less risk of a spill than a stationary fuel tank.

The 2011 RDSGEIS further confuses the issue by stating that all fuel tanks would be included in secondary containment:

> *The following measures are proposed to be required, via permit condition and/or regulation, to prevent and mitigate spills. For all wells subject to the SGEIS, supplementary permit conditions for high-volume hydraulic fracturing would include the following requirements with respect to fueling tanks and refilling activities:*
>
> > *a. Secondary containment consistent with the objectives of SPOTS 10 for all fueling tanks.*
> >
> > *The secondary containment system could include one or a combination of the following: dikes, liners, pads, holding ponds, curbs, ditches, sumps, receiving tanks or other equipment capable of containing spilled fuel. Soil that is used for secondary containment would be of such character that a spill into the soil will be readily recoverable and would result in a minimal amount of soil contamination and*

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[357] 2011 NYSDEC, RDSGEIS, Page 1-11.

[358] 2011 NYSDEC, RDSGEIS, Page 8-5.

[359] 2011 NYSDEC, RDSGEIS, Page 7-343.

> *infiltration. Draft Department Program Policy DER-1730 may be consulted for permeability criteria for dikes and dike construction standards, including capacity of at least 110% of the tank's volume [emphasis added].*[360]

Ultimately, the 2011 RDSGEIS, includes secondary containment requirements for all fuel tanks, in Appendix 10, Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing.

> 13) *Secondary containment consistent with the Department's Spill Prevention Operations Technology Series 10, Secondary Containment Systems for Aboveground Storage Tanks,(SPOTS 10) is required for all fueling tanks [emphasis added];*
>
> 14) *To the extent practical, fueling tanks must not be placed within 500 feet of a public or private water well, a domestic-supply spring, a reservoir, a perennial or intermittent stream, a storm drain, a wetland, a lake or a pond;*
>
> 15) *Fueling tank filling operations must be manned at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck, and;*
>
> 16) *Troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment.*[361]

While, it is useful that the RDSGEIS finally lands on requiring secondary containment for fuel tanks, there remains a conflict in the text where NYSDEC has proposed to exempt temporary fuel tanks.

Recommendation No. 89: The SGEIS text should be revised to remove the temporary fuel tank exemption from secondary containment described on page 7-34.

Additionally, Appendix 10 permit conditions merely echo proposed regulations at 6 NYCRR § 560.6, and do not provide additional or supplemental requirements to the NYCRR. Therefore, if adopted into regulation, the permit conditions could be streamlined.

Recommendation No. 90: Streamline the Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing to remove requirements that are redundant with the proposed revisions to NYCRR, or if retained, ensure that permit language matches the final codified version of NYCRR and cite the NYCRR requirements.

NYCRR Proposed Revisions: The proposed regulations at 6 NYCRR § 560.6 codify the requirement for fuel tank secondary containment, and set no limit on the size or duration of fuel tank use. These proposed regulations are protective of the environment. The RDSGEIS should be revised to be consistent with the proposed regulations, avoiding future confusion about NYSDEC's intent.

> §560.6 Well Construction and Operation.
>
> *(b) Site Maintenance.*
>
> *(1) For any well:*

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[360] 2011 NYSDEC, RDSGEIS, Page 7-34.

[361] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 3.

> *(i) secondary containment is required for all fueling tanks [emphasis added];*
>
> *(ii) to the extent practical, fueling tanks must not be placed within 500 feet of a perennial or intermittent stream, storm drain, wetland, lake or pond;*
>
> *(iii) fueling tank filling operations must be supervised at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck; and*
>
> *(iv) troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment required by subparagraph (i) of this subdivision.*

Recommendation No. 91: The SGEIS should be revised to be consistent with the proposed regulations, which require secondary containment for all fuel tanks (6 NYCRR § 560.6) used for shale gas drilling and HVHF operations.

While proposed regulations at 6 NYCRR § 560.6 are useful because they make it clear that secondary containment is required for all fuel tanks, the proposed regulations do not provide specific instruction on how to construct adequate containment.

Recommendation No. 92: 6 NYCRR § 560.6 should be revised to clearly state that all fuel tank secondary containment should be designed and constructed in accordance with good engineering practices, incremental to the minimum federal standards. Good engineering practices include: using coated or lined materials that are chemically compatible with the environment and the substances to be contained; providing adequate freeboard; protecting containment from heavy vehicle or equipment traffic; and having a volume of at least 110 percent of the largest storage tank within the containment area.

NYCRR Proposed Revisions: The proposed regulations at 6 NYCRR § 560.6 require a 500’ setback for fuel tanks from perennial or intermittent streams, storm drains, wetlands, lakes, and ponds, but only to the “extent practical” with no explanation of what that means in real terms, and under what conditions it would be acceptable to place a fuel tank closer. NYCRR does not include any setbacks from homes or public facilities.

> §560.6 Well Construction and Operation.
>
> *(b) Site Maintenance.*
>
> *(1) For any well:*
>
> *(i) secondary containment is required for all fueling tanks;*
>
> *(ii) to the extent practical, fueling tanks must not be placed within 500 feet of a perennial or intermittent stream, storm drain, wetland, lake or pond[emphasis added];*
>
> *(iii) fueling tank filling operations must be supervised at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck; and*
>
> *(iv) troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment required by subparagraph (i) of this subdivision.*

Recommendation No. 93: Proposed regulations at 6 NYCRR § 560.6 (b)(1)(ii) should be revised to delete the term "to the extent practical," and should include minimum setbacks for fuel tanks from homes and public buildings.

Additionally, the RDSGEIS is problematic because it still references a draft NYSDEC Program Policy (DER-17) for construction standards and a September 28, 1994 Spill Prevention Operations Technology Series (SPOTS) memo for guidance on secondary containment construction.

Recommendation No. 94: The SGEIS should not rely on a draft[362] NYSDEC Program Policy document (DER-17) for construction standards and an outdated September 28, 1994 Spill Prevention Operations Technology Series (SPOTS) memo for guidance on secondary containment construction. Instead, secondary containment requirements for fuel tanks should be codified in the NYCRR and written in a way that is clear, consistent, and enforceable.

The importance of secondary containment for fuel tanks extends beyond shale gas drilling and HVHF operations to all hydrocarbon drilling and HVHF operations.

Recommendation No. 95: Secondary containment requirements for fuel tanks should extend to all hydrocarbon drilling and HVHF operations in NYS. The requirements should not be limited to shale gas drilling and HVHF operations. Therefore, the recommendations made above should be captured in both 6 NYCRR § 560 and 6 NYCRR § 554.

The RDSGEIS does not cite existing EPA spill prevention requirements at 40 CFR § 112, which apply to all fuel tanks, including drilling tanks, at 40 CFR § 112.7(c) and 40 CFR § 112.10(c). EPA's regulations, which were revised in 2002, require secondary containment for fuel tanks at facilities storing 1,320 gallons and more. EPA allows an operator the opportunity to demonstrate under 40 CFR § 112.7(d) that it is impracticable to install secondary containment; however, EPA requires a formal written "impracticability determination." Under this determination, EPA requires periodic tank integrity testing, leak testing of the valves and associated piping, a Part 109 contingency plan, and a written commitment of manpower, equipment, and materials to respond to a spill.

Recommendation No. 96: The SGEIS should cite federal standards (similar to how NYSDEC cited relevant USEPA standards for air quality) and notify the operator that the federal standards must be met. The SGEIS should also clearly explain what additional requirements will be imposed by NYS.

The RDSGEIS should also include: periodic fuel tank inspections to examine structural conditions and document corrosion or damage; the installation of high-liquid-level alarms that sound and display in an immediately recognizable manner; the installation of high-liquid-level automatic pump shutoff devices, which are designed to stop flow at a predetermined tank content level; and a means of immediately determining the liquid level of tanks.

Recommendation No. 97: In the NYCRR, NYSDEC should require tank inspections and tank alarm systems.

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[362] If NYSDEC decides to refer to policy and guidance documents, those documents at a minimum should be final documents, and NYSDEC should state within those documents that the contents are enforceable.

NYSDEC does not address whether vaulted, double-walled, or self-diking tanks can be used as alternatives to constructing large temporary containment areas. Other oil and gas producing states allow the use of vaulted, self-diking, or double-walled portable tanks to meet the secondary containment requirement in cases where the operator can demonstrate that it is infeasible to install a containment area meeting EPA's 110% of the largest tank volume requirement. NYSDEC could consider allowing these alternative tanks in places where secondary containment is proven to be infeasible.

Vaulted, self-diking, and double-walled portable tanks are equipped with catchments that hold fuel overflow or divert it into an integral secondary containment area. Industry standards for the construction of vaulted, self-diking, and double-walled portable tanks include:

- Underwriters Laboratories' Steel Aboveground Tanks for Flammable and Combustible Liquids (UL 142);
- Appendix J of the American Petroleum Institute's (API) Welded Steel Tanks for Oil Storage (API 650); and
- API's Specification for Shop Welded Tanks for Storage of Production Liquids (API Spec 12F).

Due to the higher potential for damage during relocation and use at multiple sites, it is recommended that inspections be routinely performed on vaulted, self-diking, and double-walled portable tanks. The inspections should identify damage and corrosion using one of the following standards:

- Steel Tank Institute's (STI) Standard for the Inspection of Aboveground Storage Tanks, Third Edition (STI SP00l); or
- API's Tank Inspection, Repair, Alteration, and Reconstruction Standard (API 653).

As an oil spill prevention measure, portable tanks can be equipped with high-liquid-level alarms that sound and display in an immediately recognizable manner; high-liquid-level automatic pump shutoff devices, which are designed to stop flow at a predetermined tank content level; and a means of immediately determining the liquid level of tanks.

Recommendation No. 98: NYSDEC should clarify whether vaulted, self-diking, and double-walled portable tanks will be allowed, and codify in the NYCRR the requirements for the use of those tanks, including inspections and spill prevention alarm systems.

23. Corrosion & Erosion Mitigation & Integrity Monitoring Programs

Background: In 2009, HCLLC recommended that NYSDEC require corrosion and erosion mitigation programs. More specifically HCLLC recommended that: equipment be designed to prevent corrosion and erosion; monitoring programs be put into place to identify corrosion and erosion over the well and equipment operating lifetime; and repair and replacement of damaged wells and equipment be completed.

Downhole tubing and casing, surface pipelines, pressure vessels, and storage tanks used in oil and gas exploration and production can be subject to internal and external corrosion. Corrosion can be caused by water, corrosive soils, oxygen, corrosive fluids used to treat wells, and the carbon dioxide (CO_2) and hydrogen sulfide (H_2S) present in gas. High velocity gas contaminated with water and sediment can internally erode pipes, fittings, and valves.

HVHF treatments, if improperly designed, can accelerate well corrosion. Additionally, acids used to stimulate well production and remove scale can be corrosive. The 2011 RDSGEIS includes a discussion on corrosion inhibitors used by industry in fracture treatments, but does not require them as best practice. Furthermore, the RDSGEIS does not require facilities be designed to resist corrosion (e.g. material selection and coatings), nor does it require corrosion monitoring, or the repair and replacement of corroded equipment.[363]

As explained in Chapter 20 of this report, the use of recycled HVHF fluid can result in the inoculation of sulfate reducing bacteria in the reservoir, and increased downhole equipment corrosion. And, while NYSDEC indicates that H_2S levels may be initially low in the Marcellus Shale, this may not be the case during the full life-cycle of the well. Nor does the RDSGEIS examine the H_2S of all other low permeability gas reservoirs to know what the H_2S might be for those formations.

Corroded well casings can provide a pathway for gas and well fluids to leak into protected aquifers. Therefore, it is important to install a robust casing system, and it’s equally important to ensure that the casing system’s integrity is maintained during the well’s life.

Corrosion measured on production casing is an important piece of information, because corrosive fluids are known to also degrade the quality of the cement barrier. Corrosive fluids reduce the cement strength and make it more permeable, potentially providing a pathway for hydrocarbons to migrate from zones of higher pressure to lower pressure freshwater zones.

Additionally, the bond between the casing and cement can be compromised over the well’s life, creating a “micro-annulus” (a space between the outer pipe wall and cement sheath) that allows vertical migration of hydrocarbons along the outside of the pipe wall. [364,365] Micro-annulus’ can be formed during initial

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[363] Curran, E., Corrosion Control in Gas Pipelines, Coating Protection Provides a Lifetime of Prevention, Pipeline & Gas Journal, October 2007.

[364] See Ravi, K. (Halliburton), Bosma, M. (Shell) and Gastebled, O. (TNO Building and Construction Research), Safe and Economic Gas Wells through Cement Design for the Life of the Well, Society of Petroleum Engineering Paper No. 75700, 2002. Ravi et. al. concludes: “The extreme operating conditions that occur in gas-storage and gas-producing wells could cause the cement sheath to fail, resulting in fluid migration through the annulus…The sustained casing pressure observed on a number of wells after they have been put on production emphasizes the need to design a cement sheath that will maintain integrity during the life of the well…However, recent experience has shown that after well operations such as completing, pressure testing, injecting, stimulating and producing, the cement sheath could lose its ability to provide zonal isolation. This failure can create a path for formation fluids to enter the annulus, which pressurizes the well and renders the well unsafe to operate…Failure of the cement sheath is most often caused by pressure – or temperature-induced stresses inherent in well operations during the well’s economic life.”

cementing, or later in the well's life, due to: pipe wall thinning; cement deterioration; the shock of additional well workover activities (perforations, stimulation, drilling); pressure and temperature changes in the well; or by seismic vibrations.

In January 2011, NYS' consultant, Alpha Geoscience, recommended that NYSDEC ignore HCLLC's best practice recommendations for corrosion and erosion, citing Section 6.1.4.2 and 6.1.5.1 of the 2009 DSGEIS. In these sections, another NYS consultant (ICF) estimated the risk of groundwater contamination due to casing failure in a Class II injection well is 1 in 50 million wells.[366] Alpha Geoscience concludes that corrosion and erosion prevention, monitoring, and repair requirements are unnecessary in the NYCRR.

Neither Alpha Geoscience nor ICF provide technical justification for the use of a Class II injection well corrosion risk analysis as a surrogate for a gas well corrosion risk analysis. A Class II injection well risk profile is different than a gas well. Gas wells can continuously produce sources of corrosive gas (CO_2 and H_2S), water, and sediment, that can corrode and erode well casing and surface piping over time.

Neither Alpha Geoscience nor ICF examined:

- The full life cycle of a gas well, and the fact that there is substantial field evidence that well casings do corrode and erode over time;
- The fact that casing inspection logs, caliper logs, temperature surveys, and other wellbore diagnostics are commonly run to examine the well casing condition due to the known problem of gas well corrosion;
- Information on the amount of money spent annually on corrosion inhibitors, pipe coating, and other preventive measures to mitigate corrosion impacts;
- The fact that well service specialists routinely provide well casing patching, repair, and replacement services,[367] because gas well casing failure is a known problem; and,
- The fact that it is best practice to examine the condition of well casing over the well life to verify its integrity, especially before major well work (e.g. additional drilling, stimulation) is completed on an aging well.[368]

Additionally, Alpha Geoscience criticizes HCLLC for citing industry literature on corrosion best practices, stating that HCLLC's inclusion of this material shows industry bias. HCLLC disagrees with Alpha Geoscience's conclusion. Industry has developed most of the technology to address the problem; therefore, it is logical to cite industry literature on this point.

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[365] See Stewart, R.B. and Schouten, F.C. (Shell), Gas Invasion and Migration in Cemented Annuli: Causes and Cures, Society of Petroleum Engineering Paper No. 14779, SPE Drilling Engineering, March 1988. Stewart and Schouten conclude: "*Gas migration resulting from casing contraction is a common field problem… Annular gas-migration problems can develop in an old well owing to changes in pressure or thermal conditions in the well.*"

[366] Alpha Geoscience, Review of the dSGEIS and Identification of Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 18.

[367] Storaune, A., Winters, W.J. (BP America Inc.), Versatile Expandables Technology for Casing Repair, Society of Petroleum Engineers, SPE Paper No. 92330-MS, SPE/IADC Drilling Conference, 23-25 February 2005, Amsterdam, Netherlands, 2005, p.1.

[368] Brondel, D., Edwards, R., Hayman, A., Hill, D., Shreekant, M., Semerad, T., Corrosion in the Oil Industry, Oilfield Review, April 1994, p. 9-10.

Experienced engineers know the importance of assessing and implementing programs to mitigate corrosion/erosion risk early in the field/well lifecycle. Corrosion of gas production equipment is a fundamental concern for the oil and gas industry that has been identified for decades.

> *Failures of equipment handling or producing natural gas occur only in the absence of an adequate corrosion-control program. A successful program is shown to include (1) anticipation of corrosion in design factors of all equipment, (2) detection of corrosion within the system and measurement of its severity for future reference, (3) use of mitigation measures and (4) continual follow-up and adjustment of control techniques. Design factors to be considered are tubing couplings, packers, tubing grade and size, and the number of tubing strings to be set. Future corrosion problems and mitigation work should be recognized at the time the well completion is made so that the best possible design factors can be realized. Corrosion can be detected by gas analysis, water analysis, coupon exposures and caliper surveys. Quantitative data are needed to determine the severity of the problem and to design a suitable program of alleviation of the corrosion. Use of inhibitors and plastic coatings are popular methods for mitigation of corrosion. Both methods have advantages and disadvantages that must be realized and evaluated. Control limits for a mitigation program should be established so that the operator can be certain that he is receiving the desired protection. Gas gathering and* ***process equipment also often suffer from corrosion….***
>
> *It is suggested that an adequate corrosion-control program must include efforts at various levels of company operations. All engineers and supervisors must participate actively in the corrosion-control effort. As a property is being developed, corrosion control should be considered when the equipment to be used is being selected. When development is complete, the operating people must determine the seriousness of their corrosion problems. They must realize that the corrosion attack may change with changes in production characteristics and that absence of corrosion today does not guarantee absence of corrosion tomorrow. When corrosion is detected within an operation, mitigation is in order [emphasis added].*[369]

Because of the known problem of casing corrosion, the National Association of Corrosion Engineers (NACE) developed Recommended Practice RP0186 to mitigate external casing corrosion; this standard applies to the design of cathodic protection for external surfaces of steel well casings, and would be used when soil/subsurface reservoir conditions present a corrosive environment warranting installation of cathodic protection system installation.[370]

NACE International writes:

> *Oil and gas wells represent a large capital investment. It is imperative that corrosion of well casings be controlled to prevent loss of oil and gas, environmental damage, and personnel hazards, and in order to ensure economical depletion of oil and gas reserves necessary [emphasis added].*[371]

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[369] Fincher, D.R. (Tidewater Oil Co.), Corrosion in Gas Wells and Gas Gathering Systems, Journal of Petroleum Technology, Volume 13, Number 9, September 1961, Abstract.

[370] NACE International Standard RP0186-2001, Application of Cathodic Protection for External Surfaces of Steel Well Casings.

[371] NACE International, Application of Cathodic Protection for External Surfaces of Steel Well Casings, RP0186-2001, 2001, p.1.

Gas operators stress the importance of corrosion monitoring and control programs. For example, OMV Exploration and Production writes:

> *Corrosion remains a key issue in petroleum production. Its continued occurrence has consequences on the safety of people and environment and the integrity of facilities and affects the economy of the oil or gas field. Particularly the presence of severe environments containing corrosive components such as carbon dioxide and hydrogen sulphide poses serious problems. A central element in the design of facilities and the corrosion control is therefore the proper choice of materials which are both economical and provide a satisfactory performance over the entire service life with respect to the given environment. Prior to the production phase reliable corrosion monitoring programmes have to be selected, established, and implemented, as necessary [emphasis added].*[372]

The magnitude and complexity of a corrosion/erosion mitigation program will vary depending on site-specific conditions. The important step is to complete the initial evaluation, assess the site-specific circumstances, and develop an adequate corrosion/erosion mitigation plan. Some mitigation programs are started early, some are applied intermittently, and others are instituted later in the gas production process; in all cases, an engineering assessment prior to gas drilling and production must be completed to determine the optimal plan.

The corrosion engineering textbook, Corrosion Control in Oil and Gas Production, explains the importance of developing a site-specific plan:

> *The many possible alternatives available today for corrosion management for gas and oil well environments, dictates the need for a thorough evaluation and development of long term plans to assure a safe, economical and effective program. History has shown that both corrosion inhibition and corrosion resistant alloys (CRAs) have been used successfully in tough environments. The final decision on which method to use is often made on the basis of available capital versus long term operating costs [emphasis added].* [373]

The 2011 RDSGEIS: The 2011 RDSGEIS includes a substantially improved well casing program, including a three-casing-string design. However, this casing is typically made of carbon steel, and must be protected from corrosion and erosion. Chromium steel and corrosion resistant alloys are commonly installed in corrosive environments; however, these metals are substantially more expensive and are not currently proposed for NYS.

Well casing, once installed and cemented into place, will remain in the well for its entire lifecycle, and is often abandoned in place.[374] Therefore, it is in the operator's best economic interest to ensure that its casing investment is protected from corrosion and erosion.

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[372] Oberndorfer, M. (OMV Exploration and Production), Corrosion Control in the Oil and Gas Production-5 Successful Case Histories, CORROSION Conference 2007, March 11-15, 2007, Nashville Tennessee, NACE International, 2007, p.1.

[373] Treseder, R.S., Tuttle, R.N., Corrosion Control in Oil and Gas Production, Chapter 14, Corrosion of Steels in Gas Wells, 1998.

[374] In some circumstances corroded casing will be pulled from a well prior to abandonment, although this process can prove difficult, time consuming, and expensive for fully cemented casing strings.

It would be shortsighted for NYS to require a robust well casing program, and not build in a corrosion and erosion control program. Chemicals, metallurgy, monitoring, and repair techniques are available to the operator to manage corrosion and erosion downhole (in the well) and at its surface facilities (e.g. corrosion inhibitors, cathodic protection systems, coatings).

Tools that can be used to monitor well corrosion include caliper tools and casing inspection logs. A caliper tool is run down the inside of the well casing or tubing to measure the internal diameter and assess metal wall loss. Casing inspection logs use ultrasonic and magnetic-flux technology to estimate metal wall loss. Additionally, temperature surveys can be run to look for gas cooling anomalies in the well, which are an indication of casing holes.[375]

NYSDEC has proposed cement evaluation tools to be run when HVHF wells are initially drilled and completed, which is a best practice. Cement integrity should also be monitored periodically over the well's life if casing corrosion occurs. Casing corrosion is an indicator of potential cement deterioration, as explained above.

Without regulations, the decision to invest in corrosion/erosion mitigation and wellbore integrity monitoring is left to the operator. In some cases, operators postpone mitigation to improve early economics. Deferral strategies can produce unfavorable results in the long-term, but may be attractive to small operators that have limited funds, or to large operators that plan to reap the benefits of early production and sell assets soon thereafter. Operators may not implement, unless required, long-term monitoring when faced with declining production, lower profits and when operating cost cuts are sought.

Corrosion and erosion programs that are instituted early can prolong the life of equipment and well casings, and reduce environmental risk. Delayed attention to corrosion and erosion mitigation can result in increased safety, environmental, and human health risks.

Gas well corrosion and erosion can occur in many ways:

- Oxygen contaminated drilling fluids are injected downhole, and can corrode well casing and drilling equipment;
- Water produced along with gas can corrode well casing, tubing, and downhole equipment;
- Acid stimulation treatments, used alone or in conjunction with hydraulic fracturing, readily attack metal;
- Well casing and surface piping can be eroded by high gas production velocities, especially when laden with sediment, sands, or hydraulic fracturing proppants;
- Corrosive soils can cause external corrosion of carbon steel casing;
- Hydrogen sulfide and carbon dioxide, often present in gas production, can corrode carbon steel; and
- Higher wellbore temperatures, increased velocity, and increased salinity accelerate corrosion rates.

NYCRR Proposed Revisions: NYSDEC has not proposed any new requirements for corrosion or erosion mitigation for the Marcellus, Utica, or other low-permeability reservoirs. There are no requirements for corrosion or erosion mitigation or long-term well integrity monitoring in the existing NYCRR.

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[375] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, p. 109.

Recommendation No. 99: Best corrosion and erosion mitigation practices and long-term well integrity monitoring should be included in the SGEIS and codified in the NYCRR. Operators should be required to design equipment to prevent corrosion and erosion. Corrosion and erosion monitoring, repair, and replacement programs should be instituted.

24. Well Control & Emergency Response Capability

Background: In 2009, HCLLC recommended that NYSDEC require an operator to have an Emergency Response Plan (ERP) and a well blowout control plan. HCLLC recommended that operators be required to demonstrate that they have access to sufficient personnel and resources to respond to a fire, explosion, blowout, or other industrial accident. Best practices include: developing response and well control plans; verifying there are a sufficient number of trained and qualified personnel to carry out the plans; ensuring operators have access to the necessary response equipment; and testing (drills and exercises) the plan prior to drilling.

In 2009, HCLLC also recommended that NYSDEC examine the capacity of local emergency response teams. Oil and gas industry accidents often require highly specialized response capability and equipment. Operators should be required to supplement local emergency response resources to meet this need.

In January 2011, NYS' consultant, Alpha Geoscience, concluded that NYS well control and emergency response planning requirements are narrowly focused on the Bass Island Trend wells. Alpha Geoscience agreed with HCLLC that new regulations are needed for the formations proposed for development under this SGEIS.[376]

The 2011 RDSGEIS: The 2011 RDSGEIS includes a new section (Section 7.13) on Emergency Response Plans, which is a substantial improvement. Section 7.13 states:

> *7.13 Emergency Response Plan*
>
> *There is always a risk that despite all precautions, non-routine incidents may occur during oil and gas exploration and development activities. An Emergency Response Plan (ERP) describes how the operator of the site will respond in emergency situations which may occur at the site. The procedures outlined in the ERP are intended to provide for the protection of lives, property, and natural resources through appropriate advance planning and the use of company and community assets. The Department proposes to require supplementary permit conditions for high-volume hydraulic fracturing that would include a requirement that the operator provide the Department with an ERP consistent with the SGEIS at least 3 days prior to well spud. The ERP would also indicate that the operator or operator's designated representative will be on site during drilling and/or completion operations including hydraulic fracturing, and such person or personnel would have a current well control certification from an accredited training program that is acceptable to the Department [emphasis added].*
>
> *The ERP, at a minimum, would also include the following elements:*
>
> - *Identity of a knowledgeable and qualified individual with the authority to respond to emergency situations and implement the ERP;*
> - *Site name, type, location (include copy of 7 ½ minute USGS map), and operator information;*
> - *Emergency notification and reporting (including a list of emergency contact numbers for the area in which the well site is located; and appropriate Regional*

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[376] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 42.

> *Minerals' Office), equipment, key personnel, first responders, hospitals, and evacuation plan;*
>
> - *Identification and evaluation of potential release, fire and explosion hazards;*
> - *Description of release, fire, and explosion prevention procedures and equipment;*
> - *Implementation plans for shut down, containment and disposal;*
> - *Site training, exercises, drills, and meeting logs; and*
> - *Security measures, including signage, lighting, fencing and supervision.*[377]

Appendix 6, Proposed Environmental Assessment Form Addendum, requires an Emergency Response Plan be located at the rig, and that the plan be followed. [378]

Appendix 10, Proposed Supplementary Permit Conditions for HVHF, Condition No. 2, requires an ERP be provided 3 days prior to spud and available at the site. Condition No. 2 requires the ERP be developed in a manner consistent with the SGEIS, but it does not reference the Chapter 7.13 minimum requirements.

> *An emergency response plan (ERP) consistent with the SGEIS must be prepared by the well operator and be available on-site during any operation from well spud (i.e., first instance of driving pipe or drilling) through well completion. A list of emergency contact numbers for the area in which the well site is located must be included in the ERP and the list must be prominently displayed at the well site during operations conducted under this permit. Further, a copy of the ERP in electronic form must be provided to this office at least 3 days prior to well spud.* [379]

The addition of an Emergency Response requirement to the SGEIS is a substantial improvement. However, it is recommended that NYSDEC include a review, approval, and audit process to ensure that quality plans are developed. NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

As proposed by NYSDEC, the operator is required to submit an ERP three days prior to commencing drilling. This leaves no time for regulators to review and approve the ERP. NYSDEC proposes no process for determining the adequacy of the ERP. There is no assessment of personnel training and qualifications, equipment resources, or local emergency response services.

Industrial fires, explosions, blowouts, and spills require specialized emergency response equipment, which may not be available at local fire and emergency services departments. For example, local fire and emergency services departments typically do not have well capping and control systems.

Larger, paid fire and emergency services departments, located near existing industrial developments, may have some industrial firefighting capability; however, the level of capability should be assessed by the operator and supplemented. If local emergency response services are relied upon in the ERP, operators should ensure emergency response personnel are trained, qualified, and equipped to respond to oil and gas industrial accidents. Small, local, volunteer fire and emergency services departments will typically not be equipped or qualified to meet this need.

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[377] 2011 NYSDEC, RDSGEIS, Page 7-146.

[378] 2011 NYSDEC, RDSGEIS, Appendix 6, Page A6-7.

[379] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 1 of 17.

Recommendation No. 100: NYSDEC should identify an Emergency Response Plan (ERP) review, approval, and audit process to ensure that quality plans are developed. Objectives of the ERP should include adequately trained and qualified personnel, and the availability of adequate equipment. If local emergency response resources are relied on in the ERP, operators should ensure they are trained, qualified, and equipped to respond to an industrial accident. Additionally, NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells.[380] This risk statistic is applicable to Marcellus and other low-permeability gas reservoir drilling that is still in the exploration and appraisal phase in NYS. Blowout rates are less frequent for production wells where more information is known about the reservoir, well control is optimized, and personnel are more experienced in site-specific conditions. For example, a review of production well blowouts in California estimated 1 blowout per 2,500 wells drilled.[381] California's data showed that: 25% of the blowouts affected more than 25 acres; the average blowout lasted 18 hours; and the maximum blowout length was 6 months.

Using the California statistic of 1 blowout per 2,500 production wells drilled (which is more conservative than the exploration well statistic of 7 blowouts per 1,000 exploration wells), and NYS' estimate of 1600 wells per year over 30 years, an incremental likelihood of 19 blowouts is estimated for NYS.[382] Because some of the early wells drilled will be exploration wells, the blowout frequency many be higher in the first few years of shale gas development in NYS and it is plausible that 40[383] or more well blowouts could occur during the next 30 years. Therefore, blowouts are a reasonably foreseeable significant impact, and mitigation is warranted.

Hydrocarbon reservoirs can contain large quantities of gas and formation water, which can be released into the surrounding environment during a well blowout, resulting in significant damage. For example, the Chesapeake Energy 2011 Marcellus well blowout in Bradford County, Pennsylvania spilled thousands of gallons of fracture treatment fluid over "containment walls, through fields, personal property and farms, even where cattle continue[d] to graze."[384]

Methods to control a gas well blowout can require significant water withdrawals – from 500,000 to 6,000,000 gallons per day. Well control experts may also use foam and dry chemicals to respond to a blowout. Controlling a well blowout can create large volumes of waste. Rig-deluge operations create large pools of water that can transport oil, chemicals, fuels, and other materials toward lower elevation drainage areas.

In addition to the Chesapeake Energy 2011 well blowout, another Pennsylvania Marcellus Shale blowout occurred in 2010.[385,386] Also, in 2010, there was a major industrial fire. The 2010 incidents prompted

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[380] Rana, S., Environmental Risks- Oil and Gas Operations Reducing Compliance Cost Using Smarter Technologies, Society of Petroleum Engineering Paper 121595-MS, Asia Pacific Health, Safety, Security and Environment Conference, 4-6 August 2009, Jakarta, Indonesia, 2009.

[381] Jordan, P.D., and Benson, S. M., Well Blowout Rates in California Oil and Gas District 4- Update and Trends, Summary of Well Blowout Risks for California Oil and Gas District 4, 1991-2005, Table 1

[382] 19 blowouts= (1,600 wells drilled per year)(30 years)(1 blowout per 2500 wells drilled).

[383] 40 blowouts= 1,600 wells drilled per year)(2 years)(7 blowout per 1000 wells drilled)+(1,600 wells drilled per year)(28 years)(1 blowout per 2500 wells drilled).

[384] Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid, The Huffington Post, April 20, 2011.

[385] Blowout Occurs at Pennsylvania Gas Well, Wall Street Journal, June 4, 2010.

Pennsylvania to realize the need for its own emergency response services, with trained and qualified personnel and adequate equipment available 24 hours per day, 7 days per week. The news reported that it took "16 hours for out-of-state crews to address a June 3 blowout in Clearfield County and 11 hours to extinguish a July 23 fire in Allegheny County. In both cases, well operators had to wait for response crews to fly in from Texas."[387]

In 2010, CUDD Well Control located a new facility in Canton Township, Bradford County, Pennsylvania. Canton Township is located near the southern NYS border. It may be possible for NYS operators to contract with CUDD to provide emergency response services. However, a better alternative may be for NYS to collaborate with a well control specialist to provide more centrally located services dedicated to supporting NYS' proposed drilling activity.

The 2011 RDSGEIS requires operators to develop and implement a blowout preventer (BOP) testing program. However, the SGEIS does not unequivocally require a well control expert be on contract. It is recommended that NYSDEC require operators to have a contract in place for immediate response by a trained and qualified well control contractor. If a contract with a well control expert is not in place when a blowout occurs, contract negotiations can cause detrimental delays.

Well capping is a proven, effective, and rapid method to control a blowout. Well control contractors provide the expertise and equipment for this operation. However, in some limited cases, well capping is not effective, and a relief well may be required. Therefore, it is important for operators to also have prearranged access to a relief well rig, either via a contract with a rig provider or via a memorandum of agreement to provide emergency response assistance with a nearby operator.

Recommendation No. 101: NYSDEC should require a well blowout response plan (either included in the Emergency Response Plan or as a separate plan), a contract retainer with an emergency well control expert, and prearranged access to a relief well rig.

NYCRR Proposed Revisions: NYSDEC has proposed a new regulation at 6 NYCRR § 560.5 requiring an ERP for HVHF wells. This is a substantial improvement; however, this plan should be required for all wells in NYS, not just HVHF wells. Additionally, the NYCRR should more clearly specify the ERP content requirements and include the recommendations listed above.

Recommendation No. 102: The requirement for an Emergency Response Plan should be codified in the NYCRR. It should apply to all wells in NYS, not just HVHF wells. The NYCRR should specify ERP content requirements. These requirements should be consistent with NYSDEC's recommendations listed in Chapter 7.13 of the 2011 RDSGEIS.

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[386] Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid, The Huffington Post, April 20, 2011.

[387] http://pagasdrilling.com/tag/cudd-well-control/

25. Financial Assurance Amount

Background: In December 15, 2008, scoping comments to NYSDEC, NRDC, and its co-signatories requested the DSGEIS examine whether NYSDEC requires a sufficient financial assurance amount (in the form of a bond or other financial instrument). In its comments on the 2009 DSGEIS, NRDC and its co-signatories, as well as HCLLC, noted that the DSGEIS did not provide an analysis of the current financial assurance requirements, and requested that work be done.

HCLLC recommended that the SGEIS examine financial assurance amounts to ensure there is funding available to properly plug and abandon wells; remove equipment and contamination; complete surface restoration; and provide adequate insurance to compensate nearby public for adverse impacts (e.g., well contamination).

Long horizontal wells are more costly to plug and abandon than vertical wells. Also, surface impacts are increased when high-volume fracture stimulation treatments are employed and multiple wells are drilled from a single well pad. Both of these operations require additional gas treatment and transportation facilities.

In January 2011, NYS' consultant, Alpha Geoscience, advised NYSDEC to ignore financial assurance recommendations, declaring it "out of scope" of the SGEIS, because legislative action would be required at ECL 23-0305(8)(k).[388] HCLCC disagrees. Regardless of whether a legislative change is required, financial assurance improvements for Marcellus Shale gas well drilling should not be disregarded in the RDSGEIS; instead, the SGEIS should recommend to NYS' Legislature the need for legislative action as a mitigating measure.

The 2011 RDSGEIS: The 2011 RDSGEIS still does not include recommendations for increasing the financial assurance amounts for HVHF shale gas operations.

NYCRR Proposed Revisions: There is no proposed revision to the amount of financial security for wells up to 6,000' deep. 6 NYCRR § 551.5. For wells between 2,500' and 6,000' in depth, NYSDEC requires only $5,000 financial security per well, with the overall total per operator not to exceed $150,000.

For wells drilled more than 6,000' deep, NYSDEC is proposing a regulatory revision that requires the operator to provide financial security in an amount based on the anticipated cost for plugging and abandoning the well (6 NYCRR § 551.6).

In 2003, ICF completed a report for the New York State Energy Research and Development Authority (NYSERDA) on NYS oil and gas wells.[389] ICF's report advised NYS that well plugging and abandonment can range from $5,000 per well to more than $50,000 per well depending on the well depth, well condition, site access, and site condition.[390] ICF's 2003 report recommended that NYS consider increased financial security requirements. NYSDEC's current requirement of only $5,000 financial

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[388] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 46.

[389] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003. This report is found at http://esogis.nysm.nysed.gov/esogisdata/downloads/NYSERDA/7012.pdf. The report is listed as a draft, and a final could not be located on the world-wide web.

[390] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page. ES-1.

security per well is clearly insufficient, if ICF determined in 2003 that the cost could be as much as $50,000 per well. Today's cost would likely be higher, almost a decade later.

In Ohio, an operator is required to obtain liability insurance coverage of at least $1,000,000 and up to $3,000,000 for wells in urban areas. The Ohio Code at Title 15, Chapter 1509 requires:

> *1509.07 Liability insurance coverage. An owner of any well, except an exempt Mississippian well or an exempt domestic well, shall obtain liability insurance coverage from a company authorized to do business in this state in an amount of not less than one million dollars bodily injury coverage and property damage coverage to pay damages for injury to persons or damage to property caused by the drilling, operation, or* ***plugging of all the owner's wells in this state.*** *However, if any well is located within an urbanized area, the owner shall obtain liability insurance coverage in an amount of not less than three million dollars for bodily injury coverage and property damage coverage to pay damages for injury to persons or damage to property caused by the* ***drilling, operation, or plugging of all of the owner's wells in this state****. The owner shall maintain the coverage until all the owner's wells are plugged and abandoned or are transferred to an owner who has obtained insurance as required under this section and who is not under a notice of material and substantial violation or under a suspension order. The owner shall provide proof of liability insurance coverage to the chief of the division of oil and gas resources management upon request. Upon failure of the owner to provide that proof when requested, the chief may order the suspension of any outstanding permits and operations of the owner until the owner provides proof of the required insurance coverage.[emphasis added]*
>
> *Except as otherwise provided in this section, an owner of any well, before being issued a permit under section 1509.06 of the Revised Code or before operating or producing from a well, shall execute and file with the division of oil and gas resources management a surety bond conditioned on compliance with the restoration requirements of section 1509.072, the plugging requirements of section 1509.12, the permit provisions of section 1509.13 of the Revised Code, and all rules and orders of the chief relating thereto, in an amount set by rule of the chief.*

Recommendation No. 103: NYSDEC's financial assurance requirements should not narrowly focus on the cost for plugging and abandoning a well. Instead, NYSDEC's financial assurance requirements should include a combination of bonding and insurance that addresses the costs and risks of long-term monitoring; publicly incurred response and cleanup operations; site remediation and well abandonment; and adequate compensation to the public for adverse impacts (e.g., water well contamination). Recommendations for financial assurance improvements for Marcellus Shale gas well drilling should be included in the SGEIS as a mitigating measure, even if legislative action is ultimately required. Additionally, improved financial assurance should be codified in the NYCRR during this revision to the extent possible.

By comparison, Fort Worth, Texas requires an operator drilling 1-5 wells to provide a blanket bond or letter of credit of at least $150,000, with incremental increases of $50,000 for each additional well.[391] Therefore, under Fort Worth, Texas requirements, an operator drilling 100 wells would be required to hold a bond of $4,900,000, as compared to $150,000 in NYS.

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[391] Fort Worth, Texas Ordinance No. 18449-2-2009, An Ordinance Amending the Code of Ordinances for the City of Fort Worth for Gas Drilling, 2009.

In addition to the bond amount, Fort Worth, Texas also requires the operator to carry multiple insurance policies:

1. *Standard Commercial General Liability Policy of at least $1,000,000 per occurrence. The Standard Commercial General Liability insurance must include: "premises, operations, blowout or explosion, products, completed operations, sudden and accidental pollution, blanket contractual liability, underground resources and equipment hazard damage, broad form property damage, independent contractors' protective liability and personal injury."*
2. *Excess or Umbrella Liability of $5,000,000;*
3. *Environmental Pollution Liability Coverage of at least $5,000,000 "applicable to bodily injury, property damage, including the loss of use of damaged property or of property that has not been physically injured or destroyed; cleanup costs; and defense, including costs and expenses incurred in the investigation, defense or settlement of claims…coverage shall apply to sudden and accidental, as well as gradual pollution conditions resulting from the escape or release of smoke, vapors, fumes, acids, alkalis, toxic chemicals, liquids or gases, waste material or other irritants, contaminants or pollutants."*
4. *Control of Well Policy of at least $5,000,000 per occurrence/combined single limit with a $500,000 sub-limit endorsement for damage to property for which the Operator has care, custody and control; and*
5. *Other insurance required by Texas (e.g. Workers Compensation Insurance, Auto Insurance, and other corporate insurance required to do business in the state of Texas).*[392]

Financial assurance requirements should be increased to address worst-case risk exposure. Risk assessments should include worst-case scenario financial impact models. The risk modeling should be used to set higher financial assurance requirements.

Recommendation No. 104: The financial assurance requirements at 6 NYCRR §§ 551.5 and 551.6 are insufficient to address the risks to NYS and private parties associated with oil and gas development. It is recommended that each operator provide a bond of at least $100,000 per well, with a cap of $5,000,000 for each operator. Additionally, NYSDEC should require Commercial General Liability Insurance, including Excess Insurance, Environmental Pollution Liability Coverage, and a Well Control Policy, of at least $5,000,000. If NYSDEC deviates from these financial assurance requirements, it should be justified with a rigorous economic assessment that is provided to the public for review and comment.

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[392] Fort Worth, Texas Ordinance No. 18449-2-2009, An Ordinance Amending the Code of Ordinances for the City of Fort Worth for Gas Drilling, 2009.

26. Seismic Data Collection

Background: In 2009, HCLLC recommended that NYSDEC improve the DSGEIS and establish regulatory requirements for seismic data collection to reduce impacts to the environment and the public. The 2009 DSGEIS addressed naturally occurring seismic events in Chapter 4, but was silent on the impacts from industrial seismic exploration, which is used to locate subsurface gas reservoirs including shale gas targets.

This problem persists in the 2011 RDSGEIS. The 2011 RDSGEIS discusses naturally occurring seismic events, and seismically induced fractures from HVHF operations, but does not include any analysis of the potential impacts or mitigation needed for two-dimensional (2D) or three-dimensional (3D) seismic surveys used to target hydrocarbon formations for exploration and appraisal drilling. These seismic surveys are also useful to identify major fault systems to be used in HVHF design and modeling. Improved understanding of the subsurface stratigraphy and fault systems will improved 3D model simulation predictions and can aid engineers in designing HVHF treatments that do not link induced fractures with existing, conductive, natural fault systems that could move HF fluids into protected groundwater resources or water wells.

In January 2011, NYS' consultant, Alpha Geoscience provided a misguided recommendation to NYSDEC to ignore seismic data collection mitigation in the RDSGEIS, as "irrelevant."[393] Because seismic data collection is typically the first step in unexplored areas, to locate and optimize exploration drilling targets, seismic data collection mitigation when used to target Marcellus Shale wells is hardly "irrelevant."

Therefore, it is unclear whether NYSDEC is not familiar with the use of seismic data collection to target hydrocarbon formations for drilling, and the mitigation measures needed because its consultants advised against study of this important mitigation, or whether shale gas operators have told NYSDEC that they don't intend to collect two-dimensional (2D) or three-dimensional (3D) seismic surveys prior to exploring in the Marcellus Shale.

If operators do not intend to collect additional 2D and 3D data, that representation should be stated in the RDSGEIS, and the 2D and 3D data collection should be precluded in NYS. Otherwise, the impacts of this work should be identified and mitigated. This is an important issue to resolve, because seismic surveys can create significant surface impacts and disruptions.

Recommendation No. 105: If 2D or 3D seismic surveys are planned, or are possible in the future, the NYCRR should codify a permitting process for these activities and institute mitigating measures in the SGEIS to minimize surface impacts and disruptions, and require rehabilitation of impacted areas.

Exploration for oil and natural gas typically begins with a geologic examination of the surface structure of the earth, to identify areas where petroleum or gas deposits might exist. Once a geologist/geophysicist has identified an area of potential interest based on surface geologic maps, seismic data collection is typically obtained to identify possible subsurface hydrocarbon traps and structures.

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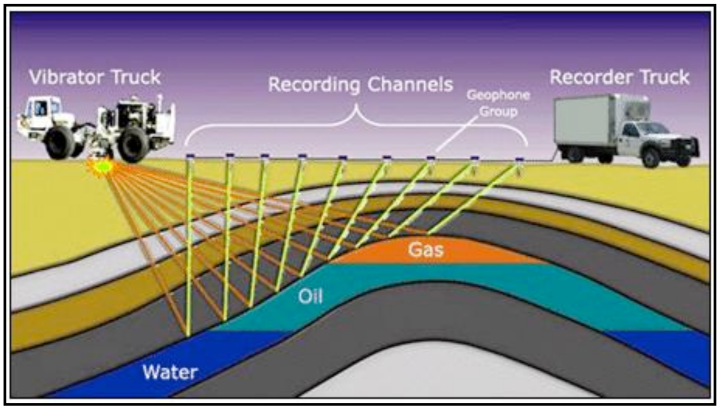
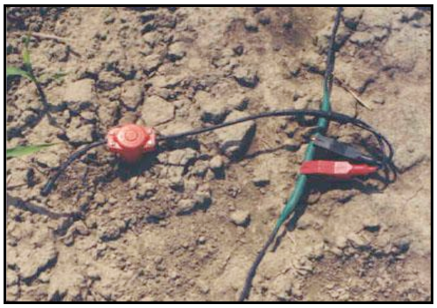
[393] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011.



Seismic exploration equipment is used to send seismic waves into the earth. Seismic waves are generated by a surface positioned source and are measured by a surface positioned receiver. The rate that seismic energy is transmitted and received through the earth crust provides information on the subsurface geology, because seismic waves reflect at different speeds and intensity off various rock strata and geologic structures. Collecting seismic data in this manner is called a Reflection Seismic Survey.[394]



A reflection seismic survey involves generating hundreds to tens of thousands of seismic source events, or shots, at various locations in the survey area. The seismic energy generated by each shot is detected and recorded by sensitive receivers (“geophones” on land and “hydrophones” under water) at a variety of distances from the source location. Geophones and hydrophones are connected by long cables to relay the collected information back to a centralized computer. The photo to the left is a geophone and cable system.[395]

For every source event, each geophone generates a seismogram or trace, which is a time series representing the earth movement at the receiver location. A record of all traces for each shot is transmitted to a computer for storage and conversion into a seamless cross-sectional representation of the subsurface for subsequent study and interpretation by a trained geophysicist.

Onland seismic operations involve generation of seismic vibrations by explosive energy sources or by mechanical sources. One type of energy source for seismic exploration is an explosive charge. Small holes (“shot-holes”), typically 4 inches in diameter are drilled into the earth surface, 10-60’ deep depending on surface terrain.[396] Although, some drill holes have been drilled to 200’.[397] The photo to the right shows an example of a shot-hole drill unit.

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[394] U.S. Geologic Survey, Seismic Data Acquisition.

[395] Geophone and cable photo from http://www.anr.state.vt.us/dec/geo/newbedu.htm, State of Vermont.

[396] Westlund, D., Thurber, M.W., Best Environmental Practices for Seismic Exploration in Tropical Rainforest, Society of Petroleum Engineers International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, SPE 10HSE 126844-PP, April 2010.

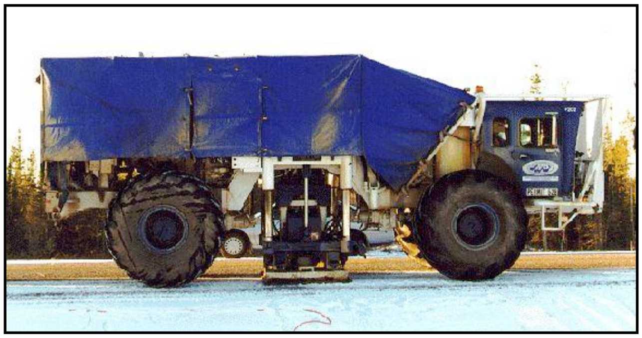
[397] US Fish and Wildlife Service, 612 FW 2, Oil and Gas, Policy Manual.

The hole must be drilled into a hard layer of soil that is sufficiently dense to carry the seismic wave.[398] Explosive charges (typically 5-50 pounds each)[399] are lowered into the hole and detonated to create a shock wave (vibration). Some states have limits on the size of charges that can be deployed near environmentally sensitive areas, human inhabitation and near roadways.

Historic use of explosives on the ground surface resulted in large craters and extensive surface damage. Explosive charges are no longer deployed at the surface. Instead, a shot-hole must be drilled and the explosive lowered into the shot-hole at a sufficient depth to prevent surface craters. Shot-holes are filled with cuttings, bentonite and rocks to minimize surface impact.

Mechanical vibrators are an alternative to the use of explosives, and are more commonly used. Mechanical vibrators provide more consistent source strength and repeatability, and they are more reliable in the case of repeat data acquisition programs or for time-lapse studies.

Mechanical vibrators can include: a pad that thumps the surface of the earth ("thumper trucks"), driven by gravity or compressed air; a truck that generates vibrations ("Vibroseis™ Truck"); and compressed air guns.[400] The photo to the right shows a Vibroseis Truck. The Vibroseis method involves a truck equipped with vibrator pads that are lowered to the ground and triggered. Depending on the subsurface target depth and the purpose of the seismic survey, two or more seismic Vibroseis Trucks (vibrating in sync) may be needed.



In cold climates, ice road construction and use of Vibroseis Trucks for seismic data acquisition is the norm. Seismic data is typically secured over the winter months along ice road routes, to reduce footprint and stress to sensitive areas of the tundra environment.

The use of thumper trucks is not considered best practice because it involves dropping a steel slab that weighs about three tons to the ground to create a seismic vibration. Thumper trucks are large, requiring extensive tree and vegetation removal, and leave land scars.

In areas where seismic data is collected in water, the energy source is usually compressed air in an airgun submerged underwater, because explosives can cause adverse impacts to aquatic life.

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[398] The Pembina Institute, Seismic Exploration, www.pembina.org.

[399] US Fish and Wildlife Service, 612 FW 2, Oil and Gas, Policy Manual.

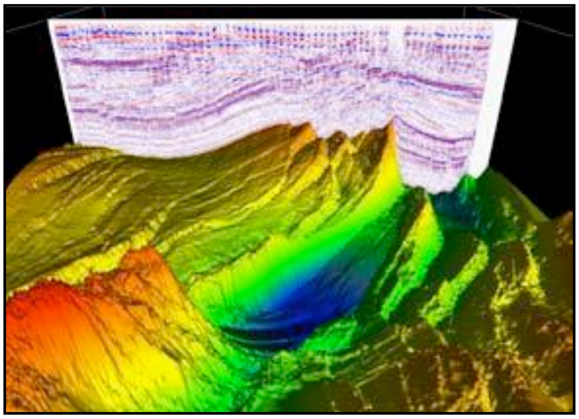
[400] Petroleum Engineering Handbook, Reservoir Engineering and Petrophysics, Volume V(A), Society of Petroleum Engineers, 2007.

Significant surface impacts can be caused by extensive tree and vegetation removal to create straight "cutlines" to run seismic equipment (as shown in the photo to the left). Lines need to be cut to run mechanical vibration equipment or set explosives to generate the seismic waves, and other seismic lines are cleared to set geophones to measure the seismic reflection. The width of each cutline depends on the seismic survey method used, but can be on the order of 20'-50' wide where large seismic equipment units are required. Best practice is to decrease the width of the cutlines to as small as possible using hand carried equipment. More recently companies have been able to reduce cutline width to 6'-10' in certain circumstances.

The spacing between each cutline is dependent on the type of seismic equipment used and depth of examination into the earth. The distance between each cutline is typically 300' apart (shallow reservoir targets) to 3,000' apart (deeper reservoir targets).[401]

Depending on existing development, infrastructure and access in the area planned for onshore seismic exploration, a seismic operator may need to build access roads, set up temporary camps and establish helicopter landings to bring in personnel and equipment. In areas where there are existing roads, housing and airports, surface disturbance can be minimized.

A basic set of seismic data can be obtained by setting a two dimensional array of seismic sources and receivers (2D seismic). Typically 2D seismic requires seismic lines tens of miles apart. Often 2D data is acquired along existing roads or access routes to minimize surface impacts. Along the 2D seismic cutlines shot-points and receivers are evenly spaced to send and receive a signal. This process produces a 2D slice of the subsurface.



If funding is available, operators generally opt to collect three dimensional seismic (3D seismic) images of the subsurface. 3D seismic data acquisition involves a much more intensive data collection effort, using multiple shot lines arranged perpendicular to multiple receiver lines of geophones, with seismic lines spaced several hundred feet apart, rather than miles apart.[402] An example of a map produced from a 3D seismic survey is shown to the left.

Seismic operations are very labor intensive and require large amounts of equipment, personnel and support systems. Depending on the size of the area under study, and the type of equipment selected, seismic operations can require dozens to hundreds of personnel. In addition to seismic exploration equipment, there is a need for housing, catering, waste management systems, water supplies, medical facilities, equipment maintenance and repair shops, and other logistical support functions. None of these impacts have been analyzed in the NYS RDSGEIS.

There are typically six different crews deployed: (1) access crews, that clear seismic lines, (2) "shooters" that drill the shot-holes and set the explosive charges or run the mechanical vibration equipment to generate seismic waves, (3) "recorders" that set the geophones and measure the seismic reflection, (4) the "pick-up" crews that move the equipment from one location to the next along the seismic lines,

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[401] The Pembina Institute, Seismic Exploration, www.pembina.org.

[402] Westlund, D., Thurber, M.W., Best Environmental Practices for Seismic Exploration in Tropical Rainforest, Society of Petroleum Engineers International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, SPE 10HSE 126844-PP, April 2010.

(5) logistical support crews that provide housing, food, medical, maintenance and repair, and transportation; and (6) remediation and plugging crews that restore the area and plug shot-holes (if used).

Recommendation No. 106: The increased industrial activity (e.g. economic impacts, noise, surface disturbance, wildlife impacts, etc.) associated with 2D and 3D seismic surveys should be examined in the SGEIS.

In 2011, HCLLC developed a report for NRDC and Sierra Club describing the types of impacts that occur from 2D and 3D seismic surveys, and made recommendations for best practices and model permit requirements. The recommendations in this report could be considered by NYSDEC in crafting seismic survey requirements for NYCRR.[403]

Recommendation No. 107: Consider the best practices and model permit requirements proposed in Harvey Consulting, LLC., Onshore Seismic Exploration Best Practices & Model Permit Requirements Report to: Sierra Club and Natural Resources Defense Council, January 20, 2011, for inclusion as mitigation measures in the SGEIS and improvements in the NYCRR to regulate seismic survey data collection.

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[403] Harvey Consulting, LLC., Onshore Seismic Exploration Best Practices & Model Permit Requirements Report to: Sierra Club and Natural Resources Defense Council, January 20, 2011.

APPENDIX A

Surface Casing Table

Appendix A - Surface Casing Table

Surface Casing Requirement	2011 RDSGEIS Appendix 8 Casing and Cementing Practices	2011 RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	2011 RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed Permit Conditions and Recommendations in 2011 RDSGEIS	NYCRR Requirements for all Wells, NYCRR Part 554	ADDITIONAL NYCRR Requirements for all HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Setting Depth	75' beyond the deepest fresh water zone encountered or 75' into competent rock (bedrock), whichever is deeper.	100’ below the deepest freshwater zone and at least 100’ into bedrock.	No requirement listed; assume it defaults to the Appendix 8 requirement of 75'.	The Appendix 10 HVHF surface casing setting depth requirement is less stringent than the Appendix 9 requirement; both should be 100'. NYSDEC should consider a 100' protection for all oil and gas wells. Additionally, NYSDEC needs to clarify whether the setting depth is intended to protect potable freshwater only, or include a broader definition of protected groundwater, which would result in deeper surface casing depths.	Surface casing must be run in all wells to extend below the deepest potable fresh water level. Neither the 75' nor the 100' setting depth below the deepest protected water zone is specified in the NYCRR.	No additional requirement.	NYSDEC should consider a 100' protection for all oil and gas wells. Additionally, NYSDEC needs to clarify whether this setting depth is intended to protect potable freshwater only, or include a broader definition of protected groundwater, which would result in deeper surface casing depths. This requirement should apply to all NYS wells.
Protected water depth estimate and verification	No requirement.	Estimated in drilling application and verified while drilling.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method. If the actual protected water depth extends beyond the estimated protected water depth, an additional string of intermediate casing should be required.	No requirement.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method. If the actual protected water depth extends beyond the estimated protected water depth, an additional string of intermediate casing should be required. This requirement should apply to all NYS wells.
Cement Sheath Width	No requirement.	At least 1-1/4".	No requirement.	A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells.

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Amount of Cement in Annulus	Not specified, but it is presumed that the goal is to complete annulus cementing, because the requirements include 25% excess cement; however, the conditions require a reporting of the cement top location, if cement is not returned to the surface, which indicates that NYSDEC could accept a partially cemented annulus.	Entire annulus must be cemented; cement squeeze may be required.	No requirement listed; assume it defaults to Appendix 8 requirement.	The surface casing annulus should be completely filled with cement; this should be clearly specified. There should be no void space in the annulus.	There is a requirement to circulate cement to the top of the hole.	No additional requirement.	The surface casing annulus should be completely filled with cement; this should be clearly specified. There should be no void space in the annulus. This requirement should apply to all NYS wells.
Shallow gas hazards	Surface hole drilling must stop and surface casing must be set and cemented before drilling deeper into hydrocarbon resources.	The likelihood of shallow gas hazards must be estimated in the drilling application and verified while drilling.	No requirement listed; assume it defaults to Appendix 8 requirement.	All oil and gas well designs and applications should plan for shallow gas hazards. Any shallow gas hazards encountered while drilling should be recorded. If a shallow gas hazard is encountered, surface casing should be set and cemented to protect water resources, before drilling deeper into hydrocarbon resources.	No requirement.	No requirement.	If a shallow gas hazard is encountered, surface hole drilling must stop, and surface casing must be set and cemented, before drilling deeper into hydrocarbon resources. All oil and gas well designs and applications should plan for shallow gas hazards. Any shallow gas hazards encountered while drilling should be recorded. This requirement should apply to all NYS wells.
Excess Cement Requirement	25%	50%	No requirement listed; assume it defaults to Appendix 8 requirement of 25%.	25% excess cement is standard practice, unless a caliper log is run to more accurately assess hole shape and required cement volume.	No requirement.	No requirement.	25% excess cement is standard practice, unless a caliper log is run to more accurately assess hole shape and required cement volume. This requirement should apply to all NYS wells.

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Cement Type	The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement.	No requirement listed; assume it defaults to Appendix 8 requirement.	The cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive.	HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) is best practice. These practices should apply to all wells, not just HVHF wells.	No requirement.	The cement must conform to the industry standards specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content and contain a gas-block additive.	The cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) is best practice. These practices should apply to all wells, not just HVHF wells.
Cement Mix Water Temperature and pH Monitoring	Required.	No requirement listed; assume it defaults to Appendix 8 requirement.	No requirement listed; assume it defaults to Appendix 8 requirement.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations.	No requirement.	The cement must conform to the industry standards specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. This requirement should apply to all NYS wells, not just HVHF wells.
Lost Circulation Control	Required.	Required.	Required.	Lost circulation control is best practice.	No requirement.	No requirement.	Lost circulation control is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

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Spacer Fluids	Required.	No requirement listed; assume it defaults to Appendix 8 requirement.	Required.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells, not just HVHF wells.
Hole conditioning before cementing	Gas flows must be killed or lost circulation must be controlled and the hole be conditioned before cementing.	No requirement listed; assume it defaults to Appendix 8 requirement.	No requirement listed; assume it defaults to Appendix 8 requirement.	Hole conditioning before cementing is best practice.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.
Cement Installation and Pump Rate	No requirement.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice; this requirement should apply to all oil and gas wells, not just HVHF wells.	No requirement.	Cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice; this requirement should apply to all oil and gas wells, not just HVHF wells.
Rotating and Reciprocating Casing While Cementing	No requirement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement.	No requirement.	No additional requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.
Centralizers	At least every 120', with a minimum of two centralizers. A table of centralizer-hole size combinations is included.	At least every 120'.	At least two centralizers (one in the middle and one at the top), and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002).	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API RP 10D-2 (July 2010).	No requirement.	In addition to centralizers otherwise required by the department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed, and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill.	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API RP 10D-2 (July 2010). This requirement should apply to all NYS wells, not just HVHF wells.

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Casing quality	All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi); used casing may be approved for use, but must be pressure tested before drilling out the casing shoe.	New pipe with minimum internal yield pressure (MIYP) of 1,800 psi, or reconditioned pipe that has been tested internally to a minimum of 2,700 psi, must be used.	New pipe is required and must conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002).	New casing should be used in all wells. Once installed, surface casing remains in the well for the life of the well, and typically remains in place when the well is plugged and abandoned. It is important that the surface casing piping string (known as "the water protection piping string") is of high quality to maximize the corrosion allowance and life-cycle of the piping. The installation of older, used, thinner pipe, with less remaining corrosion allowance, may be a temporary solution, but not a long-term investment in groundwater protection. Used piping may pass an initial pressure test; however, it will not last as long as new piping, and will not be as protective of water resources in the long-term.	No requirement.	All casing must be new and conform to the industry standards specified in the permit to drill.	New casing should be used in all wells. Once installed, surface casing remains in the well for the life of the well, and typically remains in place when the well is plugged and abandoned. It is important that the surface casing piping string (known as "the water protection piping string") is of high quality to maximize the corrosion allowance and life-cycle of the piping. The installation of older, used, thinner pipe, with less remaining corrosion allowance, may be a temporary solution, but not a long-term investment in groundwater protection. Used piping may pass an initial pressure test; however, it will not last as long as new piping, and will not be as protective of water resources in the long-term.
Casing Thread Compound	No requirement.	No requirement.	Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009).	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.	No requirement.	Casing thread compound and its use must conform to the industry standards specified in the permit to drill.	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.

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Drilling Mud	No requirement.	Compressed air or WBM, no SMB or OBM.	Not listed in Appendix 10, but the RDSGEIS text includes a section that states compressed air or WBM should be used on HVHF wells.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells, not just those described in Appendix 9.	No requirement.	No requirement.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all NYS wells.
Cement Setting Time	Compressive strength standard of 500 psi.	No requirement listed; assume it defaults to Appendix 8 requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have surface casing strings stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi.	No requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have surface casing strings stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells.
NYSDEC Inspector	No requirement.	Required to be onsite for cementing operations.	No requirement.	Best practice is to have a state inspector on site during cementing operations, to verify surface casing cement is correctly installed, before attaching the blowout preventer and drilling deeper into the formation.	No requirement.	No additional requirement.	Best practice is to have a state inspector on site during cementing operations, to verify surface casing cement is correctly installed, before attaching the blowout preventer and drilling deeper into the formation. This requirement should apply to all NYS wells.

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Cement QA/QC - Cement Evaluation Log	NYSDEC reserves the right to require the operator run a cement bond log, but does not require one on every well.	NYSDEC reserves the right to require the operator run a cement bond log, but does not require one on every well.	No requirement listed; assume it defaults to Appendix 8 requirement.	Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only QA/QC check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids, in the cement column. Circulating cement to the surface also may not identify poor cement to casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and temperature survey.	No requirement.	No additional requirement.	Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only QA/QC check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids, in the cement column. Circulating cement to the surface also may not identify poor cement to casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and temperature survey.
Formation Integrity Test	No requirement.	No requirement.	No requirement.	It is best practice to complete a formation integrity test to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. The test should be conducted after drilling out of the casing shoe, into at least 20 feet, but not more than 50 feet of new formation. The test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill.	No requirement.	No requirement.	It is best practice to complete a formation integrity test to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. The test should be conducted after drilling out of the casing shoe, into at least 20 feet, but not more than 50 feet of new formation. The test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill. This requirement should apply to all NYS wells.

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BOP Installation	Confirmation that the surface casing is set and cemented into place, such that the BOP can be secured and effective when drilling deeper into the well.	No requirement listed; assume it defaults to Appendix 8 requirement.	No requirement listed; assume it defaults to Appendix 8 requirement.	The Appendix 8 requirement is best practice. Additionally, the surface casing should be pressure tested to ensure it can hold the required working pressure of the BOP.	No requirement.	No requirement.	The Appendix 8 requirement is best practice. Additionally, the surface casing should be pressure tested to ensure it can hold the required working pressure of the BOP. This requirement should apply to all NYS wells.
Record keeping	Not specified.	Not specified.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.	No requirement.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.
Additional Casing or Repair	Not specified.	Not specified.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the Department for environmental and/or public safety reasons, may be required at any time.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.	No requirement.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the department for environmental and/or public safety reasons, may be required at any time.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.

APPENDIX B

Intermediate Casing Table

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Intermediate Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Waiver Provision to Exclude Use of Intermediate Casing	Intermediate casing is required on a case-by-case basis.	Intermediate casing is required on a case-by-case basis.	Intermediate casing is required on all wells unless a waiver is granted.	It is best practice to install intermediate casing on a case-by-case basis for most wells; however, it is best practice to install it on all HVHF wells. The waiver provision proposed in the RDSGEIS to exclude intermediate casing on HVHF wells is not technically justified.	No requirement.	Intermediate casing is required on all wells unless a waiver is granted.	It is best practice to install intermediate casing on a case-by-case basis for most wells; however, it is best practice to install it on all HVHF wells. The waiver provision proposed in the RDSGEIS to exclude intermediate casing on HVHF wells is not technically justified.
Setting Depth	No requirement.	No requirement.	The setting depth and design of the casing must consider all applicable drilling, geologic, and well control factors.	Best practice is to set intermediate casing at least 100' below the deepest protected groundwater, to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Although intermediate casing setting depth is site specific, there should be criteria for determining that depth.	No requirement.	The setting depth and design of the casing must consider all applicable drilling, geologic, and well control factors.	Best practice is to set intermediate casing at least 100' below the deepest protected groundwater, to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Although intermediate casing setting depth is site specific, there should be criteria for determining that depth. This requirement should apply to all NYS wells.
Protected Water Depth Estimate and Verification	No requirement.	No requirement.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method during drilling, ensuring intermediate casing protects that groundwater.	No requirement.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method during drilling, ensuring intermediate casing protects that groundwater. This requirement should apply to all NYS wells where intermediate casing is set.
Cement Sheath Width	No requirement.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells where intermediate casing is set.
Amount of Cement in Annulus	No requirement.	No requirement.	Intermediate casing must be fully cemented to surface with excess cement.	It is best practice to fully cement intermediate casing if technically feasible to isolate protected water zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. If the casing can not be fully cemented most states require cement to be placed from the casing shoe to a point at least 500-600' above the shoe.	No requirement.	Intermediate casing must be fully cemented to surface with excess cement.	It is best practice to fully cement intermediate casing if technically feasible to isolate protected water zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. If the casing can not be fully cemented most states require cement to be placed from the casing shoe to a point at least 500-600' above the shoe. This requirement should apply to all wells where intermediate casing is set.
Excess Cement Requirement	No requirement.	No requirement.	25% unless a caliper log is run; if a caliper log is run, the excess cement requirement is 10%.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume.	No requirement.	25% unless a caliper log is run; if a caliper log is run, the excess cement requirement is 10%.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where intermediate casing is set.

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Intermediate Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Cement Type	No requirement.	No requirement.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). The cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive.	HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where intermediate casing is installed, not just HVHF wells.	No requirement.	Cement must conform to industry standards, specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content, in accordance with the industry standards, and contain a gas-block additive.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). The cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where intermediate casing is installed, not just HVHF wells.
Cement Mix Water Temperature and pH Monitoring	No requirement.	No requirement.	Cement slurry must be prepared to minimize its free water content, in accordance with industry standards and specifications.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations.	No requirement.	Cement must conform to industry standards, specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content, in accordance with the industry standards.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where intermediate casing is required, not just HVHF wells.
Lost Circulation Control	No requirement.	No requirement.	No requirement.	Lost circulation control is best practice.	No requirement.	No requirement.	Lost circulation control is best practice. This requirement should apply to all NYS wells where intermediate casing is required.
Spacer Fluids	No requirement.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where intermediate casing is used , not just HVHF wells.
Hole conditioning before cementing	No requirement.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.
Cement Installation and Pump Rate	No requirement.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Appendix B - Intermediate Casing Table

Intermediate Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Rotating and Reciprocating Casing While Cementing	No requirement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.
Centralizers	No requirement.	No requirement.	At least two centralizers (one in the middle and one at the top), and all bow-spring style centralizers, must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002).	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010).	No requirement.	In addition to centralizers otherwise required by the Department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed, and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill.	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where intermediate casing is installed.
Casing quality	No requirement.	No requirement.	New pipe is required and must conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002).	The use of new pipe conforming to API Specification 5CT is best practice.	No requirement.	All casings must be new and conform to industry standards specified in the permit to drill.	The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where intermediate casing is set.
Casing Thread Compound	No requirement.	No requirement.	Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009).	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.	No requirement.	Casing thread compound and its use must conform to industry standards specified in the permit to drill.	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.
Drilling Mud	No requirement.	No requirement.	No requirement.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells during the period when drilling occurs through protected water zones.	No requirement.	No requirement.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells during the period when drilling occurs through protected water zones.
Cement Setting Time	No requirement.	No requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi.	No requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells, not just HVHF wells.

Appendix B - Intermediate Casing Table

Intermediate Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
NYSDEC Inspector	No requirement.	No requirement.	Required to be onsite for cementing operations.	Best practice is to have a state inspector onsite during cementing operations.	No requirement.	No requirement.	Best practice is to have a state inspector onsite during cementing operations. This requirement should apply to all NYS wells where intermediate casing is installed.
Cement QA/QC - Cement Evaluation Log	No requirement.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the intermediate casing.	The use of a cement evaluation logging tool is best practice.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the intermediate casing.	The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where intermediate casing is set.
Record keeping	Not specified.	Not specified.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.	No requirement.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.
Additional Casing or Repair	No requirement.	No requirement.	No requirement.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the department for environmental and/or public safety reasons, may be required at any time.	No additional requirement.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.

APPENDIX C

Production Casing Table

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Casing Design	No requirement.	No requirement.	Full string of production casing be set across the production zone and be run to surface, and that the production casing be cemented in place.	For all wells, it is best practice for the productive horizon(s) to be determined by coring, electric log, mud-logging,and/or testing to aide in optimizing final production string design and placement. It is best practice to install production casing on a case-by-case basis for most wells; however, it is best practice to install a full string of production casing on HVHF wells to provide a conduit for the HVHF job and provide an extra layer of casing and cement.	The drilling, casing and completion program adopted for any well shall be such as to prevent the migration of oil, gas or other fluids from one pool or stratum to another.	Full string of production casing be set across the production zone and be run to surface, and that the production casing be cemented in place.	For all wells, it is best practice for the productive horizon(s) to be determined by coring, electric log, mud-logging,and/or testing to aide in optimizing final production string design and placement. It is best practice to install production casing on a case-by-case basis for most wells; however, it is best practice to install a full string of production casing on HVHF wells to provide a conduit for the HVHF job and provide an extra layer of casing and cement.
Cement Sheath Width	No requirement.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged.	No requirement.	No additional requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells where production casing is set.
Amount of Cement in Annulus	The production casing cement shall extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less. If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows. The Department may allow the use of a weighted fluid in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem.	No additional requirement. Appendix 8 requirement would apply.	If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).	Cementing production casing to surface if technically feasible (becomes more difficult with increasing depth), or at least 500' into the intermediate casing string is best practice.	If it is elected to complete a rotary-drilled well and production casing is run, it shall be cemented by a pump and plug or displacement method with sufficient cement to circulate above the top of the completion zone to a height sufficient to prevent any movement of oil or gas or other fluids around the exterior of the production casing.	If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).	Cementing production casing to surface if technically feasible (becomes more difficult with increasing depth), or at least 500' into the intermediate casing string is best practice. This requirement should apply to all NYS wells where production casing is set.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Excess Cement Requirement	A minimum of 25% excess cement shall be used. When caliper logs are run, a 10% excess will suffice. Additional excesses may be required by the Department in certain areas.	No additional requirement. Appendix 8 requirement would apply.	No additional requirement. Appendix 8 requirement would apply.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume.	No requirement.	No additional requirement.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where production casing is set.
Cement Type	No requirement.	No requirement.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive.	HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where production casing is installed, not just HVHF wells.	No requirement.	Cement must conform to industry standards, specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content, in accordance with the industry standards, and contain a gas-block additive.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where production casing is installed, not just HVHF wells.
Cement Mix Water Temperature and pH Monitoring	The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing tickets and/or the drilling log. WOC time shall be adjusted based on the results of the test.	No additional requirement. Appendix 8 requirement would apply.	No additional requirement. Appendix 8 requirement would apply.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations.	No requirement.	No additional requirement.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where production casing is required, not just HVHF wells.
Lost Circulation Control	No requirement.	No requirement.	No requirement.	Lost circulation control is best practice.	No requirement.	No additional requirement.	Lost circulation control is best practice. This requirement should apply to all NYS wells where production casing is required.
Spacer Fluids	No requirement.	No requirement.	A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where production casing is used, not just HVHF wells.
Hole conditioning before cementing	No requirement.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Cement Installation and Pump Rate	The pump and plug method shall be used for all production casing cement jobs deeper than 1500 feet. If the pump and plug technique is not used (less than 1500 feet), the operator shall not displace the cement closer than 35 feet above the bottom of the casing. If plugs are used, the plug catcher shall be placed at the top of the lowest (deepest) full joint of casing.	No additional requirement. Appendix 8 requirement would apply.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. The pump and plug installation method is a best practice.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.
Rotating and Reciprocating Casing While Cementing	No requirement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This will be come more difficult with a deviated wellbore, but should be attempted if achievable.	No requirement.	No additional requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This will become more difficult with a deviated wellbore, but should be attempted if achievable. This requirement should apply to all NYS oil and gas wells, not just HVHF wells.
Centralizers	Centralizers shall be placed at the base and at the top of the production interval if casing is run and extends through that interval, with one additional centralizer every 300 feet of the cemented interval.	No additional requirement. Appendix 8 requirement would apply.	At least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002)	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010).	No requirement.	In addition to centralizers otherwise required by the Department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed, and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill.	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where production casing is installed.
Casing quality	The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.	No additional requirement. Appendix 8 requirement would apply.	Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited.	The use of new pipe conforming to API Specification 5CT is best practice.	No requirement.	All casings must be new and conform to industry standards specified in the permit to drill.	The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where production casing is set.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Casing Thread Compound	No requirement.	No requirement.	Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009).	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.	No requirement.	Casing thread compound and its use must conform to industry standards specified in the permit to drill.	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.
Cement Setting Time	Following cementing and removal of cementing equipment, the operator shall wait until a compressive strength of 500 psi is achieved before the casing is disturbed in any way.	No additional requirement. Appendix 8 requirement would apply.	After the cement is pumped, the operator must wait on cement (WOC): 1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psi, and 2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test.	Operations shall be suspended until the cement has been permitted to set in accordance with prudent current industry practices.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. This requirement should apply to all NYS wells, not just HVHF wells.
NYSDEC Inspector	No requirement.	No requirement.	This office must be notified _______ hours prior to production casing cementing operations.	Best practice is to have a state inspector onsite during cementing operations. This is more typical for surface and intermediate casing, but can be considered for production casing as well.	No requirement.	No additional requirement.	Best practice is to have a state inspector onsite during cementing operations. This is more typical for surface and intermediate casing, but can be considered for production casing as well.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Cement QA/QC - Cement Evaluation Log	No requirement.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the production casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 “Other Testing and Information” under the heading of “Well Logging and Other Testing” of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009).	The use of a cement evaluation logging tool is best practice.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the production casing.	The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where production casing is set.
Record keeping	No requirement.	No requirement.	A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.	No requirement.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Additional Casing or Repair	No requirement.	No requirement.	Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.	No requirement.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the department for environmental and/or public safety reasons, may be required at any time.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.

Appendix D: List of Acronyms

^{210}Po	Polonium 210
2D	two-dimensional
3D	three-dimensional
API	American Petroleum Institute
API RP	American Petroleum Institute Recommended Practice
AQ	Air Quality
AMD	Acid mine discharge
ARD	Acid Rock Drainage
Bcf	billion cubic feet
BOP	Blow-out preventer
BTEX	benzene, toluene, ethylbenzene, and xylenes
BUD	Beneficial Use Determination
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board
CDA	Concentrated Development Area
CRI	Cuttings reinjection technology
CRA	Corrosion-resistant alloys
CRDPF	Continuously Regenerating Diesel Particulate Filters
DOI	United States Department of the Interior
DMM	Division of Materials Management
EAF	Environmental Assessment Form
EPA	Environmental Protection Agency
ERP	Emergency Response Plan
GHG	Greenhouse Gases
H2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutants
HVHF	High Volume Hydraulic Fracturing
JPAD	Jonah-Pinedale Anticline Development Area
LDAR	Leak Detection and Repair
MACT	Maximum Achievable Control Technology
MFN	Microseismic Fracture Network
MMscf	Million standard cubic feet
MSDS	Material Safety Data Sheet
MSW	Municipal solid waste
NAAQS	National Ambient Air Quality Standards
NACE	National Association of Corrosion Engineers
NO$_X$	Nitrogen Oxide
NORM	Naturally Occurring Radioactive Material
NRDC	Natural Resources Defense Council
NYCRR	New York Code of Rules and Regulations
NYS	New York State
NYSDEC	New York State Department of Environmental Conservation
NYSERDA	New York State Energy Research and Development Authority
NYSDOH	New York State Department of Health
OBM	Oil-Based Mud
OSHA	Occupational Safety and Health Administration
OSPAR	Oslo-Paris Convention

P&A	Plug & Abandonment
PA	Pennsylvania
PADEP	Pennsylvania Department of Environmental Protection
PLONOR	Pose Little Or No Risk
$PM_{2.5}$	Particulate Matter, 2.5 microns or smaller in diameter
POTW	Publically Owned Treatment Works
ppm	parts per million
psi	pounds per square inch
QC/QA	Quality Control/Quality Assurance
Ra	Radium
RDSGEIS	Revised Draft Supplemental Generic Environmental Impact Statement
REC	Reduced Emission Completions
RP	Recommended Practice
RCRA	Resource Conservation and Recovery Act
SBM	Synthetic-Based Muds
SCR	Selective Catalytic Reduction
SDWA	Safe Drinking Water Act
SEQRA	State Environmental Quality Review Act
SPDES	State Pollutant Discharge Elimination System
SO_2	Sulfur Dioxide
SPCC	Spill Prevention Control and Countermeasures
SPOTS	Spill Prevention Operations Technology Series
SRB	Sulfate-reducing bacteria
STEL	Short-term exposure limit
STI	Steel Tank Institute
SWPPP	Storm Water Pollution Prevention Plan
TDS	Total Dissolved Solids
TEG	Triethylene Glycol
TENORM	Technologically Enhanced Naturally Occurring Radioactive Material
TVD	True Vertical Depth
USDW	Underground Sources of Drinking Water
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	Volatile Organic Compound
WBM	Water-based muds
WOC	Wait on Concrete

Attachment 2

Tom Myers, Ph. D.

Technical Memorandum

Review and Analysis

Revised Draft

Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program

Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

September 2011

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Contents

INTRODUCTION

This technical memorandum reviews aspects of the *Revised Draft Supplemental Generic Environmental Impact Statement* (RDSGEIS) on the *Oil, Gas and Solution Mining Regulatory Program regarding Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoir*. The New York State Department of Environmental Conservation (NYSDEC) is the lead agency. Throughout this review, I refer to the document as the RDSGEIS. The document was "revised" since its initial publication in 2009. I had prepared a review of the 2009 DSGEIS as Myers (2009).

Appendix A to this technical memorandum is my specific review of Appendix 11 in the RDSGEIS, which has been excerpted from the 2009 DSGEIS without change. Appendix B to this technical memorandum is a paper I wrote which is currently undergoing peer review for a journal; this paper concerns vertical transport of contaminants from the shale to freshwater groundwater.

Since the 2009 DSGEIS, the New York State Energy Research and Development Authority (NYSERDA) contracted with Alpha Geoscience (Alpha) to review the comments I prepared on the 2009 DSGEIS (Myers, 2009). Alpha produced a report titled: *Review of dSGEIS and Identification of Best Technology and Best Practices Recommendations, Tom Myers: December 28, 2009*, prepared by Alpha. The RDSGEIS does not reference, or apparently rely, on this Alpha review in any meaningful way; the bibliography includes a list of 2011 reports by Alpha, but the apparent reference to this review (Alpha 2011) does not include my name. The consultants bibliography includes a subheading with Alpha's report, with "Myers" misspelled, but no apparent use of this reference either. Alpha's reviews prepared for NYSERDA were not available directly on the RDSGEIS web page other than through an obscure link. Appendix C to this technical memorandum is my response to Alpha (2011).

This technical memorandum also reviews the water resources/hydrogeology aspects of the revised regulations, published as *Proposed Express Terms 6 NYCRR Parts 550 through 556 and 560, Subchapter B: Mineral Resources*, referred to throughout as the proposed regulations. This technical memorandum proposes additional regulations throughout the review, and then includes a separate section regarding specific proposed regulations.

The report focuses on three main aspects of the RDSGEIS: (1) hydrogeology, including the hydraulic fracturing (fracking) process, (2) low flow surface water resources, and (3) water-resource-related setbacks. Hydrogeology includes review of the geology, contaminant transport, shale hydrogeology, groundwater quality, and induced seismicity analyses. Low flow surface water resources include an assessment of the analysis required to determine passby flows and the requirements/restrictions on pumping from aquifers. Consideration of the proposed setbacks includes whether the proposed setback is based on facts or analysis. Specific setbacks considered include those proposed to protect aquifers, wells, springs, and other water-related resources.

The RDSGEIS provides data and analysis almost exclusive to the Marcellus shale, although the regulations purport to govern all low-permeability formations, including the Utica shale (which is mentioned in the RDSGEIS). Developing different low-permeability formations would have different effects than would development of the Marcellus shale, which is the focus of the RDSGEIS. Deeper shale, such as the Utica shale, would generate far more cuttings and use more drilling mud, which present different disposal issues. The amount of water used for fracking could be different, as well. Development of shallower shales would increase the regional hydrogeology impacts and increase the potential vertical contaminant transport and the prevalence of improperly plugged abandoned wells. Additionally, the RDSGEIS focused its analysis from the total amount of surface water withdrawals to wastewater disposal on the wells expected in the Marcellus shale. Additional shale development would vastly increase the impacts beyond those revealed in this RDSGEIS

- *The RDSGEIS and proposed regulations should acknowledge that they apply only to the Marcellus shale.*
- *Additional low-permeability gas plays require additional supplemental GEIS analyses as suggested in RDSGEIS 3.2.1*.

The focus on this review is on development of the Marcellus shale, because except for Chapter 4, the RDSGEIS discussion is limited to the Marcellus shale.

SUMMARY OF FINDINGS

The RDSGEIS only poorly describes the hydrogeology of the Marcellus shale area and of the shale in particular. It does not provide a description of what fracking does to the shale or how it affects the regional hydrogeology. There is no description provided of the geologic formations between the shale and the surface beyond the general stratigraphy and stating that it would be nonconductive to upward flow, a point not supported with data or by the literature. The fault mapping is outdated.

Industry should be required to complete geophysical logging, including conductivity, to determine the lower extent of freshwater (Williams 2010). The definition of freshwater should be as protective as federal standards, meaning that surface casing should extend to TDS at 10,000 ppm.

The description of fracking is incomplete and incorrect from a hydrogeologic perspective. The contention that out of formation fracking is rare is incorrect based on industry data which has documented fractures as much as 2000 feet above the top of the shale in other states. Also, the contention that fracking pressure dissipates immediately upon cessation of injection is also incorrect, except right at the well. Model simulations show that pressure in the shale remains elevated for more than three months and that that prevents some of the injected fluid from flowing back to the gas well. The injected fluid displaces substantial amounts of formation fluid from the shale into surrounding formations; existing and new fractures allows that fluid to move much further from the shale than expected due simply to the volume injected.

The RDSGEIS dismisses the concept of contaminant transport from the shale to the near-surface aquifers, but there is overwhelming evidence that it is at least possible. Fracking fluids and methane have been found in water wells from fracking in different areas. Simulations indicate it could occur much more in the future. Fracking displaces large quantities of brine, and fractures provide pathways to the surface; fracking may also widen those existing pathways. Areas of natural artesian pressure would allow advection to move fluids and contaminants vertically upward. Mapping areas of artesian pressure, improved regional fault mapping, and site-specific project by project fault mapping should be employed to avoid areas of enhanced vertical transport potential. Long-term multilevel monitoring is also needed to track the future potential of vertical contaminant movement.

NYSDEC proposes setbacks that are not obviously based on observed data. If the setback from fracking in a protected watershed is 4000 feet, the setback from primary or principal aquifers or from public water supply wells should be no less, unless justified by site-specific analyses. Wells located in a 100-year floodplain have a greater than 1 in 4 chance of being flooded in a 30-year project life, therefore wells should be setback further from streams.

The proposed monitoring plans are paltry and insufficient. Simply monitoring existing water wells only shows when that user is affected, it does not protect the aquifer. Water wells are not designed for monitoring. The industry should establish a dedicated groundwater monitoring system downgradient from every well pad, out to at least the distance that a contaminant would travel in five years. Monitoring should continue for at least five years after the cessation of production.

The required passby flows have improved since 2009, as has the method for determining them. In general requiring the Q60 and Q75 monthly flow avoids diversions at all when flows are in the bottom 40 or 25 percent of their normal monthly flow regime, depending on area and month. Q75 only applies to larger streams (> 50 square mile watershed) during the winter months when flow is generally higher. The RDSGEIS should provide some data to show the estimation methods for ungaged sites is accurate.

HYDROGEOLOGY

This section considers all aspects of the RDSGEIS that concern underground resources, including aspects of geology, shale hydrogeology, contaminant transport, the descriptions of fracking and the potential for fracking-induced seismicity. The toxicity of fracking fluid additives was considered was considered by Dr. Glenn Miller.

General Hydrogeology

The distinction between primary and principal aquifers and other sources (RDSGEIS, p. 2-20) ignores the connections between surface and groundwater. Groundwater from principal aquifers may seep into streams, especially during periods of low flow. Because those aquifers are also used by New Yorkers for water supply, the assertion in the RDSGEIS that "one quarter of New Yorkers … rely on groundwater as a source of potable water" (Id.) understates the number of people who may be affected by groundwater contamination

RDSGEIS Figure 2.1 shows that the north end of the shale parallels a large principal aquifer north of Syracuse. This coincidence deserves explanation at some point in the document.

The RDSGEIS mentions that one quarter of New Yorkers rely on groundwater as a source of potable water (RDSGEIS, p. 2-20). This downplays the connection of groundwater with surface water; many aquifers support stream flow, especially during low flow period, therefore aquifer contamination potentially affects many more people.

Safe yield (RDSGEIS, p. 2-29) is an outdated and flawed concept which should not be repeated in the RDSGEIS. It is flawed because all pumping depletes the aquifer, which contradicts the definition of the phrase (Id.). The preferable concept is sustainable yield which is the amount of water that can be pumped without having significant negative effects on the aquifer and on resources connected to that aquifer; what is significant is a societal question related to the values that depend on the aquifer (Alley et al, 1999).

Presence of Fresh and Salt Water

The federal Safe Drinking Water Act (SDWA) defines an underground source of drinking water (USDW) as "[a]n aquifer or portion of an aquifer that supplies any public water system or that contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/l total dissolved solids and is not an exempted aquifer" (http://water.epa.gov/type/groundwater/uic/glossary.cfm). However, NYSDEC apparently ignores this federal requirement where it specifies that surface casings be extended to 75 feet below the transition from fresh- to saltwater but also specifies 850 feet below ground surface (bgs) as a "practical generalization for the depth to potable water", the point at which near-surface freshwater transitions to saline water, which corresponds to 1000 ppm total dissolved solids (TDS) and 250 mg/l chlorides (RDSGEIS, p. 2-23, 6NYCRR §550(at)). The NYSDEC regulations, by only protecting water to a 1000 ppm cutoff for TDS may not provide protections that for some waters that could apparently meet the definition under the SDWA.

The hydrogeology of southern New York over the Marcellus gas play does suggest that there may be very little water with a TDS higher than the threshold that could actually be developed. Williams (2010) found that freshwater transitions to salt water at about 200 feet bgs in valley areas and about 800 ft bgs in upland areas in three counties in the middle of the Marcellus shale gas play. There was uncertainty around the depth estimates with some freshwater observations at deeper depths. Also the distinction between fresh- and saltwater in his survey of both water and gas wells was based on taste tests rather than any scientific measurement. Williams et al (1998) found similar results in similar geology just across the border in Pennsylvania. Many electric conductivity logs for bedrock water wells in the north Catskill Mountains (Heisig and Knutson 1997) showed that EC would jump from low values representing freshwater to high values representing salt water in a short transition zone or threshold. This suggests that many of the bedrock areas over the Marcellus shale gas play have either high-quality, low-TDS water, or very poor-quality high-TDS water; few wells apparently have water quality near the actual cut-off value. Considering the geology of the area, the zones that have high TDS are also mostly very low hydraulic conductivity zones, so they would not be considered an aquifer because they would not produce sufficient water to support a water supply.

However, the presence of salt water welling up under the alluvial aquifers, which often coincides with fault zones, suggests that salt water does move upward in fractured areas. Water with TDS up to 10,000 ppm may be developable in these higher conductivity fracture zones. In these areas, the NYSDEC regulations may be violating the SDWA requirements to protect USDWs, although the regulations regarding development in primary and principal aquifer may limit drilling in the areas underlain by fractured rock which could have developable high TDS water. Regardless of those aquifer regulations, the threshold for protection should include all areas that qualify as underground sources of water as defined under the Safe Drinking Water Act. These would include waters with TDS up to 10,000 ppm where they exist in an aquifer, and to 1000 ppm or

250 mg/l Cl- in areas underlain by unconductive bedrock. See the separate technical review submitted by Harvey Consulting LLC, for further discussion of the requirements on the SDWA.

- The operator should extend the surface casing to below the 10,000 ppm TDS threshold, unless the operator can show that the formation containing groundwater between 1000 and 10,000 ppm could not produce water in usable quantities. In this case, the operator should extend the surface casing to below the 1000 ppm TDS threshold.

The RDSGEIS does not indicate that the regulations will require the driller to actually locate the transition depth, which would define the depth below which the surface casing would extend a minimum of 75 feet (RDSGEIS, p. 7-50).

- *The regulations should require the operator to complete geophysical logging, including specific conductance logging, prior to casing the well, to determine the actual depth of protected water to which to apply the casing regulations.*

Hydrogeology of the Shale

RDSGEIS Section 4.0 covers Geology, but leaves out most of the important aspects of the Marcellus shale. There is no discussion of hydrogeology of the formations between the targeted shales and the surface, including no discussion of the hydrogeology of the shale itself beyond mention of the permeability. This failure means there is no baseline against which to compare the hydrogeologic changes caused by fracking. There is no hydrogeologic description of the sedimentary layers between the shale and the surface other than very cursory mentions of how it has low permeability. The lack of data on the hydrogeology of formations between the target shale and ground surface is important because NYSDEC relies on geology to “limit or avoid the potential for groundwater contamination” (RDSGEIS, p. 6-2).

Formations that lie between the shale and the surface are generally considered a natural control on fracture propagation and contaminant transport vertically from the shale (RDSGEIS, p. 6-54). RDSGEIS Figure 4-2 does not support the statement that overlying formations will prevent vertical movement of contaminants (RDSGEIS, p. 6-54) because it shows that layers above the Marcellus are primarily sand, limestone, and shale, with no indication of the proportion of each, which controls their conductivity and their propensity to propagate fractures. Most important from the perspective of contaminant transport from the shale to the surface is the prevalence of fractures, both due to faults and otherwise. Faults could be a pathway for vertical contaminant transport (Osborn et al 2011; Myers in review) and could also allow fractures to propagate further from the shale. The RDSGEIS discusses faults only with regard to present day seismicity and the potential for induced seismicity and presents an outdated map (Isachsen and McKendree 1977). A more detailed an integrated analysis of faults and fractures revealed there are many more faults in New York’s Appalachian Basin than previously suspected (Jacobi 2002). The RDSGEIS should include up-to-date information and acknowledge that more faults are probably yet to be found.

There is little information provided in the geology or hydrogeology sections about the make-up of the shale, beyond the amount of organic carbon. The geology chapter does not even mention the presence of pyrite in the Marcellus shale, although there is a brief reference to it for the Utica shale. The sections on “Solids Disposal” mentions pyrite and acid rock drainage of cuttings derived from the Marcellus shale. “As the basal portion of the Marcellus has been reported to contain abundant pyrite (an iron sulfide mineral), there exists the potential that cuttings derived from this interval and placed in reserve pit may oxidize and leach, resulting in an acidic discharge to groundwater, commonly referred to as acid rock drainage (ARD)” (RDSGEIS, p 7-67). ARD will be discussed more below in the Regulations section.

Most industry references state the Marcellus shale is “low-permeability” (RDSGEIS, p. 2), and the proposed regulations apparently rely on this categorization, although not all sources agree with it. Soeder (1988) described Marcellus shale as “surprisingly permeable” and presented data showing the permeability ranges up to 60 microdarcies, as compared to the Huron shale with permeability two orders of magnitude lower. Most reported permeability values are estimated from core samples, but, in a hydrogeologic sense, these estimates do not represent the formation-wide conductivity; point estimates due to scaling effects can be several orders of magnitude less conductive than the formation as a whole due to preferential flow through fractures (Schulze-Makuch et al, 1999), which are prevalent in this area. RDSGEIS Figure 4-2 also does not show the fractures in the overlying formations which prevail throughout New York including in the Marcellus shale zone (Myers in review).

The assertion that the shale requires fracturing “to produce fluids” (Id.) does not prove that the shale above the Marcellus is equally poorly transmissive. Shales above the Marcellus have not apparently trapped gas or fluids for significant time periods, a fact which undercuts the claim they are not transmissive or there is a lack of vertical flow. Fractures that go out-of-formation above the shale connect the shale with the much more transmissive formations above the shale.

The Geology section should also discuss general groundwater flow paths in the formations above the shale; this should include vertical gradients and recharge zones.

- *The RDSGEIS should discuss the hydrogeology of the formations between the targeted shale and ground surface, including data on the hydraulic conductivity of the formations.*

- *The RDSGEIS should also map the groundwater gradients for the formations just above the targeted shale using water level data obtained from geothermal applications and previous deep wells.*
- *The NYSDEC should require the industry to do a seismic survey to locate faults near proposed drilling, within half a mile of the center of the well pad or 1000 feet beyond the projected end of the horizontal wells, whichever is further from the well pad.*
- *The RDSGEIS should include up-to-date fault mapping.*
- *Industry should be required to complete and provide to the NYSDEC geophysical logging of the formations above the targeted shale showing fractures, lithology, and groundwater characteristics.*

Description of Hydraulic Fracturing

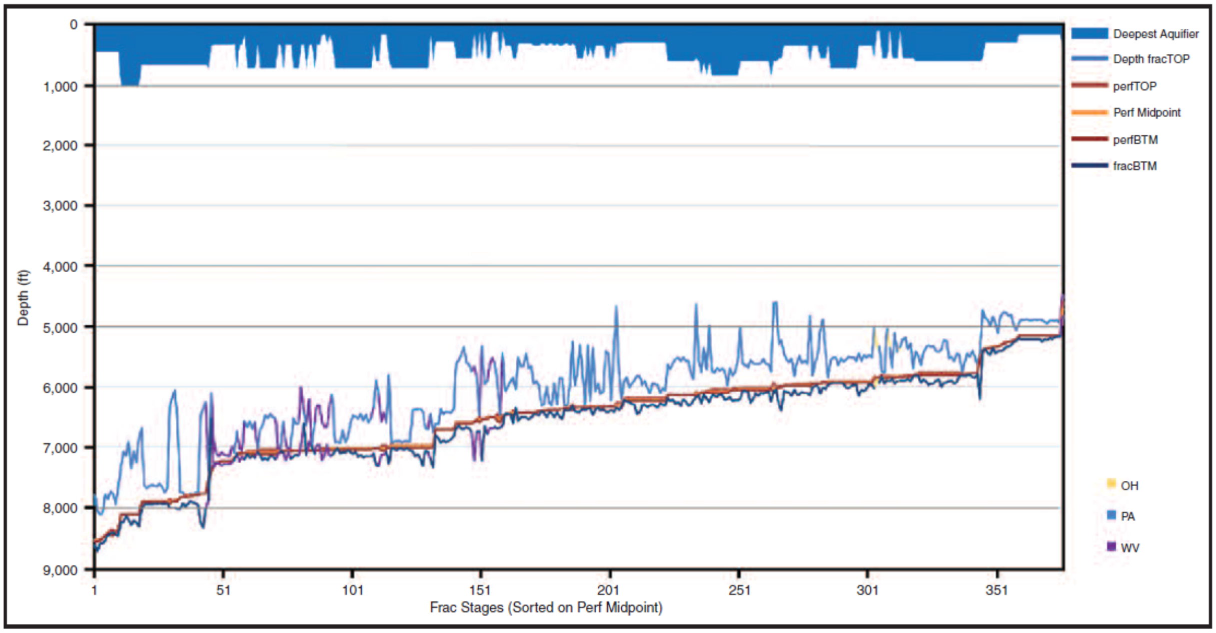
RDSGEIS Chapter 5 describes the fracking process, but it does not describe what actually happens to the shale – what does it look like after fracking and what are its properties. It is much more permeable to gas flow, perhaps substantially so, therefore it must also be much more transmissive to water flow. With up to an expected 40,000 horizontal wells over the next 30 years in New York (RDSGEIS, p. 6-6), the properties of the shale, which currently is an aquitard, will change substantially. The RDSGEIS completely fails to address these changes.

Industry designs fracking jobs to keep the fractures in the shale, but data show that the results of the fracking do not always or even often verify the design. The industry rarely monitors or measures the actual extent of fractures (RDSGEIS, p. 5-88), beyond monitoring pressure and injected fluid during fracking. The RDSGEIS references Fisher (2010) as being proof that fractures do not extend into the aquifer zone, but his data actually show that fractures commonly go out of formation (Figure 1). His data show many instances of the top of the fracture zone being more than 1000 feet above the centerline of the shale. As the depth to the centerline of the shale decreases from 8000 to 5000 feet, the vertical fracture growth also appears to decrease from 2000 feet above to 500 feet above the centerline of the shale. The apparent trend to fracture growth above the formation decreasing with decreasing depth may relate to the pressure on the rock or its hardness. The data were not sorted according to formation type and there is no data concerning shale thickness, therefore it is unknown whether fractures extend further in some types of rock or whether out-of-formation fractures are more common with thinner shales.

- *The RDSGEIS should not rely on industry's alleged intent to avoid out-of-formation fracking as a means of preventing the consequences of out-of-formation fracking.*

- *The RDSGEIS and regulations should require geophysical logging and microseismic tests to map how far fractures extend out of formation, and the density of the fractures in different formation. This information should be publically available so that all companies can benefit from experience and so that the public can better understand the process.*

FIGURE 2



Marcellus Shale Mapped Fracture Treatments (TVD)

Figure 1: Figure 2 from Fisher (2010) showing the well centerline and a depth to the top of the fracture zone.

It is common practice to compare pressure and flow rate monitoring results from fracking operations to expected values from pre-fracking modeling as a method for evaluating the results of a fracking procedure (RDSGEIS, p. 5-88). Considering that many things affect the pumping flow rate, including pores between the well and the leading extent of the fluid moving away from the well, hydraulically it is difficult to imagine that a significant pressure drop would accompany the leading edge of the fluid reaching surrounding formations. Fracturing into surrounding formations would not bring additional water into the shale, as suggested (Id.), because of the pressures as described elsewhere (Myers in review). The increased porosity in the shale would release substantial brine bound in the shale.

Fracking injects up to 7.2 million gallons of frack fluid into the shale over a well bore up to 4000 ft long – the RDSGEIS suggests these are general upper limits based on fracking in the Marcellus shale in other states. Fractures form or widen as the injection pressure exceeds the normal stress in the shale (RDSGEIS, p. 5-95). The injection would slowly displace any water and gas that exists in the (extremely small) pore spaces near the well; it would push the natural fluid away from the well bore. Because less than 35% of the injected fluid returns to the well as flowback, a significant proportion of the injected fluid remains underground, presumably occupying pores extending out from the well bore. Assuming a job injects 5 million gallons and there is 20% flowback, approximate average values, and 10% effective porosity resulting from the fracking, the fluid could occupy all pore spaces in a 21-ft diameter cylinder centered on the well. Assuming a more realistic resulting effective porosity of 1%, the fluid could fully occupy the pores out to 62 feet in all directions from the well. Fluids that existed there prior to fracking would be pushed further from the wellbore, likely into surrounding formations. Thus, simple consideration of the volume of fracking fluid injected shows that fluid would move far from the well bore and displace formation fluids even further The calculation does not account for pre-existing preferential flow paths or heterogeneities in the direction that fractures develop, so the fluid would likely move further from the well bore in some directions. The fluid would also follow pathways created by the fractures above the shale, thus fluids could end up much further from the well bore than simple considerations would indicate. .

Shale NG development will affect a large proportion of the shale in New York with fracking fluid, as can be shown by comparing expected fracking fluid volumes with shale volume. The RDSGEIS does not indicate the total area of Marcellus shale within New York. However, Figure 2 in Myers (in review) shows the extent of shale within New York to be 18,680 sq miles. Assuming an average thickness of 100 ft, the total volume is $5.2x10^{13}$ ft^3. If the expected 40,000 wells are all developed in the Marcellus shale, the injected water volume will approximate $2.1x10^{10}$ ft^3, which at porosity of 0.01 means that fracking fluid would occupy all of the pores in about 4% of the total Marcellus shale volume[1]. This assumes that none of the fluid reaches surrounding formations, which as shown above is unlikely. It is also unlikely that development will be evenly spaced over the shale as supposed in this calculation, therefore the effect in areas of concentrated development could be underestimated.

Fracking efficiency does not improve if the well spacing is significantly less than 300 m, or about 1000 ft (Krissane and Weisset 2011). It is therefore appropriate to assume that fracking changes the shale over the entire spacing unit, or an area of 660 by 4000 ft. The total area affected by 40,000 wells would be about 3800 square miles, which is about 20% of the total shale area in New York. Based on the extent that injected fluid reaches from the well and the frequency of out-of-formation fracturing (Fisher 2010), it is reasonable to conclude that most fracking affects the shale to its edge. Fracking, based on these assumptions, will significantly change the hydrogeology over at least 20 % of a shale aquitard that extends over 18,680 square miles of New York. Because not all of the total area will be developed, it is a good assumption

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[1] This calculation assumes 5,000,000 gallons injected per well and 20% flowback for each of 40,000 wells.

that where development actually occurs, fracking will substantially change the shale hydrogeology.

The statement, that "the volume of fluid used to fracture a well could only fill a small percentage of the void space between the shale and the aquifer" (RDSGEIS, p. 6-53), is also misleading. The total proportion of pores actually filled by injected fluid may be relatively small, but combined with displaced existing brines the injection will affect groundwater over a much larger proportion of the pores. The boundary between salt and freshwater may be displaced or disrupted by advection and dispersion of and by fluids associated with fracking. Additionally the changed properties of the shale over a large area will affect the upward movement of the natural brines. Simple consideration of advection and dispersion shows that the current balance between fresh and salt water could be substantially upset by fracking.

The RDSGEIS also erroneously claims that the pressure applied for injection will dissipate immediately upon cessation of pumping; in the well bore that may be correct, but the fact that pressure exists to push fluid back into the well bore proves that residual pressure remains in the shale and possibly beyond. The statement that "the amount of time that fluids are pumped under pressure into the target formation is orders of magnitude less than the time that would be required for fluids to travel through 1,000 feet of low-permeability rock" (RDSGEIS, p. 5-94, p. 6-53) is technically correct but highly misleading because pressures and conditions for transport from the shale to the near surface will exist long after fracking has finished. Fluids can move away from the well bore at distances from the well bore after the injection ends until the pressure has dissipated; the contrary statement (RDSGEIS, p. 5-94) is wrong in that respect. Myers (in review) describes the modeling of injection and its effect on the pressure distribution in detail. The following is a simpler and more accurate description that should be what appears in the RDSGEIS:

> Hydraulic fracturing involves high pressure injection of fracking fluid into the shale from a horizontal well. This injection fractures the shale and increases the size and connectivity of existing pores. The high pressure creates a pressure gradient from the well to a point in the shale just beyond the expanding volume of injecting fluid where the pressure remains equal to background. If the fluid disperses from the well evenly, the volume will be a cylinder. As injection continues, the radius of the cylinder increases and pressure gradient is from the well to the edge of the cylinder. Offsetting the decreased pressure gradient is an increased effective cross-sectional area for the fluid to cross. The flow away from the well fractures the shale, creating new fractures and increasing the size of the existing fractures. When injection ceases the pressure in the well drops immediately to atmospheric pressure coincident with the well-bottom depth. However, the pressure in the shale begins to drop more slowly, initially equals that caused by injection. Flow away from the well continues as the pressure in the reservoir

created by the HVHF treatment moves fluids towards the well and away from the well both but since there is no more pressure being applied at the well the pressure in the shale near the well begins to drop.

Descriptions in the RDSGEIS (p 5-94) are therefore wrong. Fracking is a transient situation wherein a pressure divide, where the pressure is higher between the well and the end of the fluid, sets up with some fluid movement toward the well and some away from the bore continues. The modeling (Myers in review) shows that this requires about 90 days to effectively dissipate. This counters several statements in the RDSGEIS implying that all fracturing and flow from the well bore ceases at the end of fracking, in about five days.

The claim that the flow direction away from the wellbore would be reversed during flowback (RDSGEIS, p. 6-54) also cannot be correct if only 10 to 30% of the injected fluid actually returns to the well. Some must continue to flow away from, or at least not toward, the well.

NYSDEC makes an unreasonable assumption regarding the flow around the shale after fracking, regarding a discussion of the period between fracking operations if refracking would occur. "It is important to note, however, that between fracturing operations, while the well is producing, flow direction is towards the fracture zone and the wellbore" (RDSGEIS, p. 5-99). Because the goal is to attract gas from the shale, any such low pressure would likely affect just the fracked shale, not formations away from the shale in which fluids would flow according to the background hydraulic gradient. That a small amount of formation water may be produced with time indicates that water from only a small portion of the shale near the well flows toward the well. If the natural gradient in formations above the shale has a vertical component, there will be upward advection of water and contaminants away from the shale.

- *Measurements of the water pressure profile should be made in each well prior to fracking, as it is drilled and before it is cased. This could be a part of the geophysical logging process*.

NYSDEC assumes that it will be rare for a well to be refracked, that is, to repeat the fracking operation years after initially completing it, inappropriately relying on "Marcellus operators'" assurances without reference to a source (RDSGEIS, p. 5-98).

Contaminant Transport from the Shale

The RDSGEIS completely dismisses the concept of vertical contaminant migration from the shale to fresh-water aquifers. Statements suggesting that the only way for the public to be exposed to fracking fluid would be through an accident or spill (RDSGEIS, 5-74) reflect the dismissal of the potential long-term transport from the shale. This section reviews the evidence and potential for contaminant transport from the shale.

Claiming that regulatory officials from 15 states have "testified that groundwater contamination as a result of the hydraulic fracturing process … has not occurred" (RDSGEIS, p. 6-41 & 6-52) is misleading because they have simply never looked for contamination beyond reports from water well owners. There are no monitoring well networks designed to monitor contaminant transport upward from the fracked shale. The upward transport could also take years, decades, or centuries, not just the few days considered in the RDSGEIS. They are wrong to suggest there is no evidence for such transport.

Two reports have documented or suggested the movement of fracking fluid from the target formation to water wells (EPA 1987; Thyne 2008) linked to fracking in wells. Thyne (2008) had found bromide in wells 100s of feet above the fracked zone. The EPA (1987) documented fracking fluid moving into a 416-foot deep water well in West Virginia; the gas well was less than 1000 feet horizontally from the water well, but the report does not indicate the gas-bearing formation. There is also recent evidence of fracking fluid reaching several domestic drinking water wells near Pavillon, WY from a deep source in a sedimentary sandstone and shale formation Diquilio et al 2011). Deep monitoring wells (depth not specified) have detected synthetic organic compounds including glycols, alcohols, and 2-butoxyethanol, BTEX (including benzene at 50 times the MCL), phenols, trimethylbenzenes, and DRO. Dissolved methane was found at near-saturation levels with an isotopic signature similar to production gas. The EPA identified three pathways for fluid movement. One was nearby wellbores. The second was fluid movement from low permeability sandstone into more conductive sandstone nearby. Third was out-of-formation fractures forcing fracking fluid into overlying formations. NYSDEC should consider this example as a cautionary tale of the potential for vertical movement of fracking fluid to near-surface aquifers.

Methane contamination has been observed to occur in many areas near fracking operations. The RDSGEIS acknowledges that gas migration occurs (RDSGEIS, p. 6-42), but suggests it is limited to well construction problems. This assumption ignores the studies which link the source to much deeper formations (Osborn et al 2011, Thyne 2008). Myers (in review) and Osborn et al (2011) indicate that gas transport could indicate pathways which could also be longer-term fluid pathways; if there is a pathway for gas, there is also a pathway for water.

The RDSGEIS dismisses diffusion of chemicals from the shale to the surface because this would dilute their concentrations; this is correct, but diffusion is only a minor process in the movement of chemicals to the surface and is the wrong process to analyze for consideration of whether vertical transport could occur. Contaminants move by advection, dispersion, and diffusion, with the later being a minor component. Advection would be the most likely transport process (Myers in review). Upward movement of chemicals could occur by advection wherever there is an upward vertical component to the hydraulic gradient; fractures and faults would enhance that flow. Myers (in review) simulated transport through the bulk media as requiring from 100s to 1000s of years, depending on hydraulic properties and gradient; fractures substantially decreased that simulated time.

The RDSGEIS relies on an analysis by ICF (2009), included in the RDSGEIS as Appendix 11, for its dismissal of potential vertical contaminant transport. Dismissing the potential for such transport based on the gradient occurring just for the time of fracking simply illustrates a lack of understanding of the process and associated groundwater and contaminant flow. ICF (2009) had been part of the 2009 version of the DSGEIS. Appendix A of this technical memorandum reviews ICF (2009) again in detail and Appendix B presents a copy of a journal article (Myers in review), which analyzes in detail the potential for transport from the shale to the surface.

The RDSGEIS should reconsider some of its assumptions and implement several regulatory changes, as specified here:

- *ICF (2009) should be removed in its entirety and substituted with an analysis that at least acknowledges the potential risk for long-term contaminant transport from the shale to the surface. All citations to and conclusions based on ICF (2009) should also be removed from the RDSGEIS.*
- *The RDSGEIS should include the foregoing recommendations concerning hydrogeology, and regulations should be promulgated specifically requiring the delineation of properties of the geologic formations above the shale, the locations of fractures, and mapping of the hydraulic gradients near the proposed drillsites.*
- *The RDSGEIS and regulations should require driller to implement a long-term monitoring plan with wells established to monitor for long-term upward contaminant transport, as described below in the section concerning groundwater monitoring.*

Other Pathways for Groundwater Contamination

Section 2.4.5 incorrectly claims that "[i]mproperly constructed water wells can allow for easy transport of contaminants to the well…" (RDSGEIS, p. 2-22). Transport "to the well" depends on flowpaths and gradients near the well which would only marginally be affected by well construction. Improper water well construction does allow transport of contaminants along the casing which could allow contaminants to move among aquifers, once the contaminants reach the well. Improperly constructed wells can allow contaminants from aquifer layers which were not intended to be screened to transport to the producing layers.

Flowback and produced water are important potential contaminants, primarily in the potential for blowouts or spills just after fracking and in the potential for leaks from the well bore. Estimates are that from 9 to 35% of the injected fracking fluid, expected to vary from 2.4 to 7.8 million gallons per well, would return as flowback (RDSGEIS, p. 5-99). This is a total flowback of 216,000 to 2.7 million gallons per well (Id.). Estimates also indicate that up 60 percent of the flowback would return within the first four days after fracking ceases (RDSGEIS, p. 5-100). The upper estimate based on these ranges is that 60 percent of 2.7 million gallons, or 1.62 million gallons of flowback will occur within four days of the cessation of fracking. Modeling in Myers (in review) confirms both the relative proportion of injected fluid that becomes flowback and the rapid rate.

Flowback is a mixture of returning fracking fluid and formation fluid, but the limited chemistry data presented in the RDSGEIS suffers from being a single sample per well (RDSGEIS, p. 5-105). The RDSGEIS states that some of the data was provided by the Marcellus Shale Coalition, an industry group, but without reference or actually providing the data; it is not possible for the reader to assess or draw independent conclusions that might differ from the statements in the RDSGEIS. The available data does not apparently allow an assessment of the proportion of shale to injected water. For example, samples with very high salt content probably consist more of shale brine than fracking fluid. RDSGEIS Table 5.10 demonstrates, by its illustration of poor water quality, that the water must be contained. The minimum, median, and maximum for TDS, at 1530, 63,800, and 337,000 mg/l, respectively, suggests the proportions vary widely but that more than half of them are saltier than ocean water. The range in chemicals such as benzene, at 15.7, 479.5, and 1950 ug/l, shows that some flowback could be extremely toxic; the NY MCL for benzene is 5 ug/l, thus most of the samples above detect exceed the standard for this contaminant. Because of the toxic chemistry of flowback water, much more data is necessary, as specified here:

- *The RDSGEIS should present temporal flowback data from specific wells, in tabular or graphical form.*
- *The RDSGEIS should present an appendix with raw data provided by the Marcellus Shale Coalition or link to the data on the internet*.
- *Table 5.10 could be made more understandable by including the detect and MCL levels.*

The RDSGEIS promises that flowback would be contained in “water-tight tanks” for onsite handling (Id.), but the document does not discuss the sizing of the tanks. The proposed regulations address flowback and requirements for capturing it at many points (6 NYCRR §560), but also fails to specify a size. For example, the operator must include " the number and total capacity of receiving tanks for flowback water" (6 NYCRR § 560.3(a)(12)), and must have secondary containment, "as deemed appropriate by the department"…"sufficient to contain 110 percent of the total capacity of the single largest container or tank within a common containment area" (6 NYCRR § 560.6(x)(26)(i)). Because there are no specifications for the size of the "single largest container", the required secondary containment sizing is not useful.

- *The RDSGEIS and proposed regulations must specify the necessary total capacity for tanks to contain flowback. The required capacity must reasonably exceed the expected flowback as discussed above. It must be able to capture within four days, 60 percent of the 35 percent of the maximum amount of fluid to be injected for fracking.*

RDSGEIS Chapter 5 lists many chemicals that could be used in fracking fluid, but does not list any properties of these chemicals which could affect their flow through soils or through groundwater. The RDSGEIS does not provide data regarding whether and how much they will be attenuated. However, the RDSGEIS inappropriately relies on attenuation (p. 6-53) to mitigate against the potential for long-distance transport.

- *The RDSGEIS should either provide data concerning the transport properties of the various chemicals or not rely on attenuation as a means of mitigating the transport which could results from spills and leaks.*

Groundwater Quality Monitoring

The previous sections of this report have highlighted the poor water quality of fluids associated with fracking operations – the fracking fluid itself and the produced shale-bed water – and the various pathways for aquifers to be contaminated. Small quantities of either of these fluids can significantly pollute groundwater and surface water. The RDSGEIS provides some setbacks in an attempt to protect various receptors – wells, aquifers, or streams – and the adequacy of these is discussed below. With the potential for spills and leaks from multiple sources associated with these operations, the requirements for groundwater quality monitoring in the RDSGEIS and the regulations is paltry and insufficient, as described here.

The proposed monitoring consists only of testing existing private water wells within 1000 ft of the drill site, or to 2000 ft if none are located within 1000 ft (RDSGEIS, p. 1-10, 7-44). While this is necessary for the protection of the well owner, it is insufficient for the long-term protection of the aquifer. Domestic wells have not been designed to function as water quality monitoring wells which causes many problems in sampling and interpreting the data. Thyne explains clearly why domestic wells are poor monitoring wells:

> First, the number of domestic well sample points is far exceeded by the potential point sources (gas wells). Domestic wells are much less than ideal for sampling purposes. Domestic wells are not placed to determine sources of contamination in groundwater. They are not evenly spaced around gas wells or within close enough proximity to determine the presence of chemicals associated with methane that degrade rapidly. Domestic wells are generally screened over large intervals making vertical spatial resolution for samples difficult nor are the wells are not constructed to facilitate measurement of water table elevation or downhole sampling. This forces sampling to occur at the surface after pumping raising the possibility of sampling artifacts. In addition, since domestic wells are the sole source of drinking water for individual properties, it is difficult to arrange access to take samples due to privacy issues, and the County may bear potential liability for damage during sampling and interruption of water supply. (Thyne 2008, p 10-11)

A monitoring well system should be designed so that a contaminant plume will neither pass horizontally between the monitoring wells nor above or below the screened interval. The best way to be certain of intercepting a contaminant passing a point in an aquifer is to span the entire aquifer with well screen. A long screen may increase the chances of detecting the presence of a potential contaminant which may indicate the site being monitored has developed a leak, but will dilute the concentration by mixing contaminated water with cleaner water. A sample extracted from such a well will be a conglomerate of the chemistry of the entire screen thickness; if the screen spans multiple lithologies, the water within the well bore will not be representative of any lithology (Shosky, 1987). It can only be effective only for substances which do NOT naturally exist in the region of the aquifer. Monitoring with long screens is good only for presence/absence determinations.

Concentrations vary throughout an aquifer, both vertically and horizontally. The concentration determined from any well will represent an average over the entire screen length. Therefore, to monitor trends in concentration, screens should span representative vertical sections

The spatial layout of the monitoring well system should be based on the conceptual flow and transport model for flow from the gas well through the aquifer, which includes flow pathways and possible contaminant dispersion. Monitoring wells should be placed as close to the expected flow path as possible, where the concentration will be highest. However, because of uncertainty in the prediction of the flow path, monitoring wells should also be spaced laterally away from the expected flow path. These lateral wells should detect lower concentrations than the one in the predicted flow path. If the lateral wells actually have higher concentration, the predicted flow path may be incorrect and monitoring wells should be added further from the predicted flow path to improve the understanding of the flow and movement of the contaminant plume.

Monitoring wells or piezometers should be placed close to the potential source for early detection, but also at a distance from the source to increase the chances that they will intercept the contaminant and to assess the rate of contaminant movement. If many wells detect the contaminant, the concentration variation would indicate the degree of dispersion. Denser well networks will have a better chance of detecting the contaminant and providing accurate description of it dispersal.

Considering the above fundamentals of a monitoring system, the following recommendations, in addition to sampling the existing private wells, should be added to the RDSGEIS and partly replace proposed regulations in 6 NYCCR §560.5(d)

- *The operator should prepare a conceptual flow path model for groundwater and contaminant transport from the drill pad to and through nearby aquifers.*
- *As part of the conceptual model, the operator should estimate the distance that a contaminant would travel from the well pad in various time periods, including one month, six months, one year, and five years.*
- *Dedicated groundwater monitoring wells should be reasonably located along and perpendicular to the projected flow path out to the five-year travel distance. At a minimum, there should be a transect of monitoring wells/piezometers at the one-month travel distance from the well and halfway between the well and important receptors, meaning wells or discharge points such as springs or streams.*
- *Monitor wells should span the surface aquifer and piezometers should have multiport sampling capabilities for twenty foot intervals at the top of the saturated zone and every 100 feet to the bottom of the freshwater zone. This will help establish vertical concentration and hydraulic gradients.*
- *The monitoring system should be established to establish baseline data including seasonal variability for at least one year prior to drilling and fracking.*

Monitoring transport from the deep shale is more difficult because a substantial flux of contaminants could be released from most anywhere in the fractured shale as a result of oil and gas development. Time intervals for transport could be more than 100 years, but fractures could decrease the time frame to as short a time as a few years. Fracture zones therefore could be monitored, but if they are known the industry should avoid fracking near them, both to avoid vertical transport and induced seismicity. It is therefore reasonable to require a dedicated monitoring well in the middle of each well pad wherever there is an upward flow gradient.

- *Industry should establish a multiport piezometer system from the shale to the bottom of the freshwater zone in the center of all well pads.*

- *The industry should provide the funding to maintain the piezometers system for at least 100 years beyond the end of gas production, to account for the long potential travel times.*

WATER RESOURCES

This section concerns primarily the controls on making water withdrawals for fracking. The section focuses on surface water diversions but also considers diversions from aquifers.

The RDSGEIS notes correctly that without proper controls, the withdrawals of water from streams and aquifers to use in fracking could have significant ecologic and hydrologic impacts (RDSGEIS, p. 6-2). The "natural flow paradigm" is a good description of the interdependencies of the stream ecology with all of the hydrologic regimes (RDSGEIS, p. 6-4). The description of the depletion to an aquifer and the interconnection of aquifers with surface water (RDSGEIS, p. 6-5) is also good. Treating the withdrawals as consumptively lost to the system (RDSGEIS, p. 6-9) is appropriate because in essence, with recycling of flowback, the water will not return to the system. These are acknowledgements which should lead to good regulation of withdrawals, if properly considered in the rulemaking.

The discussion and comparison of the withdrawals for fracking with statewide water uses (Withdrawals for High-Volume Hydraulic Fracturing, RDSGEIS, p 6-9 thru 6-13) are scientifically unsupported and irrelevant;. The potential impacts of withdrawals are a matter of scale and depend on their size, the size of the stream, and antecedent moisture conditions.

Much of the regulation of withdrawals from streams focuses on passby flows. The RDSGEIS defines a passby flow as "a prescribed quantity of flow that must be allowed to pass an intake when withdrawal is occurring" (RDSGEIS, p 2-30) which also specifies a low flow condition "during which no water can be withdrawn" (Id.). Specific definitions will be discussed below, but in reality the lower specified values can allow significant damage to occur to streams, especially smaller ones. If the required passby flow is small compared to the average, meaning it has a long return interval, it will only rarely restrict water withdrawals. If flows on the river can be reduced to a low passby flow, then diversions can reduce the flow to low, long return interval rates much more frequently; this is tantamount to imposing low-frequency, high-damaging, drought on the streams much more frequently.

The Delaware River Basin Commission (DRBC) does not have a specific passby flow requirement and usually uses the 7Q10 flow, the seven-day low flow with a ten-year return interval, for water resources evaluation (RDSGEIS, p. 7-13). The RDSGEIS indicates this is not protective (Id.) and as described in the previous paragraph, it would allow the 10-year low flow to manifest much more frequently. The Susquehanna River Basin Commission (SRBC) regulations are more complicated, but generally use the 7Q10 or from 15 to 25 percent of the average daily flow (RDSGEIS, p 7-15, 16). Neither is protective and the NYSDEC proposes to use the natural flow regime method (NFRM) method for all regions (RDSGEIS, p 7-16).

The RDSGEIS expresses the intent to use the NFRM only in permit conditions, however, as the document acknowledges that guidance has not yet been completed (RDSGEIS, p. 7-3). As authority, the RDSGEIS cites 6 NYCRR § 703.2, which states that "[n]o alteration that will impair the waters for their best usages" will be allowed. "For the purpose of this revised draft SGEIS only, the Department proposes to employ the NFRM via permit conditions as a protection measure pending completion of guidance." (Id.). NYSDEC also indicates that the requirement could be "imposed via permit condition and/or regulation" (RDSGEIS, p. 7-22).

- *NYSDEC must include the requirement for using the NFRM in the regulations if it is to be consistently enforceable; the proposed regulations do not currently require use of the NFRM to establish the requisite passby flow in a stream.*

The NFRM attempts to protect the distinctive flow patterns for each stream, including the "variable magnitude, duration, timing, and rate of change of flow rates and water levels" (RDSGEIS, p 7-18). The RDSGEIS proposes to use the "Q75 and/or Q60 monthly exceedence values for establishing passby flows" (Id.). An Qx exceedence value is the flow rate which is exceeded x percent of the time. Another way of considering the Q75 and Q60 exceedance values is that the passby flow would be greater than the flow which the stream exceeds 25 or 40 percent of the time. This is much higher than a 7Q10 flow. However, in a small stream, diversions could change a flow regime from wet (higher than average) to significantly below average.

NYSDEC appears to intend that if the watershed exceeds 50 square miles, the passby flow will be Q75 for the winter/spring months of October through June and Q60 for the summer months of July through September, whereas for smaller watersheds (Area<50 sq miles), the Q60 value applies all year (RDSGEIS, p 7-19). NYSDEC at least recognizes that small streams need more protection and that low flows can be more critical during the summer when temperatures are higher. This means that at least 40 percent of the time, withdrawals will not be allowed. For another short time period (up to the time for which the actual streamflow and the required passby flow is less than the preferred withdrawal rate), withdrawals will be limited to prevent the streamflow from being reduced to below the passby flow.

The RDSGEIS does not discuss how the recommended passby flows were chosen, in terms of habitat protected. There is an implication that Q60 and/or Q75 mean the same amount of habitat would be protected; this may simply be incorrect because streams are not created equal. The NYSDEC should apply a second filter and actually require a determination of the habitat at Q60 and limit the change in habitat. This is one advantage of the Susquehanna River Basin Commission method (RDSGEIS, p 7-15, -16).

The flow estimation method assumes a linear relation between baseflow and drainage area (RDSGEIS, p 7-19). The assumption is that streamflow increases consistently in a downstream direction in proportion to the contributing drainage area. Because it is essential to the method, the RDSGEIS should present data to justify their assumptions. Analyzing streams with two or more gages, the Qx flow at one would be calculated according to the area proportionality relationship with the other gage; the RDSGEIS should present this type of verification to prove the method is suitable.

On streams without gages, the RDSGEIS indicates that NYSDEC will use factors developed from regression equations based on their location in New York (RDSGEIS, Fig 7.1, Table 7.2). The table provides coefficients in cfs/sq mi for the passby flow for the different geographic zone by month. Presumably, they are based on basin areas as discussed above, with different requirements for greater than and less than 50 sq miles. The RDSGEIS should compare values determined with Table 7.2 with the actual value determined for gaged streams to verify the table. Statements such as "[t]he passby flow requirement … would fully mitigate any significant adverse impact from water withdrawals" (RDSGEIS, p 7-22) are unsubstantiated and unjustified.

The passby flow requirements effectively ignore the potential cumulative impacts, irrespective of the following sentence: "The application of the NFRM to all water withdrawals to support the subject hydraulic fracturing operations would comprehensively address cumulative impacts on stream flows because it will ensure a specified minimum passby flow, regardless of the number of water withdrawals taking place at one time" (RDSGEIS, p. 7-25). The RDSGEIS continues by indicating that "significant adverse cumulative impacts would be addressed by the NFRM … because each operator … would be required, via permit condition and/or regulation, to estimate or report the maximum withdrawal rate and measure the actual passby flow for any period of withdrawal" (RDSGEIS, p. 7-25, -26). The RDSGEIS analysis of the prevention of cumulative flow impacts appears limited to these statements. Clearly, several concurrent withdrawals along a stream reach could cumulatively decrease the flow at the more downstream sites to less than the passby flow, if the timing of withdrawals is not controlled and if there are not adequate measurements ongoing at the site which compare the actual flow to the required passby flow. Short of establishing a gaging station with flow/stage relationship, it is difficult to measure flows frequently enough to monitor short-term flow changes, therefore it is unlikely that an operator would be able to react sufficiently to preserve the passby flow.

The following are recommendations for improving the passby flow requirement to be used by NYSDEC

- *The program must be codified into regulations.*
- *The methods for estimating passby flows at ungaged sites must be verified as to their accuracy.*
- *NYSDEC should coordinate operators so their withdrawals do not cumulatively cause flows to drop below the required passby flows at any point along the stream.*
- *The operator should establish a temporary flow/stage relationship with at least a staff gage that should be monitored.*
- *Passby flows should be maintained with consideration to the measurement error inherent in the technique. The operator should assume that the measurement method is overestimating flow and therefore maintain a flow greater than the passby flow by as much as the error estimate.*

NYSDEC recognizes that groundwater pumping could deplete streams and also recognizes that pumping effects on the aquifers must be limited (RDSGEIS, pp 6-5, -6). Regarding groundwater pumping, the "Department proposes to impose requirements regarding passby flows as stated in this document" (RDSGEIS, p 7-25). The RDSGEIS does not discuss how the potential impacts to a stream will be estimated or how passby flows will be maintained, especially considering the lag time between groundwater pumping and the time for effects to manifest in the streams.

- *NYSDEC should prohibit groundwater pumping in tributary watersheds when analysis indicates that the time for a pumping effect to reach the stream is less than 30 days.*
- *NYSDEC should require a suitable groundwater analysis to estimate the effect on groundwater discharge to streams.*

The RDSGEIS indicates that industry has begun recycling more of its wastewater (RDSGEIS, p. 1-2). Recycling flowback water is good for reducing the amount of water to be disposed of, but it will not significantly decrease the water volume needed for fracking because the amount recovered as flowback is just 10 to 30 percent of the amount originally injected. Tracking the flowback to be recycled should be part of the new "Drilling and Production Waste Tracking" process (RDSGEIS, p. 1-13).

PROJECT MITIGATION MEASURES

The primary mitigation schemes proposed in the RDSGEIS are setbacks, which the RDSGEIS treats as additional precautionary measures (RDSGEIS, p. 1-11). This section considers whether the setbacks are sufficient or arbitrary. A list in section 1.8 introduces additional precautionary measures; they are repeated in section 3.2.4. The following lists the proposed mitigation setbacks from the RDSGEIS and provides brief comment:

> "Well pads for high-volume hydraulic fracturing would be prohibited in the NYC and Syracuse watersheds, and within a 4,000-foot buffer around those watersheds."

The primary pathway if wells are prohibited within 4000 feet of the watershed boundary would be underground, since topography would cause contaminants to flow away from the watershed boundary, assuming this coincides with a topographic divide. In general, 4000 feet is probably sufficient, but a site specific consideration of the geology should be included to ascertain that the groundwater divide would not place the well within the watershed and that geologic formations are not dipping in the direction of the watershed.

- *This setback is not specified in the regulations, but should be.*
- *The operator should be required to analyze the local geology to determine whether the groundwater divide would allow transport into the prohibited watershed.*

> "Well pads for high-volume hydraulic fracturing would be prohibited within 500 feet of primary aquifers (6 NYCCR §560.4(a)(2),(subject to reconsideration 2 years after issuance of the first permit for high-volume hydraulic fracturing)"

The implication of only a 500 –ft setback is that there is no groundwater connection, but if groundwater in the bedrock connects with the aquifer, there is a potential for a rapid transport of contaminants from a spill through fractures to the aquifer. Contamination will easily spread through the highly conductive aquifer (RDSGEIS, p. 6-37). The risk to the aquifer would be the same as to the prohibited watersheds, so there is no reason the distance should be different. If the ground surface slopes from the well to the primary aquifer, there is a significant risk of a spill reaching the aquifer through surface channels.

- *The prohibition in* 6 NYCCR §560.4(a)(2) *should be increased to 4000 feet, unless a site specific analysis demonstrates there are no fractures connecting the bedrock with the aquifer and there are no obvious surface water pathways.*
- *Additionally, the RDSGEIS should publish the area the Marcellus shale zone overlapped by primary aquifers and the area that would be included as buffer; this would help the public to understand how much land the prohibition affects.*

> "Well pads for high-volume hydraulic fracturing would be prohibited within 2,000 feet of public water supply wells, river or stream intakes and reservoirs (6 NYCCR

> §560.4(a)(4)) (subject to reconsideration 3 years after issuance of the first permit for high-volume hydraulic fracturing)"

Essentially, there is no reason for this offset to be less than the offset from a primary aquifer. Considering a public water supply well, the operator should be required to perform a capture zone analysis for the well, and if the well could draw contaminants from a spill to the well, the gas well should not be permitted in that location.

- *The setback for public water supply wells should also be 4000 feet.*
- *Additionally, the operator should identify the capture zone for flow to the well and identify the five year transport distance contour.*

> "The Department would not issue permits for proposed high-volume hydraulic fracturing at any well pad in 100-year floodplains". (6 NYCCR §560.4(a)(4))

For wells that might operate for 30 years, there is a 26% chance[2] of a 100-year flood occurring during the period the well would be operated.

- *Wells should be prohibited within at least the 500 year return interval floodplain, because the damages from significant flooding could be very substantial.*

> "The Department would not issue permits for proposed high-volume hydraulic fracturing at any proposed well pad within 500 feet of a private water well or domestic use spring, *unless waived by the owner*." (6 NYCCR §560.4(a)(4)), emphasis added.)

NYSDEC should not allow the owner to waive this requirement because health and safety are at risk. More than just the "owner" may use the source, and the owner could sell to someone who does not understand the situation.

- *6 NYCCR §560.4(a)(1) should be changed to remove the waiver from the water well owner unless the owner is required to disclose the waiver to a future buyer in perpetuity.*

In general, some of the points discussed above mention that NYSDEC will revisit the need for the setback in the future. These reconsiderations are not part of the regulations. If so, the NYSDEC should specify in detail the performance standards that must be met in order for the setback requirement to be relaxed, and should acknowledge that a supplemental EIS would be completed to consider those changes.

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[2] The probability that a event with a p probability will occur during n observations (years) may be determined with a binomial distribution.

The RDSGEIS also specified the following factors which would require site-specific SEQRA analysis.

1) Any proposed high-volume hydraulic fracturing where the top of the target fracture zone is shallower than 2,000 feet along any part of the proposed length of the wellbore.
2) Any proposed high-volume hydraulic fracturing where the top of the target fracture zone at any point along any part of the proposed length of the wellbore is less than 1,000 feet below the base of a known fresh water supply.
These requirements should be considered together – if the top of the shale is less than 2000 feet bgs or 1000 feet below the bottom of the aquifer, a site-specific SEQRA review will be required. The depths seem arbitrary, and must be based on a perceived potential for vertical transport from the shale to the receptor.

3) Any proposed well pad within 500 feet of a principal aquifer:
The only difference between a primary and principal aquifer is the number of people potentially using the aquifer. Principal aquifers are thought to be productive enough to be an important source and contamination with fracking fluid or flowback could render them unusable without substantial remediation. Wells near principal aquifers should be subject to the same setback as well near a primary aquifer.

4) Any proposed well pad within 150 feet of a perennial or intermittent stream, storm drain, lake or pond:
Again, rather than allowing development subject toa site-specific study, development within 150 feet of these streams should be prohibited. It is difficult to imagine how study will prevent a spill which is, by its nature, unexpected.

5) A proposed surface water withdrawal that is found not to be consistent with the Department's preferred passby flow methodology as described in Chapter 7;
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6) Any proposed water withdrawal from a pond or lake;
7) Any proposed ground water withdrawal within 500 feet of a private well;
8) Any proposed ground water withdrawal within 500 feet of a wetland that pump test data shows would have an influence on the wetland:
Requirements 5 through 8 are acceptable limits for requiring site-specific study.

9) Any proposed well location determined by NYCDEP to be within 1,000 feet of its subsurface water supply infrastructure

This applies to areas outside the NYC watershed that contain NYC infrastructure (RDSGEIS, p 6-1). It is unclear whether there is any infrastructure that would actually be affected by fracking outside of the watershed. Fracking should not be allowed within 1000 feet of any NYC water supply infrastructure to prevent damage.

Acid Rock Drainage

The RDSGEIS refers in several locations to an acid rock drainage (ARD) mitigation plan which would be required for the on-site burial of Marcellus Shale cuttings (RDSGEIS, p 7-67). In general, our recommendation is that on-site burial not be allowed (see the report by Harvey Consulting, LLC). NYSDEC does not describe an adequate mitigation plan to prevent the leaching of ARD into groundwater. It does not specify testing which is essential to know how much neutralizing rock must be supplied.

For each well, prior to disposal of the cuttings, an adequate set of samples should be collected from the cuttings to test for acid generation. Adequate sampling would be representatively spaced along the horizontal well bore; initially, many samples would be needed to determine the variability among samples; samples every 100 feet would be desirable until sufficient data is collected from New York shales to characterize the variability along the horizontal well bore.

At least three types of testing should be completed:

- Acid base accounting – Modified Sobek procedure
- Net acid/alkaline production
- Meteoric water mobility testing – ASTM E-2242-02

These tests should provide adequate information to determine the amount of neutralizing rock which should be added to the cuttings to prevent ARD from leaching through the waste. Ideally, if the rock is potentially acid generating (PAG), kinetic tests should be completed to better assess the PAG potential, but this may not be possible in a timely fashion. The regulations should reflect these testing requirements. Final disposal must include adequate encapsulation to assure neutralization in perpetuity. It must also include adequate monitoring to assure that ARD does not leach into the underlying groundwater. A mitigation plan must be in place to remediate any disposal sites that do leak ARD.

COMMENTS ON SPECIFIC PROPOSED REGULATIONS

The proposed regulations increase the overlap lengths for cement plugs in abandoned O&G wells from 15 to 50 feet at several locations (6 NYCRR§ 555.5(a)). This increase in plug length is an improvement but not sufficient or well planned in all locations. Rather than filling "with cement from total depth to at least 50 feet above the top of the shallowest formation from which the production of oil or gas has ever been obtained in the vicinity" (6 NYCRR§ 555.5(a)(1)), the regulation requiring cementing to 50 feet above the top of the shallowest formation in which gas has been observed; not all gas pockets have actually produced gas but could cause methane contamination if they are not already sealed off by casing. The regulations should specify that the cement plug "below the deepest potable fresh water level" should overlap the transition than be just below it because even a short section of uncased well bore open to the salt water could mix into the well and to above the fresh water line (6 NYCRR§ 555.5(a)(3)).

The definition of "public water supply" (6NYCRR§ 560.2(19)) appears to include only groundwater by referring to "a…well system which provides piped water". However, the definition of "reservoir" (6NYCRR§ 560.2(20)) includes "waterbody designated for use as a dedicated public water supply". The regulations must clear up this inconsistency by making clear that a "public water supply" includes ground- and surface water.

Operators must include in their applications various items (6NYCRR§ 560.3). The following address some of these requirements by number (the setback requirements were addressed above in the section concerning setbacks).

(2): The estimated maximum depth and elevation of bottom of potential freshwater: The operator should also be required to complete geophysical logging including conductivity measurements to verify the depth, unless it had been based on "previous drilling on the well pad".

(3): The "proposed volume of water to be used in hydraulic fracturing": The operator should also be required to discuss and specify how the estimated volume was determined.

(5), (6): The two parts specify that the application will provide the distance to various features but only if they are within a given specific distance. With current geographic information systems technology, there is no difficulty in obtaining these distances. The application should provide the distance to the water supply features in (5) and the aquifer and stream features in (6) if they are within two miles.

Mapping requirements for the application are specified in 6 NYCCR § 560.3(b). The topographic map requirements (6 NYCCR § 560.3(b)(2) require essentially a site map within 2640 feet of the proposed surface location (RDSGEIS, p. 3-9). This should be increased to 1 mile from the site, so that the map would be two by two miles centered on the proposed well pad. The map should include locations of all aquifers, water wells, stream channels, and other water features. The map should also include surface geology including faults. If fractures dominate the surface bedrock, contaminants can move quickly to wells. Contaminant pathways for transport from the pad should be identified on the map. Contaminants would not move far upgradient, so the NYSDEC should focus downgradient. The following recommendations should be included in regulations regarding the requirements of well drillers to take steps to protect nearby wells.

- *The operator should complete site specific geology/hydrogeology studies to map the potential flow paths for contaminants released from the well pad or the well bore.*
- *All wells within a five-year transport zone should be located and included in sampling plans discussed below. Additionally, dedicated monitoring wells should be established within this zone, also as described below.*

The regulations require the operator to record and report the depths and flow rates where "freshwater, brine, oil and/or gas were encountered or circulation was lost during drilling operations" (6 NYCCR 560.6(c)(22)). The operator should identify these areas with specific conductivity logging. The regulations do not specify any limits or actions that the operator should take if certain flow or losses were recorded; they do not specify what the department will do with this information.

The required treatment plan "must include a profile showing anticipated pressures and volumes of fluid for pumping the first stage" (6 NYCCR 560.6(c)(22)). The operator also "must make and maintain a complete record of it hydraulic fracturing operation including the flowback phase" (6 NYCCR 560.6(c)(26)viii). The operator should compare the "anticipated pressures and volumes" with the actual values.

The operator must suspend operations immediately "if any anomalous pressure and/or flow conditions is indicated or occurring which is a significant deviation from either the treatment plan" (6 NYCCR 560.6(c)(26)vii). This is good, but the regulations do not define anomalous or what a significant deviation from the treatment plan would be, or what the follow-up action would be to assess and remedy damages.

Also, the required record of the fracking operation, 6 NYCCR 560.6(c)(26)viii, includes rates, volumes, and pressures of all injected and flowback fluids to the well. The department only requires a synopsis be provided to the department. There is no description what a synopsis should include. Instead, the department should require the full record be provided to the department, and this record should be made publically available online.

The regulations allow a well owner to waive setback requirements (6NYCRR§ 560.4(a)(1)). This should not be allowed unless there is also a requirement to inform potential purchasers of the well in the future of the waiver.

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APPENDIX A

Review of Appendix 11, Excerpt from ICF Report, Task 1, 2009

Analysis of Subsurface Mobility of Fracturing Fluids

Agreement No. 9679

Reviewed by

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December 7, 2009

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Introduction

The New York State Energy and Development Authority (NYSERDA) contracted with ICF International to prepare a review of the hydraulic fracturing process as it will likely be applied to the Marcellus Shale in New York; this review was published as a supporting document for the 2009 RDSGEIS prepared by the New York State Department of Environmental Conservation. For the 2011 RDSGEIS, Appendix 11 presents excerpts from that report regarding the subsurface mobility of fracturing fluids. This is a review of Appendix 11, revised from a review completed by this author of the ICF International report contained in the 2009 RDSGEIS.

In summary, ICF completed an analysis of the potential for contamination to flow from the shale to freshwater aquifers, but misrepresented the actual situation in many ways. The basic problem was they conceptualized the flow potential incorrectly. They considered the gradient incorrectly and assumed that if the transport did not occur within the time period of fracturing, it would not occur. They assumed that the fluids leaving the shale would completely disperse, and be diluted, by occupying and being retained in every pore between the shale and the aquifers. They did not consider preexisting fractures. They ignored any potential pre-existing vertical gradient which would drive contaminants leaving the shale to the aquifers. Although they presented a geochemical analysis which could explain why some attenuation could occur, they provided no site specific or fluid specific data to indicate that it would occur.

Exposure Pathways

ICF analyzes the potential for fracturing fluid to flow from the shale to the freshwater aquifers anywhere from 1000 to 5000 feet above. The first problem is that the potential contaminants are both fracturing fluid and connate (formation) water existing in the shale before fracturing, which could contain extremely high concentrations of TDS, benzene, or radioactive materials. Therefore, ICF should have considered the potential for flow of both fracturing fluid and connate water. Ambient water could both be pushed from the shale by the injection of fracturing fluid and just by the opening of the pore spaces which would increase the permeability and allow more of a natural connection.

ICF calculates the gradient between the fracture zone and the bottom of the freshwater zone, which they set at 1000 feet bgs to be conservative in because much of the groundwater below this level in southern New York is not an underground source of drinking water either because it is too salty or the formation is not sufficiently productive to be considered an aquifer. However, their calculation applied only during the period of injection. Myers (in review) demonstrated through modeling that the fracking pressure would dissipate over a period of months, not immediately after fracking ended, because of the fluid that has been pushed away from the well. The effective gradient is from the well to just beyond the migrating fluid where pressures would not yet have been affected by the current fracking.

ICF also ignores the potential for a natural upward gradient, which could be due to natural artesian pressure. Myers (in review) also discusses the potential for this in detail.

ICF properly calculated the pressure that would occur in the shale during fracturing based on the effective stress in the formation and the amount of pressure required to overcome the in-situ horizontal stress (ICF, pages 25-26); accepting the assumptions in the following quote, equation 12, and equations 7 through 11 used to derive it, is an accurate description of the head applied to the shale during fracturing.

> Since the horizontal stress is typically in the range of 0.5 to 1.0 times the vertical stress, the fracturing pressure will equal the depth to the fracture zone times, say, 0.75 times the density of the geologic materials (estimated at 150 pcf average), times the depth. To allow for some loss of pressure from the wellbore to the fracture tip, the calculations assume a fracturing pressure 10% higher than the horizontal stress… (ICF, pages 25-26)

ICF uses that equation with the gradient equation 6 to estimate the gradient between the shale and freshwater aquifer, “during hydraulic fracturing”, for a variety of depths of the aquifer and the shale. The numbers are correct, for an aquifer depth of 1000 feet and shale depth of 2000 feet, they show the gradient to be about 3.6, but the concept applied in the derivation is wrong as described above. During hydraulic fracturing, variously estimated through the RDSGEIS documents as occurring for up to 5 days, there is no hydraulic connection between the shale and the bottom of the freshwater aquifer and it is therefore inappropriate to consider the gradient across that thickness. The correct conceptualization is described in the following paragraph.

Upon applying a pressure in the shale, as occurs during the injection for fracturing, a very high pressure head is developed at the well and nearby shale. This pressure causes the gradient that drives the fluid away from the well into the shale, where it causes the shale to fracture. Fluid may continue to flow into surrounding formations. During the process, the pressure begins to increase away from the well which establishes a steep gradient near the well. Away from the well at any given time during injection, the pressure is less than at the well. The pressure drop from the well to any point in the shale away from the well is a function of the friction incurred by the fluid flowing away from the well. At some distance from the well, the pressure is only at background. The distance at which the pressure is only background is the point at which the injection fluid has not yet reached. Beyond the point to which the injection fluid flows, there is NO hydraulic connection. For this reason, ICF's calculation for gradient between the injection pressure in the shale and the bottom of the freshwater aquifer is hydrogeologically incorrect. ICF is effectively analyzing a steady state situation that would occur if the injection pressure continued until the pressure stabilized between the shale and the freshwater aquifer.

ICF acknowledges the reality that transient or non-steady conditions will prevail and that the actual pressure gradient will be higher closer to the shale. "In an actual fracturing situation, non-steady state conditions will prevail during the limited time of application of the fracturing pressures, and the gradients will be higher than the average closer to the fracture zone and lower than the average closer to the aquifer." (ICF, pages 26-27)

However, they do not carry the analysis any further and seem to argue that immediately after injection ceases, all upward gradient will cease: "It is important to note that these gradients only apply while fracturing pressures are being applied. Once fracturing pressures are removed, the total head in the reservoir will fall to near its original value, which may be higher or lower than the total head in the aquifer" (ICF, page 27). The implication from this statement is that ending injection will cause the pressure in the reservoir to drop back to background, immediately. This is not possible, any more than it is possible for the drawdown in a pumping well in an aquifer to return to pre-pumping conditions immediately upon cessation of pumping.

For example, consider that during a five-day injection period, the pressure propagated outward from the well as described in Myers (in review). When injection ends, the pressure within the well may almost immediately return to background, but the pressure in the surrounding formation will still be very high. This is the pressure which will drive the flowback to the well, as described throughout the RDSGEIS. The initial flowback is fluid right next to the well – the fluid that had just been injected. The pressure field created in the formation away from the well is the pressure that causes a gradient to push the fluid back into the well.

As long as there is flowback, there is a gradient toward the well, and residual pressure in the shale or surrounding formations. With distance from the well, the pressure increases (as required for there to be a gradient back to the well). At any given time, there will be a point of maximum pressure beyond which the pressure becomes lower; in other words, a cross-section through the formation away from the well showing the pressure head would show the pressure rising from the well to the peak and falling from the peak to the point the pressure reaches background. (This is similar to the concept in hydrogeology that during pumping, the maximum drawdown caused by a well is at the well; when the well ceases to pump, the water level will initially rise quickly, but the drawdown away from the well will continue to expand for a period of time.)

ICF considers that local drawdown caused by production from the well will further prevent flow away from the well: “During production, the pressure in the shale would decrease as gas is extracted, further reducing any potential for upward flow” (ICF, page 27). This is probably correct, but the process described in the preceding paragraph likely causes some of the fluid to have moved beyond this propagating drawdown. The fact that only 35% of the injected fluid returns as flowback (RDSGEIS, Gaudlip et al, 2008) would seem to confirm that much of the injected fluid gets beyond the point where the reversing gradient would pull the fluid back to the well.

ICF also relies on there being no connection between the shale and surrounding formations, as indicated by the high TDS content of water in the shale. This may reflect the pre-fractured conditions, but the fracturing process could open a connection between formations. As noted in the main body of this review, out-of-zone fracking is not uncommon, therefore it is reasonable to assume that connections between the shale and surrounding formations do occasionally occur.

The analysis provided by ICF in section 1.2.4.3, Seepage Velocity, is irrelevant because it considers the velocity between the shale and the freshwater aquifer, using a gradient established in the previous section that only applies for as long as the injection. Their calculation of 10 ft/day (ICF, page 28) relies on that average gradient. They seem to acknowledge the fallacy of their assumptions by stating: “The actual gradients and seepage velocities will be influenced by non-steady state conditions and by variations in the hydraulic conductivities of the various strata” (ICF, page 28, emphasis added). ICF carries the error into section 1.2.4.4, Required Travel Time, by calculating how long it would take for flow at the seepage velocity calculated in the previous section to reach the freshwater aquifers.

ICF's fourth argument is that even if all of the injected fluid moves vertically out of the shale towards the freshwater aquifer, it would have to disperse among all of the pores between the shale and the aquifer – a truly nonsensical idea. The calculation requires that 4,000,000 gallons of fluid would be evenly dispersed throughout a 40-acre well spacing. In other words, they assume that about 4,000,000 gallons of injected fluid would evenly disperse through all of the void, assuming porosity of 0.1, over a 1000-foot thickness 40 acres in area, or about 1.3 billion gallons of void space, would cause a dilution factor of 300 (ICF, pages 30-31). This is wrong for the following reasons.

- An injected fluid would move as a slug along the gradient. In this case, with a natural upward gradient, any fluid that escapes the well bore (does not flowback) would disperse upward. It would not diffuse through every pore space between the shale and aquifer. Advective forces would move it upward as a slug with dispersion spreading it out both vertically and horizontally. It will dilute, but far less than postulated by ICF's analysis.
- The vertical flow would follow preferential flow paths rather than advecting upwards uniformly across 40 acres. The image painted by ICF is that the fluid would flow upward to the aquifer with the leading edge moving at exactly the same rate over the entire area. Even if there are no fractures, faults, or improperly plugged wells, simple finger flow, caused by heterogeneities in the material properties, would cause an uneven distribution of the contaminant.

ICF also rejects the concept of fractures, faults, or unplugged wells by claiming it is "extremely unlikely that a flow path such as a network of open fractures, an open fault, or an undetected and unplugged wellbore could exist that directly connects the hydraulically fractured zone to an aquifer" (ICF, page 31). They provide no data or references to assess the probability that such a network is "extremely unlikely" or to justify their conclusion. More importantly, for fractures to facilitate a connection between the shale and the aquifers, it is not necessary for the fracture to exist over the entire thickness. As ICF (page 5) mentions, the Marcellus Shale has substantial natural fractures, and therefore it is possible that the surrounding formations, sandstone or shale, also have fractures. It is not necessary for the flow to follow a fracture all the way to the aquifers, but it could enhance the velocity of movement. Fractures could also further disperse the flow vertically, as discussed in Myers (in review).

ICF also mentions geochemistry as a reason that transport of contaminants from the shale to the aquifers will not occur. While it is possible for attenuation to occur as contaminants move through a formation, without site specific and chemical specific data, they should not make such an argument.

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APPENDIX B

Prepublication Copy

Myers, T., in review. POTENTIAL CONTAMINANT PATHWAYS FROM HYDRAULICALLY FRACTURED SHALE TO AQUIFERS

POTENTIAL CONTAMINANT PATHWAYS FROM HYDRAULICALLY FRACTURED SHALE TO AQUIFERS

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ABSTRACT

Hydraulic fracturing (fracking) of deep shale beds to develop natural gas has caused concern regarding the potential for various forms of water pollution. Two potential pathways – diffuse transport through bulk media and preferential flow through fractures – could allow the transport of contaminants from the fractured shale to aquifers. There is substantial geologic evidence that natural vertical flow drives contaminants, mostly brine, to near the surface from deep evaporite sources. Interpretative numerical modeling shows that diffuse transport could require up to tens of thousands of years to move contaminants to the surface, but also that fracking the shale could reduce that transport time to tens or hundreds of years. Conductive faults or fracture zones, as found throughout the Marcellus shale region, could reduce the travel time further. Injection of up to 15,000,000 liters of fluid into the shale generates high pressure at the well which decreases with distance from the well and with time after injection as the fluid advects through the shale. The advection displaces native fluids, mostly brine, and fractures the bulk media and widens existing fractures. Simulated pressure returns to pre-injection levels in about 90 days. The overall system requires from three to six years to reach a new equilibrium reflecting the significant changes caused by fracking the shale. The rapid expansion of hydraulic fracturing requires that monitoring systems be employed to track the movement of contaminants and that gas wells have a reasonable offset from faults.

Introduction

The use of natural gas (NG) in the United States has been increasing, with 53 percent of new electricity generating capacity between 2007 and 2030 projected to be with NG-fired plants (EIA 2009). Unconventional sources account for a significant proportion of the new NG available to the plants. A specific unconventional source has been deep shale-bed NG, including the Marcellus shale primarily in New York, Pennsylvania, Ohio, and West Virginia (Soeder 2010), which has seen over 4000 wells developed between 2009 and 2010 in Pennsylvania (Figure 1).Unconventional shale-bed NG differs from conventional sources in that the permeability is so low that gas does not naturally flow in timeframes suitable for development. Hydraulic fracturing (fracking, the industry term for the operation (Kramer 2011)) loosens the formation to release the gas and provide pathways for it to move to a well.

Fracking injects 13 to 19 million liters of fluid consisting of water and additives, including benzene at concentrations up to 560 ppm (Jehn 2010), at pressures up to 69,000 kPa (PADEP 2011) into low permeability shale to force open and connect the fractures. This is often done using horizontal drilling through the middle of the shale. Horizontal wells may be more than a kilometer (km) long. The amount of injected fluid that returns to the ground surface after fracking ranges from 9 to 34 percent of the injected fluid (Alleman 2011; NYSDEC 2009), although some would be formation water.

Many agency violation reports and legal citations (ODNR 2008; PADEP 2009) and peer-reviewed articles (DiGuilio et al. 2011; Osborn et al. 2011; Breen et al. 2007; White and Mathes 2006) have found more gas in water wells near areas being developed for unconventional NG, documenting the source can be difficult. One reason for the difficulty is the different sources – thermogenic for gas formed by compression and heat at depth in shale and bacteriogenic for gas formed by bacteria breaking down organic material (Schoell 1980). The source can be distinguished based on both C and H isotopes and the ratio of methane to higher chain gases (Osborn and McIntosh 2010; Breen et al 2007). Thermogenic gas can reach aquifers only by leaking from the well bore or by seeping vertically from the source. In either case, the gas must flow through potentially very thick sequences of sedimentary rock to reach the aquifers. Many studies which have found thermogenic gas in water wells found there to be more gas near fracture zones (DiGuilio et al. 2011; Osborn et al. 2011; Thyne 2008; Breen et al. 2007), suggesting that fractures are pathways for gas to move from shale or other deep formations to aquifers.

A pathway for gas would also be a pathway for fluids and contaminants to advect from the fractured shale to the surface, although the time for transport would likely be longer. Two reports (DiGuilio et al. 2011; EPA, 1987) have documented the presence of fracking fluid in aquifers and another found elevated chloride (Thyne 2008), linked to fracking, in wells, although the exact source and pathways had not been determined.

There is sufficient documented gas movement and circumstantial evidence regarding fluids movement to suggest that there is a potential for fracking fluid or shale-bed formation fluid to reach aquifers. With the vastly increasing development of unconventional NG sources, the risk to aquifers could seemingly be increasing. However, there is almost no data concerning the movement of contaminants along pathways from depth, either from wellbores or from deep formations, to aquifers. The only way in the short term to explore the risk is with conceptual analyses.

To consider the potential transport from depth to aquifers, I have considered first the potential pathways for contaminant transport through bedrock between deep shale and surface aquifers, and the necessary conditions for such transport to occur. Second, I have estimated contaminant travel times through the potential pathways, with a bound on these estimates based on formation hydrologic parameters, using interpretative MODFLOW-2000 computations. The modeling does not, and cannot, account for all of the complexities of the geology, which could either increase or decrease the travel times compared to those considered herein. The intent of this study is to characterize the risk factors, so the modeling is used, similar to that by Hsieh (2011), to consider the possibilities.

The Marcellus shale area of northern Pennsylvania and southern New York is the study area (Figure 1), although the concepts should apply anywhere there is a deep unconventional NG source separated from the surface by sedimentary rock.

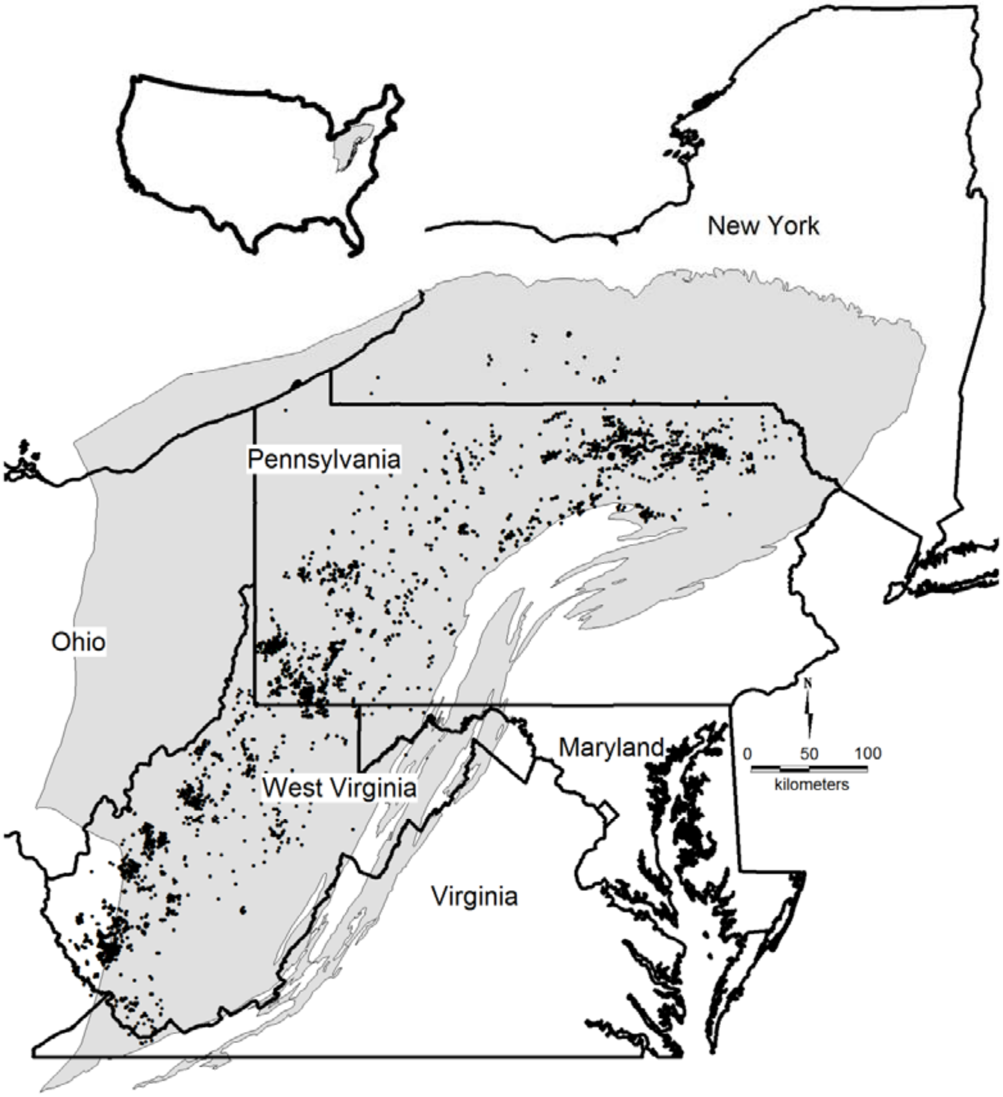

Figure 2: Location of Marcellus shale in northeastern United States. Location of Marcellus wells (dots) drilled July 2009 to June 2010 and total Marcellus shale wells in New York and West Virginia. There are 4064 wells shown in Pennsylvania, 48 wells in New York, and 1421 wells in West Virginia. Faulting in the area may be found in PBTGS (2001), Isachsen and McKendree (1977), and WVGES (2011, 2010a and 2010b).

Method of Analysis

I consider several potential scenarios of transport from shale, 1500 m below ground surface to the surface, beginning with pre-development steady state conditions to establish a baseline and then scenarios considering transport after fracking has potentially caused contaminants to reach the overlying formations. To develop the conceptual models and MODFLOW-2000 simulations, it is necessary first to consider the hydrogeology of the shale and the details of hydraulic fracturing, including details of how fracking changes the shale hydrogeologic properties.

Hydrogeology of Marcellus Shale

Shale is a mudstone, a sedimentary rock consisting primarily of clay- and silt-sized particles, which tend to break in one direction (Nichols 2009). It forms through the deposition of fine particles in a low energy environment, such as a lake- or seabed. The Marcellus shale formed in very deep offshore conditions during Devonian time (Harper 1999) where only the finest particles had remained suspended. Because sufficient organic matter settled with the clay and silt, anaerobic decomposition caused the formation of methane. The depth to the Marcellus shale varies to as much as 3000 m in parts of Pennsylvania, and averages about 1500 m in southern New York. Between the shale and the ground surface are layers of sedimentary rock, including sandstone, siltstone, and shale (NYSDEC 2011).

Marcellus shale has very low natural intrinsic permeability, on the order of 10^{-16} Darcies (Kwon et al. 2004a and 2004b; Neuzil 1994 and 1986), which makes it an extremely efficient seal, or capstone, for keeping natural gas in underlying sandstone. At a gradient equal to 1 with an intrinsic permeability equal to 100×10^{-9} darcies, water would flow only 0.000025 m in a year.

Schulze-Makuch et al. (1999) described Devonian Shale of the Appalachian Basin, of which the Marcellus is a major part, as containing "coaly organic material and appear either gray or black" and being "composed mainly of tiny quartz grains < 0.005 mm diameter with sheets of thin clay flakes". Median particle size is 0.0069±0.00141 mm with a grain size distribution of <2% sand, 73% silt, and 25% clay. Primary pores are typically 5 x 10^{-5} mm in diameter, matrix porosity is typically 1% to 4.5% and fracture porosity is typically 0.078 to 0.09% (Schulze-Makuch et al. 1999 and references therein).

The Marcellus shale is fractured by faulting and contains synclines and anticlines which cause tension cracks (Engelder et al. 2009; Nickelsen 1986). It is sufficiently fractured in some places to support water wells just six to ten km from where it is being developed for NG at 2000 m below ground surface (bgs) in eastern Lycoming County, Pennsylvania (Lloyd and Carswell 1981) (Figure 2).

Porous flow in unfractured shale is negligible due to the low bulk media permeability, but at larger scales the fractures control and may allow significant flow. Conductivity scale dependency (Schulze-Makuch et al.1999) may be described as follows:

$$K = Cv^m$$

K is hydraulic conductivity (m/s), C is the intercept of a log-log plot of observed K to scale (the K at a sample volume of 1 m^3), V is sample volume (m^3), and m is a scaling exponent determined with log-log regression; for Devonian shale, C equals -14.3 and m equals 1.08 (Schulze-Makuch et al. 1999). Most of their samples were small because the deep shale is not easily tested at a field-scale and no groundwater models have calibrated for flow through the Marcellus shale, therefore field scale K estimates are uncertain. Considering a 1 km square area with 30 m thickness, the Kh would equal 5.96x10^{-7} m/s (0.0515 m/d). This effective K is low and the shale would be an aquitard, but a leaky one.

Contaminant Pathways from Shale to the Surface

Three studies (Osborn et al. 2011; Thyne 2008; Breen et al. 2007) have found gas in near-surface water wells and suggested that the most likely cause was vertical transport of gas from depth, possibly linked to the presence of faults through which the gas could flow. Osborn et al. (2011) found systematic circumstantial evidence for higher methane concentrations in wells within 1 km of Marcellus shale gas wells that had been fracked. Gas moves through fractures depending their width (Etiope and Martinelli 2001) and is a primary concern for many projects, including carbon sequestration (Annunziatellis et al. 2008) and natural gas storage projects (Breen et al. 2007).

Pathways for gas suggest pathways for fluids and contaminants, if there is a gradient. Vertical hydraulic gradients of a up to a few percent, or about 30 m over 1500 m, exist throughout the Marcellus shale region as may be seen in various geothermal developments in New York (TAL 1981). Brine more than a thousand meters above their evaporite source (Dresel and Rose 2010) is evidence of upward movement of contaminants from depth to the surface. The Marcellus shale, with salinity as high as 350,000 mg/l (Soeder 2010; NYDEC 2009), may be a primary brine source. Relatively uniform brine concentrations over large areas (Williams et al. 1998) suggest widespread diffuse transport, which would occur if there is a sufficient concentration gradient. The transition from briny to freshwater suggests a long-term equilibrium between the upward movement of brine and downward movement of freshwater.

Faults, which occur throughout the Marcellus shale region (Gold 1999), could provide pathways (Caine et al. 1996; Konikow 2011) for more concentrated advective and dispersive transport. Brine concentrating in faults or anticline zones reflects potential preferential pathways (Wunsch 2011; Dresel and Rose 2010; Williams 2010; Williams et al. 1998).

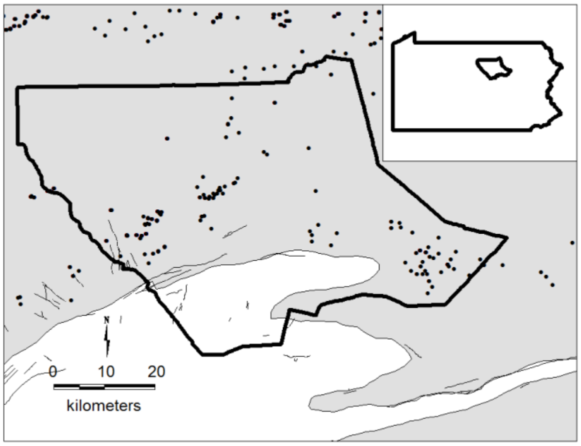

Figure 3: Marcellus shale wells and the Marcellus outcrop in Lycoming County, Pennsylvania. The grey shading is the area of Marcellus shale, which outcrops along its boundary along an area about 1 km wide (Lloyd and Carswell 1981). Faults from PBTGS (2001).

Effect of Hydraulic Fracturing on Shale

Fracking increases the permeability of the targeted shale to make extraction of natural gas economically efficient (Engelder et al. 2009; Arthur et al. 2008). Fracking creates fracture pathways with up to 9.2 million square meters of surface area in the shale accessible to a horizontal well (King 2010; King et al. 2008) and connects natural fractures (Engelder et al. 2009; King et al. 2008). No post-fracking studies that documented hydrologic properties such as conductivity were found while researching this article (there is a lack of information about pre- and post-fracking properties (Schweitzer and Bilgesu 2009)), but it is reasonable to assume the K increases significantly because of the newly created and widened fractures.

Fully developed shale typically has wells spaced at about 300-m intervals (Krissane and Weissert 2011; Soeder 2010). Up to eight wells may be drilled from a single well pad (NYDEC 2009; Arthur et al. 2008), although not in a perfect spoke pattern. Reducing by half the effective spacing did not enhance overall productivity (Krissane and Weissert 2011) which indicates that 300–m spacing creates sufficient overlap among fractured zones to assure adequate gas drainage. The properties controlling groundwater flow would therefore be affected over a large area, not just at a single horizontal well or set of wells emanating from a single well pad.

Fracking is not intended to affect surrounding formations, but shale properties vary over short ranges (King 2010; Boyer et al. 2006) and out of formation fracking is not uncommon. Fluids could reach surrounding formations just because of the volume injected into the shale, which must displace natural fluid, such as the existing brine in the shale. For example, if 15 million liters is injected into shale over a 1000 m long horizontal well, the fluid could occupy all of the pore spaces within 7 to 16 m from the well for effective porosity ranging from 0.1 to 0.02. Even with 20% of the fluid returning to the well, a significant amount of existing pore space would be occupied by the injected fluid, displacing the existing brine and gas.

Analysis of Potential Transport along Pathways

Fracking could cause contaminant to reach overlying formations either by fracking out of formation, connecting fractures in the shale to overlying bedrock, or by simple displacement of fluids from the shale into the overburden. Advective transport will manifest if there is a significant vertical component to the regional hydraulic gradient. Advective transport can be considered with the simple particle velocity determined with Darcy velocity and effective porosity.

Numerical modeling provides flexibility to consider potential conceptual flow scenarios, but should be considered interpretative (Hill and Tiedeman, 2007). Numerical simulation presented herein was completed with the MODFLOW-2000 code (Harbaugh et al. 2000). The simulation considers the rate of vertical transport of contaminants to near the surface for the different conceptual models, based on an expected, simplified, realistic range of hydrogeologic aquifer parameters.

MODFLOW-2000 is a versatile numerical modeling code, but it is not perfect for all of the factors required for this simulation. The native water at depth near the shale is brine, much saltier than seawater, therefore the injected fluid would be lighter so buoyancy factors may speed the upward flux beyond the simple consideration of hydraulic gradient. As more data becomes available, it may be useful to consider the added upward force caused by the brine by using the SEAWAT-2000 module (Langevin et al. 2003).

Vertical flow would be perpendicular to the general tendency for sedimentary layers to have higher horizontal than vertical conductivity. Fractures and improperly abandoned wells would provide pathways for much quicker vertical transport than general advective transport. This paper considers the fractures as vertical columns with cells having much higher conductivity than the surrounding bedrock. The cell discretization is fine, so the simulated width of the fracture zones is realistic. Dual porosity modeling would not be useful because high velocity vertical flow through the fractures is unlikely. MODFLOW-2000 has a module, MNW (Halford and Hansen 2002), that could simulate flow through open bore holes. Open boreholes would clearly provide rapid transport if the head deep in the borehole exceeds that near the surface or if fractures containing fracking fluid intersect or come close to the borehole. Because it is possible to simply plug open boreholes, I have limited consideration here to fractures; however, models of well fields should include known boreholes.

The thickness of the formations and fault would affect the simulation, but much less than the several-order-of-magnitude variation possible in the shale properties. The overburden and shale thickness were set equal to 1500 and 30 m, respectively, similar to that observed in southern New York. The estimated travel times are proportional for thicker or thinner sections. The overburden could be predominantly sandstone, sections of shale, mudstone, and limestone could exert local control. The vertical fault is assumed to be 6 m thick.

There are five conceptual models of flow and transport of natural and post-fracking transport from the level of the Marcellus shale to the near-surface to consider with an interpretative numerical model.

1. The natural upward diffuse flow due to a head drop of 30 m from below the Marcellus shale to the ground surface, considering the variability in both shale and overburden K. This is a steady state solution for upward advection through a 30-m thick shale zone and 1500-m overburden and is a baseline condition for upward flow through unfractured sedimentary rock.
2. Same as number 1, but with a fracture zone connecting level of the shale with the surface. This emulates the conceptual model postulated for flow into the alluvial aquifers near stream channels, the location of which may be controlled by faults (Williams et al 1998). The fault K varies from 10 to 1000 times the surrounding bulk sandstone K.
3. This scenario tests the effect of extensive fracturing in the Marcellus shale by increasing the shale K from 10 to 1000 times its native value over an extensive area. This transient solution starts with initial conditions being a steady state solution from scenario 1. The K in the shale layers increases from 10 to 1000 times at the beginning of the simulation, to represent the relatively instantaneous change on the regional shale hydrogeology imposed by the fracking. This scenario estimates both the changes in flux and the time for the system to come to equilibrium after fracking.
4. As number 3, considering the effect of the same changes in shale properties but with a fault as in number 2.
5. This scenario simulates the actual injection of 13 to 17 million liters of fluid in five days into fractured shale from a horizontal well with and without a fault.

Model Setup

The model domain was 150 rows and columns spaced at 3 m to form a 450 m square (Figure 3) with 50 layers bounded with no flow boundaries. The 30-m thick shale was divided into 10 equal thickness layers from layer 40 to 49. The overburden layer thickness varied from 3 m just above the shale to layer 34, 6 m layer 29, 9 m to layer 26, 18 m in layer 25, 30 m to layer 17, 60 m to layer 6, 90 m to layer 3, and 100 m in layers 2 and 1

The model simulated vertical flow between constant head boundaries in layers 50 and 1, as a source and sink, so that the overburden and shale properties control the flow. The head in layers 50 and 1 was 1580 and 1550 m, respectively, to create an upward gradient of 0.019 over the profile. Varying the gradient would have much less effect on transport than changing K over several orders of magnitude and was therefore not done.

This simulation considers particle travel times between the top of the shale and the top of the model domain based on an effective porosity of 0.1. A 6-m wide fault is added for some scenarios in the center two rows from just above the shale, layer 39 to the surface. The fault is an attempt at considering fracture flow, but the simulation treats the six meter wide fault zone as homogeneous, which could underestimate the real transport rate in fracture-controlled systems. The simulation also ignores diffusion between the fracture and the adjacent shale matrix (Konikow, 2011).

Scenario 5 simulates injection using a WELL boundary in layer 44, essentially the middle of the shale, from columns 25 to 125 (Figure 3). It injects 15 million liters over one 5-day stress period, or 3030 m^3/d into 101 model cells at the WELL. The modeled shale K was changed to its assumed fracked value at the beginning of the simulation. Simulating high rate injection generates very high heads in the model domain, similar to that found simulating oil discharging from the well in the Deepwater Horizon crisis (Hsieh, 2011) and water quality changes caused by underground coal gasification (Contractor and El-

Didy 1989). DRAIN boundaries on both sides of the WELL simulated return flow for sixty days after the completion of (Figure 3), after which the DRAIN was deactivated. The sixty days were broken into four stress periods, 1, 3, 6, and 50 days long, to simulate the changing heads and flow rates. DRAIN conductance was calibrated so that 20% of the injected volume returned within 60 days to emulate standard industry practice (Alleman 2008; NYSDEC 2009). Recovery, continuing relaxation of the head at the well and the adjustment of the head distribution around the domain, occurred during the sixth period which lasted for 36,500 days, a length of time that simulation of scenarios 3 and 4 indicated would suffice.

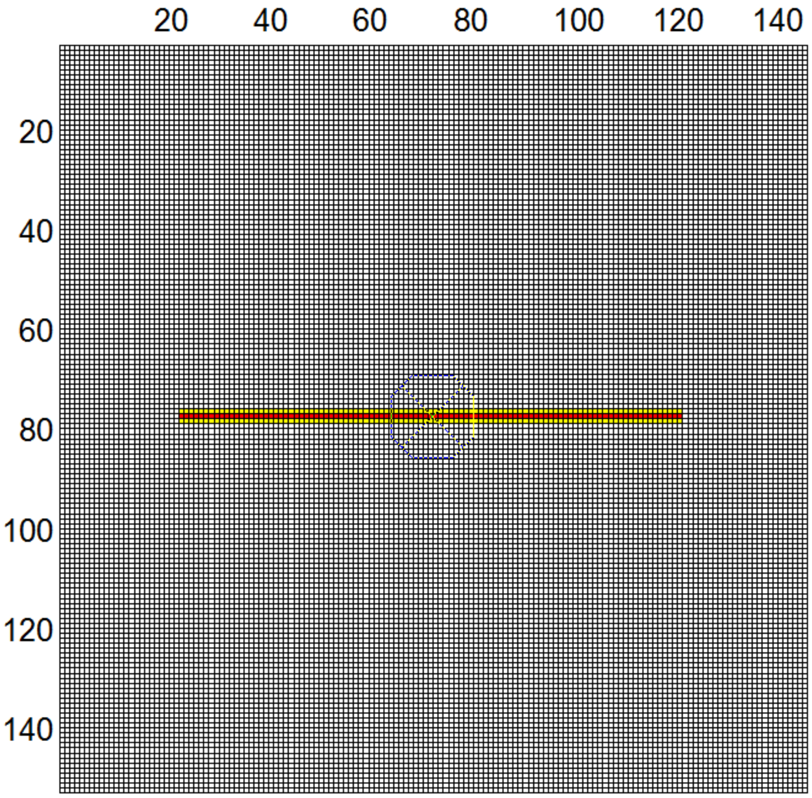

Figure 4: Model grid through layer 44 showing the horizontal injection WELL (red) and DRAIN cells (yellow) used to simulate flowback. The figure also shows the monitoring well.

There is no literature guidance to a preferred value for fractured shale storage coefficient, so I estimated S with a sensitivity analysis using scenario 3. With fractured shale K equal to 0.001m/d, two orders of magnitude higher than the in-situ value, the time to equilibrium resulting from simulation tests of three fractured shale storage coefficients, 10^{-3}, 10^{-5}, and 10^{-7} m^{-1}, varied twofold (Figure 4). The slowest time to equilibrium was for $S=10^{-3}$ m^{-1} (Figure 4), which was chosen for the transient simulations because more water would be stored in the shale and flow above the shale would change the least.

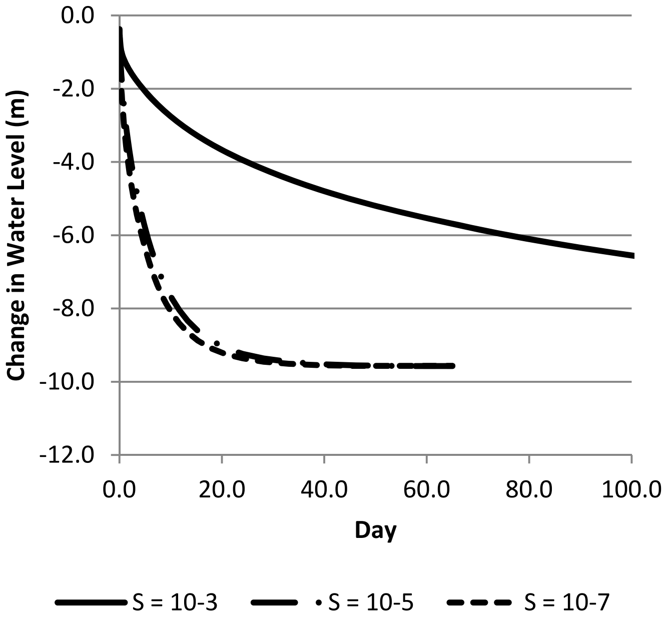

Figure 5: Sensitivity of the modeled head response to the storage coefficient used in the fractured shale for model layer 39 just above the shale.

Results

Scenario 1

The travel time for a particle to transport through 1500 m of sandstone and shale equilibrates with one of the formations controlling advection (Figure 5). For example, when the shale K equals $1x10^{-5}$ m/d, transport time does not vary with sandstone K. For sandstone K at 0.1 m/d, transport time for varying shale K ranges from 40,000 years to 160 years. The lower travel time estimate is for shale K similar to that found by Schulze-Makuch et al. (1999). The shortest simulated transport time of about 20 years results from both the sandstone and shale K equaling 1 m/d. Other sensitivity scenarios emphasize the control exhibited by one of the media (Figure 5). If shale K is low, travel time is very long and not sensitive to sandstone K.

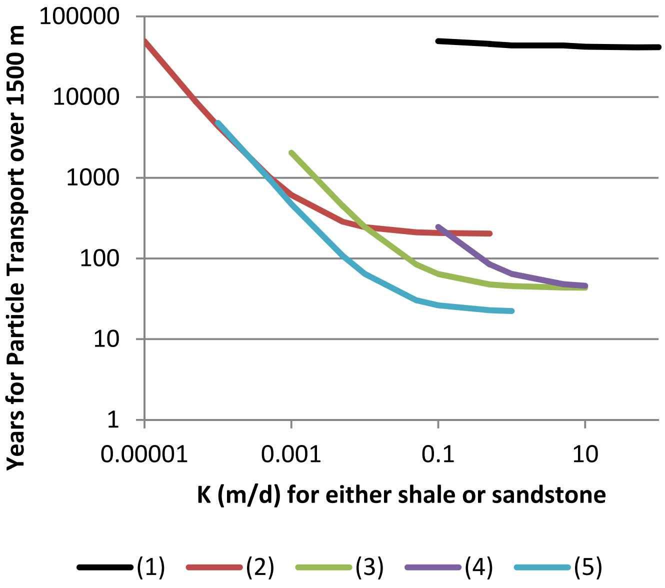

Figure 6: Sensitivity of particle transport time over 1500 m for varying shale and sandstone vertical K. Effective porosity equals 0.1. (1) – varying Kss, Ksh=10-5 m/d, (2) – varying Ksh, Kss= 0.1 m/d, (3) – varying Kss, Ksh = 0.1 m/d, (4): varying Kss, Ksh = 0.01 m/d, and (5): varying Ksh, Kss= 1.0 m/d.

Scenario 2

Vertical transport time through a system including a high-K fault zone was limited primarily by the shale K, presumably because the fault K was one to two orders of magnitude more conductive than that of the surrounding sandstone (Figure 6). Including a fault increased the particle travel rate by about 10 times (compare Figure 8 with Figure 6). The fault K controlled the transport rate for shale K less than 0.01 m/d. A highly conductive fault could transport fluids to the surface in as little as a year for shale K equal to 0.01 m/d (Figure 6).

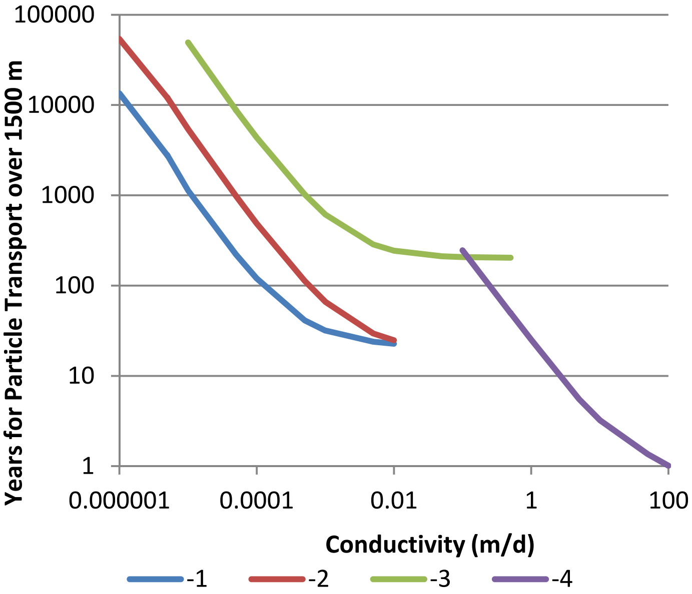

Figure 7: Variability of transport through various scenarios of changing the K for the fault or shale. Effective porosity equals 0.1. (1): Vary Ksh, Kss=0.01 m/d; (2): Varying Ksh, Kss=0.1 m/d; (3), no fault; (4): Varying K fault, Kss=0.1 m/d, Ksh=0.01 m/d. Unless specified, the vertical fault has K=1 m/d for variable shale K.

Scenarios 3 and 4

Scenarios 3 and 4 estimate the time to establish a new equilibrium for scenarios 1 and 2. Equilibrium times would vary by model layer as the changes propagate through the domain, and flux rate for the simulated changes imposed on natural background conditions. The fracking-induced changes cause a significant decrease in the head drop across the shale and the ultimate adjustment of the potentiometric surface to steady state depends on the new shale properties.

The time to equilibrium for one scenario 3 simulation, shale K changing from 10^{-5} to 10^{-2} m/d with sandstone K equal to 0.1 m/d, varied from 5.5 to 6.5 years, depending on model layer (Figure 7). Near the shale (layers 39 and 40), the potentiometric surface increased from 23 to 25 m reflecting the decreased head drop across the shale. One hundred meters higher in layer 20, the head increased about 20 m. These changes reflect the decrease in K across the shale. Simulation of scenario 4, with a fault with K=1 m/d, decreased the time to equilibrium to from 3 to 6 years within the fault zone, depending on model layer (Figure 7). Faster transport occurred only in areas near the fault. Highly fractured sandstone would allow more vertical transport, but diffused advective flow would also increase so that the base sandstone K would control the overall rate.

The flux across the upper boundary changed within 100 years for scenario 3 from 1.7 to 345 m^3/d, or 0.000008 m/d to 0.0017 m/d. There is little difference in the equilibrium fluxes between scenario 3 and 4 indicating that the fault primarily affects the time to equilibrium rather than the long-term flow rate.

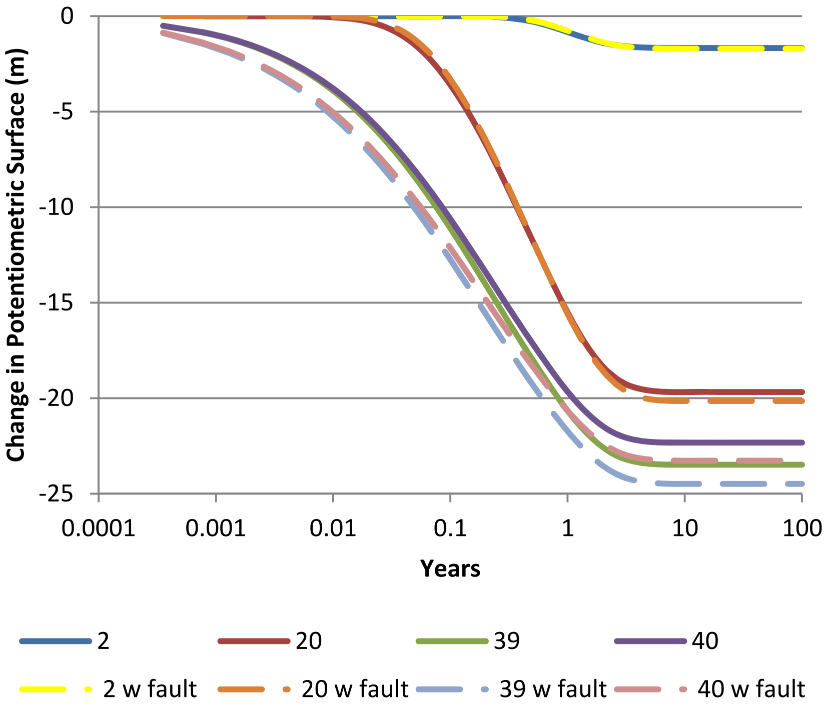

Figure 8: Monitoring well water levels for specified model layers due to fracking of the shale; monitor well in the center of the domain, including in the fault, K of the shale changes from 0.00001 to 0.01 m/d at the beginning of the simulation.

Scenario 5: Simulation of Injection

The injection scenarios simulate 15 million liters entering the domain at the horizontal well and the subsequent potentiometric surface and flux changes throughout. The highest potentiometric surface increases (highest injection pressure) occurred at the end of injection (Figure 8), with a 2400 m mound at the horizontal well. The peak pressure simulated both decreased but occurred longer after the cessation of injection with distance from the well (Figure 8). The pressure at the well returned to within a meter of pre-injection levels in about 95 days (Figure 8). After injection ceases, the peak pressure simulated further from the well occurs longer from the time of cessation, which indicates there is a pressure divide beyond which fluid continues to flow away from the well bore while within which the fluid flows toward the well bore. The simulated head returned to near pre-injection levels slower with distance from the well (Figure 9), with levels at the edge of the shale (layer 40) and in the near-shale sandstone (layer 39) requiring several hundred days to recover. After recovering from injection, the potentiometric surface above the shale increased in response to flux through the shale adjusting to the change in shale properties (Figure 9), as simulated in scenario three. The scenario required about 6000 days (16 years) for the potentiometric surface to stabilize at new, higher, levels (Figure 9). Removing the fault from the simulation had little effect on the time to stabilization, and is not shown.

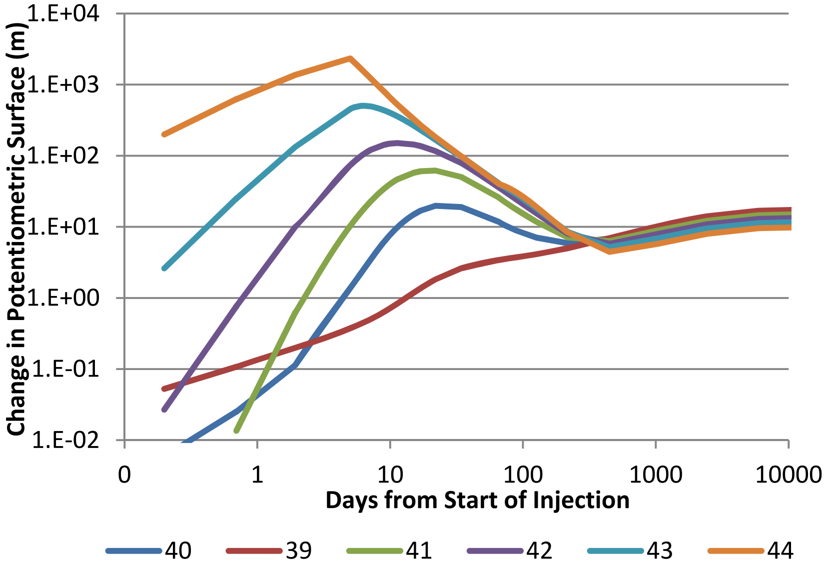

Figure 9: Simulated potentiometric surface changes by layer for specified injection and media properties; Kss=0.01 m/d, Ksh = 0.001 m/d, Kfault = 1 m/d. S(fractured shale) = 0.001 m^{-1}, S(ss) = 0.0001 m^{-1}

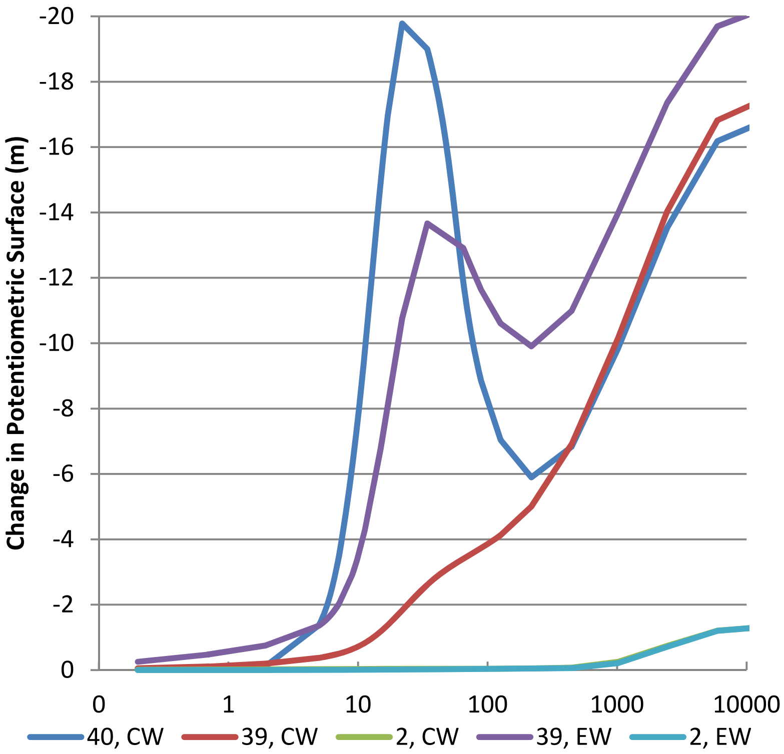

Figure 10: Simulated potentiometric surface changes for layers within the shale and sandstone. CW is center monitoring well and EW is east monitoring well, about 120 m from the centerline. Fault is included. The line for Layer 2, CW plots beneath the line for Layer 2, EW. Kss = 0.01 m/d, Kshale = 0.001 m/d, Kfault=1m/d, S(fractured shale) = 0.001 m^{-1}, S(ss) = 0.0001 m^{-1}

Prior to injection, the steady flow for in-situ shale ($K=10^{-5}$ m/d) was generally less than 2 m^3/d and varied little with sandstone K (Figure 5). Once the shale was fractured, the sandstone controlled the flux which ranges from 38 to 135 m^3/d as sandstone K ranges from 0.01 to 0.1 m/d (Figure 10), resulting in particle travel times of 2390 and 616 years, respectively. More conductive shale would allow faster transport (Figure 8). Adding a fault to the scenario with sandstone K equal to 0.01 m/d increased the flux to about 63 m^3/d with 36 m^3/d through the fault (Figure 10) and decreased the particle travel time to 31 from 2390 years. The fault properties control the particle travel time, especially if the fault K is two or more orders of magnitude higher than the sandstone.

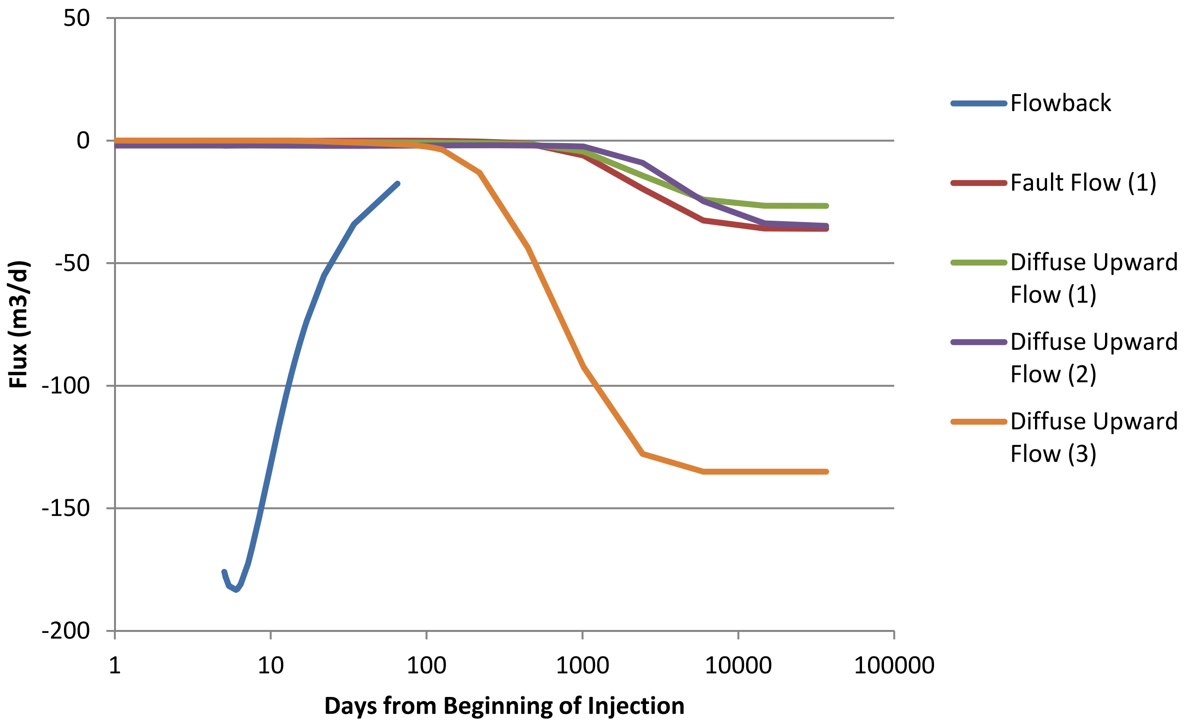

Figure 11: Various fluxes for three separate scenarios. Flowback is the same for all scenarios. (1): Kss=0.01 m/d, Kshale = 0.001 m/d, Fault K = 1 m/d; (2): Kss = 0.01 m/d, Kshale = 0.001 m/d, no fault; (3) Kss= 0.1 m/d, Kshale = 0.001 m/d, no fault.

Simulated flowback varied little with shale K because it had been calibrated to be 20 percent of the injection volume. A lower storage coefficient or higher K would allow the injected fluid to move further from the well, which would lead to less flowback. Lower K would also lead to higher injection pressure which in turn would fracture the shale more.

Vertical flux through the overall section with a fault varies significantly with time, due to the adjustments in potentiometric surface. One day after injection, vertical flux exceeds significantly the pre-injection flux about 200 m above the shale (Figure 11). After 600 days, the vertical flux near the shale is about 68 m^3/d and in layer 2 about 58 m^3/d; it approaches steady state through all sections after 100 years with flux equaling about 62.6 m^3/d. The 100-year steady flux is about 61.5 m^3/d higher than the pre-injection flux because of the changed shale properties.

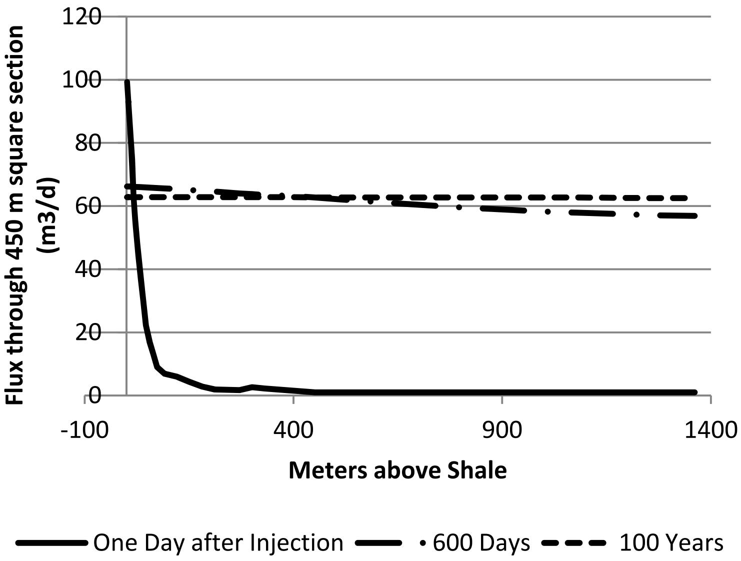

Figure 12: Upward flux across the domain section as a function of distance above the top of the shale layer. Cross section is 202,500 m^2.

Discussion

The interpretative modeling completed herein has revealed several facts about fracking. First, MODFLOW can be coded to adequately simulate fracking. Simulated pressures are high, but velocities even near the well do not violate the assumptions for Darcian flow. Second, injection for five days causes extremely high pressure within the shale that decreases with distance from the well. The time to maximum pressure away from the well lags the time of maximum pressure at the well. The pressure drops back to close to its pre-injection level at the well within 90 days, indicating the injection affects the flow for significantly longer periods than just during the fracking operation. Although the times may vary based on media properties, the difference would be at most a month or so, based on the various combinations of properties simulated. The system transitions within six years due to changes in the shale properties. The same order of magnitude would apply to changes in shale properties from less to more conductive. The equilibrium transport rate would transition from a system requiring thousands of years to one requiring hundreds of years or less within less than ten years.

Third, most of the injected water in the simulation flows vertically rather than horizontally through the shale. This reflects the higher sandstone K 20 m above the well and the no flow boundary within 225 m laterally from the well, which emulates in-situ shale properties that would manifest at some distance in the shale.

Fourth, the interpretative model accurately and realistically simulates long-term steady state flow conditions, with an upward flow that would advect whatever conservative constituents exist at depth. Using low, unfractured K values, the transport simulation may correspond with advective transport over geologic time although there are conditions for which it would occur much more quickly (Figure 5). If the shale K is 0.01 m/d, transport could occur on the order of a few hundreds of years. Faults through the overburden could speed the transport time considerably. Reasonable scenarios presented herein suggest the travel time could be decreased further by an order of magnitude.

Fifth, fracking increases the shale K by several orders of magnitude. The regional hydrogeology changes due to the increased K. Vertical flow could change over broad areas if the expected density of wells in the Marcellus shale region (NYSDEC 2011) actually occurs.

Sixth, fault fracture zones coming close to contacting the newly-fractured shale could allow contaminants to reach surface areas in tens of years. Faults can decrease the simulated particle travel time several orders of magnitude.

Conclusion

Fracking can release fluids and contaminants from the shale either by changing the shale hydrogeology or simply by the injected fluid forcing other fluids out of the shale. The complexities of contaminant transport from hydraulically fractured shale to near-surface aquifers render estimates uncertain, but a range of interpretative simulations suggest that transport times could be decreased from geologic time scales to as few as tens of years. Preferential flow through fractures could further decrease the travel times to as little as just a few years.

There is no data to verify either the pre- or post-fracking properties of the shale. The evidence for potential vertical contaminant flow is strong, but there are also almost no monitoring systems that would detect contaminant transport as considered herein. Several improvements could be made.

- Prior to hydraulic fracturing operations, the subsurface should be mapped for the presence of faults and measurement of their properties
- A reasonable setback distance from the fracking to the faults should be established. The setback distance should be based on a reasonable risk analysis of fracking increasing the pressures within the fault.
- The properties of the shale should be verified, post-fracking, to assess how the hydrogeology will change.
- A system of deep and shallow monitoring wells and piezometers should be established in areas expecting significant development, before that development begins (Williams 2010).

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Appendix C

Review of NYSERDA Commissioned Review of Myers Comments on the 2009 DSGEIS

Prepared by: Tom Myers

11/30/11

Introduction

The New York State Energy and Resource Development Agency (NYSERDA) commission Alpha Geosciences (Alpha) to complete a review of the comments I had prepared for the 2009 Draft Supplemental Generic Environmental Impact State (DSGEIS). This report replies to some of those review comments. Throughout, I refer to the review as “Alpha”.

General Points

Alpha divided my comments into various subsets for their response, but they rely very much on several points throughout their response. One is their perception of there being no hydraulic connection between groundwater at depth, in the Marcellus shale, and the near-surface aquifers; they also dismiss the analysis from ICF (2009) on the same basis, even though they have no data with which to dismiss the argument. Their second line of reasoning is the results or conclusions from the 2004 EPA study of coal bed methane fracking.

Alpha rejects the suggestion that a water balance for the project area or subareas “would not serve the purpose of the SGEIS” (Alpha, at 4). They provide no reason for this conclusion, but also state that a “water balance clearly is site-specific” (Id.). A water balance can be useful for any size study area or portion of the study area. A water balance for the overall study area would help to understand the total volume of water involved in fracking; a similar argument can be made for a watershed – a water balance for the groundwater would help to understand whether the water amounts used for fracking is a substantial portion of the local water balance.

Alpha partially rejects my suggestion that a better description of the area’s hydrogeology is needed by quoting my statement that “the Marcellus Shale is ‘notoriously heterogeneous’” (Alpha, at 4). The request for a better description pertains to the overall area, not specifically the Marcellus shale. Additionally, the statement supports the concept that reported permeability values for the shale may not be representative and that broader scale description are required.

Hydraulic Connection between Shale and Surface

Alpha argues that the “target shales exist as an isolated system from the overlying fresh water-bearing units” (Alpha, at 4). “Isolated” overstates the case even for natural conditions, although the connection may be limited, as I accepted in 2009. Alpha claims that the “shales … are not part of, and are not connected to, the regional hydrogeological systems. Their baseline geologic evidence that fluid migration to overlying fresh water aquifers is improbable includes studies that show the Marcellus shale has remained isolated from overlying formations for millions of years" (Alpha, at 5). Alpha does not directly provide citations for these "studies", but in the next sentence references the "facts that these units are 'overpressured' and that natural gas and saline water has remained trapped … for millions of years" (Id.) to two industry studies and the GEIS. This all ignores the science, cited in Myers (in review) of the upward movement and artesian pressure, observed during geothermal exploration, in formations above the shale. The salt in the shale may be the source of the salt in overlying formations, with the upward movement of salt balanced by the downward movement of freshwater recharge. This balance could be substantially upset by the changes wrought by fracking on the shale.

The "overpressuring" of the shale does not prove that the shale itself is isolated. Overpressuring is due to the gas being contained in the low permeability, very small pore spaces of the shale. Once fracked, the overpressuring may provide an initial source for water to flow into the formations above the shale.

The isolation argument is invoked again, by Alpha, at 11&12, 20, and 33.

My discussion relied and continues to rely for the 2011 rDSGEIS on the fact that fracking will change those conditions, changing the shale from an almost impervious aquitard into a low-conductivity formation; the previously isolated formation water will no longer be "isolated" because fracking fluid injection will push some into surrounding formations. The "overpressuring" in the shale may suggest that the shale itself is isolated at least in places. Myers' (2009 and in review) argument relies on the connection in the formation above the shale. Once fracked, the shale will have a much higher permeability so that fluids in the shale can move into surrounding formations within which the general groundwater flow will control.

Alpha refers to the fact that shallow water wells may be hydrofractured as "additional evidence that natural fractures and structures are not necessarily transmissive" (Alpha, at 4 and 37). This is a comparison of "apples and oranges". Hydrofracturing water wells may be done to increase their yield when screened in low-transmissivity formations; fracking water wells is done to increase the well yield from a few gallons per minute. The transmissivity of unfracked shale is orders of magnitude less than that in the formations in which a water well may have been screened. The cause for fracking in water wells differs from the cause for fracking a gas well; the comparison is irrelevant and proves nothing about the isolated nature of shale.

A further reliance on "overpressuring" is demonstrated (Alpha, at 5) where Alpha notes that eight research wells in the Marcellus shale had pressure gradients of 0.46 to 0.51 psia/ft when hydrostatic pressure is 0.433 psia/ft. That waters remain contained in the shale even with this overpressuring demonstrates their isolation. Once fracking hydraulically connects the shale with the overlying formations, the overpressuring is a source of pressure that would cause an upward gradient. The pressure would likely dissipate with time, but it would also cause an upward gradient after fracking.

Alpha indicates that my "hypothetical pathway … to ground water is along faults and fractures that intersect the Marcellus or induced fractures that extend beyond the target formation" (Alpha, at 5). This mischaracterizes the argument in two ways. First, it ignores the potential flow through the bulk media, through the primary porosity of the formations; this pathway would be slower, but flow is possible if there is a connection (Myers, in review) with the newly fractured shale. Myers (in review) found this flow to require from 100s to 1000s of years for contaminant transport. Second, natural faults and fractures do not have to "intersect" the shale, just reach its edge. Fluids within the shale would access the natural fractures above the shale, once fracked; the overpressuring would provide an added gradient for flow from the shale to surrounding formations, once fracking releases the fluids.

Alpha's second point is correct; out-of-formation fractures would provide an additional pathway. Although Alpha continues to suggest that out-of-formation fracking is rare, in their view, more current evidence is that it occurs frequently and extends as much as 2000 feet above the target formation (Fischer 2010); Alpha even references a personal communication from Fisher (Alpha, at 24) to recommend that the "SGEIS acknowledge that hydrofracturing has been shown to induce fractures beyond the target formation" (Id.). It appears that Alpha is not familiar with up to date literature or science.

Alpha rejects the "suggestion of 'head level maps'" that I had suggested in 2009 based on their rejection of the concept of saturated conditions from the "top of the target zone to the land surface" (Alpha, at 20). If there is no connection, groundwater levels will show nothing. They also note the isolation argument (at 20, 21) to reject the need for head level maps. Head level maps as recommended by Myers (2009) would confirm or deny the presence of upward head gradients in the formations above the shale. Once released by fracking, contaminants could advect along the flow paths which would be delineated by the hydraulic gradient. Although the fracking itself will change the gradient and potentially increase the potential upward flow, mapping the groundwater levels would assist the NYSDEC in determining where transport is possible. Alpha's recommendation is to basically ignore science and ignore the possibility of upward flow. Alpha replied to my comment suggesting that the rDSGEIS discuss properties resulting from fracking by discussing the direction that fractures would take in the shale (Alpha, at 15). My comments indicated that the rDSGEIS should include hydrogeologic properties, therefore Alphas reply was not responsive to the comment. Alpha's response that my "argument that the fractures will extend to and connect overlying fractures or paleofractures contradicts rock mechanics principles and field observations" is countered by the recent data in Fisher (2010) showing out-of-formation fracking. Alpha is unclear and provides no references as to how the comments contradict "rock mechanics principles".

I had also recommended that the NYSDEC require the industry to monitor post fracking shale properties. Alpha states that "[f]racture monitoring is required by the Proposed Supplementary Permit Conditions … (#33 and #34)" (Alpha at 16). That is incorrect; those permit conditions require the driller report on recorded operations during fracking, including pressure and the amount of injected, but that is not the same thing as doing post-frack monitoring, which could include microseismic surveys or core sampling. They also suggest that "[f]racture monitoring also can be evaluated on a well-specific basis using the same criteria as the requirement to collect core samples and well logs" (Alpha, at 16). Those requirements are for pre-fracking conditions, not post-fracking.

Myers' Groundwater Modeling and ICF Analytical Modeling

I prepared (Myers 2009) an interpretative numerical groundwater model to consider whether and over what time frame flow could occur from the shale to freshwater aquifers. The "theory supporting Myers' model" is NOT from Hill and Tiedeman (2007) (Alpha, at 23). The reference is to the concept of "interpretative" modeling as opposed to a calibrated, predictive model. "Myers acknowledges that his model is not calibrated and cannot be used for predictive purposes" (Alpha, at 12). An interpretative model is not used for prediction, so Alpha's attack on the model is an attack here is irrelevant. The model does assume that the interburden between the ground surface and top of the shale is saturated, but not through the "isolated shale gas formations" (Id.). Again, the modeling is of the interburden and the shale, once it is fracked to its edge or beyond, is a boundary or a source of both fluids and contaminants. Or, flow through the shale is estimated based on its extremely low in-situ conductivity.

The numerical model I used in 2009 was not "to support [my] opinion" (Id.) but to test my conceptualization as to whether the flow was possible and under what conditions. Alpha criticizes the fact the model "oversimplifies ground water flow and transport". All groundwater models simplify flow; simple applications of Darcy's law are the most oversimplified analyses. The addition of secondary permeability, or fracture flow, to a contaminant transport analysis usually increases the rate that contaminants move, thus my estimated times should be low.

Alpha asserts that my "offered alternate model is not technically defensible" apparently based on their perceived lack of a hydraulic connection. They state that an assumption of a hydraulic connection "contradicts decades of hydrofracturing data and experience in the U.S." (Alpha, at 11) without referencing or outlining the data in support of their contention. They also claim that my analysis is based on "the entire bedrock stratigraphic column [being] highly fractured" (Alpha, at 12). This statement does not reflect the analysis in Myers (2009), for reasons noted above - the conductivity values used for the formations between the shale and surface were based on observed primary conductivity values (Anderson Woessner 1992), not fractured values.

ICF's flow equations are correct (Alpha at 11), but the problem is how they were parameterized and time frame they were applied over. As Myers (2009) discussed, the relevant gradient is not from the well to the aquifers, but from the well to just beyond the influence of the spreading injected fracking fluid, the point at which the background pressure has not changed. Also, the conductivity parameters for the formations between the shale and the aquifers do not reflect fractures, unless specifically parameterized as such. The parameters reflect standard textbook bulk conductivity values for sandstone.

Vertical Contaminant Transport

I had argued that "natural gradients" would allow vertical contaminant transport of frack fluid through advection. Alpha claims that "Engelder refutes that injected frac water would migrate vertically upward in his slide-presentation review of others" (Alpha, at 24). Aside from the confusing phrase, "slide-presentation review of others", this line of reasoning cannot be correct because frack fluid is lighter than the high-TDS brine found in the shale; buoyancy due to frack fluid being lighter than brine would enhance its upward movement. The movement of high-TDS formation water could be inhibited by its denser nature, but the point is that upward hydraulic gradients cause the flow. The overpressuring discussed above is proof of these upward gradients and suggestive that fracking would release some of this pressure into the formations lying above.

Engelder's "principle of viscosity" (Id.) may apply "to ground water as well as gases", but the fact that low viscosity gases have been contained from vertical migration for millions of years does not mean that fracking will not release contaminants that could migrate upward much quicker. The relevant "containment" is provided in the shale and has nothing to do with the properties of overlying formations. Shale has contained gas for millions of years; fracking will cause that gas to be released in 30 to 50 years (the length of time most wells will produce). This can only occur if the properties that contain the gas will vastly change.

Leaks from Well Bores

The DSGEIS had implied that leaks do not occur from properly-constructed wells, but did not specify how often wells are found to not be properly constructed, and I requested (Myers 2009) that they provide an estimate of the times the wells are not properly constructed. Alpha responded with a quote from an industry source that estimated risk from failures to properly constructed wells is less than one in 50 million (Alpha, at 32). Alpha should have included the entire paragraph from which they selectively chose their quote, because it indicates the wells considered are class II injection wells and are properly constructed. Fracking wells experience a much higher, although much shorter, pressure during operations. They also should realize that the comment had to do with wells that are improperly constructed, because most failures, those that have allowed gas into groundwater, have resulted from improperly constructed wells.

Alpha also protests too much when they discuss my examples of gas in water wells (Alpha, at 33, 34). Incidents not related specifically to fracking are relevant because they show that the gas does move long distances through the groundwater, regardless of the source. Coal bed methane development relies on the gas moving through the groundwater, in coal seams, to the production wells; those production wells commonly pump as much water as do water wells, so, if gas is present to move to the water wells, the conceptual model for flow to water wells is similar. The point has to do with gas moving through aquifers due to any source – direct from the shale or a leak from the well bore.

Comparison to CBM Wells

Alpha used the conclusion to the EPA's 2004 CBM study, that fracking in coal seams poses little or no threat to underground sources of drinking water (Alpha, at 20) to support their conclusion that I had ignored relevant data (EPA's study) and that my arguments were fallacious because CBM wells are a much higher risk. They also state that "[c]oalbed hydrofracturing events approximate conditions where shale hydrofracturing is performed closest to ground water resources" (Id.). This is simply not true, and it directly contradicts the conditions that the EPA put on their conclusion. EPA relied on the nature of CBM wells for their conclusion. “Although potentially hazardous chemicals may be introduced into USDWs when fracturing fluids are injected into coal seams that lie within USDWs, the risk posed to USDWs by introduction of these chemicals is **reduced significantly by groundwater production and injected fluid recovery**, combined with the mitigating effects of dilution and dispersion, adsorption, and potentially biodegradation” (EPA, 2004, at 7-5, emphasis added).

In fracked shale, there is no intentional “injected fluid recovery” brought about by pumping the injection wells, as in CBM wells. CBM wells pump water toward the gas well; this pumping decreases the hydrostatic pressure which releases the gas from the coal. Water and contaminants in the coal seam flows toward the CBM well. If there were contaminants in the coal, they would be drawn toward the CBM well.

Fracking in a coal seam would require much less pressure as well which would cause less out-of-formation fractures, which would limit the chance for out-of-formation fractures to occur. Additionally, EPA relies on the “high stress contrast between adjacent geologic strata” as a barrier to fracture propagation. The fact the coal is softer and the seams are much shallower and require much less fracking pressure helps to limit the fractures to the coal, much in contrast to shale seams (Fisher, 2010).

Finally, although the EPA’s reasoning is reasonable, their methodology for concluding there has been no contamination is suspect; they only considered reported cases of contamination rather than relying on monitoring data. Fracking fluids in water wells near coal seams would be reported only if someone detects a problem. There have been cases of methane reaching water wells in the coal seams, but methane is obvious as it bubbles coming from the faucet.

Alpha claims that “Myers fails to address the historical data presented by ICF (2009, p. 22)” (Alpha at 19). ICF (2009, p 22) does not actually present data, contrary to Alpha’s allegation. GWPC (1998), the source of ICF’s “data”, presents the results of a survey to which officials from states with over 10,000 coal-bed methane wells had responded they had never found groundwater contamination. However, contrary to Alpha’s allegation, GWPC did not analyze 10,000 wells’ worth of data. GWPC does not present monitoring data as proof, they present survey data from agency personnel claiming there has been no reported contamination. There is no indication whether the agencies ever looked for contamination beyond the claims of well owners. ICF also notes that coal seams may be used as aquifers, but did not indicate how many of the coal seams being developed by the CBM wells in the states replied to by the agency personnel were also aquifers.

Alpha truly mixes apples and oranges by using studies of CBM development, including fracking, to conclude that shale-gas development poses no threat to groundwater.

General Hydrogeology

Alpha’s response to comments regarding aquifer depletion is a stretch to show how they actually disagree with my comments. Specifically, my comments about failures to regulate are replied to by stating the various commissions must permit the withdrawal – the problem is that there are really no specifics provided about how the decision to permit would be granted. The DSGEIS did not specify what standard had to be met, beyond simple reporting, to be granted a permit.

Mitigating Surface Water Impacts

Alpha goes out of its way to find something to criticize in its review of my general surface water comments (Alpha, at 44, 45). My comments were generally qualitative and Alpha's responses are generally not substantial enough to require a reply here.

In Alpha section 4.2, regarding the use of the natural flow regime method, Alpha states that I was incorrect in claiming the NYSDEC would not require its use (Alpha, at 48). The 2011 rDSGEIS states clearly that it is NYSDEC's intent to require use of the NFRM, but the 2009 DSGEIS only states that it is "preferred", not required (2009 DSGEIS, at 7-3).

Alpha responds in detail to my comments regarding the Delaware and Susquehanna River Basin Commissions' methods (Alpha at 46, 47), even though they acknowledge the dSGEIS would require the NFRM. Because the rDSGEIS states the NFRM will be used throughout the project area, there is little reason to reply further to Alpha's comments at this point.

Ultimately, Alpha adapts many of my recommendations regarding surface water flow (Alpha, at 50, 51). They do not specifically endorse the recommendation to minimize the effect on aquatic habitats (outlined at Alpha, p. 47), the RDSGEIS does adapt a recommendation for using the Q60 or Q75 flow by month, which by month is better than my original recommendation.

Setbacks

Alpha discusses vertical setbacks along with my comments on monitoring and the need for water level mapping (Alpha, section 3.1). Much of their response relies on their perceived lack of hydraulic connection among formations, which has been discussed above.

Regarding horizontal setbacks, I had suggested that the recommended values are not based on any data or analysis of their effectiveness. Alpha simply rejects this without providing any reference, data, or results. "Myers assumes the setbacks proposed in the dSGEIS are not based on analysis; however, the setbacks are supported by practical application, experience, and historical analyses" (Alpha, at 43). Alpha repeats this sentence twice, verbatim, on the same page. When stating something as being based on analyses, it is customary scientific practice to cite the references to these analyses, something Alpha has failed to do. Alpha also suggests the "dSGEIS reference SEQRA, NYSDOH, NYC Watershed Rules and Regulations, the Clean Water Protection Act, and public water protection rules from other states" (Id.). Alpha does not indicate where in the dSGEIS these references are made, not indicates that the references include any analysis. Referencing others' rules without analyzing their effectiveness is not a scientific justification for specifying a setback. My statements are not that the setbacks are wrong, but that it is unknown whether they are effective. My recommendations may be larger than those in the dSGEIS, but they are designed to be protective to encourage a site specific analsis.

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Attachment 3

Glenn Miller, Ph.D.

Review of the

Revised Draft
Supplemental Generic Environmental Impact Statement on The Oil, Gas and Solution Mining Regulatory Program
Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

Prepared for:
Natural Resources Defense Council
New York, New York

Prepared by
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Reno, NV

January 6, 2012

This document represents a review of the Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) regarding proposals to develop natural gas wells using high-volume hydraulic fracturing in New York. I have specifically examined some of the chemical and toxicological issues, particularly related to the fracturing additives used, and the management of the severely contaminated flowback/produced brines. The RDSGEIS, in general, is an improved document compared to the previous draft of the potential environmental impact of the very large number of gas wells being proposed in much of New York. However, several key potentially significant adverse impacts remain inadequately addressed.

The following comments should be considered.

A. The water that flows back immediately following hydraulic fracturing is heavily contaminated (flowback), primarily with the Marcellus formation contaminants, and represents the most problematic chemical contamination potential, due to the large volumes of contaminated water generated. The brines that will be produced during gas production[1] will have higher concentrations of naturally occurring contaminants than flowback water (although lower volumes) and similarly represent a serious chemical contamination potential.

The RDSGEIS recognizes these problems and goes a long way towards evaluation and management of the contaminants; however, it still does not present a comprehensive wastewater management and disposal plan that will handle the anticipated large volumes of heavily contaminated wastewater. Further efforts are required to properly understand the contaminants in the flowback water, and develop management and disposal solutions.

Four problematic components of the flowback water and produced brines are present, including: (1) salts, other inorganic constituents, and metals and metalloids; (2) the radioactive component (NORM); (3) organic substances (from the hydrocarbon formation) and (4) hydraulic fracturing chemical additives.

1. ***Salts, other inorganic constituents, metals and metalloids in the formation water that are brought to the surface both as flowback and as production brines*:** The largest mass component of the formation water is salts and other inorganic constituents. The concentration of these constituents varies widely, as does their toxicity. Because the flowback is proposed to be collected and temporarily stored in closed systems, disposal of these large volumes of water is the largest problem with its management. The RDSGEIS discusses the problems with management of this water, and in

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[1] The terms produced brine, production brine, produced water, and produced water brine are used interchangeably throughout these comments for formation water that is produced up the well.

particular the discharge of high total dissolved solids (TDS) water into receiving waters (see, for example pages 7-63), and stipulates that flowback produced water and brines will need to be regulated as industrial wastewater.

Table 5-10 of the RDSGEIS shows that produced waters (from Pennsylvania and West Virginia) containing the formation water are variable in chemical composition, but include not only simple salts (e.g., sodium, potassium, chloride, bromide, sulfate, fluoride, etc.) but also a variety of metals with varying frequency (cadmium, mercury, cobalt, nickel) and metalloids (arsenic, selenium, boron). Some of the constituent concentrations are very high, particularly sodium chloride, which has a mean concentration of over 10% by weight. Some samples had over 30% by weight simple salts plus other contaminants. The extreme contamination of these wastewaters and the high variability of contaminant levels make these waters complicated for treatment and potential reuse, as well as for tracking and disposal. If improperly managed and released to surface or groundwater, severe contamination is a reasonably foreseeable outcome. In particular, if this contaminated water intercepts domestic groundwater sources, the potential exists to permanently damage aquifers as current and future domestic water supplies.

While recognizing the problems with management of this water, the RDSGEIS fails to clearly state how this water will be either disposed in a manner that protects human health and the environment, or otherwise treated to remove the contaminants. While the RDSGEIS provides a range of treatment and disposal alternatives, the RDSGEIS does not sufficiently analyze the environmental or human health impacts associated with any of these treatment and disposal options. Further, the RDSGEIS implies that virtually all of the wastewater generated in New York will be managed out of state, where regulations may be less stringent, due to the lack of treatment capacity for these contaminated waters in New York.

2. ***Radioactive Substances (NORM):*** The RDSGEIS also recognizes the issues associated with management of NORM that comes to the surface either in the flowback or the production brines. However, similar to the salt problem discussed above, it does not explicitly indicate how wastes contaminated with NORM will be regulated and disposed.

   Examples of NORM concentrations in flowback are presented in Table 5-24, and in produced brines in Appendix 13. As expected, the NORM present in the flowback is somewhat lower than in the brines, due to dilutions when fresh water is used for the primary fracturing fluids. Less dilution would be expected if the flowback is reused as a portion of the fracturing fluid for another well.

Only three produced brine samples are shown in Appendix 14, but the level of radioactivity as gross alpha is very high, from about 18,000 pCi /L to 123,000 pCi/L. The standard for safe drinking water is 15 pCi/L (gross alpha).

The RDSGEIS does not propose a disposal solution for residual NORM, if it is separated from the produced water and the flowback water. Dilution of the brines to a drinking standard of 15 pCi/L (gross alpha) will require 1000x to 10,000x dilutions, and is unlikely to be acceptable in any jurisdiction, particularly when the components that are causing the radioactivity are not specified. While some mention of regulatory oversight is made in the RDSGEIS, there are no explicit indications of how these waters will be regulated or managed. The RDSGEIS does not propose a technically sound or viable solution for disposing of these radioactive materials. The RDSGEIS has not examined options such as evaporation-crystallization treatment or chemical precipitation. These processes will produce a very large tonnage of salts containing radioactive and metal waste. The lack of a thorough treatment and disposal analysis presents a serious problem when assessing the risk and potentially significant adverse impacts of these substances. There is effectively no analysis of how these materials will be disposed, other than a general (potential) suggestion that new licensing may be required.

For an adequate environmental analysis, it is also critical to identify the sources of the gross alpha radiation. Gross alpha radiation is defined by the U.S. EPA (40 CFR Parts 9, 141, and 142 [National Primary Drinking Water Regulations; Radionuclides; Final Rule]) as the total amount of alpha radiation minus the alpha radiation coming from uranium and radon. Table 2.3 of the RDSGEIS, which specifies the primary drinking water standards, is unclear as to how New York regulates radioactivity, other than to indicate that it will limit "alpha particles" to 15 pCi/L in drinking water, but does not indicate if that includes uranium. For the three samples of groundwater indicated in Appendix 13, only a small fraction of the components of the gross alpha have been identified, with the largest component being ^{226}Ra. For the three samples provided in Appendix 13, the individual gross alpha contributors can be summed to provide only 14-24% of the gross alpha in the water samples. The RDSGEIS does not identify the source of the remaining 76%+ alpha radiation; this omission constitutes a major flaw in the radioactive waste treatment and disposal analysis.

While it may be difficult to get an exact mass balance, accounting for less than 25% of the alpha radioactivity is insufficient.

It is unclear whether the data in Appendix 13 were based on the EPA gross alpha radiation definition, but the implications are substantial. If the EPA gross alpha radiation definition is used (which is probably the case), some other source of the alpha radiation will be present (e.g., polonium) as was observed in the Florida phosphate industry (Burnett, et al., 1988). Verifying radioactive waste constituents is particularly important when assessing radioactive waste risk and to develop viable treatment and disposal options. Radioactive materials will also precipitate as scale in equipment; therefore, verifying radioactive waste constituents is also important for determining the radioactive risk as pipes are disassembled when cleaning is needed, or when the wells are disassembled when gas production ceases. If the source of the excess alpha radiation is polonium, the residual radioactivity from water treatment or scale management will potentially be more expensive to manage safely. The RDSGEIS has not analyzed the polonium risk, or treatment and disposal options for radioactive waste containing polonium.

While the U.S. does not have a polonium 210 standard, both Canada and the European Union do (see accompanying comments of Dr. Ralph Seiler), and it is lower or similar to the U.S. radium standard (5 pCi/L). Polonium is soluble in water under reducing conditions, and should be assumed to contribute to the alpha emission from the formation water, unless NYSDEC can rule out the risk. Polonium's risk contribution, however, is not currently analyzed in the RDSGEIS, and is a critical data gap in the NORM analysis. Polonium is a strong alpha emitter, but most importantly, treatment/management of these waters for disposal should require knowledge of the composition of the alpha emitting NORM component. Only then can appropriate methods for treatment and disposal be developed.

An additional component of the naturally occurring radioactivity is radon, a gaseous odorless radioactive element that is responsible for approximately 21,000 deaths from lung cancer each year (ATSDR, 2012), and is second only to cigarette smoking for causing this disease. Southern New York is already recognized as a region where elevated radon (>4 pCi/L) is common. Adding radon to households either from improperly vented gas utilizing appliances or through water systems that have been contaminated with natural gas leaks in groundwater supplies presents an additional risk factor for radon.

Data on radon in natural gas from the Marcellus Shale formation is very scant, and the RDSGEIS does not contain a sufficient amount of data to verify the maximum concentrations of radon expected in Marcellus Shale gas, or any other natural gas that may be developed under the proposed scope of the SGEIS. The amount of radon in natural gas is a critical measurement that should be made, to examine the incremental risk of radon exposure in homes and places of business that use natural gas or well water that could experience higher radon content as Marcellus and other shale gases are produced in NYS. While normal natural gas use in properly ventilated burners is unlikely to contribute to radon concentrations in closed spaces (see accompanying Seiler report), poorly vented areas may result in increased radon concentrations, and certain scenarios (e.g., high use of natural gas for industrial applications, restaurants that use gas burners)

> should be subject to risk assessment. The risk of radon exposure from burning natural gas in poorly ventilated areas is likely to be greatest in indoor areas that already have elevated radon exposure levels.
>
> An additional risk is when natural gas from a well leaks into an aquifer used as a well water source. Depending on concentrations of radon in the water, and the use of that water, radon levels can potentially be elevated in homes. This is a separate risk than from burning natural gas, but it is reasonable to develop scenarios where highly radon-contaminated gas moves through the soil profile and into homes. However, there are only scant radon data that can provide a basis for estimating those risks.

Recommendation 1. The SGEIS should clearly identify treatment and disposal options for flowback and wastewater, analyze the range of treatment and disposal alternatives, and propose the best technology and best practices for handling this waste. These technologies and practices should be included in the SGEIS as a mitigation measure, and codified in the NYCRR. The SGEIS treatment and disposal options for flowback and wastewater analysis should include a detailed examination of the waste constituents including, at a minimum: salts and inorganic constituents; NORM; metals and metalloids; organic substances (from the hydrocarbon formation); and fracture treatment additives.

Recommendation 2. The SGEIS should examine the existing wastewater treatment capacity in NYS, compared to the potential volume and composition of wastewater that will be generated by the proposed development, and make specific recommendations to ensure sufficient waste handling capacity exists before authorizing the proposed development. If waste will be transported to other states, the SGEIS should examine the impacts of that waste handling option as well.

Recommendation 3. The components of the gross alpha radioactivity should be identified in the RDSGEIS, and mitigation measures should be proposed to address radioactivity risk. The RDSGEIS does not identify 76%+ of the gross alpha radioactivity. The specific definition of gross alpha radioactivity should also be stated, or the EPA definition should be used.

Recommendation 4. The RDSGEIS should determine whether polonium is a significant component of alpha emission in formation waters, and polonium-contaminated wastewater should be regulated/managed appropriately to limit its discharge to surface or groundwater, as should all of the individual components of NORM.

Recommendation 5. Specific treatment methods to remove radioactive constituents from flowback and produced water need to be identified. If the radioactive constituents are removed from wastewater, management methods and disposal sites for the residual radioactive wastes should be identified. (See further discussion below.)

Recommendation 6. Additional radon measurements are needed to determine the range of concentrations of radon expected in Marcellus Shale gas or any other gas that may be developed under the proposed scope of the SGEIS. Gas measurement should be made at the wellhead, where natural gas is being used, including homes, businesses that use large amounts of natural gas, and in areas where natural gas leaks have been found. The SGEIS should include radon testing requirements as a mitigation measure, and this requirement should also be codified in the NYCRR.

3. ***Hydrocarbons present in the formation water:*** Hydrocarbons present in the flowback and produced water are characteristic of fuel hydrocarbons, and are represented by (a) compounds that, in some cases, are carcinogenic (e.g., benzene, benzo(a)pyrene); (b) common solvents (e.g., toluene, ethylbenze); and (c) the primary fuel components of natural gas, particularly methane. Common solvents and primary gas components, although generally of lower solubility in water, represent a toxic contribution that can be a serious risk, if they are released either into surface water or as a vapor that may subject persons living in the area to exposure.

4. ***Hydraulic fracturing additives:*** The range of hydraulic additives is very large, and difficult to assess from a risk perspective since the list is almost certainly incomplete, specific information on the chemicals is lacking, and the specific rate of usage is not offered. Thus, not knowing the composition of the specific additives and the amounts provides effectively no basis for estimating the risk of these components of the flowback or produced water, and the RDSGEIS falls seriously short in this regard. A mere laundry list of these components does not meet requirements for analysis of their potential impacts. The list is so long, and the data on each component so incomplete, that it falls far short of the data that would normally be contained in a professional scientific risk analysis. Additionally, Tables 5.4 and 5.5 use trade names, and while the New York regulators may have information on the constituents in those products, that information was not available for this review. Additionally, the public does not have access to this information, and thus the public cannot legitimately understand or evaluate the risk of these products to their health or the environment that they live in.

   Table 6.1 reports the constituents found in flowback, and effectively none of the additive compounds used in fracturing were reported in the flowback, except for the hydrocarbons that occur naturally in the hydrocarbon formations (benzene, toluene, xylene, naphthalene, etc.). In fact, the only non-fuel compound found in flowback that is also mentioned as a hydraulic fracturing additive is propylene glycol. This analysis demonstrates a significant problem in examining flowback chemical composition. Either NYSDEC is concluding that chemicals injected into the formation do not return in the flowback (improbable), or NYSDEC has not employed the correct analytical methods to evaluate flowback waste constituents.

> It is not clear from the RDSGEIS how many of the additives were actually subjected to analysis in the flowback samples. Most of the chemicals listed in Table 6.1 that are used as additives will not be detected/measured by the standard methods used to determine hydrocarbons and metals. Therefore, the absence chemical additives in the flowback samples shown in the RDSGEIS is likely a function of incomplete laboratory analysis. For example, it is not clear that any attempt was made to actually measure the following three compounds in the flowback water: (1) 1-propanesulfonic acid; (2) 2-propenoic acid, homopolymer, ammonium salt; (3) acetic acid, hydroxyl-, reaction products with triethanolamine. None of the methods used by the Marcellus Shale Coalition (see Chapter 5-109) would, in this reviewer's estimation, be suitable for measuring these compounds. In fact, many, if not most of the additives, require very specialized methods for analysis; some are multiple chemicals (e.g., polymers), and some are relatively unstable (e.g., acrylamide).
>
> There is, however, an implication that since the compounds were not subject to analysis, and thus not observed in the flowback water, they do not exist in the flowback water, which is a scientifically unjustified conclusion and almost certainly not the case.
>
> Table 6.1 should be re-created with an additional column that indicates whether the compounds would have been measured with the analytical scheme utilized (e.g., gc-ms, icp-ms, ion chromatography for anions, etc.). Additionally, the RDSGEIS should list the analytical method required to detect each compound in the flowback. The detection limit for each method should be specified.
>
> A full analysis for all of the additives utilized in hydraulic fracturing is indeed a challenge, but the SGEIS should clearly indicate which compounds could be measured by the protocol utilized, which could not, and what method would be required. It is likely that most if not all of the additives used that are not found in the formation water were not actually measured/determined. Thus, Table 6.1 has very limited value, and provides a distorted view of what is actually being measured.

Recommendation 7. The analytical tables for hydraulic fracturing additives should be revised to clearly show the analytical methods utilized and whether the analytical methods used, and detection limits provided by those methods, are sufficient to protect human health and the environment. The tables should verify if the additives were actually measured in the flowback water.

Recommendation 8. The RDSGEIS should include as a mitigation measure a list of analytically testing methods required to test flowback prior to disposal; these testing requirements should also be codified in the NYCRR.

A detailed risk assessment of each of the potentially toxic additives is a reasonable request. Leakage of flowback water to domestic water has been demonstrated recently in Wyoming by the U.S. EPA (2011) and represents a potential threat to ground water in New York. It is not sufficient to simply argue that gas wells will not leak, since leaks are now apparent in certain well fields (e.g., most recently in Wyoming (US EPA, 2011a)), as well as in Pennsylvania (Pennsylvania DEC, 2011). When leaks occur, it is probable that the greatest risk will be from the naturally occurring substances, but the additives also pose a non-trivial risk.

Practically speaking, it is more efficient and cost-effective to limit the additives used, rather than test for every possible additive in the flowback. Other governments and agencies have developed simplified methods and lists for prohibiting toxic additives, and assessing their risk (e.g., OSPAR PLONOR, C-NLOPB Guidelines, The Norwegian Pollution Control Authority; see accompanying report of Susan Harvey regarding additives). NYS could develop a similar list of prohibited additives, and a process for approving additives for use that will offer a method for reducing risks to both the public and workers.

Some of the additives being used are serious carcinogens, and may be difficult to measure. Two examples of these are acrylamide and acrylonitrile. Both are carcinogenic and, while not long lived in the environment, can create serious exposure concerns to workers and the public.

Acrylonitrile has been found in Pennsylvania and/or West Virginia in water samples taken near hydraulic fracturing operations (data received from individuals who had samples analyzed). It was also observed in flowback water from the Marcellus Shale Coalition (page 5-115 of the RDSGEIS). Acrylonitrile is a carcinogenic (US EPA, 2011b) and exclusively anthropogenic compound. It can be measured in a standard purge and trap gc-ms method, and has been used in Pennsylvania, and is indicated in a patent issued to Halliburton (Halliburton Energy Services, U.S. Patent 7799744). This compound is one of the more toxic compounds used as additives, yet is not even mentioned in the RDSGEIS (Table 5.9). Failure to include a chemical additive that is commonly used and known to be carcinogenic and toxic to humans is a serious deficiency in the RDSGEIS.

Failure to include Acrylonitrile in Table 5.9 raises uncertainty in what other harmful chemical were not listed or examined in the RDSGEIS. Additionally, the RDGSEIS lacks of information on additives use rates. Therefore, the RDSGEIS analysis of the potential significant adverse impact of additive use is, at the least, incomplete.

Acrylonitrile, butadiene and styrene (ABS polymer) are mixed "on the fly" with the uncoated propping agent to create a polymer covering on the propping agent. From the Halliburton patent:

> Some suitable polymers include, but are not limited to, acrylic polymers such as acrylonitrile polymers, acrylonitrile copolymers, and mixtures thereof. Some preferred polymers include homopolymers and copolymers of polyacrylonitrile (including copolymers of acrylonitrile and methyl acrylate, methyl methacrylate, vinyl chloride, styrene and butadiene), polyacylates, polymethacrylates, poly(vinyl alcohol) and its derivatives, and mixtures thereof. As used herein the term "acrylic" polymers refers to any synthetic polymer composed of at least 85% by weight of acrylonitrile units (the Federal Trade Commission definition). Thus, the definition of the term may include homopolymers of polyacrylonitrile and copolymers containing polyacrylonitrile. Usually they are copolymers of acrylonitrile and one or more of the following: methyl acrylate, methyl methacrylate, vinyl chloride, styrene, butadiene. However, polymers that do not meet the definition of an acrylic polymer (such as those having less than 85% acrylonitrile) may also be suitable. For instance, Example 3 uses poly(acrylonitrile-co-butadiene-co-styrene) that contains approximately 25 wt % acrylonitrile.

Further down the patent, the "on-the-fly" process is described.

> In particular embodiments of the present invention, the particulates may be coated with the polymer solution and introduced into the treatment fluid, which acts as the aqueous medium, directly prior to being introduced into a subterranean formation in an on-the-fly treatment.

This process is likely to be inefficient and likely to release substantial amounts of acrylonitrile and styrene into the water used in the fracturing process. Acrylonitrile has been found in flowback water (page 5-115 of the RDSGEIS), and reports are available that show that it has been detected in surface and ground water in Pennsylvania, and is perhaps one of the most unambiguous anthropogenic indicators that off-site contaminated water has been in communication with the water used in the fracturing process. NYSDEC should determine if this polymer and application method is appropriate for use in New York, and require acrylonitrile and styrene as two of the suite of compounds to be analyzed in flowback before it leaves the wellsite.

Recommendation 8. The NYSDEC should re-examine the additives used in hydraulic fracturing and conduct a much more detailed analysis of the risk of these compounds. Specifically , acrylamide and acrylonitrile, a carcinogenic and exclusively anthropogenic compound used in hydraulic fracturing, should be measured in flowback water, and an assessment made as to whether and/or how use of this compound should be permitted. The conclusions of such analysis should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

B. The analytical data presented in Tables 5.10, 5.23, 5.24 and 6.1 all indicate a lack of detailed understanding of the quality of the flowback, and indicate

an inadequate understanding of the methods necessary to fully characterize the wastewater.

The errors in Tables 5.10, 5.23, 5.24 and 6.1 are sufficiently glaring that they need a much more detailed review. For example, in Table 5.10, the dissolved metal concentrations in some cases are higher than total metals. Iron, for example, has a median concentration 29.2 mg/L, but the dissolved median concentration is 63.25 mg/L. Similarly, the mean manganese concentration is 1.89 mg/L, while the dissolved manganese concentration is 2.975 mg/L. There cannot be higher amounts of dissolved iron and manganese than total iron and manganese.

The data from the Marcellus Shale Coalition was not displayed, other than as a table of compound detections. These samples were collected from 19 gas well sites in Pennsylvania and West Virginia. All samples were collected by a single contractor and the analyses performed by a single laboratory, which should reduce the variability. This would appear to be a very valuable data set, but surprisingly, no data were presented regarding concentrations of the analytes. Some comments were provided on the types of compounds detected, although it was not clear which types of water contained these constituents. Additionally, chlorinated hydrocarbon insecticides were detected, which is very surprising, since these compounds could not have been found in the formation water, and have not been used in the U.S. since the 1970's. They are likely false positives, although it is not possible to make that determination, based on the discussion in the RDSGEIS. Data obtained from the Marcellus Shale Coalition should be presented, which compares, for example, flowback water from different wells under similar conditions (e.g., immediate flowback versus flowback in subsequent days).

Finally, the data in Table 6.1, which focuses on the additives used in hydraulic fracturing, is problematic. As discussed above, it is highly unlikely that attempts to determine the concentrations of the fracturing additives were actually conducted, since many of these compounds are difficult to determine. The implication remains, however from Table 6.1, that these compounds were actually considered in some appropriate analytical scheme. This is almost certainly not the case, and Table 6.1 should be clarified.

Recommendation 9. Each of the SGEIS tables of analytical data should be reviewed by an analytical chemist, and the data be presented in a scientifically accurate and quality controlled manner. The data in Table 6.1 should be clarified and the compounds which were not subjected to specific analyses should be identified.

C. Permissible treatment of the flowback and the produced water is not well defined. It is unclear how the post-treatment residual salts and radioactivity will be managed. There does not appear to be any complete treatment of these waters that will be permitted in New York.

There are four possible treatment options for flowback and produced water discussed in the RDSGEIS: (1) reuse, (2) deep well injection, (3) treatment in municipal facilities, or (4) treatment in privately owned facilities. None of these options is properly analyzed in the RDSGEIS, and the potential significant adverse impacts of each are therefore not disclosed nor possible mitigation identified.

"Treatment" of flowback for *reuse* is discussed in Section 5.12. Reuse of the flowback conserves fresh water and allows contaminated water to be used instead during fracturing. However, the RDSGEIS only considered treatments for removal of salts that would allow for reuse in other hydraulic fracturing operations, and evaluated how specific requirements for reuse could be met by various treatment processes (e.g., membrane, ion exchange or evaporative processes). It did not analyze the residual contaminants removed by evaporative or membrane processes and thus concentrated, or how those contaminants would be managed, other than to indicate that the residual salts, or concentrated brine will require "further treatment or disposal." The SGEIS must address how this highly concentrated and toxic residue will be regulated and managed.

Three hundred tons of salt will exist in one million gallons of flowback or produced water brine, if you assume a 7% (70,000 mg/L) salt solution. The source of the alpha emitters also must be identified, as is discussed above. If, as is suspected, polonium is present in the flowback water, it represents an additional management burden of the flowback and produced water that must be evaluated.

Beyond reuse, the disposal options considered in the RDSGEIS only included injection wells (although there are currently no industrial waste injection wells capable of handling this wastewater in NYS), municipal sewage treatment facilities (of which there are currently none that are permitted to accept flowback and produced water), and private treatment plants (of which none currently exist in New York). Therefore the RDSGEIS examines options that do not exist, and does an incomplete job of that examination.

The RDSGEIS did not consider whether there are other, less environmentally harmful, options that exist for treatment and disposal of flowback and produced water. More importantly, the RDSGEIS fails to evaluate the potentially significant adverse environmental impacts and human health risks associated with each treatment and disposal option.

Section 6.1.8.1 indicates that "[f]lowback water may be sent to POTW's", but then describes the limitations that may preclude disposal of these waters in POTWs. The RDSGEIS requires that a "facility must first evaluate the pollutants present in that source of wastewater against an analysis of the capabilities of the individual treatment units and the treatment system as a whole to treat these pollutants" (page 6-57); however, before such an evaluation can be conducted, the well operator must obtain a complete analysis of the flowback water (which as explained above, has not been done).

Additionally, the diversity of the flowback water quality is such that a POTW would need to conduct an extensive and expensive analysis of each water type that was delivered to the POTW under those guidelines. Since most of the additives are clearly not subject to routine analyses, it appears doubtful that a POTW could ever accept this type of waste. Also, if the limitation of 15 pCi/L of radium in the influent is enforced, a large portion (as yet not determined) of the flowback water could not even be accepted. Finally, the requirement of a complete description of the contaminants in the water is likely to add an additional burden to using POTW's for disposal, that this option may be precluded for most of the flowback water. Therefore, the proposal to use POTWs as a potential treatment and disposal method is scientifically and technically unsupported.

One serious problem with the proposed discharge (dilution) of fracture treatment wastewater via a municipal or privately owned treatment plant is the observed increases in trihalomethane (THM) concentrations in drinking water reported in the public media (Frazier and Murray, 2011), due to the presence of increased bromide concentrations. Bromide is more reactive than chloride in formation of trihalomethanes, and even though bromide concentrations are generally lower than chloride concentrations, the increased reactivity of bromide generates increased amounts of bromodichloromethane and dibromochloromethane (Chowdhury, et al., 2010). Continued violations of an 80microgram/L THM standard may ultimately require a drinking water treatment plant to convert from a standard and cost effective chlorination disinfection treatment to a more expensive chloramines process for water treatment. Although there are many factors affecting THM production in aspecific water, simple (and cheap) dilution of fracture treatment water in a stream can result in a more expensive treatment for disinfection of drinking water. This transfer of costs to the public should not be permitted.

NORM, the inorganic substances, and the organic compounds from the formation also represent serious contamination potential and require an appropriate level of treatment. The exact method of treatment that NYSDEC expects to require for any municipal or private treatment facilities that may be permitted is unclear. The RDSGEIS suggests that there will be some level of wastewater dilution through discharge into a receiving stream, at least in some cases. The analysis should be much more explicit about how wastewaters will be treated, both in-state and out-of-state. New drilling operations should not be permitted until adequate management/disposal of these waters is evaluated, with public comment required on the proposed methods, an analysis of the impacts associated with each, as well as mitigation measures as required by SEQRA.

Injection of the waste fluids into fully permitted underground injection control (UIC) wells is an option also, although this method is problematic due to the lack of permitted wells in New York, and the distance the contaminated water would need to be trucked in order to dispose of it in other states where permitted wells exist (e.g., Ohio). The recent seismic activity in Ohio from disposal of fracturing fluids also raises serious concerns whether this option is safe. Given the difficulties of wastewater treatment, UIC is likely the popular choice for wastewater disposal from the Marcellus region. However, NYS' increase wastewater load, along with increased wastewater generated from the increased drilling in Ohio and surrounding states, will likely pose an injection capacity problem for Ohio UIC wells. The RDSGEIS has not examined whether it is possible, or safe to install disposal wells in NYS' or whether a nearby state has sufficient capacity to inject NYS' incremental waste load, or whether this is the best technical solution. These are all potential significant adverse impacts that should be, but are not, addressed in the RDSGEIS.

Out-of-state management of waste is contemplated in Section 5.13.3.3., but is identified as not being within the regulatory purview of New York. However, simply stating that wastewater will likely be managed "out-of-state" is insufficient. Wastewater handling is an unmitigated significant impact in the RDSGEIS as currently proposed. The proposal to export NYS' wastewater and not examine this significant impact is not justified.

NYSDEC should instead evaluate the impacts of, clear cradle-to-grave oversight and management, identify the best solutions for waste handling, and include those requirements as mitigation measures in the RDSGEIS.

Furthermore, even if some export of wastewater is permitted, SEQRA requires analysis of the impacts of any potential waste management options, even if they are to occur outside of New York.

Finally, road spreading for dust control and de-icing would apparently (and appropriately) not be allowed for flowback water, but could be used under certain conditions for the produced brines. A rationale for this distinction is not provided, and permitting road spreading of produced water is not recommended, since the brines will have higher concentrations of NORM than the flowback water, and may include polonium. Some rationale should be provided for this distinction, particularly since it is apparently unknown if any of the hydraulic fracturing additives are even detected in the flowback water (see Table 6.1). It is clear, however, that the NYSDEC is concerned about using the brines for roads and will require a specific permit for this application. Whether a permit will be granted presumably will depend on the amount of radioactivity present in the water. Under no circumstances should brine solution that has a gross alpha concentration of greater than 15 pCi/L be applied to roads. Ultimately, this practice should not be allowed – there are simply too many questions about the identity and amount of contaminants in these fluids.

Recommendation 10: The RDSGEIS should identify and evaluate the impacts of the various options that are proposed to be permitted for management of wastewater, and identify any proposed mitigation for identified significant adverse impacts, which should be set forth in the proposed regulations.

Recommendation 11. Specific influent contaminant load restrictions need to be explicitly identified including those for: fracking additives, NORM (including gross alpha), TDS and other relevant contaminants in this management description.

D. Cuttings disposal: Disposal of cuttings is considered in the RDSGEIS, although the treatment is incomplete. Cuttings from the shales of marine origin such as the Marcellus Shale (particularly the horizontal cuttings) will require further examination to determine if they contain large amounts of salts, similar to the produced brines, or if they contain excessive alpha emitters. While the measurements of radioactivity, based on a gamma detector, do not indicate high levels of radioactivity, further analysis is required to determine the leachability of these cuttings. Polonium is only a very weak gamma emitter, and thus it would not be observed by simple gamma counting. The organic (reducing) components of the shales chemically trap uranium and potentially other radionuclides, and when they are subject to oxidizing conditions, increases in the solubility/mobility of some of the radionuclides (particularly uranium) is likely. The leachability of these cuttings under oxidizing conditions thus requires further analysis, as discussed at the bottom of page 6-65. However, these determinations need to be made, and the risks and potential mitigation identified, *prior* to permitting the wells.

Recommendation 12. The RDSGEIS must fully evaluate the potential significant adverse impacts of cuttings disposal and identify any necessary mitigation to address such impacts, which should be set forth in the proposed regulations.

E. Odors are a continuing concern from gas wells: A variety of chemicals are present in hydrocarbon formations that can present a serious odor problem, which can be both a serious human health problem and affect the quality of life of persons living near these sites. A very common, but toxic, constituent is hydrogen sulfide, characterized by a rotten egg smell. Other organic sulfides can also be present, including a variety of alkyl sulfides. Odors are very difficult to regulate, due to the vagaries associated with odor detection, acclimation, and differential effects on different persons. The severity of an odor is in the nose of the beholder. Thus, each well should be assessed to determine the potential of migration of volatile substances from the well operation to surrounding residents. Odor complaints should be taken seriously, and the presumption should be that an odor complaint is valid, and an investigation of the source required.

Hydrogen sulfide is, however, probably the most acutely toxic component present in a potential natural gas leak, and it can pose a serious health risk to surrounding residents, in addition to causing odor complaints. Sulfide monitors should be required at least two points, corresponding to most probable downwind locations at the fenceline. When hydrogen sulfide is detected above the odor thresholds, the source of the odor should be identified and eliminated.

Setbacks from an operating well will help to minimize the impact of odors on the surrounding residents. (Setbacks are discussed in further detail in the accompanying reports being submitted under cover of the Louis Berger Group.)

Recommendation 13. The RDSGEIS must fully evaluate the potential significant adverse impacts associated with odors and hydrogen sulfide emissions, and identify any necessary mitigation to address such impacts, which should be set forth in the proposed regulations.

F. Monitoring of nearby domestic wells for contamination from gas drilling operations should be conducted at regular intervals during and following hydraulic fracturing. While the drilling company would be required to test domestic wells for contamination prior to gas development operations, these same wells should be tested during production, and subsequent to discontinuing production to determine if hydraulic fracturing has resulted in contamination (See the accompanying report of Dr. Tom Myers). At present, the documents are silent on this requirement and effectively transfer this responsibility to the well owner. The analytes that should be determined should include, at a minimum, the components of natural gas (methane, ethane, etc.) and also toxic volatiles from the formation water (benzene, toluene, xylenes), salts and relevant inorganic contaminants, and the additives used during the hydraulic fracturing. This list should be developed based on those specific additives used.

Recommendation 14. The RDSGEIS and proposed regulations should require that monitoring of domestic wells situated in close proximity to gas drilling operations to be required at regular intervals during and following hydraulic fracturing. Because of the slow movement of groundwater, routine analysis of those domestic wells should be continued at least 20 years.

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Attachment 4

Ralph Seiler, Ph.D.

Review of the

Revised Draft
Supplemental Generic Environmental Impact Statement On The Oil, Gas and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

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1/11/12

This document represents a review of the Revised Draft Supplementary Generic Environmental Impact Statement (RDSGEIS) regarding the hydraulic fracturing proposals to develop natural gas wells in New York. I have specifically examined issues related to NORM in the flowback/produced brine, as well as of radon in the gas itself. My comments supplement those of Glenn C. Miller, Ph.D.

Issue 1.

Unidentified sources of gross alpha and beta radioactivity in flowback water and production brine.

Gross alpha radioactivity in the brines (Appendix 13) and flowback water (Table 5-24) can be very high. In the brines, gross alpha is usually from 8,000 to 20,000 pCi/L, with a maximum of 120,000 pCi/L (Well Webster T1). In the brine samples with high gross alpha, the sum of uranium (U) , thorium (Th) , radium-226 (^{226}Ra) and radium-228 (^{228}Ra activities is much less than the measured gross alpha. Individual analyses of flowback water are not given, but the aggregated data similarly suggest that the sum of U, Th, and ^{226}Ra and ^{228}Ra activities is also much less than the measured gross alpha. These results indicate one of two things:

1. There are analytical problems with the gross alpha measurements, probably caused by the high salinity of the water.
2. There is an unidentified alpha emitter present in the water.

High salinity can cause the measured gross alpha to significantly overestimate the actual alpha activity of a sample (Arndt and West, 2007). The recommended mass placed on a planchet for gross alpha is only100 mg, so given a brine Total Dissolved Solids (TDS) of 350,000 mg/L (p. 6-61), only ~0.4 ml of sample should be placed on a planchet. The high TDS means it is easy for too much mass to be placed on the planchet, or the small volume means the mass may be unevenly distributed. Both of these factors can contribute to reduced precision and accuracy in the gross alpha analysis.

Appendix 13 indicates all of the relatively long-lived, naturally occurring alpha emitters in the brines were measured except polonium-210 (^{210}Po). Radon itself would not contribute at all to the measured gross alpha because it is a gas. In the gross alpha measurement, an aliquot of sample water is placed in a planchet and evaporated to dryness. After drying, the planchet is commonly flamed until it glows red to drive off hygroscopic water from the salts. Because of this, alpha radioactivity from radon does not contribute to gross alpha radioactivity.

^{210}Po normally binds strongly to sediment particles and concentrations in fresh groundwater are typically <1 pCi/L. In some geochemical settings ^{210}Po activities have exceeded 500 pCi/L in drinking-water wells in the US (Seiler et al., 2011), however this is extremely rare and fewer than 100 US wells have been reported with >15 pCi/L. ^{210}Po is known to be present in oil-field brines (Parfenov, 1974), however, the reported ^{210}Po activities in the brines were relatively low, about 100 pCi/L.

On p. 6-205 the RDSGEIS states radium is the primary radionuclide of concern, but this may not be the case if the excess alpha radioactivity is caused by the presence of ^{210}Po. If ^{210}Po is present in high levels, it may be much harder and more expensive to treat the contaminated water and manage the waste. Ra can be removed from water with relatively simple technology such as water softeners. On the other hand, Charles County in Maryland found the best way to remove Po from a contaminated public-supply well was with reverse osmosis. Treating millions of gallons of brine with reverse osmosis would be expensive and difficult, and could increase the cost to the public if treated at a public treatment facility. It could cause the gas to be more expensive to the consumer if the operator is made to bear the cost of treatment at an on-site or privately-owned treatment facility.

Gross beta radioactivity in many of the wells in some of the wells is several thousand pCi/L. To evaluate the significance of this, you need to know the potassium concentrations because ^{40}K is the source of almost all natural beta. If gross beta minus a correction factor for K were to exceed 50 pCi/L in a municipal well, the operator would have to identify the major contributors to gross beta. One potential contributor to gross beta is lead-210 (^{210}Pb), which was not measured. This is potentially important because ^{210}Pb decays to ^{210}Po and could support it in the water.

Issue 1 Recommendations

The cause of the excess alpha radioactivity in the brine and flowback samples needs to be determined. ^{210}Po may be present at high concentrations and could pose a significant risk to health and the environment if oil-field brines are inadequately disposed of because it bioaccumulates. Samples from some of the more contaminated wells should be reanalyzed for the same suite of analytes as before, except this time include ^{210}Po. Redoing the complete suite will provide an idea on how adequately the less expensive gross alpha analysis identifies the presence of ^{210}Po. All samples analyzed for NORM (e.g. p. 6-61) as part of the regulatory process should include ^{210}Po, at least until it has been demonstrated that ^{210}Po is not an important source of alpha radioactivity.

NYSDEC should identify what the important contributors to gross alpha are (probably radium and ^{210}Po) and identify how, if at all, the brine and flowback water will be treated, taking economic considerations into account. Failure to do so constitutes a potentially significant adverse impact that would not have been disclosed or mitigated.

The principal contributer to the gross beta radioactivity is probably potassium-40 (^{40}K), but this should be confirmed because ^{210}Pb can also contribute to gross beta, and if present ^{210}Pb can support aqueous ^{210}Po. An estimated ^{40}K activity, based on the potassium (K) concentrations for the brines, should be added to Appendix 13 so the gross beta measurements can be evaluated. It is presumed that K was measured, even though no major ion analyses for the brines were found in the RDSGEIS. A theoretical activity ratio of 0.818 pCi/mg was reported by Friedlander et al. (1981) and can be used to convert concentrations to activities.

Issue 2.

Documentation of analytical methods

It is important that all analytical methods that will be used to analyze pollutant levels are well documented, but the RDSGEIS does not indicate what they would be.

Issue 2 Recommendations

It is presumed the alpha emitters were analyzed by alpha spectrometry, but the RDSGEIS should confirm this. The RDSGEIS also needs to provide reporting limits for the other analytes, not just provide a list of the analytes to be measured. An analysis for arsenic is useless if the reporting limit is 50 ppb when the drinking water standard is 10 ppb.

Documentation of the method is particularly important for the gross alpha analysis. EPA Method 900.0 for gross alpha allows samples to be composited quarterly and allowed to sit for up to a year before analysis. Unfortunately, the EPA approved analytical method can allow more than 60% of the ^{210}Po in a sample to be lost due to decay during that year (Seiler et al., 2011). A simple statement that Method 900.0 will be followed is inadequate. The RDSGEIS should explicitly state that samples for gross alpha will not be composited and must be analyzed within 3 days of sample collection. Analysis within 3 days is SOP for many agencies and finding labs that can meet that requirement should not be a problem.

Issue 3.

Radon in Natural Gas

Radon is known to be present in natural gas and will be delivered with the natural gas to consumers. Burning of natural gas in stoves, water heaters, and furnaces does not affect the radioactivity of radon and consumers will be potentially exposed to increased levels of atmospheric radon.

The RDSGEIS does not include measurements of radon concentrations in the natural gas, nor does it indicate plans to monitor it. Radon concentrations in natural gas are extremely variable and can be very high. Natural gas from Texas and Kansas had radon concentrations ranging between about 5 and 1500 pCi/L (Dixon 2001,

Table 2). This raises the possibility that radon concentrations in gas from the Marcellus Shale could be much higher values than are in the gas currently being used. In addition, the hydraulic fracturing process would be designed to maximize extraction of natural gas from the formation, and as a consequence may also maximize extraction of radon from the formation.

The pipeline from well heads tapping the Marcellus Shale will be much shorter than the existing 1500 mile pipeline delivering gas from Texas/Louisiana. Assuming the gas moves through the pipeline at 10 mph, it would take 6.25 days for gas from the wellhead to the consumer, and during this time ~68 percent of the radon will decay. If wellheads in the Marcellus Shale are only 100 miles from the consumer then only 7 percent of the radon would have decayed. Because of this, even if the wellhead radon concentrations in gas from the Marcellus Shale were identical to those of the currently used natural gas, consumers would be exposed to greater radon concentrations because the wellheads are closer.

Dixon (2001) provided a risk assessment for the radon in natural gas in the UK. The average radon in natural gas from the UK wells was 5.4 pCi/L, and, as a worst-case scenario, Dixon (2001) assumed that there was instantaneous delivery of the gas so that no radon decay occurred between the wellhead and the consumer. Dixon (2001) concluded there was negligible risk to the public from release of radon in combustion gasses, and that the average dose to the public using 100 cubic meters of gas would be only 4 microSieverts per year (μSv/yr). The greatest risk was to workers in large commercial kitchens who would receive a dose of 19 μSv/yr.

Issue 3 Recommendations

The risk to the public from radon in the natural gas probably is small. Measurements of radon in the gas are needed, however, to confirm that radon levels in the gas are within the expected range. A new risk assessment should be made using actual measurements of radon in gas from the Marcellus Shale and other factors specific to New York, such as the background radon concentration for the area. For a worst-case scenario the assumption should be made that there is instantaneous delivery of gas from the wellhead to the consumer.

Issue 4.

^{210}Po Buildup in Delivery Pipes

On page 6-205 of the RDSGEIS there is a discussion of scale buildup in pipes and equipment, but the discussion seems to indicate Ra is the principle radionuclide of concern. If radon, ^{210}Pb or ^{210}Po are present at high concentrations in the water or gas, a more significant health risk for workers could be ^{210}Po in the scale. Summerlin and Prichard (1985) evaluated this and concluded that workers cleaning impellers could be exposed to high levels of atmospheric ^{210}Po.

Consumers and State and Local workers may also be exposed to ^{210}Po, which will form in scale on all pipes carrying natural gas with radon in it. The amount of ^{210}Po buildup will depend on the amount of radon in the gas. Plumbers and City/State employees working on the pipes may not know what precautions need to be taken, and thus could be exposed to ^{210}Po in the scale.

Another issue is the volatility of ^{210}Po, which is completely volatile at temperatures above 500°C (Radford and Hunt, 1964). Because of this, ^{210}Po that accumulates near burners that have been turned off may be vaporized when burners are turned on. This could potentially expose consumers to health risks from inhaling ^{210}Po. In cases of accidents or fires involving gas lines, first responders and the public near the incident could also be exposed to ^{210}Po through inhalation. This risk is not specific to gas from the Marcellus Shale. The health risks, however, would be related to the amount of radon in the gas and thus the amount of ^{210}Po that would build up, and this is not known for gas from the Marcellus Shale.

Issue 4 Recommendations

Measurements of radon in natural gas from the Marcellus Shale need to be made. A risk assessment should be made for inhalation of ^{210}Po resulting from scale buildup in delivery pipes.

Issue 5.

^{210}Po drinking-water standards

Table 2-3 presents drinking water standards for radionuclides. The US does not have a standard specifically for ^{210}Po largely because ^{210}Po is extraordinarily rare in drinking water. The US standard for ^{210}Po is exceeded if the gross alpha minus the U activity exceeds 15 pCi/L. Canada and the European Union have set drinking-water standards specific for ^{210}Po at 5.4 and 2.7 pCi/L, respectively (Health Canada, 2007; Commission of the European Communities, 2001). The regulatory use of the gross alpha standard assumes it will adequately identify samples with ^{210}Po levels that exceed health safety standards. For several reasons related to Po chemistry and the gross alpha analytical method, this may not be the case (e.g. Seiler, 2011).

Item 5 Recommendations

For any analysis where there may be actual human exposure, the RSDGEIS should analyze ^{210}Po analyses using alpha spectrometry rather than using gross-alpha analyses as an inexpensive but inadequate surrogate.

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Attachment 5

Susan Christopherson, Ph.D.

Memorandum

To: Kate Sinding, Natural Resources Defense Council

From: Susan Christopherson, Ph.D.

Date: January 11, 2012

This memorandum comments on issues in the sections of the 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) and accompanying documents that address the social and economic impacts of natural gas development using high volume hydraulic fracturing (HVHF) proposed for New York, and evaluates the sufficiency of the impact analysis presented and the mitigation measures identified. HVHF describes a stage in the gas extraction process whereby large amounts of water, toxic chemicals, and sand are injected at high pressure to create fissures in low-permeability formations and thereby allow the release of gas. The process is capital intensive, and throughout its duration, poses significant environmental risks. The New York State Department of Environmental Conservation (NYSDEC or the Department) is charged with identifying and evaluating the impacts of gas development using HVHF, including both the benefits and the costs that will be borne by the communities and counties where drilling will occur.

In preparing these comments, the key documents reviewed include:

- The 2009 scope of work for the SGEIS.
- Comments prepared by AKRF and other technical experts on the 2009 draft SGEIS.
- A report prepared by Sammons, Dutton and Blankenship (2010) in response to comments on the 2009 draft SGEIS analysis of socio-economic impacts.
- The RDSGEIS released in September 2011 and particularly sections addressing socioeconomic and community impacts (6.8 and 6.12) and mitigation (7.0).
- The Economic Assessment Report (EAR) prepared by Environment and Ecology LLC to accompany the RDSGEIS.

These comments also draw on my own research on input/output models and community impacts and on research that has been conducted on the social and economic impacts of natural gas drilling in shale gas plays across the United States. Other documents cited in these comments are included in the reference list.

Although NYSDEC has included more information on the social and economic impacts of gas development using HVHF in the RDSGEIS than it did in the 2009 draft, the RDSGEIS still does not effectively assess those impacts or provide appropriate mitigation strategies. These comments identify areas of social and economic impact that require additional or revised research or analysis in the SGEIS. Overall, the discussion of social and economic impacts in the RDSGEIS is poorly organized. Social and economic topics are discussed in several sections of the RDSGEIS and statements are made in some sections that are contradicted by evidence in others. The differences between the social and economic impacts of vertical and horizontal drilling are not addressed in a systematic way. Critical assumptions underlying the socioeconomic impact analysis were accepted from industry sources (the Independent Oil and Gas Association of New York or IOGA NY) without independent verification.

Substantive concerns include the following:

1. The assessment of economic benefits (jobs and taxes) relies on questionable assumptions about the amount of gas extractable in the New York portion of the Marcellus Shale. The range of estimates for extractable gas appears to be skewed to the high end, leading to an overestimation of economic benefits.

2. The model used to assess social and economic impacts presents natural gas development as a gradual, predictable process beginning with a “ramp-up” period and then proceeding through a regular pattern of well development over time. Experience from shale plays in the Western United States demonstrates that volatility and unpredictability are intrinsic to natural gas extraction, as operating companies assess their commercial options from one shale play to another or within one shale play and allocate rigs to respond to those options. The model used in the RDSGEIS is misleading, giving the impression that communities in the drilling regions will experience economic disruption only once, during a ramp-up phase, rather than periodically, as operating companies repeatedly enter and leave the region. The problems with the model are then compounded, as projected impacts on population, jobs, and housing are predicated on one-time ramp-up and adjustment phases rather than on a process in which rigs may move in, move out, and move in again, in an unpredictable sequence. Because many of the negative social and economic impacts of HVHF gas extraction (such as housing shortages followed by excess supply) are a consequence of unpredictable development, the model used in the RDSGEIS cannot appropriately assess those impacts. The limitations of the model should have been explained with reference to the literature that describes the irregular, unpredictable course of natural gas development, including rig movement among shale plays and the frequency of re-fracturing wells.

3. The RDSGEIS does not assess public costs associated with natural gas development. A fiscal impact analysis of the base costs to the state and localities that will occur with any amount of HVHF gas development is required along with an estimate of how costs will increase and accumulate as development expands. Although some of the potential community character and economic costs associated with the projected drilling scenarios are mentioned in the RDSGEIS, there is no attempt to quantify those costs to the state or localities either as part of the modeling process or separately.

4. The long-term economic consequences of HVHF gas development for the regions where production occurs are not addressed despite a widely recognized literature indicating that such regions have poor economic outcomes when resource extraction ends.

5. Mitigation of enumerated negative social and economic impacts of HVHF gas development is presumed to occur by means of phased development and regulation of the industry, but no evidence or information is provided to indicate whether, and if so how, that would occur. For example, NYSDEC proposes to ask operators to identify inconsistencies with local zoning and other comprehensive land use planning, but there is no explanation of how the inconsistencies will be addressed in the permitting process or regulatory system. All mechanisms that will be relied on to address adverse social

and economic impacts need to be defined and incorporated into enforceable mitigation measures.

Part I of these comments focuses on the socioeconomic impact analysis in section 6.8 of the RDSGEIS. Section 6.8 adopts the assumptions utilized in the EAR and summarizes its more detailed description of anticipated impacts from HVHF gas development. Part I.A pays particular attention to the model employed in the EAR and its assumptions about how the exploratory, drilling, production, and resource depletion phases of development will occur. These assumptions do not adequately consider the uncertainties and risks associated with HVHF gas development. Part I.B comments on particular issues and areas of impact addressed in the RDSGEIS. Part II discusses issues pertaining to the distribution of economic benefits that are raised by the EAR but not addressed in the RDSGEIS. Part III comments on the mitigation proposed for potentially significant social and economic impacts.

I. NYSDEC's Socioeconomic Impact Analysis

A. The Unpredictability of Natural Gas Production and How It Is Treated in the RDSGEIS

The EAR's projections concerning population, jobs, housing, and revenue are predicated on the assumption of a regular, predictable roll-out of the exploratory, drilling, and production phases of the natural gas development process, rather than the irregular pattern typically associated with such development.

Natural gas drilling is a speculative venture and the amount of commercially extractable gas from any particular well is uncertain. Because of the speculative nature of the industry, there are significant economic risks associated with natural gas production. These risks are magnified by the costs involved in natural gas development, which uses capital-intensive technologies such as those engaged in hydraulic fracturing.

The industry is organized in such a way that these risks can be lessened. For example, a limited number of rigs is available nationally, and they are deployed among and within natural gas plays based on calculations of well productivity and commercial return. The drilling labor force is not fixed to a place, but moves with the rigs based on operator company strategies. Work is carried out by contractors on a project-by-project basis to maximize flexibility and efficient deployment of the specialized skills needed.

Because of the speculative character of commercial development of natural gas plays, there are uncertainties in how any shale gas play or portion of a play will be developed. What this means in practical terms is that the regions where shale gas development occurs can experience considerable volatility in the timing of well development and in the scale of well development (in the total number of wells). This central feature of natural gas development has critical implications for the economies of natural gas development regions. As production fluctuates, regions may experience short- and medium-term volatility in population, jobs, revenues, and housing vacancies (Best, 2009; Headwaters Economics, 2011; Jacquet, 2009; Sammons, Dutton and Blankenship, 2010).

The EAR does recognize both production volatility and price volatility in the gas industry. In describing national drilling activity, the authors report: "The number of active gas drilling rigs fluctuated substantially over the decade, with the number of rigs in the most active quarter being 2.35 times the number in the least active quarter." (EAR, 2-2). In New York, "the average wellhead price for natural gas remained at relatively low levels in the 1990s, generally increased thereafter, reaching a peak in 2008, and then fell sharply in 2009." (EAR, 3-12).

The EAR also briefly mentions the difficulties that the unpredictability and volatility of natural gas development presents for predicting social and economic impacts (e.g., EAR, 4-59, 4-111). The model used to project socioeconomic impacts ignores those issues, however, and assumes instead that the HVHF natural gas development in New York will have a different pattern than that historically associated with such development. Rather than occurring in irregularly recurring waves (or "boom-bust cycles"), development in New York is assumed to be steady and predictable.

The RDSGEIS mentions the uncertainty and variation in well productivity in sections not addressing socioeconomic impacts (RDSGEIS, 2-5, 2-62, 2-74, 4-17). However, the section of the RDSGEIS that specifically addresses socioeconomic impacts (Section 6.8) ignores the evidence of unpredictability in the pace and scale (timing and total well development) of natural gas development from New York counties with vertical well development and from other shale plays. Instead, it reports results from the model used in the EAR to project social and economic impacts from HVHF gas development that assume a regular, incremental, and predictable pattern of well development and production over a 60-year period, both on a statewide basis in three defined regions and under two development scenarios (low and average). Like the EAR, the RDSGEIS neglects the implications of variable well productivity and commercial viability -- critical considerations that will affect the pace and scale of drilling as well as its geographic distribution.

A1. Uncertainties Regarding Well Productivity

<u>The RDSGEIS and accompanying EAR do not meaningfully recognize a central category of uncertainties that will affect the pace and scale of drilling – the uncertainties surrounding well productivity.</u> Instead, NYSDEC states with respect to the low and average development scenarios analyzed:

> Both development scenarios assume a <u>consistent</u> timeline for development and production. Development is assumed to occur for a period of 30 years, starting with a 10-year ramp-up period. The number of new wells constructed each year is assumed to reach the maximum in Year 10 and to continue at this level until Year 30, when all new well construction is assumed to end.

(RDSGEIS, 6-209).

This approach is one of the major weaknesses of the RDSGEIS because the assumptions of a 30-year well production cycle and a sub-regionally consistent roll-out of wells that will move through the drilling and production phases over 60 years are not supported by evidence from other shale plays. In fact, there is sufficient evidence of precipitous declines in well productivity and the costs of HVHF gas development relative to ultimate recovery to raise questions about why the 30-year development/60-year productivity profile was adopted (Berman, 2010; Berman and Pittinger, 2011; Hughes, 2011; Urbina, 2011). In an analysis of shale gas wells across shale plays, Berman and Pittinger (2011) found thousands of wells that dropped below commercially viable production between 5 and 12 years after initial drilling. The average commercial life of these wells was 8 years. NYSDEC should not have used data provided only by IOGA to construct the roll-out model; rather, it should have obtained evidence and data from independent sources who do not stand to benefit from the projection of long-term, predictable resource development.

Another example of questionable assumptions that likely over-estimate potential gas extraction from the New York portion of the Marcellus Shale is the well productivity projections used in the EAR. These are presented in Tables 4-3, 4-4 and 4-5 of the EAR. Although ultimate recovery figures are not presented in the EAR, they can be calculated based on the yearly production projections presented in 4.1.3 and the number of wells projected in 4.1.2.

These productivity projections are considerably higher than the well productivity results from existing shale plays found by Berman and Pittinger (2011). In addition, calculations of well productivity over the 60 year period produce ultimate recovery figures for the New York portion of the shale play that, in the medium and high scenarios, exceed most scientific estimates of ultimate recovery (Coleman et al, 2011). Although the 29 Tcf low scenario (for 60 years) does not exceed geologist Terry Engelder's estimate for New York's portion of the Marcellus shale, the productivity projections seem particularly questionable considering that, "The Marcellus fairway in New York is expected to have less formation thickness, and because there has not been horizontal Marcellus drilling to date in New York the reservoir characteristics and production performance are unknown. IOGA-NY expects lower average production rates in New York than in Pennsylvania." (RDSGEIS, 5-139).

Moreover, as pointed out by a group of economists commenting on the EAR assumptions and methods (Barth, Kokkelenberg and Mount, 2011), the range of estimates of productivity is so large as to be meaningless. For example, estimates for well productivity during the 23rd year of production range from 600 billion to 3.6 trillion cubic feet, a variation on the order of 600%. Accuracy in these estimates is critical to derive estimates of tax and employment effects. As it stands, the estimates used in the EAR are no better than bloated "guesstimates."

The use of IOGA's estimates as the sole source of well productivity projections undermines the credibility and accuracy of the EAR and the RDSGEIS. The estimates of well productivity must be revised to more accurately reflect expert opinion on anticipated well productivity in the New York portion of the Marcellus shale. In addition, the RDSGEIS must be updated to reflect the Energy Information Administration's revised estimates of natural gas in the Marcellus shale based on the USGS analysis (Coleman et al, 2011).

The uncertainties associated with the productivity of extraction from the Utica shale must also be addressed, if Utica shale wells are to be included in the SGEIS analysis. In the EAR, the projections for the number of wells to be drilled include those for the Utica shale. There are significant uncertainties about the productivity of that play, the geographic variation in liquid content across that play, whether the well spacing and fracture treatment would resemble those for the Marcellus, and what technologies would be used in Utica shale development (Yost, 2011). These unknowns are significant and indicate that Utica shale development may proceed differently than Marcellus shale development and utilize different technologies.

The unspecified inclusion of well numbers and productivity figures from the Utica shale also raises questions about the extrapolated employment, housing and tax implications that are attributed to Marcellus shale development.

The issues surrounding productivity are further complicated by the common practice of re-fracturing wells to increase pressure and productivity. If re-fracturing is practiced in New York Marcellus wells, communities will be repeatedly subjected to the environmental disruptions associated with heavy industry.

The uncertainties around and questions raised about long-term well productivity argue for modeling a shorter-term development and production cycle. At the very least, the competing evidence concerning well productivity and the cost of recovery should have been discussed in the RDSGEIS to qualify assumptions concerning the production cycle and estimated ultimate recovery.

A2. Impacts of the Uncertainties Associated with HVHF Gas Development

<u>Evidence from Western shale plays indicates that the volatile pace and scale of natural gas development drives many environmental and social and economic impacts</u> (Best, 2009; Jacquet, 2009; Headwaters Economics, 2010). Impacts directly affected by the pace and scale of drilling include:

1) Labor force needs and behavior. (How much of the workforce remains transient rather than becoming local? A local labor supply cannot develop if gas development is unpredictable.)
2) Demands placed on public services, including health facilities, public safety, and schools. (Can communities adapt over time or are there unpredictable rises and falls in demand?)
3) Community character impacts from increases in traffic, noise, construction disruption, and the transient population. (Do these increases roll out in a regular fashion with the expectation that disruptive “ramp-up” will end or are they unpredictable over a long period of time?)
4) Impacts on rural industries, such as tourism. (Can the scale of noise and traffic be predicted to occur only for a short period or are disruptive activities likely to recur over a longer period of time, for example, with re-fracturing of wells?)
5) Housing demand and cost. (Will there be periodic housing shortages with homelessness and lack of affordable housing for people on fixed incomes, potentially followed by excess housing supply and falling home values?)

To illustrate: As well pad construction begins in an area, jobs increase along with housing construction and business development. A transient population (in addition to transient industry workers) migrates to the area because of the prospect of jobs, increasing the demand for housing and services, including education and health. For a variety of reasons (price of natural gas, availability of higher value opportunities elsewhere, rig availability), natural gas development may drop off in the area within five-ten years of this initial “ramp-up.” Evidence from gas plays in Western states indicates that this drop-off may be sudden. In the wake of this drop in production and the number of drilling rigs in the area, the transient population leaves and resident communities are left without jobs and revenue. Local governments may still be paying the public costs of ramping up to respond to the initial “boom.” If conditions change (rigs become available, prices rise), the rigs may return to the area, causing another production “boom” with all of its attendant costs.

This pattern is described by Spelman (2009) and is associated with a reluctance of business (other than the gas industry) to invest in regions characterized by boom-bust economies. A contemporary example of such reluctance is contributing to the housing crisis in the Williston North Dakota Bakken Shale development. According to interviews conducted there: “Developers have been slow to build more apartments, largely because they got stung by the region's last oil boom that went bust in the 1980s.” (MacPherson, 2011).

This volatile pattern is dramatically different from the scenario presented in the EAR and RDSGEIS. In both documents, communities are assumed to be impacted by a boom only once (during “ramp-up”) and are gradually able to adjust to natural gas drilling. Many of the economic benefits that the RDSGEIS and EAR associate with natural gas development are predicated on this gradual, regular development scenario. For example, the RDSGEIS assumes that as the industry “matures” in the region, local residents will be trained and hired for drilling jobs. If, as has been the case with vertical drilling in New York State and in the Western US shale plays, development follows a more irregular pattern, then the higher paid technical jobs are less likely to evolve into stable local employment. In addition, the jobs in ancillary industries (retail and services) are likely to disappear and reappear as rigs leave and re-enter the region at unpredictable intervals. The RDSGEIS’s use of a model built around regular, predictable development of the shale gas resource raises doubts about the projection of economic benefits based on that model.

A3. Hot Spots, Socioeconomic Impacts, and Public Costs

Contrary to the contention that the regularized development model “does not significantly affect the socioeconomic analysis” (RDSGEIS, 6-209), smoothing out the unpredictability and unevenness of development covers up many of the negative cumulative social and economic impacts that arise from the unpredictability of shale gas development. The RDSGEIS admits that steady, constant well construction is “unlikely” (RDSGEIS, 6-209), but it fails to analyze the implications of this admission and offers no description or evaluation of the adverse impacts of temporally and spatially uneven development.

In contrast with the model used in the RDSGEIS, natural gas development does not resemble a “manufacturing” process. Some wells will have long production phases; others will have dramatic declines in productivity after a relatively short period. Well productivity may be uniformly low across a region, or there may be long-term well productivity in particular “hot-spots.” The question of how many wells will exhibit long-term productivity and where they will be located is unknown before exploratory drilling takes place and, even then, well productivity will be unpredictable.

The RDSGEIS admits that its socioeconomic analysis is based on average well productivity (RDSGEIS, 6-210), but the production process in natural gas (pace and scale) is not effectively captured using averages. The uncertainties in the geographic extent of drilling and the potential for intensive development in “hot spots” have implications for social and economic impacts. For example, if drilling is concentrated in particular locations rather than rolled out uniformly across sub-regions of the landscape for 60 years (as is modeled in the RDSGEIS and EAR), wealth effects and tax revenues also will be concentrated in particular localities. The social and economic costs of spatially concentrated drilling, however, will be experienced across a much wider geographic area, because public services will be required in areas without HVHF development (and therefore not receiving tax revenues from drilling), but close enough to serve the transient population associated with the industry. There is no attempt to address this likely unbalanced distribution of positive and negative impacts in the RDSGEIS.

Finally, the RDSGEIS does not sufficiently model the resource depletion phase of the exploration, drilling, production, and resource depletion cycle and its implications for local and regional economies. Figure 6.13 (RDSGEIS, 6-215) shows the drop in direct and indirect employment following resource depletion. This depiction needs to be accompanied by analyses of how the resource depletion phase will be reflected in royalty payments and tax revenues.

A4. Socioeconomic Impact Analysis Can Accommodate the Uncertain Pace and Scale of Gas Development

If the impacts of volatility are to be mitigated, their prevalence in natural gas extraction regions needs to be acknowledged in the SGEIS. It is difficult to model the unpredictable pace and scale of natural gas production, but that difficulty is no excuse for ignoring adverse social and economic impacts arising from volatile and unpredictable development. Those impacts have been documented in relation to the phases of exploration, construction and drilling, production, and resource depletion, recognizing the company strategies that produce economic volatility in resource extraction regions (Jacquet, 2009; Kelsey, 2009; Sammons, Dutton and Blankenship, 2010).[1]

In cases where it is not possible to model specific cause-effect relationships (such as the relationship between well development and public costs), but where there is evidence of potential adverse impacts, those impacts should be recognized and documented. Sammons, Dutton and Blankenship (2010) take this approach in their report

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[1] From Sammons, Dutton and Blankenship (2010):

> Several recent studies address (social and economic) aspects of natural gas development in the western U.S. They include the *Northwest Colorado Socioeconomic Analysis and Forecasts* prepared for the Associated Governments of Northwest Colorado and the *Sublette County Socioeconomic Impact Study: Phase I Final Report* and *Phase II Final Report,* prepared for the Sublette County, Wyoming Board of County Commissioners. A third report, the *ExxonMobil Piceance Development Project Environmental Assessment - Socioeconomic Technical Report,* prepared by the authors for the U.S. Bureau of Land Management White River Field Office, assesses potential effects of a specific natural gas project in the context of ongoing large scale natural gas development in northeastern Colorado. A more recent journal article, *Energy Boomtowns & Natural Gas: Implications for Marcellus Shale Local Governments & Rural Communities,* published by the Northeast Regional Center for Rural Development, describes a model for impact assessment, presents a case study describing Sublette County's experience with large scale natural gas development and discusses some possible implications for Marcellus Shale development.

commissioned by the New York State Energy Research and Development Authority (NYSERDA) to describe socioeconomic impacts that can be anticipated with HVHF gas development. In addition, NYSDEC needs to quantify known social and economic costs even if their occurrence cannot be synchronized with their scenario model of development. This quantification can be accomplished through examination of comparable cases of impact, a standard method used in fiscal impact analysis (Kotval and Mullin, 2006).

B. NYSDEC's Analysis of Specific Socioeconomic Impacts: Model Assumptions and the Use of Representative Regions

The RDSGEIS presents only a fraction of the material contained in the EAR and acknowledges: "A more detailed discussion of the potential impacts, as well as the assumptions used to estimate the impacts, is provided in the Economic Assessment Report, which is available as an addendum to this RDSGEIS." (RDSGEIS, 6-207). This section identifies questions and concerns regarding the assumptions underlying the model used to predict impacts of HVHF development in New York State. These comments focus particularly on the use of representative regions to project impacts throughout New York State, including those for Utica shale gas drilling.

B1. The Use of Representative Regions

NYSDEC's use of a set of Southern Tier counties to represent all counties in New York that may experience HVHF shale gas drilling (EAR, 6-217) raises concerns about the representativeness of these counties. The EAR and RDSGEIS define three representative regions for the socioeconomic analysis, with Region A representing counties accounting for a high percentage of overall well development, Region B representing counties with about half the development of Region A, and Region C representing counties not expected to have much production but with a history of drilling. In the RDSGEIS, characteristics from a representative region are used to make assumptions about socioeconomic impacts in other New York State regions where drilling may occur. For example, tourism impacts are assumed to be minimal for all regions based on the continued presence of a tourism industry in Region C. The EAR and NYSDEC need to provide evidence (in industrial composition, growth rates, and population composition) to support the assumption that these counties are "representative" of all the counties that may experience drilling.

In addition, the EAR indicates that it addresses "local" impacts, but there is no analysis below the county scale. Analysis of differential economic impacts in urban and rural areas, for example, is critical to understanding the total economic impact picture. For example, counties in Region A in the EAR scenario analysis include both urban areas such as the Binghamton Metropolitan Statistical Area and rural areas where tourism and agriculture are the primary industries. Urban areas will garner more expenditures from natural gas drilling in the region, but are also likely to have negative impacts in the form of increased crime and demand for health services (because of their location in the urban areas). Rural areas will experience intense impacts on their small rural communities, including demand for housing and increases in road damage, as well as potential negative effects on agriculture and tourism. These local impacts, and how the costs and benefits will be distributed, need to be assessed separately.

B2. The Use of a RIMS Input-Output Model to Assess Social and Economic Impacts

A central component of the EAR is use of a Regional Industrial Multiplier System (RIMS) model developed by The Bureau of Economic Analysis. This type of model is useful for comparing different types of investments and for examining inter-industry linkages, but it has a significant drawback as the central model for the RDSGEIS analysis of socioeconomic impacts because it can only project economic benefits. It cannot measure or assess the costs of proposed gas development using HVHF or tell us anything about fiscal impacts.

The purpose of the model is to deduce direct and indirect economic impacts of new expenditures in a region. This type of model is very limited in the types of impacts it can assess. It is typically used to estimate some economic impacts, but is not useful to assess the wide range of social impacts that have been identified as occurring with HVHF shale gas drilling. So, for example, the model can be used to derive population increases and then, to crudely extrapolate potential housing demand. It cannot tell policy makers anything about the impact of housing demand on different population segments or on community character.

The results of this kind of model will always be positive because the model begins with the inflow of expenditures in the region. If the modelers had examined new expenditures flowing into the region's tourism or agricultural sectors those, too, would be positive. The model provided in the RDSGEIS does not allow us to assess opportunity costs, that is, to compare the economic impacts of shale gas drilling with those that might occur with increased investments and expenditures in other industries. This is important not only because shale gas drilling impacts are being considered in "isolation," but because investments in industries such as tourism and agriculture might decrease because of "crowding out" by HVHF activity (Christopherson and Rightor, 2011)

A model of this type is completely dependent on assumptions about the source of expenditures in the region. For example, in the case of HVHF gas development, the model is based on assumptions such as those about where the labor force hired in the drilling phase will spend the money they earn -- in the drilling region or in their home states? These assumptions are critical to the model results and should have been made available so that the accuracy of the model could be analyzed.

The presentation of the model results in the EAR is neither useful nor informative. Much of the text is devoted to tables that present mechanical calculations. These tables should have been relegated to an appendix and the body of the report used to lay out and support the assumptions that underlie the calculations.

In December 2011, the consulting firm that developed the EAR was asked to evaluate costs associated with gas development using HVHF in New York State. Because the RIMS input-output model and the associated scenario approach cannot address the costs of such development, the use of this approach rather than one that addresses costs as well as benefits needs to be justified and re-visited. In addition, because of its inability to address costs, the model does not provide information on impacts that require mitigation. Given the inadequacies of the EAR model and the significance of local and state costs to decisions about shale gas drilling in the state, revised EAR findings regarding costs must be prepared and an opportunity for public review and comment on the revised EAR afforded before the SGEIS is finalized.

C. NYSDEC Analysis of Selected Social and Economic Impacts

This section comments on section 6.8 of the RDSGEIS, which assesses a selective subset of the many social and economic impacts anticipated with HVHF natural gas drilling. These include: (1) economy and employment, (2) population, (3) housing, (4) government revenue and expenditure, and (5) environmental justice. This section concludes with comments on material presented in the EAR that is not discussed in section 6.8, but which is relevant to the RDSGEIS findings regarding social and economic impacts.

C1. Economy and Employment

Employment. The oil and gas industry is not likely to be a major source of jobs in New York, because of the project-based nature of the drilling phase of natural gas production (rigs and crews move from one place to another and activities are carried out at each well) and because of its capital intensity (labor is a small portion of total production costs) (Jacquet, 2009). The emerging information on actual employment created in Pennsylvania in conjunction with Marcellus drilling shows much smaller numbers than industry-sponsored input-output models projected.

Although the industry points to years of drilling experience in New York, the oil and gas industry employed only 362 people in New York State in 2009 (0.01% of the state's total employment) (EAR, 3-7). 43% of those workers (157) were employed in Region C, the region where vertical natural gas drilling is most significant in New York. Wages for these workers constituted 0.04% of the wages in the two-county region with almost 4,000 active gas wells (EAR, 3-31).

The employment multiplier projected for New York State (2.1766) (derived from the model used in the EAR) is exceptionally high, especially for investment from a capital-intensive industry. (A 2.0 multiplier is considered generous by most regional economic analysts.) This underscores the importance of making the assumptions underlying the model transparent. For example, is the basis for the multiplier used an assumption that expenditures on real estate development resulting from the HVHF gas development will accrue disproportionately to New York state firms? If so, why? Because unrealistic and overly optimistic assumptions made in constructing the models may overstate economic benefits, assumptions underlying this RIMS model need to be available for scrutiny.

Finally, the employment figures presented in Table 4-8 are "full–time-equivalent" (FTE) jobs. These jobs do not correspond with what the ordinary person thinks of as a job – a person employed full-time to carry out certain tasks. They are a composite of part-time and full-time jobs that might be developed from the 410 job activities associated with constructing and drilling a well and from the subsequent production phase. These may not be new jobs, but existing jobs required to sustain industry activity. Finally, the EAR does not provide sufficient context for evaluating the employment impact of gas development using HVHF in the state. Projected employment in HVHF development should be compared with that in other New York industries, including tourism, to place the numbers in perspective. Projected increases in employment in these other industries should be provided to enable comparison and to estimate costs and benefits of permitting HVHF gas development.

Impacts on other regional Industries. Having described in detail the modeled economic and employment growth from the gas industry, the RDSGEIS then mentions the potential adverse impacts on existing industries in the regions where natural gas development will occur. In a bare two paragraphs, the RDSGEIS admits:

> Conversely, some industries in the regional economies may contract as a result of the proposed natural gas development. Negative externalities associated with the [sic] natural gas drilling and production could have a negative impact on some industries such as tourism and agriculture. Negative changes to the amenities and aesthetics in an area could have some effect on the number of tourists that visit a region, and thereby impact the tourism industry. However, as shown by the tourism statistics provided for Region C, Cattaraugus and Chautauqua Counties still have healthy tourism sectors despite having more than 3,900 active natural gas wells in the region.
>
> Similarly, agricultural production in the heavily developed regions may experience some decline as productive agricultural land is taken out of use and is developed by the natural gas industry.

(RDSGEIS, 6-230).

In contrast with the pages of projected benefits from gas development, the RDSGEIS offers no detailed description and no quantitative analysis of the effects of HVHF development on existing industries and the associated impact on the state of New York's economy. This omission is particularly important for the counties defined in the EAR as "representative" because industries, including agriculture and tourism, are significant employers in those counties and are important to the overall economy of the State. There is no analysis of how the "crowding out" of existing industries may impact the regional or statewide economy or of the implications of the loss of industrial diversity to the long-term prospects for regional economic sustainability.

The inadequate assessment of the impacts on existing industries in the region that will be affected by HVHF gas development is problematic not only because the state does not have adequate information to assess costs and benefits of HVHF gas development, but also because negative impacts on industries such as tourism and agriculture, including dairies and wineries, will undermine state investments intended to support those industries. As discussed in detail below, given the importance of these industries in the state and regional economy, the evidence that they will be negatively affected by HVHF gas development should have been analyzed in detail and quantified when possible.

Tourism. The RDSGEIS makes no effort to quantify the value of tourist activities that may be adversely affected by gas development but rather dismisses any impacts as insignificant.

Nearly 674,000 New York jobs were sustained by tourism activity last year, representing 7.9% of New York State employment, either directly or indirectly. New York State tourism generated a total income of $26.5 billion, and $6.5 billion in state and local taxes in 2010.

Tourism in the Southern Tier counties includes a wide range of activities, from visits to the Corning Glass Museum to hiking, hunting, and fishing in the rural areas. The Southern Tier Central (STC) Planning District, which includes Chemung, one "fairway" county (where significant natural gas drilling is anticipated because of the geologic formation) located in Region A in the RDSGEIS analysis, has published a study indicating that:

> In 2008, visitors spent more than $239 million in the STC region across a diverse range of sectors. The tourism and travel sector accounted for 3,335 direct jobs and nearly $66 million in labor income in the STC region that year. When indirect and induced employment is considered, the tourism sector was responsible for 4,691 jobs and $113.5 million in labor income. In addition, the travel and tourism sector generated nearly $16 million in state taxes and $15 million in local taxes, for a total of almost $31 million in tax revenue -- a tax benefit of $1,181 per household.

(Rumbach, 2011, page 1).

Tourism is thus a significant contributor to the counties in New York potentially impacted by HVHF gas development. The tourist opportunities and activities also contribute to the quality of life of local residents and attract companies in other sectors, such as manufacturing.

NYSDEC's use of Chautauqua and Cattaraugus Counties as the basis for contending that tourism will not be significantly impacted in New York is not persuasive. First, the evidence offered for the judgment that those counties have "healthy tourism sectors" (RDSGEIS, 6-231) consists of nothing more than the statement that: "In 2009 wages earned by persons employed in the travel and tourism sector in Chautauqua and Cattaraugus counties (Region C) were approximately $77.5 million, or about 3.0% of all wages earned in Region C" (NYSDOL 2009b*)* (see Table 3-37)" (EAR, 3-27). Without comparing Chautauqua and Cattaraugus over time with similar counties where natural gas development has not taken place, it is impossible to determine whether the tourism sector of the Region C counties has been negatively impacted by shale gas drilling.

The contention that those counties represent a tourism success story is contradicted by data presented in the EAR, which shows that from 2007 to 2009, Region C tourism employment declined 17%, and wages declined 13% (EAR, 3-28). While a portion of this decline might be attributable to the recession, there is no justification for describing waning tourism in the region as "healthy."

In addition, there is growing evidence regarding the negative effects of shale gas drilling on tourism in the counties where shale gas drilling takes place (Rumbach, 2011).

> Evidence from other shale plays in the Western U.S. indicates that natural habitat tourism (whether hunting, fishing, birding or hiking) may be disrupted for long periods of time and in some cases where infrastructure, such as compressor plants and pipelines, disrupts habitats, may be permanently altered.

(Sammons, Dutton and Blankenship, 2010). Negative impacts derive not only from the loss of habitat for outdoor sports, but also from the "crowding out" of tourism activities (because of increasing prices in the drilling region and the loss of hotel spaces to gas industry workers) and from the impact of regional industrialization on the tourism brand. For example, tourism centers in Upstate New York, such as the Finger Lakes wineries, may experience losses when tourists looking for a rural retreat find themselves driving through an industrial region with heavy truck traffic and shift their allegiance to quieter and more accessible vacation spots. In addition, the RDSGEIS does not assess the impacts on tourism from degradation of historical and cultural assets.

The EAR also conflates access to private recreational land for purposes of hiking, hunting, and fishing with the success of commercial tourism businesses. The relationship between personal recreational opportunities and natural gas development is presented as one of personal trade-offs in terms of land use. The negative impacts on the options of non-land owning recreationists are mentioned but not addressed (EAR, 4.58).

Rumbach's assessment of HVHF gas development on tourism is that:

> ….individual impacts are unlikely to have serious and long-term consequences, but without mitigation, cumulatively they could do substantial damage to the tourism sector. Examples of such impacts include strains on the available supply and pricing of hotel/motel rooms, shortfalls in the collection of room (occupancy) taxes, visual impacts (including wells, drilling pads, compressor stations, equipment depots, etc.), vastly increased truck and vehicle traffic, potential degradation of waterways, forests and open space, and strains on the labor supply that the tourism sector draws from. All told, the region's ability to attract tourists could be damaged in the long-term if the perception of the region as an industrial landscape outlasts the employment and monetary benefits of gas drilling.

(Rumbach, 2011, page 2).

The RDSGEIS fails to address the long-term costs associated with displacing business in existing industries, such as tourism, that provide economic diversity in the regional economy and thus increase its prospects for sustainability.

Agriculture. Potential negative impacts on agricultural production and land use are noted, but their impact is not assessed nor are any mitigation measures proposed (RDSGEIS, 6-231). There is no analysis of whether and how HVHF gas development will affect sub-sectors of agriculture, such as dairy farming, which are of key importance in the New York economy.

Milk and other dairy products account for more than half the total value of agricultural products sold in New York State, accounting for $2.2 billion in receipts in 2010. According to the US Department of Agriculture, New York ranks third in the US in production and sale of dairy products. Certainly the size and importance of this industry to the New York economy warrants a full analysis of how production and producers will be impacted by HVHF gas development. Instead, the RDSGEIS lacks an economic assessment of how temporary and long-term agricultural costs and productivity will be affected by HVHF development.

Recent evidence from Pennsylvania indicates that agriculture and particularly dairy farming may be significantly affected by drilling activity. For example: "(Bradford) county's dairy herd has decreased over the last decade from 30,000 head in 2002 to just under 20,000 head today. Another 15 dairies have been sold since the beginning of the year (2011)" (Tomes, 2011). Although evidence from Pennsylvania is anecdotal, there is sufficient information to indicate that one of New York's major industries will be negatively affected by HVHF gas drilling.

Dairy farms are decreasing in areas with natural gas development both because some farmers have another source of income and because costs for dairy farmers are going up as a consequence of the impact of the drilling economy in the county. For example, competition for truck drivers is raising the cost for dairy farmers to transport their milk to processors. In addition to the impacts on the dairy farms themselves, the infrastructure that supports dairy farming in Bradford County is being affected. For example, an agricultural equipment dealer in the County has gone out of business because of an inability to hire and retain a workforce (Tomes, 2011).

There are also land use impacts that affect farmers, including impacts not only from the well pads, but also from the ancillary industrial facilities, such as "laydown yards" (operations and storage sites), pipelines, and compressor stations (Tomes, 2011).

The American Farmland Trust (2011) has submitted comments on the RDSGEIS that summarize its expert assessment of the impact on agricultural production in New York State:

> …the DEC's analysis of the impacts of drilling and hydraulic fracturing to agricultural land is inadequate and encourages specific analysis of the likely impacts of such activities to agricultural land resources. The SGEIS analysis should consider the scale of farmland likely to be converted by both direct drilling activities and the off-site drilling support services and other types of residential and commercial development that is anticipated as a result of natural gas drilling. In addition, it should consider the impacts of such activities to agricultural land values and on the ability of New York farmers to maintain their competitiveness in a global economy.

Upstate New York is currently experiencing a resurgence in its food processing industry, and the State Agricultural and Markets Program has a stated policy of encouraging more dairy production in the state. In July 2011, the State of New York provided $16 million in incentives to a dairy processing company in Chenango County in Central New York. According to a statement by Governor Cuomo: "Agro Farma's expansion in Chenango County will create hundreds of new jobs and increase the demand for milk from New York dairy farms," (press release available at: http://www.governor.ny.gov/press/07212011DairyProductsCompany).

The support from New York's Empire State Development Corporation reflects the significance of this industry to the regional and state economy. A full economic assessment of potential impacts to this industry is warranted. This assessment should include labor costs (from competition for truckers, for example) and impacts on specialty agricultural producers, such as organic farmers. New York State has the fourth largest number of organic farms in the U.S.

The Finger Lakes wineries, combining agriculture and tourism, are another important subset of New York industries that may also be affected by HVHF gas development in Upstate New York. New York State ranks third nationally in grape production. Tourists visiting the wineries may not want to drive through industrial development and its associated truck traffic in order the reach the wineries, even if the wineries are not locally impacted by the drilling process. Given the importance of this and other sectors of New York's agricultural industry to the Upstate New York "brand" and the investment of State resources to build the industry, the SGEIS needs to separately assess the impacts on this industry and develop mitigation policies to address the negative impacts identified.

Manufacturing. Finally, the RDSGEIS and the EAR focus exclusively on impacts to agriculture and tourism because the use of land by those industries potentially competes with use of land for gas development. Focusing on that competition may make sense for the largely rural representative regions defined in the EAR, but it does not make sense for representative regions with more diversified economies, including substantial manufacturing. A report by the New York State Comptroller's office in 2010 shows that the Southern Tier has 14% of Upstate manufacturing. Manufacturing should be included in the assessment of impacts on existing industries, because of its significance in Region A and because gas development will affect the labor supply and industry wage rates in counties where manufacturing plays a significant role in the economy.

C2. Population

The RDSGEIS and EAR do not address population impacts on community services, such as schools and health, but only population as it relates to employment and the labor market. There was no attempt to look at actual population trends in counties with significant gas drilling and whether they reflect a decline in economic diversity that makes population levels less sustainable. An analysis of the long-term population trends in shale gas drilling counties in the US is necessary to determine the impact of HVHF gas development on New York counties. A projection based on labor demand is not sufficient.

The EAR assumes that, for the first 30 years, the population increases in counties that "host" natural gas drilling will be modest. It notes, for example:

> [A]ctual population impacts may also be less than what is described in the following section because currently unemployed or underemployed local workers could be hired to fill some of the construction and production positions, thereby, reducing the total in-migration to the region.

(EAR, 4-59).

By focusing only on population changes directly related to gas industry employment, the RDSGEIS avoids addressing the potential for long-term population decline beyond the loss of industry workers. Many areas with significant natural gas drilling lose population over time. That has been the case with Chautauqua and Cattaraugus counties (Region C) in New York.

In addition, the RDSGEIS assumes a gradual (rather than disruptive) integration of the unemployed population in the region and of transient workers into the labor force required by the industry. Experience from other states, however, contradicts the assumption of easy integration of the resident workforce and of newcomers to the regional labor force: “In areas of Pennsylvania where Marcellus shale drilling activity is occurring, it has been difficult at times to accommodate the influx of new workers” (Kelsey, 2011). The potential for a low-skilled, transient workforce to migrate into the area is not considered, although there is evidence from Western shale plays that this occurs, and is particularly likely with high national unemployment rates.

> [B]ecause labor markets are imperfect, [and] the availability of a relatively large number of jobs may result in an influx of job seekers, some of whom lack necessary skills and qualifications and may be relatively indigent. To the extent that indigent job seekers are unable to find jobs or do not have resources to secure housing and transportation to work; they can become a burden for local human service agencies. This situation can be exacerbated by weak economic conditions in other parts of the state or country.

(Sammons, Dutton and Blankenship, 2010, page 13).

The RDSGEIS fails to address this evidence of adverse economic impacts.

C3. Housing and Property Values

<u>The potential impacts on the housing supply, housing costs, and housing financing are inadequately assessed in the EAR. In addition, the social and economic impacts of unpredictable shortfalls in housing followed by periods in which there is an excess supply are not addressed.</u>

The report assumes that the current housing stock would be used to house any workers who move to the production region on a “permanent” (more than one year) basis (EAR, 4-107 (concluding “the impact on the supply of permanent housing units would be negligible at the statewide level during the production phase”)). Given the quality and age of the housing stock in the region, evidence from Pennsylvania indicates that it is likely that there will be a demand for new single-family housing (Kolb and Williamson, 2011). This new housing stock will create new and additional construction jobs, increasing population pressure, accelerating the “boomtown” phenomenon. This housing may also contribute to sprawl around urban population centers such as Binghamton. When drilling ceases, either temporarily or permanently, the value of this new housing is likely to plummet (Best, 2009).

With respect to temporary housing, the EAR (EAR, 4-111) admits:

> In areas of Pennsylvania where Marcellus shale drilling activity is occurring, it has been difficult at times to accommodate the influx of new workers (Kelsey 2011). There have been reports of large increases in rent in Bradford County, Pennsylvania, as a result of the influx of out-of-area workers (Lowenstein 2010). There have also been “frequent reports” of landlords not renewing leases with existing tenants in anticipation of leasing at higher rates to incoming workers, and reports of

> an increased demand for motel and hotel rooms, increased demand at RV camp sites, and increases in home sales (Kelsey 2011). Such localized increases in the demand for housing have raised concerns about the difficulties caused for existing local, low-income residents to afford housing (Kelsey 2011).

If communities add substantial temporary, short-term housing or single-family housing to accommodate development-phase workers, surplus capacity may exist in all these types of units after development is completed. Based on evidence from other shale gas plays, all of these adverse impacts (initial housing shortage, surplus supply if rigs leave temporarily and depressed value in some areas) may occur (Best, 2009; Sammons, Dutton and Blankenship, 2010).

The EAR (EAR, 4-111) also acknowledges the potential impact of the volatility of the production cycle on the housing market and property values:

> The demand for housing, both temporary and permanent, would be expected to change over time. The demand for housing would be the greatest in the period during which the wells in an areas are being developed, and demand would decline thereafter. This would create the possibility of an excess supply of such housing after the well development period (Kelsey 2011). If well development in a region occurs in some areas earlier than in others, then housing shortages and surpluses may occur at the same time in different areas within the same region.
>
> The natural gas market can be volatile, with large swings in well development activity. Downswings may cause periods of temporary housing surplus, while up-swings may exacerbate housing shortages within the regions.

A recent study of the impact of HVHF gas development in Pennsylvania indicates that impacts on the housing supply are significant, especially for people at the economic margins (Williamson and Kolb, 2011). These impacts pose environmental justice concerns and require mitigation strategies.

With respect to impacts on property value, the EAR authors found that having a well on a property was associated with a 22% reduction in the value of the property; that having a well within 550 feet of a property increased its value; and that having a well located between 551 feet and 2,600 feet from a property had a negative impact on a property's value. Thus,

> …not all properties in the region would increase in value, as residential properties located in close proximity to the new gas wells would likely see some downward pressure on price. This downward pressure would be particularly acute for residential properties that do not own the subsurface mineral rights (EAR, 4-114).

The EAR authors attributed the positive impact on property values of having a well located within 550 feet of a property to the prevention of further gas well development in that area due to a spacing order and setback conditions that prevented well drilling close to existing wells.

The assertion in the EAR that property owners in the drilling region would see an overall increase in property values is based on increased demand and economic activity. Evidence from Pennsylvania and from Western Shale plays indicates that this demand may not occur in the county or locality where the drilling is occurring (Patton et al, 2010).

The EAR's assumption of recovering property values after the completion of HVHF gas development does not take into account the potential for re-fracturing of wells to increase their productivity or the effects of waves of development in which drilling moves in and out of an area. The prospect of industrial activity is what drives down investment in regions open to boom-bust development and also negatively impacts property values (Spelman, 2009). A more definitive analysis of impacts of on property values, including mortgage availability, in regions affected by drilling is needed.

C4. Government Revenues and Expenditures

The RDSGEIS assumes, based on the RIMS model, that economic benefits from HVHF gas development, presumably including benefits to revenue, will be substantial, but there is no fiscal impact analysis or cost-benefit analysis to substantiate that assumption. A fiscal impact analysis is required, given that:

(1) Many purchases by drilling companies are tax exempt (EAR, 4-116).

(2) Costs to the state that will reduce or offset tax revenues are not calculated. For an example of this problem, see the discussion of rail infrastructure in the RDSGEIS section on transportation impacts. The provision of tax rebates to railroad companies and to industry facilities represent lost revenue to the State and the locality. The EAR admits that in addition to tax benefits, "such as expensing, depletion, and depreciation deductions," which reduce taxable income, "New York State offers an investment tax credit (ITC) that could substantially reduce most, if not all, of the net income generated by these energy development companies" (EAR, 4-115 to 4-116).

(3) Substantial negative fiscal impacts are detailed in the EAR that are not quantified or fully acknowledged in the SGEIS:

> High-volume hydraulic fracturing operations would also result in some significant negative fiscal impacts on the state. The increased truck traffic required to deliver equipment, supplies, and water and sand to the well sites would increase the rate of deterioration of the state's road system. Additional capital outlays would be required to maintain the same level of service on these roads for their projected useful life. Depending on the exact location of well pads, the state may also be required to upgrade roads and interchanges under its jurisdiction in order to handle the additional truck traffic. The potential increase in accidents and potential additional hazardous materials spills resulting from the increased truck traffic also would require additional expenditures. Finally, approval of transportation plans/permits would place additional administrative costs on the New York State Department of Transportation (EAR 4-116).

There are now numerous studies available to calculate road damage, and the counties in the "fairway" in New York State have undertaken baseline studies that would enable accurate calculation of the costs of road damage (Randall 2011). There is plenty of expertise available in the state to draw on, including Cornell Local Roads program, which has completed a thorough analysis of the kind of damage and what it would cost to repair.

The EAR also recognizes additional public costs associated with Marcellus shale gas development:

> Additional environmental monitoring, oversight, and permitting costs would also accrue to the state. In order to protect human health and the environment, New York State would be required to spend substantial funds to review permit applications; to ensure that permit requirements were met, safe drilling techniques were used, and the best available management plans were followed; and to provide enforcement against violations. In addition, the state would experience administrative costs associated with the review of well permit applications and leasing requirements and enforcement of regulations and permit restrictions. All of these factors could result in significant added costs for the New York State government.
>
> The New York State Department of Health would also incur additional costs due to the need to provide additional technical support and oversight services to local governments that would monitor water quality in local drinking water wells (EAR, 4-116).
>
> In addition to the positive fiscal impacts discussed above, local governments would also experience some significant negative fiscal impacts as a result of the development of natural gas reserves in the low-permeability shale. As described in previous sections, the use of high-volume hydraulic-fracturing drilling techniques would increase the demand for governmental services and thus increase the total expenditures of local government entities. Additional road construction, improvement, and repair expenditures would be required as a result of the increased truck traffic that would occur. Additional expenditures on emergency services such as fire, police, and first aid would be expected as a result of the increased traffic and construction and production activities. Also, additional expenditures on public water supply systems may be required. Finally, if substantial immigration occurs in the region as a result of high-volume hydraulic fracturing operations, local governments would be required to increase expenditures on other services, such as education, housing, health and welfare, recreation, and solid waste management to serve the additional population (EAR, 4-138).

The RDSGEIS mentions public costs associated with the increased demand for community social services, police and fire departments, first responders, schools, etc., but makes no attempt to calculate the costs and consider them in the context of a fiscal impact assessment. Experience in other shale gas plays demonstrates that these costs are likely:

> Natural gas development and production-related activities and the incremental population associated with those activities will generate

> demand for the full range of local government facilities and services and for some state government services. For example, during exploration and moderate stages of development, demand is usually limited to law enforcement, emergency response, emergency medical and road and highway maintenance and traffic control. Traffic, vehicle and industrial accidents and issues associated with a single-status, predominately working-age male workforce are the primary drivers associated with emergency response and law enforcement increases. Because many workers are temporary, and do not have local general purpose health care providers, they commonly use hospital emergency rooms for what would be otherwise be routine health care visits.

(Sammons, Dutton and Blankenship, 2010, page 19).

This knowledge regarding public costs and fiscal impacts should have been reflected in the RDSGEIS. These costs may occur even if the amount of commercially extractable natural gas does not reach projected levels. They need to be calculated both in terms of the baseline costs that are likely to occur with <u>any</u> drilling activity and in relation to varying levels of drilling activity.

Addressing the variability is important because there are distinct community character impacts attributable to large-scale development that have been identified and documented in other shale plays.[2] For example:

> …some areas that experience large scale development have reported substantial increases in a variety of crime and social problems including alcohol and drug-related offenses, traffic offenses, disturbances, assaults and domestic conflicts. Although some increases in crime and social problems would be anticipated to accompany any increase in population, some researchers have also attributed the increased levels of crime and social problems to the temporary and transient nature of the workforce and their living conditions. There has been some debate in the social impact assessment literature about whether or not crime and other adverse social indicators increase at higher rates in communities experiencing large-scale development than average rates for all communities. But the implications are clear that increases in crime and social problems are likely with large-scale development, even if they are proportionate to the increase in the numbers of people working and living in affected communities.

(Sammons, Dutton, and Blankenship, 2010).

Given the scale of development being projected, the thresholds for community costs and

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[2] *See* Sublette County Socioeconomic Impact Study Phase I Final Report. Ecosystem Research Group. , January 2008. Pages 54 – 58 and Index Crimes, Arrests, and Incidents in Sublette County 1995 to 2004: Trends and Forecasts, Prepared by J. Jacquet. Sublette County, Wyoming, April 2005, *available at:* http://www.sublettewyo.com/DocumentView.aspx?DID=351; Local Social Disruption and Western Energy Development: A Critical Review, Wilkinson et.al. Pacific Sociological Review Volume 25. July 1982. *available at:* http://www.sublettewyo.com/archives/42/Local_Social_Disruption__Critical_Review_Response_and_Commentary [1]. pdf.

adaptation to the impacts related to population increase or demand for services (administrative, school, health, public safety) must be addressed by the SGEIS. Evidence from Pennsylvania indicates that ability to adapt to these community social and economic impacts is critical to short-term and long-term community well-being (Kolb and Williamson, 2011; Kelsey, 2010, 2011).

(4) Costs will vary with the nature of population increases driven by the permitting of HVHF gas development. For example, indigent job seekers unable to find jobs and without resources to secure housing or transportation to work can become a burden for local human service agencies. This situation may be exacerbated by weak economic conditions in other parts of the state or country.

An example of this phenomenon is documented in a study carried out by Guthrie Hospital/Troy Community Hospital in Bradford County, Pennsylvania, where impacts from HVHF gas development in the county have significantly increased demand for health services (Covey 2010). The hospital is treating a new non-English speaking clientele and has had to hire translators. They have also had to purchase new equipment and have experienced a significantly increased demand on their emergency room services. The new demand affects not only the bottom line of providers, but also the availability of and access to health care for residents of the region in which drilling is occurring.

(5) There is no analysis of the expected lag between immediate costs and anticipated revenues. This lag may be 2-3 years, during which communities will be faced with significant public service costs.

(6) A tax profile needs to be presented over time, not one for a single year, in order to understand how natural gas drilling has fiscally impacted Region C, where most wells are currently located and where wells have increased.

C5. Environmental Justice Impacts

A section on Environmental Justice, included at the end section 6.8 of the RDSGEIS, notes that well permits are currently exempt from screening under NYSDEC Commissioner Policy 29, Environmental Justice and Permitting (CP-29) (RDSGEIS, 6-263). NYSDEC suggests that a drilling permit applicant could, “when necessary,” conduct a GIS analysis to identify potential environmental justice areas. The RDSGEIS should set forth criteria to determine when such an analysis would be “necessary” and should include the requirement in standard permit conditions or regulations. Moreover, given the known housing impacts of gas development on low-income populations, efforts to mitigate significant adverse environmental justice impacts must include not only the “additional community outreach activities” required in the RDSGEIS, but also substantive measures to prevent dislocation and homelessness.

II. Additional Economic Impacts Identified in the EAR But Not Addressed in the RDSGEIS

The RDSGEIS presents only a fraction of the material contained in the EAR and acknowledges: “A more detailed discussion of the potential impacts, as well as the assumptions used to estimate the impacts, is provided in the Economic Assessment Report, which is available as an addendum to this SGEIS" (RDSGEIS, 6-207). This section comments on material presented in the EAR that is not discussed in section 6.8, but which is relevant to the RDSGEIS findings regarding social and economic impacts.

A. The Distribution of Impacts of HVHF Gas Development in New York State

The socioeconomic impact analysis should systematically describe the geographic distribution of impacts. In New York, as is explained below, the creation of high-paying jobs as a result of expenditures in industries outside the extraction industry is likely to occur outside the production region. This is important because regions where natural resource extraction takes place (and especially rural regions with little economic diversity) have been found to end up with poorer economies at the end of the resource extraction process (Best, 2009; Sammons, Dutton and Balnkenship, 2010). Mitigation measures need to be identified to address long-term costs to the rural counties where extraction will be concentrated.

The EAR calculates the impact of a $1 million increase in the final demand in the output of the oil and gas extraction industry on the value of the output of other industries in New York State (EAR, 3-6). The EAR then makes a series of statements concerning where the economic benefits of HVHF development are expected to occur. For example:

> The proposed use of high-volume hydraulic fracturing would have a significant, positive impact on employment in New York State as a whole and in the affected communities. However, the distribution of these positive employment impacts would not be evenly distributed throughout the state or even throughout the areas where low-permeability shale is located. Many geological and economic factors would interact to determine the exact locations where wells would be drilled. The location of productive wells would determine the distribution of impacts.

(EAR, 4-46; emphasis added).

The location of wells is, however, only one factor affecting the distribution of economic impacts in New York State. Many wells are drilled in rural areas with no or very limited commercial services near-by. If that is the case, then the economic impacts (in the form of expenditures by drillers and companies) will not occur close to the drilling site. Some will occur in centers – perhaps across a municipal or county line – where there are stores and restaurants that the drilling company employees use for meals and supplies. Some economic impacts will occur in far away places, such as New York City, where the drilling company can buy specialized services, such as tax accounting and legal services, to meet their business needs.

This potentially broad distribution of economic impacts is reflected in the multipliers reported in the EAR as follows:

> As anticipated, the direct effect employment multiplier for the State of New York (2.1766) was substantially larger than the multipliers for the individual regions, which had direct-effect employment multipliers of 1.4977 in Region A, 1.3272 in Region B, and 1.4357 in Region C (USBEA

> 2011a, 2011b, 2011c, 2011d). (EAR, 4-19).

These multipliers are affected by purchases by the gas drillers from other industries in the economy. In this case, the RIMS model used in the EAR indicates that three largest industries in which purchases will be made (and additional employment created) are: (1) real estate and rental; (2) professional, scientific, and technical services; and (3) management of companies). We can anticipate that purchases from these industries would have a strong effect in New York State as a whole because these industries have a strong presence in New York State.

What the multipliers also tell us, however, is that the jobs indirectly created by purchases of goods and services by the natural gas developers are not likely to be located in the counties where HVHF gas development occurs. Multipliers tell us how strong the industry is in a region or state. Higher multipliers indicate that those businesses that the oil and gas industry is likely to purchase goods and services from are present. Lower multipliers indicate a small industry presence and thus a lower likelihood of purchases in that geographic area. So, for example, a natural gas development company would employ professional services as a consequence of expanding drilling in Chautauqua County, but is likely to go to New York City to purchase those services because they are more likely to be available in New York City. Companies providing professional services in New York City are more likely to stay there rather than move to the Southern Tier because they have more opportunities to attract diverse industries to their specialized services in New York City than in Elmira or Jamestown.

If the EAR seeks to project the impact of expenditures on the regions in the state likely to be affected by HVHF gas development, it needs to disaggregate these impacts to show what proportion of the impacts in the three largest sectors (real estate and rental; professional, scientific, and technical services; and management of companies) is actually likely to occur in the representative regions. Although the authors assert that as the natural gas industry grows, more of the suppliers would locate to the representative regions and less of the indirect and induced economic impacts would leave the regions, no evidence is presented to substantiate this assumption. This assumption contravenes economic knowledge about agglomeration economies and company location behavior, which indicates that specialized services will remain in higher order centers (like New York City) and not re-locate to counties, especially rural counties, where drilling is occurring. The more likely outcome is indicated by a study of the impact of gas drilling on Western State economies, which found that natural gas drilling may have positive fiscal impacts at the state level, but negative fiscal impacts for the regions in which it occurs (Headwaters Economics, 2011).

B. The Distribution of Economic Impacts in New York Versus Those in Other States

Nationally, Texas and Oklahoma are the major beneficiaries of natural gas development, wherever production takes place in the United States. According to *Mine K. Yücel and Jackson Thies of* the Dallas Federal Reserve (2011): “An increase in oil and gas production **anywhere** benefits the state (of Texas) and its energy sector, which provides oilfield machinery and energy services to the rest of the world.” See also subsection C, below. Nevertheless, because of its capital intensity, natural gas drilling does not have a large employment impact, even in Texas. Gas development thus plays a minor role in the economies of even these resource extraction states.

C. The Distribution of Highly-Skilled Jobs

Petroleum engineers are listed as one of the most common occupations in the oil and gas industry (EAR, 3-8, Table 3-10). The geographical analysis of this occupation by occupational employment statistics indicates that the states with the highest employment in this occupation are Texas, Oklahoma, and Louisiana. In 2010, the total U.S. employment of petroleum engineers was 28,210, of which 15,510 were employed in Texas, and 10,380 of those worked in the Houston metropolitan area. Thus, even in Texas, the employment in this occupation is concentrated in the Houston metropolitan area, not in the drilling areas.

The likely distribution of highly paid occupations is demonstrated by the Bureau of Labor Statistics (BLS) Occupational Employment Statistics Data on one of the most numerically significant skilled occupations, that of petroleum engineer. According to the BLS, only a fraction of petroleum engineers (in the hundreds) are employed in non-metropolitan areas in the U.S. (BLS, 2010). This data, too, suggests that the rural areas of New York that are likely to experience the most intensive gas development will not see an increase in highly skilled and highly paid jobs related to the oil and gas industry.

III. Inadequacy of Proposed Mitigation Measures

A. Mitigation Measures That Address Potential Impacts Related to Volatility in the Pace and Scale of Drilling Should Be Required

The mitigation chapter of the RDSGEIS implies that negative impacts will be mitigated through the permitting process and a secondary level of review triggered by the operator’s identification of inconsistencies with comprehensive land use plans. The measures identified are only advisory. The RDSGEIS proposes no requirements to mitigate adverse socioeconomic impacts in this process.

Mitigation measures should be developed that would require operating companies to submit plans for exploration and development in a county or counties to county planning offices for review of cumulative impacts and mitigation (for example truck traffic routing), a model used in Western U.S. drilling regions (Headwaters Economics, 2011). This assessment is also completed for National Environmental Policy Act compliance when development proceeds on public lands.

Because the RDSGEIS acknowledges that the pace and scale of development are difficult to ascertain until exploration and production begin to proceed, it is critical that a permit and regional Plan of Development (POD) review process be set up that alerts local officials to the need for long term planning for land use, schools, public safety and public health. The POD, outlining the pace, scale, and general location in which development will occur, enables local government to anticipate and develop strategies to mitigate cumulative impacts (Sammons, Dutton and Blankenship, 2010). The near-term projections of development activity should include all secondary facilities (e.g., water extraction, waste disposal, pipeline construction) in the area to be affected.
A POD would allow communities in that region to prepare for the disruption and negotiate the least disruptive and damaging development plan.

Another mechanism for reducing the unpredictability and uncertainty of natural gas production at the regional scale is being developed by the Nature Conservancy with pilot projects in the Western States and planned in Pennsylvania (see Kiesecker et al, 2010). Their objective is a science-based, landscape-scale approach to Marcellus gas development that will secure measurable conservation outcomes, while enhancing industry's ability to operate in an environmentally sensitive and cost-efficient manner. To be enforceable, this cooperative approach, based on a partnership between the operating company and local public officials, needs to be codified in a binding agreement. Partnerships of this sort may be useful, but they cannot serve as mitigation for significant adverse socioeconomic impacts unless they are mandatory.

B. Mitigation Should Address Housing and Urban Development Impacts, Including Sprawl and Excess Substandard Housing

Evidence from Pennsylvania and Western shale plays indicates the likelihood of negative impacts on the quality of the temporary and permanent housing stock, a high rate of homelessness for extensive periods, and displacement of low income people from affordable housing. Given the presence of small cities in the region, mitigation measures should include required assistance to cities in the affected region to encourage new housing development in already-developed urban areas and the development of temporary housing that could be transformed to other uses once the influx of transient workers resides. Mitigation measures should also address the impacts of the loss of affordable housing units in the region.

C. Mitigation Should Address Long-Term Social and Economic Impacts

The RDSGEIS and the EAR describe significant adverse social and economic impacts, such as those produced by the volatility of natural gas development on the housing market of regions where development occurs. No mitigation strategies are recommended to alleviate long-term costs that are reasonably assumed to be associated with natural resource development, including HVHF development. Mitigation strategies directed at these long-term costs to the affected regions need to be developed and described in the SGEIS. Mitigation strategies also need to be developed to address the resource depletion phase of the exploration, drilling, development and resource depletion process. In this phase, population and jobs leave the region and tax revenues may be insufficient to pay for the capital investments made to serve the population influx during the drilling and production phases of development. Mitigation strategies should include policies to prevent negative impacts on existing industries, including agriculture, tourism and manufacturing.

D. Mitigation Should Require That Monitoring Reports Projecting Industry Development Plans Be Prepared by the State in Cooperation with Industry and Filed Semiannually

As development activities begin and progress, the information provided in initial projections should be required to be confirmed or revised on a semiannual basis. Information provided in the semiannual assessment and projection should include: (1) employment for each activity; (2) identification and location of contractors; (3) demographic characteristics and residence of employees who will be working in the region. This information is critical to forecasting and meeting housing and service demands.

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Attachment 6

Meliora Design, LLC.

Technical Memorandum

Review and Analysis of the

Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas, and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

and the

Draft New York State Department of Environmental Conservation SPDES General Permit for Stormwater Discharges from High-Volume Hydraulic Fracturing

January 10, 2012

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Introduction

This memorandum reviews both the *Revised Draft Supplemental Generic Environmental Impact Statement* (RDSGEIS) *on the Oil, Gas and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs* and the Draft *New York State Department of Environmental Conservation SPDES General Permit for Stormwater Discharges from High-Volume Hydraulic Fracturing* (SPDES HVHF GP). The focus of this memorandum is the potential impacts on surface water resources that result from land disturbance and alteration, including impacts related to increased erosion and sedimentation, as well as impacts that result from increased and altered stormwater discharges. The review of both the RDSGEIS and the Draft SPDES HVHF GP are co-dependent, as the Department has indicated that general or (substantially similar) individual SPDES permit coverage will be the primary means of regulatory oversight for HVHF operations (and presumably for other low-volume hydraulic fracturing activities, although this is not explicitly stated).

The land disturbance associated with HVHF construction activity has the potential to negatively impact surface water quality in the same manner as other land disturbance activities, as discussed in Attachment A, and the lack of a local government land development review process increases the potential for greater water quality impacts through the increased disturbance of steep slopes, sensitive areas, proximity to unmapped headwater streams, etc. Furthermore, the land disturbance nature of HVHF operations results in a dispersed industry across a wide area, with a large (and unknown) number of stream crossings and an increase in road traffic and gravel road construction. The documented water quality impacts of roads (including gravel roads) are also discussed in Attachment A.

Summary of Key Findings:

The RDSGEIS provides only a very brief generic discussion on the potential land disturbance and associated stormwater and water quality impacts on surface waters from HVHF (and well drilling in general). While the RDSGEIS acknowledges that this land disturbance has potential for water quality impacts, and the Department has made a positive determination that a SPDES permit is required, the RDSGEIS provides little specific discussion or consideration of the land disturbance and surface water quality impacts. Specifically:

- The RDSGEIS makes no attempt to evaluate the <u>cumulative</u> impacts of HVHF activity on water resources, at either the small (headwater stream) scale, or the larger watershed scale. Even very general cumulative estimates of land disturbance, and its associated water quality impacts, are not provided. Since the 1992 GEIS, the use of improved geographic information system (GIS) software and modeling tools has expanded the ability of scientists, engineers, and regulators to quantify the scale and impact of proposed activities on water resources. Such analysis has become standard industry practice for watershed planning and the development of TMDL (Total Daily Maximum Load) studies to determine the level of pollutant load (and required pollutant load reduction) to meet water quality standards. The RDSGEIS fails to provide any such analysis, and instead only acknowledges stormwater impacts with little industry-specific consideration, and no consideration of total or cumulative impacts. **A more detailed and comprehensive evaluation of the amount of anticipated land disturbance and associated water quality impacts is essential for a full environmental impact analysis, and to inform any determinations by the Department on the appropriate regulatory permitting requirements.**
- The RDSGEIS fails to consider the potential surface water impacts of stream crossing activity associated with HVHF well pads, most notably, stream

crossings associated with gathering lines and access roads (to both well pads and compressor stations). Stream crossings and the associated water quality impacts are not fully addressed in the RDSGEIS, and are specifically not included in the Draft SPDES HVHF GP. It is unclear how many stream crossings may be anticipated, and of these, how many will essentially be unregulated under current Department regulations. It is unclear what the anticipated environmental impacts of these stream crossings will be on water quality and aquatic systems. **The RDSGEIS should provide some estimate of the extent of anticipated stream crossings, potential water quality impacts, and proposed Department requirements to regulate and mitigate these impacts.**

- The RDSGEIS does not adequately address private well setbacks, road spreading of brine, gather lines, fueling areas, on-site disposal of drill cuttings, and acid rock drainage. Each of these has the potential to significantly impact and impair water quality. **The RDSGEIS should provide additional information regarding each of these impacts, specifically with regard to landowner notification of well setbacks, cumulative impacts of road spreading of brine, minimizing stream crossings with gather lines, addressing the non-stationary status of fueling areas, and consideration of ARD impacts from disposal of drill cuttings.**
- With the exception of watersheds that serve as unfiltered drinking water supplies and receive Filtration Avoidance Determination (FAD) status, the RDSGEIS and SPDES HVHF GP do not provide any specific consideration of whether different performance requirements or standards are necessary to protect water quality for higher quality watersheds, impaired streams, or areas of denser well pad development on a watershed basis. There is no documentation to support that proposed setbacks are adequate to protect water quality in all situations (i.e., higher quality streams, percent of land disturbance within a watershed, site specific conditions such as steep

slopes). **The RDSGEIS should provide some analysis or justification as to why a single set of performance requirements is applicable in all watersheds and all situations, regardless of stream designation or current levels of impairment or high quality.**

- Even if the proposed setbacks discussed in Chapter 7 were adequate, they are not clearly coordinated with the EAF requirements in Appendices 4, 5, 6 and 10 and the Draft SPDES HVHF GP mapping and documentation requirements (and the SPDES HVHF GP is presumably the regulatory mechanism for compliance). **The Draft SPDES HVHF GP mapping requirements must be at a scale and level of site-specific detail to accurately reflect the required information, and SPDES mapping requirements must be consistent with those identified in the RDSGEIS.**
- The RDSGEIS fails to provide a clear and accessible process for public and local government access to site specific HVHF activity information. At the same time, DEC expects local governments to provide notice to the Department if a proposed HVHF activity is not in compliance with local zoning or land use regulations. This approach puts the regulatory burden on a local government that wishes to challenge a proposed permit application while simultaneously failing to provide local government with access to the necessary information. **The burden of demonstrating compliance with local government land use requirements should fall on the industry, not local government and the public,** with supporting public access to all information regarding proposed land disturbance activity, and reasonable timeframes and processes for comments and addressing of concerns.
- The Draft SPDES HVHF GP is essentially a compilation of the Department's general permits for both construction activity and industrial activity. The general permit process is essentially "self-regulating," relying on the regulated industry to adhere to certain compliance requirements. Based on the very limited discussion of land disturbance and surface water impacts in the RDSGEIS, it is uncertain whether a general permit process will be

sufficient to protect water quality. It is also not clear that an industry that is NOT subject to local government review and approval, unlike virtually all other land disturbance activities addressed by general permits, can be adequately regulated through a general permit process. This is especially important for a heavy industrial activity that will be occurring in areas not zoned or accustomed to heavy industrial activity at the scale that will occur with HVHF operations.

- The general permit process does not provide a timeframe (and process) for public review, comment, and objection to any or all parts of a general permit coverage. Essentially, permit coverage is automatically granted to the industry by providing notice to the Department and meeting minimum performance requirements. There is no opportunity for public access to information or appeal of permit coverage. **It is essential that the SPDES HVHF GP provide a process for public access to all information associated with HVHF land disturbance and water quality impacts, and that a process and timeline be developed to allow for public comment and appeal of general permit coverage for a specific site *before* general permit coverage is granted. It is essential that the permit coverage timeline be adjusted to provide for public comment and appeal.**

Comments on the RDSGEIS

As previously indicated, the discussion in the RDSGEIS on the total land use impacts and associated water quality impacts as a result of both land disturbance during construction and post-construction stormwater management is extremely limited.

Comment 1:

Chapter 5, Natural Gas Development & High-Volume Hydraulic Fracturing. Section 5.1 of the RDSGEIS discusses the impacts of Land Disturbance, including Access Roads, Well Pads, Utility Corridors, and Well Pad Density. See pages 5-6 through 5-31. Estimates of land disturbance associated with each of these well drilling activities are provided but total or cumulative land disturbance is not addressed.

Comment 2:

Section 5.1 *Land Disturbance* identifies a number of types of land disturbance activities associated with HVHF including utility corridors (including gathering lines), compressor facilities, and access roads associated with compressor facilities. The Draft HVHF SPDES permit (Part III.A.3) does NOT address construction of gathering lines, compressor facilities, or the access roads associated with compressor facilities.

Recommendation: The RDSGEIS must provide a process for regulation and mitigation of the land disturbance impacts associated with gathering lines, compressor facilities, and the access roads associated with compressor facilities. The RDSGEIS cannot identify the SWPPP as "*the principal control mechanism to mitigate potential significant adverse impacts from stormwater runoff*" (Section 7.1.2 SGEIS) without providing for adequate management requirements for all HVHF activities in the Draft SPDES HVHF GP.

Further discussion in Section 5.1 provides some analysis of disturbance areas associated with gathering lines, compressor stations, and access roads to compressor stations, but specific consideration of the impacts of these activities is not discussed in Chapter 6, and specific recommendations to reduce the impacts of these components (such as co-locating gathering lines along well pad access roads) is not provided in Section 7 or the Draft HVHF SPDES permit.

Comment 3:

Section 5.1.1 *Access Roads* indicates that roads may be placed across ditches, but does not discuss the construction or widening of access roads that cross streams or wetlands. The potential impacts of such crossings are not discussed in Section 6.1.2, *Stormwater Runoff* or other portions of Section 6, nor are the mitigation measures for road crossings of streams and wetlands addressed in Section 7.1.2 *Stormwater.* Setbacks for roads from streams and wetlands are not specifically addressed in either Chapter 7 or the Draft HVHF SPDES permit, nor are requirements for stream and wetland crossings provided. It is not clear as to whether an Article 15 Stream Disturbance Permit from the DEC will be required for HVHF projects and what compliance might entail. It is noted that Photos 5.1 and 5.2 of the RDSGEIS portray access road stream crossings, but the impacts of the stream crossing are not addressed.

Road crossings of streams and wetlands will be unavoidable during the development of HVHF sites. Section 5.1.1 acknowledges that the length of road may be influenced by selecting a route to avoid environmentally sensitive areas, but mitigation measures recommending such route selection are not specifically addressed in either Chapter 7 or the Draft HVHF SPDES Permit. Estimates of the number and extent of anticipated stream and wetland crossings are not provided in Section 5.1.1.

Recommendation: The proximity of roads to streams and wetlands, and the unavoidable need to cross streams and wetlands, increases the risk that erosion and sedimentation will cause measurable impacts on water quality. Poorly constructed stream crossings can directly impact aquatic communities.[3, 7] Excessive sediment levels are one of the primary threats to US surface waters[10] and have multiple effects on stream health. The RDSGEIS should provide estimates of the anticipated extent of road crossings of streams and wetlands, as well as an evaluation of the potential environmental impacts of these crossings. Furthermore, avoidance and mitigation measures should be addressed in the RDSGEIS and incorporated into the regulatory process. Specific requirements and guidelines to mitigate the impacts of stream and wetland crossings should be provided.

Recommendation: If the SPDES HVHF GP is to be the primary mechanism for regulation, then the permit should include a defined documentation process to require the applicant to reduce the number and extent of stream crossings. This section should be incorporated into Part IV, *Contents of the Construction SWPPP*, as a requirement of Section A.1 and include both mapping requirements and narrative that documents the need for each stream crossing and explanation as to why any individual stream crossings cannot be reduced or combined. Road crossings on areas specifically in conflict with local government land use regulations should be identified, as well as road crossings on steep slopes erodible soils, or intact woodlands.

Comment 4:

Section 5.1.2 *Well Pads* notes that well pad size is determined by site topography, but no estimates are provided regarding the impact of slope on well pad size and disturbance footprint, and the increased impacts on erosion and sediment discharge. The area of disturbance can be increased by up to 50% on slopes exceeding 15 degrees[8] (the Draft HVHF SPDES permit allows disturbance on slopes up to 25% in AA or AA-s watersheds. It is not clear that there is a limit on slope construction in other watersheds). The stormwater and erosive impacts of well pads on steep slopes continues through the life of the well pad. At a minimum, the Draft SPDES HVHF GP should preclude well pad construction on slopes over 25%.

Recommendation: Section 5.1.2 should provide some evaluation of the anticipated increase in well pad disturbance as a function of slope (and required cut and fill) as a result of the impacted terrain conditions specific to New York. Section 7 of the RDSGEIS should provide discussion of specific mitigation measures to reduce the impacts of well pad construction on slopes. The HVHF SPDES permit should include specific requirements to reduce construction of well pads on steep slopes, limits on steep slope construction in all watersheds, and provide discussion and requirement of implementation measures to reduce the long-term water quality impact of well pads on slopes when such systems are constructed. Additional measures to prevent sediment discharge from construction on steep slopes should be defined and required as part of the facility SWPPP. It is not clear that the general requirements of either the 2005 New York State Standards and Specifications for Erosion Control or the 2010 New York State Stormwater Management Design Manual provide sufficient specific guidance to address the additional impacts associated with well pad construction on slopes. Both erosion control measures and stormwater measures must be adjusted in their design to account for the greater water quality impacts of well pad location on slopes.

Comment 5:

Section 5.1.2 *Well Pads* and **Section 5.1.4** *Well Pad Density* do not provide any specific information or estimates of well pad or HVHF facility location or density with regards to watershed drainage areas, or analysis of the anticipated density of well pads within intermittent or perennial headwater stream drainage areas. Section 6 does not discuss the impacts on water quality of well pad density within the drainage area of an intermittent or perennial stream. Headwater and intermittent perennial streams originate with a drainage area of 5.5- to 37-acres[5], increasing the likelihood of a HVHF well pad being within several hundred feet of an intermittent or perennial stream, and the likelihood that the disturbance will represent a sizable portion of the total drainage area to a headwater stream (i.e. 7.4 acres of total disturbance for a multi-well pad during the drilling phase, and 1.5

acres of disturbance during the drilling phase could represent a very large percentage of the drainage area of a headwater or small stream).

Recommendation: Current research[2] indicates a positive relationship between stream water turbidity and well density within a drainage area or watershed. The RDSGEIS does not provide any analysis or consideration of potential levels of watershed disturbance as a result of HVHF activities, and the resulting potential impacts on water quality, although such an analysis is well within current mapping and GIS capabilities and should be included in the RDSGEIS.

Comment 6:

While some mention of gathering lines is included in **Section 5.1.3** *Utility Corridors*, including an estimate of 1.66 acres per well pad, no discussion is made of the anticipated extent of stream crossings, or the cumulative levels of land disturbance associated with gathering lines on a watershed or other basis. No further discussion is provided in Chapters 6 and 7 specific to gathering lines. It is unclear exactly how the current DEC permit process for pipeline stream crossing is adequate to protect water quality from either a land disturbance or stream crossing impact from gathering lines, or how gathering line construction will be addressed and/or coordinated with the Draft HVHF SPDES permit process (which does not currently address gathering lines).

Recommendation: This issue requires additional consideration in the RDSGEIS, and the specific permitting requirements for gathering line stream crossings should either be identified in the Draft HVHF SPDES permit or coordinated with this permit so that impacts are reduced. Specifically, measures to reduce the impact of gathering line stream crossings (and general construction) by coordination of this construction with other well site needs should be required.

Comment 7:

Chapter 6, Potential Environmental Impacts. Section 6.1.2 *Stormwater Runoff*, discusses both stormwater impacts and erosion and sedimentation construction issues. However, this discussion is very general in nature, comprising only 1-1/4 pages within Chapter 6 for both of these topics. No discussion is provided regarding the specific magnitude and issues of concern associated with stormwater and erosion impacts from the various HVHF activities (i.e. well pad construction, and variations on well pad construction such as disturbance footprint from construction on steep slopes). Rather, it is simply noted that the potential for water resource impacts exists, and that these impacts may cause increased runoff volumes, greater erosive forces, heightened sediment loads, etc.

Recommendation: Research data and engineering methodologies are available to quantify the potential adverse water quality impacts, either on a "typical" facility basis or an anticipated watershed basis (using the estimates of acreage developed in Section 5). Such analysis would provide at least some basis for determining whether the requirements of the Draft HVHF SPDES GP are adequate for the industry. These estimates would also provide information on the cumulative impacts of HVHF on water quality and stream health and should be included in the RDSGEIS.

Comment 8:

Chapter 7, Mitigation Measures. Section 7.1.2 *Stormwater,* discusses stormwater management in general terms, with a non-specific discussion of the particular issues associated with HVHF stormwater and erosion. Much of the generic discussion focuses on pollution prevention from exposed industrial activities. Less than one page addresses stormwater management mitigation measures related to land use changes, and one-half page addresses mitigation associated with stormwater and erosion issues from construction activities. Section 7.1.3 discusses spills and containment, which is also addressed in the SPDES HVHF GP. However, much of this discussion is focused on industrial spill control, not stormwater impacts.

Chapter 7 indicates that the Department intends to issue a single SPDES General Permit that will encompass all issues of construction stormwater and erosion control, post-construction stormwater management, industrial stormwater management, and pollution prevention/spill control. Specifically, page 7-26 states: *The Department has determined that natural gas well development using high-volume hydraulic fracturing would require a SPDES permit to address stormwater runoff, erosion, and sedimentation. The SPDES permit will address the construction of well pads and access roads and any associated soil disturbance, as well as provisions to address surface activities associated with high-volume hydraulic fracturing for natural gas development. Additionally, during production of the natural gas, the Department will require coverage under the SPDES permit to remain in effect and/or compliance with regulations. The Department proposes to require SPDES permit conditions, a Comprehensive SWPPP (stormwater pollution prevention plan), and both structural and non-structural Best Management Practices (BMPs) to minimize or eliminate pollutants in stormwater. The Department is proposing the use of a SPDES general permit for high-volume hydraulic fracturing (HVHF GP), but the Department proposes to use the same requirements in other SPDES permits should the HVHF GP not be issued.*

Recommendation: The HVHF SPDES permit should be specific to this industry and impose requirements that reflect the lack of local government review and approval of the land development activities associated with the industry. The RDSGEIS should specifically identify the areas where additional permit requirements specific to the industry are necessary to protect water resources.

Comment 9:

Section 5.1.1 *Access Roads* notes that roads may be constructed by placing crushed stone or gravel, but Section 6 does not specifically address the water quality issues associated with the long-term use of gravel roads (after construction), nor does Section 6 provide any estimate of potential pollutant loadings associated with gravel roads, specifically estimates of sediment generation. Research data[4] indicates that gravel roads can be a significant source of sediment pollution, and data to support sediment pollutant load estimates is available but requires an estimate of the anticipated extent and area of gravel access roads to be constructed, which is not provided in Section 5.1.1. Gravel access roads serving HVHF will be subject to undefined levels of truck traffic, which has a greater impact on road condition and erosion than regular vehicle traffic. Section 6.1.2 *Stormwater Runoff* discusses the impacts of sediment on streams and notes that "*steep access roads…pose particular challenges.*" **Section 7.1.2** *Stormwater* indicates that the construction of access roads will be addressed by the SPDES permit, but neither Section 7.1.2 nor the Draft HVHF SPDES permit provide specific recommendations to reduce the length and width of gravel access roads, to reduce construction access roads on steep slopes, or to reduce the specific impacts of gravel road and sediment generation once the construction period has ended. General reference to the State stormwater manual is not sufficient for this issue as it relates to HVHF. There is no requirement in the Draft HVHF SPDES mapping requirements to indicate or accurately depict the length, width, or slope of gravel access roads. Since these areas will generate sediment pollutants through the life of the project, specific guidelines to mitigate pollution from access roads are warranted.

Recommendation: The RDSGIES should provide more detailed information on the specific impacts of gravel access roads with regards to sediment generation, and the estimated extent of potential pollutant loads. Section 7 of the RDSGEIS should provide discussion of specific mitigation measures to reduce the impacts of access road construction. The HVHF SPDES permit should indicate specific requirements for the documentation of access road lengths and widths, and requirements to reduce construction on steep slopes, reduce road width, and implement other measures to reduce the water quality impact of access roads. Measures to maintain gravel access roads in a manner that prevents sediment discharge (over the life of the project) should be defined and required as part of the facility SWPPP.

Comment 10:

Section 7.1.11.1 *Setback from private well*, Section 7.1.11.1 states that "The Department proposes that it will not issue permits for high-volume hydraulic fracturing within 500 feet of a private water well or domestic supply spring unless waived by the landowner." However, the Draft SPDES permit does not require the applicant to map the location of private water wells or springs that may be within 500 feet, or to notify the landowner. Coverage under the GP is granted within 30 calendar days of the Department receiving the NOI (and meeting the requirements of Part II.B.2). How will the Department or the applicant be aware of the existence of private water wells within 500 feet? This is also not included in Section 5 of the Environmental Assessment Form, but IS included in the Proposed EAF Addendum Requirements for HVHF. It is not clear how 500 feet was determined as sufficient distance to support a private well from HVHF activities as no supportive reasoning is provided.

Recommendation: Require that all private water wells and domestic supply springs within 2,640 feet and 500 feet, respectively, to be located on the Site Map (prepared under Part IV.C.1.b and as a requirement to the Site Map in the SWPPP). The NOI form should require that the applicant confirm that there are no such wells within 500 feet, and provide proof to the Department of landowner waiver receipt (by certified mail or similar means).

Recommendation: The SWPPP should identify the private water well or spring in the narrative (Part XI.3) and identify measures undertaken to protect the private well and to address emergency spill situations.

Comment 11:

Section 7.1.11.2 *Setbacks from Other Surface Water Resources* states *"*Existing regulations prohibit the surface location of an oil or gas well within 50 feet of any 'public stream, river or other body of water.'" The 1992 GEIS proposed that this distance be increased to 150 feet and apply to the entire well site instead of just the well itself*"*. The Draft HVHF SPDES permit (Section I.D.4) requires a setback of 150 feet from the well pad and perennial or intermittent streams, but does not address setbacks from other HVHF site components.

Recommendation: As discussed later in specific recommendations associated with the Draft HVHF SPDES permit, required setbacks of any length are meaningless unless the water features are accurately identified and located. A USGS 7-1/2 minute topographic map, at a scale of 1" = 2000' is inadequate for this purpose. It is essential that the Draft HVHF SPDES permit require mapping at a scale that can accurately depict both existing natural features (such as steep slopes and headwater streams) as well as proposed HVHF components.

Comment 12:

There are benefits associated with a single SPDES GP (or a single individual SPDES permit) that addresses construction, post-construction stormwater, and industrial stormwater and spill containment for each project in one permit. These benefits include a comprehensive evaluation of each project, potential continuity in responsible facility personnel, and consistency of management practices through both construction and operation.

However, the Department is largely drawing on the current requirements in the existing SPDES general permit for construction (New York State Department of Environmental Conservation SPDES General Permit For Stormwater Discharges From Construction Activity Permit No. GP-0-10-001) and the existing SPDES general permit for industry (New York State Department of Environmental Conservation SPDES Multi-Sector General Permit For Stormwater Discharges Associated With

Industrial Activity Permit No. GP-0-06-002). The Department is combining many (but not all) requirements of these two GPs into one HVHF GP and, in doing so, does not include provisions that would otherwise be required of permittees seeking either of the existing permits alone..

For the issues of site disturbance, stormwater management, setbacks, disturbance of sensitive features, erosion, and other impacts associated with many non-HVHF land development projects and industrial activities, there is an additional level of professional review and regulation in the form of local laws, regulations, plans or policies implemented by the local planning board or authorized board. In other words, for non-HVHF projects, such as land development projects, there is often a local project review of proposed plans by a professional reviewer knowledgeable in local conditions, supported by the review of an authorized board whose members possess local knowledge. Local regulations are likely to impose more rigorous mapping requirements, stormwater calculations, and design detail than those imposed in a Department general permit, and furthermore, project submissions receive local, professional review. In these circumstances, successful design and compliance (with the requirements of Department general permit) is more likely when supported by a secondary level of performance requirements and review at the local level.

The issuance of a single GP for HVHF (that encompasses many requirements of both existing Department GPs) will not have the benefit of local review and specific local performance requirements. The potential impacts of HVHF projects on land disturbance, stormwater, erosion, sensitive sites, etc. is at least as significant (if not more significant) than other, locally regulated land disturbance and industrial activities. HVHF is also a “heavy” industry that will be located in many areas unaccustomed to heavy industry.

Recommendation: The Department should provide the opportunity for local review by revising the SPDES HVHF GP to address compliance with applicable local ordinances. For instance, those activities which would typically require issuance of

GP-0-10-001 should be required to comply with all local ordinance requirements as they apply to HVHF activities. Additionally, the Department should require SPDES HVHF GP permittees to provide written notification to the Department from the affected local governments that the conditions of local ordinances are met to the satisfaction of the local governing authority prior to issuance of the permit. Comment 14 below discusses this further.

Comment 13:

HVHF compliance with the requirements of the GP are largely self-reviewing and self-monitoring, as facilities are required to develop and implement a SWPPP, but there is generally no review of the SWPPP unless the Department elects to request and review the SWPPP for a specific facility. Absent this specific request by DEC, the SWPPP is simply maintained on-site. In addition, DEC does not propose any mechanism that would enable it to effectively evaluate successful implantation of a SWPPP.

Recommendation: The SPDES HVHF GP should be revised to make public all documents, specifically including the SWPPP, available for review by the Department and the public. In all instances, the Department should establish a mechanism to routinely review whether applicants have successfully implemented their SWPPPs. Dated digital photos that support inspection and compliance per permit and SWPP requirements should be a requirement for permit coverage.

Comment 14:

Chapter 8 , Permit Process and Regulatory Coordination; **Section 8.1.1.5** *Local Planning Documents* of the SGEIS states:

> *However, in order to consider potential significant adverse impacts on land use and zoning as required by SEQRA, the EAF Addendum would require the applicant to identify whether the proposed location of the well pad, or any*

> *other activity under the jurisdiction of the Department, conflicts with local land use laws or regulations, plans or policies. The applicant would also be required to identify whether the well pad is located in an area where the affected community has adopted a comprehensive plan or other local land use plan and whether the proposed action is inconsistent with such plan(s). For actions where the applicant indicates to the Department that the location of the well pad, or any other activity under the jurisdiction of the Department, is either consistent with local land use laws, regulations, plans or policies, or is not covered by such local land use laws, regulations, plans or policies, the Department would proceed to permit issuance unless it receives notice of an asserted conflict by the potentially impacted local government.*

This approach is problematic. While it is the responsibility of the applicant to determine whether or not there are any conflicts, it is up to the potentially impacted local government to provide notice to the Department of an asserted conflict that has not been identified by the applicant. Although the RDSGEIS states that the Department would notify local governments of all applications for high-volume hydraulic fracturing in the locality, through the use of an electronic notification system to local government officials (see DSGEIS at 8-4), DEC offers no guarantee that this system will be in place prior to the issuance of permits and does not specifically describe when in the permitting process such notification to local governments will occur. These are critical issues that should be addressed. Further, it is unclear how the Department will determine *"whether significant adverse environmental impacts would result from the proposed project that have not been addressed in the SGEIS and whether additional mitigation or other action should be taken in light of such significant adverse impacts." RDSGEIS at 8-5.* It is also not clear as to whether this determination process applies to all HVHF GP applicants, or only those subject to SEQRA determination.

Recommendation: In consideration of the Department's decision to regulate HVHF under a single SPDES general permit without the important supplemental benefit of local review and local laws, regulations, plans or policies (that virtually all other land development and industrial construction projects are subject to when obtaining SPDES permit coverage), obtaining General or Individual Permit coverage (for all HVHF projects) should also require the applicant to notify the local government (as well as the Department) that there are no conflicts with local laws, regulations, plans or policies, and to provide supporting documentation of the evaluation to the local government and Department. This will allow local governments to receive the necessary information to "assert" a potential conflict that may not have been identified by the applicant. Without this critical information, local governments cannot be expected to "assert" a potential conflict to the Department.

Comment 15:

As discussed above, Section 5.1 of the RDSGEIS provides estimates of land disturbance for well pads and associated construction activities (roads, utility corridors, compressors, etc.), including total estimated disturbance per pad for multi- and single-well pads. The RDSGEIS notes that most wells will be multi-pad wells with a net disturbance of 7.4 acres per pad (reducing to 1.5 acres per pad during production). A spacing of 640 acres per multi-well pad is presented in Table 5.1 of the RDSGEIS. However, no consideration is provided of the anticipated disturbance and well pad density on a watershed basis, or proximity to streams and anticipated stream crossings, and no consideration is provided on the potential individual and cumulative effects on stream health.

A recently published study of natural gas development in the Fayetteville and Marcellus formations in Arkansas and Pennsylvania[2] used current topographic data, well development data, and readily available land use analysis computer modeling tools (ArcHydro Version 1.3) to evaluate both the overall well pad density per drainage area and well proximity to streams in these formations in Arkansas and Pennsylvania. This desktop analysis was further supported by in-stream turbidity measurements in seven different drainage areas with different well densities.

This report had several significant findings, most notably it "identified a positive relationship between stream water turbidity and well density. Turbidity was not positively correlated to other land use cover variables." (Entrekin, et al, "Rapid Expansion of Natural Gas Development Poses a Threat to Surface Waters, pg 507). The report further concluded that "preliminary data suggest that the cumulative effects from gas well and associated infrastructure development are detectable at the landscape scale."

This study also determined that approximately 17% of the active Pennsylvania wells were within 100 meters (328 feet) of a stream, and all wells were within 300 meters (984 feet) of a stream. Gas wells "were located, on average, 15 km (9.3 miles) from public surface-water drinking supplies and 37 km (23 miles) from public well water supplies." The report noted that "although wells are generally constructed far from public drinking-water sources, there is potential for wastewater to travel long distances given that many of the components, such as brines, will not settle out or be assimilated into biomass." In other words, due to the nature of material from HVHF wells, discharges that reach streams (due to inadequate stream setbacks) may travel to public drinking supplies, even if the surface water supplies are distant to the well.

Chapter 6 of the RDSGEIS broadly identifies potential environmental impacts on water resources (Section 6.1), including polluted stormwater runoff and spills. The RDSGEIS does not specifically discuss the cumulative impacts of land disturbance on surface water quality (i.e. whether turbidity or other measures of stream impact increase with well density). The RDSGEIS makes no attempt to estimate well density and land disturbance on a drainage area basis with regards to water quality impacts or consideration of specific watersheds and designated uses. No specific consideration is given to the topography and stream density of New York State with regards to land disturbance and proximity to surface waters.

Such an analysis would provide a far better estimate of potential surface water impacts and the extent of anticipated land disturbance on a watershed or drainage area basis. This information would inform the state as to the watershed impacts from HVHF activities, and provide some additional basis for well density in different watersheds. It would also better inform the decisions regarding setback distances discussed in Sections 7.1.5 and 7.1.11.2.

As discussed previously, most headwater and small perennial streams are not indicated on USGS 7-1/2 minute topographic quadrangles, and hence will not necessarily be identified under the current mapping requirements in the Draft HVHF SPDES permit. Headwater streams generally originate with a surface drainage area of 5 to 37 acres.[5] The study discussed above had a stream threshold of 12.4 acres. With a disturbance footprint of 7.4 acres per multi-well pad, drilling activities could potentially impact as much as 60% of the land area in a headwater stream drainage area (assuming 12.4 acres per drainage area). The extent and impact of land disturbance in headwater streams is not addressed in any manner in the RDSGEIS.

<u>Recommendation</u>: The RDSGEIS should provide some technically supported evaluation of the anticipated well density on a drainage area basis, with consideration of water quality impacts. The analytical land use tools, data, and models available today are <u>significantly</u> more robust than the environmental tools available during the development of the 1992 GEIS (and such tools are often used to support TMDL determinations). In other words, the density of anticipated land disturbance and proximity to streams and wetlands could easily be mapped and evaluated using anticipated development rates and relevant information from states such as Pennsylvania. At a minimum, representative watersheds could be evaluated in detail to represent anticipated conditions, and using topographic data and average proximity to streams could be estimated. Relevant well drilling data is also available from other states such as Pennsylvania. High-volume hydraulic fracturing is “distinct from other types of well completion” as noted in the RDSGEIS, and warrants additional consideration.

This type of land use and density evaluation will allow the Department to better assess the potential impacts of high-volume hydraulic fracturing on both watershed land use and proximity to streams, and can provide a technical basis for HVHF well density and setback decisions. It can also inform decisions regarding well density and setbacks in waters with TMDLs. But at this time there is no watershed impact consideration of HVHF well location and density. It is unclear whether the various setbacks discussed in the RDSGEIS are adequate to protect water resources during HVHF activity, or whether these setbacks merely represent an arbitrarily selected value.

Recommendation: To facilitate Department identification of wells that may have an impact on small headwater streams, the Draft SPDES HVHF GP could require that each well pad application document the total amount of anticipated land disturbance, and the percent of land disturbance within the drainage area of the well pad location. This is not a difficult estimate for the permit applicant to develop using current mapping tools, and will provide some indication that adjacent streams may be small and especially vulnerable to land use impacts.

Comment 16:

Section 7.1.3.1 indicates that fueling tanks are considered "non-stationary" at well pads, and therefore exempt from Department storage and registration requirements. Section 7.1.3.1 does state that secondary containment is required for all fueling tanks, and that fueling tanks would not be positioned within 500 feet of perennial or intermittent stream, storm drain, wetland, lake or pond.

It is unclear how this requirement will be met or maintained, especially in light of the fueling tanks being "non-stationary." Specific requirements are not reflected in the Draft HVHF SPDES permit, either in the general SWPPP requirements or the Fueling Area requirements. It is unclear how this setback will be identified and maintained, and how the Department intends to ensure compliance. The requirements for fueling areas in the Draft HVHF SPDES permit are the same general requirements applied to all industrial facilities and do not have any specific consideration of the nature and conditions of HVHF sites and fueling needs.

Recommendation: The RDSGEIS and Draft HVHF SPDES permit must address the issue of containment for “non-stationary” fueling tanks, and all other non-stationary tanks.

Comment 17:

The RDSGEIS **Section 7.1.7.2 Road Spreading** indicates that NORM concentration data in brines is insufficient to allow road spreading under a BUD, and that as more data becomes available the Department will evaluate the BUD petitions. However, the RDSGEIS is inadequate in that no consideration has been made of the total potential increase in chlorides on roads as a result of the HVHF industry disposing of brines in this manner, and the anticipated levels of chlorides and other compounds in the brine. Again, the RDSGEIS has not considered the cumulative impacts of the generation of this material and the potential volume of material application on roadways. No estimate is made of the volume of production brine that may be disposed of on roadways. No consideration is provided regarding what might be “safe” levels of chlorides (or other compounds) in different situations, or what other additional compounds that may be found in production brine that would preclude the use of the material for roadway application. The requirements in the current BUD have no basis as being sufficient for protecting water quality, and are generally self-monitored by the industry.

Unless the use of production brine is demonstrated as being a beneficial use for the public in roadway safety, application to roadways should not be seen as a viable disposal method. Much more research on the effects of the material on plant and aquatic systems is required.

Recommendation: The RDSGEIS should provide better information regarding anticipated brine production levels and disposal needs as a result of HVHF activity. Future authorization of the application of brines under a BUD should not be allowed until this information has been developed and provided for public review and comment.

Comment 18:

Section 7.1.9 Solids Disposal indicates that the generation of acid rock drainage (ARD) may occur as the result of material from certain portions of the Marcellus shale. The RDSGEIS indicates that an ARD mitigation plan would be required for in-site burial, but is not required for off-site disposal.

No estimate is provided within the RDSGEIS of the potential amount or magnitude of the generation of this material, and whether or not the amount of ARD material is of concern, or within which watersheds such material may be anticipated. The generation of ARD is of significant concern and impact on watershed health, and warrants more detailed analysis of the anticipated locations and extent where ARD may be an issue. It is not clear if this is expected to be an extensive concern, and no consideration is made of the amount and extent of the ARD material encountered in other states such as Pennsylvania, and how much this material has created additional acid discharge problems in other states. This issue is not addressed in the HVHF SPDES draft permit.

Recommendation: Estimates of the anticipated extent of such material should be included in Chapter 6.1.9.2, and coordinated requirements for ARD treatment (as discussed in Section 7) incorporated into the Draft HVHF SPDES permit. This material has significant potential impact to water quality.

Comment 19:

The EAF addendum should clearly define the process and timeline for notification of local government, and for the Department's process for determination of permit applicability when notice is received from the applicant or local governments that a conflict with local laws, regulations, plans or policies exists. Furthermore, the EAF addendum should address the issue of HVHF GP coverage upon NOI submission when such local conflicts exist.

Recommendation: Coverage should NOT begin until proof of notification to local governments has been received by the Department, local governments have been provided sufficient information and time to "assert" any unidentified potential conflicts, and the Department has made project specific determinations regarding the impact of identified or asserted conflicts. A timeline and process must be defined.

Comment 20:

EAF Appendix 12 Beneficial Use Determination (BUD) Notification Regarding Road Spreading states that "Any person, including any government entity, applying for a Part 364 permit or permit modification to use production brine from oil or gas wells or brine from LPG well storage operations for road spreading purposes (i.e. road deicing, dust suppression, or road stabilization) must submit a petition for a beneficial use determination (BUD)." This petition must include sampling data (although the sampling parameters are limited), a map indicating roads where brine is to be spread, and a general narrative of practices to be implemented, including avoiding applying brines within 50 feet of a stream or waterbody, avoiding application during rainfall periods or on slopes greater than 10 percent.

Chlorides are toxic to many plants and freshwater aquatic plants and invertebrates[14] with levels as low as 30 mg/L toxic to plants, and at 1000 mg/L toxic to aquatic plants and invertebrates. Chlorides also impact the use of surface water for potable water sources.

While chlorides are applied to roads during snow and ice conditions for safety reasons, many state Departments of Transportation have begun programs to significantly reduce the use of chlorides and implement alternative de-icing practices to reduce the impacts of chloride on both vegetation and stream system health.

Recommendation: Additional analysis of potential impacts must be done to evaluate potential impacts from road spreading, including analysis to support that the proposed setback criteria are sufficient to protect water quality, as well as to define required sampling requirements for BUD petitions.

Comment 21:

In addition to defining the processes and timelines for review and notification requirements, coordinating permit approvals and public participation activities would ensure compliance with all applicable statutes and eliminate any conflicts that may arise. Regulatory permit tracking, municipal coordination and public outreach and participation should be integrated and automated to the fullest extent possible to ensure satisfactory oversight of gas development operations. This includes the use of internet and GIS technologies for geovisualization, database management, and compliance with all regulatory requirements.

One example of internet-based GIS information sharing is the Pennsylvania Department of Environmental Protection's (PA DEP) eMapPA website. PA DEP uses this online application that is updated on a regular schedule and tied to a multitude of databases which track publicly available information (air quality, water quality, mining/reclamation, natural resources, etc.) on a publicly accessible GIS website. (See http://www.emappa.dep.state.pa.us/emappa/viewer.htm).

Recommendation: With regard to regulatory permit tracking, PA DEP has developed an additional tool called Environment, Facility, Application, Compliance Tracking System (eFACTS). PA DEP staff, as necessary, has internal agency access to this database system, cross-referenced by regulatory program, in which permits and permittees may be tracked and updated with regard to permits issued, violations, etc. This information is also available to the public, in a limited format, via the internet at http://www.dep.state.pa.us/dep/efacts/efacts.html. If not already available through the NYS Department Application Review Tracking (DART) system, the development of such a system would be very beneficial for tracking SPDES

HVHF GPs, as well as other state issued permits associated with gas development projects, including dirt/gravel roads, stream crossings, etc. This information should be linked to any web-based GIS application.

Recommendation: Population of a geodatabase may occur through the submission of GIS data by permittees. Permit application packages could and should be front loaded for digital information by requiring permittees to submit GIS data (i.e., shapefiles in an accepted Metadata format) about their project sites. At a minimum, a project boundary on georeferenced state plane coordinate system should be required. This website should also link each project boundary to any online permit tracking system, including the email address of appropriate personnel to whom comments may be submitted.

Recommendation: In addition to sharing GIS data with local governments, NYSDEC should, if it has not already, implement a requirement for municipal notification similar to those commonly referred to in Pennsylvania as Act 14 notices. Pennsylvania permitting processes include requirements for written notifications to be sent to each municipality and county government in which the permitted facility is or will be located under an amendment to the Commonwealth's Administrative Code. These notifications allow 30 days for specific municipal and county comments.

Recommendation: Additional public participation may be solicited by the publication of notices of pending permits in NYSDEC's Environmental Notice Bulletin (ENB). Certain SPDES permitting actions are already included in the monthly ENB; however, it may be beneficial to provide a section specific to those SPDES permits issued for HVHF gas development on the ENB website and linked to the DART system.

Comments on the Draft SPDES HVHF GP

Impacts to surface water quality from gas exploration and extraction activities can occur during the construction of the facility, the operation of the facility, and as a result of inadequate restoration of the facility after operations have ceased. Applying specific performance standards and consistent regulatory oversight through a thorough permitting process is essential to ensuring the prevention of water quality impacts. A comprehensive permitting process should include, but not be limited to, the following considerations:

- Clearly defined permitting process and timelines;
- Sound technical guidelines specific to the activities being permitted;
- Compliance with both State and local regulations prior to final permit approvals;
- Opportunities for public participation, outreach, and comment.

These considerations, as well as a comprehensive evaluation of all potential environmental impacts, are essential to the development of permitting procedures that are adequately protective of environmental resources.

The RDSGEIS notes that certain water resources, such as the New York City and Syracuse drinking water supplies, have been the subject of extensive comment and warrant different regulatory requirements (i.e. a prohibition on drilling). Specifically, the "Department finds that standard stormwater control and other mitigation measures would not fully mitigate the risk of potential significant adverse impacts on water resources from high-volume hydraulic fracturing." RDSGEIS at 7-55.

In a paper prepared by Patrick O'Dell, a professional engineer with the National Park Service Geologic Resources Division, Mr. O'Dell noted that "If the public depends on operators in general to voluntarily use measures such as 'best management practices' to meet an agency's standards of resource protection, the public will be disappointed. This is because operators are sometimes willing to assume more environmental risk in exchange for a reduction in expense or acceleration of project completion."[8]

Given these comments, and that the Department recognizes that "*standard stormwater control and other mitigation measures would not fully mitigate the risk of potential significant adverse impacts on water resources from high-volume hydraulic fracturing*," and the Department's decision to preclude HVHF in FAD watersheds (Section 7.1.5), the validity and effectiveness of a self-monitoring GP process for other watersheds cannot be assumed to be protective of water resources, and the SPDES permit and associated regulatory activities must be developed to address these concerns.

In comments provided to the Pennsylvania DEP, Dr. James Schmid[14] PhD made the following recommendations that are directly applicable to NYSDEC regarding the HVHF SPDES permitting process in New York:

a. Place all gas-related permit applications, issued permits, and enforcement actions online in an electronic database accessible by public.
b. Include stream encroachment for pipelines *(in the SPDES permit).*
c. Select a significant number of permit applications for file and on-site audit, to ascertain trends in adequacy of permitting process.
d. Disallow general permits in Exceptional Value and High Quality waters (or in New York, require individual permits for AA or A drinking water streams and T or TS trout streams).
e. Require an inventory for all EV or HQ streams within 500 ft of well pads.

f. Make an attained use determination at every stream proposed for impact that has not been studied.
g. Require disclosure of ALL related facilities in each project application, require disclosure of all land and water disturbances for each well or well pad so that projects do not incorrectly fall below thresholds.
h. Require construction of impermeable holding areas sufficient to contain spills and prevent release outside pad.
i. Require accounting of tree clearing. Provide plans and timetable for reforestation.
j. Gathering lines and water pipelines should follow existing roads rather than new ROWs. New ROWs should be demonstrated to reduce stream/wetland crossings.
k. Distinguish between new stream crossings and those made atop existing culverts.

With these and other previously discussed recommendations in consideration, the following comments are provided with regards to the current Draft HVHF SPDES General Permit:

Comment 1: The Draft HVHF SPDES permit is primarily a compilation of the existing Construction SPDES GP (001) and the Industrial Stormwater GP (002). It has not been significantly modified to address the issues specific to HVHF. Additionally, the Draft HVHF SPDES permit should encompass ALL components of a well project (well pads, access roads, water lines, gathering lines, compressor stations, water withdrawals, transportation of materials, waste management) with considerations specific to HVHF, or clearly provided coordination with other permitting requirements specific to these issues.

Comment2: Given the lack of local land use review, the mapping and data requirements for the SWPPP should be coordinated with the mapping/data requirements of the Environmental Assessment Form, and all information should be available digitally for access by local government, property owners, and the general public. The RDSGEIS Appendix 5 *Environmental Assessment Form Attachment to Drilling Permit Application* does NOT reflect all site data requirements described in Appendix 6 *Proposed EAF Addendum Requirements for High-Volume Hydraulic Fracturing*.

Comment3: The SPDES HVHF GP should be modified to include construction and stormwater discharges related to gathering lines, compressor stations and compressor station access roads, or to clarify how these activities will be addressed under another permit.

Comment 4: In the absence of more explicit requirements, such as the submission of supporting calculations for BMP design, owners/operators are likely to use a generic narrative for multiple wells, with exception of mapping requirements. It is important that the SPDES HVHF GP requirements for mapping be site specific, comprehensive, at a scale that provides info needed. Generic SWPPPs tend to be ignored.

The following comments are in regard to specific sections of the Draft SPDES HVHF GP as noted.

Part I GENERAL PERMIT COVERAGE AND LIMITATIONS

Comment 5:

Section B.2 Maintaining Water Quality – This section places the burden of identifying a violation of a water quality standard on the Department, as opposed to the permittee. In the Industrial Stormwater GP, the burden of identifying such stormwater discharges is placed on the permittee: "*If there is evidence indicating* *that the stormwater discharges authorized by this permit are causing, have the reasonable potential to cause, or are contributing to an excursion above an applicable water quality standard, the permittee must take appropriate corrective action and notify DEC of corrective actions taken*." Similar responsibility should be placed on the permittee for HVHF activities.

Comment 6:

Section C.3 Non-Stormwater Discharges – This section authorizes non-stormwater discharges and adds "uncontaminated discharges from well site dewatering operations" to the list of allowable non-storm discharges. Is this section referring to only de-watering of erosion and sediment control measures in site development or to well drilling material? This should be clarified.

Comment 7:

Section D.2 Activities Which are Ineligible for Coverage under this General Permit – This section precludes the construction of HVHF only on locations where the stream designation is AA or AA-s, **and** there is no impervious cover **and** the slopes are greater than 25% or E / F slope designation. Does this mean that if there is some impervious cover on such a site that HVHF is allowed? Does this mean that all other sites have no limits on slope (unless identified by the applicant as addressed in local land use regulations **and** identified as an objection by local government)? Is disturbance of steep slopes allowed in T streams? Should steep slope disturbance be precluded in proximity to water bodies and wells and identified in setbacks? The RDSGEIS notes in Section 6.1.2 that "*Steep access roads, well pads on hill slopes, and well pads constructed by cut-and-fill operations pose particular challenges, especially if an on-site drilling pad is proposed.*" This section should be substantially re-evaluated to preclude or define limits on coverage for steep slopes, etc. in all watersheds. Additionally, the Department should develop specific performance parameters/requirements for coverage of such activities on steep slopes under an Individual Permit for sites not addressed under the GP, rather than issuing an Individual Permit that is substantially similar to the GP. Additionally, this section should clarify that local land use regulations regarding steep slopes and other environmental constraints apply unless waived by local government.

Comment 8:

Section D.4 Setbacks for Well Pad – These setbacks should reflect further consideration in the RDSGEIS, and include all setbacks discussed and identified in the RDSGEIS and appendices – such as setbacks from private water supply wells and springs, public water supply wells, residences, etc. This section should also clarify where ALL HVHF activities are prohibited (i.e. within 100-year floodplain, within 4,000 feet of unfiltered water supply watersheds, within 2,000 feet of public water supply, etc.).

All setback dimensions should be indicated on the GP mapping requirements.

Additionally, this section should clarify that local land use regulation setbacks also apply unless waived by local government. The permittee should prepare documentation that such land use regulations have been evaluated, and the local government notified if local land use requirements have not been met.

Part II Obtaining General Permit Coverage

Comment 9:

A. Notice of Intent (NOI) Submittal – The applicant is required to submit an NOI form to the Department, and prepare a SWPPP. The SWPPP must be available to the Department (if requested) and maintained on site. This process does not provide for public access and notification (other than the publication in a newspaper, which is easily overlooked by the public).

The public, including immediately adjacent property owners, should have opportunity for notification when such notification is submitted to the Department.

Many local governments have adjacent property owner notification requirements as part of the local zoning and land development process. Since this process does not apply to HVHF, a process of notification to adjacent and potentially impacted property owners should be included in Section II.A. Clarification of the definition of "potentially impacted property owners" requires further consideration in the RDSGEIS. Potentially, notice should be provided to water suppliers, etc.

If coverage under the GP is dependent upon development and implementation of the SWPPP, then the SWPPP must be available for public review upon request. It is likely that most members of the general public would not necessarily know how to request or obtain a copy of the SWPPP. As previously suggested, an on-line database would allow public and Department access to the SWPPP. It is unreasonable to allow the industry to obtain GP coverage without an opportunity for public comment.

Comment 10:

B.2.3.b General Permit Authorization – Given the unique nature of HVHF construction, and the lack of local government review regarding land use disturbance and stormwater management, the permit should impose a time period between preparation and submission of any and all required materials and actual permit coverage. All material should be digitally submitted and all information regarding land disturbance activities should be available and accessible for public review and comment, with a minimum 30-day period for public comment before permit coverage. HVHF practices are different from other industrial practices and coverage under a general permit must provide some process for public review and comment on permit coverage.

Comment 11:

C. Impaired Waters and TMDLs – The RDSGEIS has not provided any documentation or consideration as to whether a general permit is sufficient to prevent further water quality impacts in impaired waters and especially watersheds with TMDLs. A requirement should be imposed for the permit applicant to identify to the Department when the discharge will occur in impaired waters, and what specific additional measures are being implemented to provide protection for the specific pollutants of concern. The Department should maintain specific records and documentation of HVHF activities in impaired waters. Additional monitoring and reporting requirements are warranted in impaired waters, and should be submitted to the Department, not just maintained on site.

Part III – DEVELOPMENT AND ADMINISTRATION OF THE CONSTRUCTION SWPPP

Comment 12:

A.3. Development of the Construction SWPPP – Section 5.1 of the RDSGEIS identifies a number of types of land disturbance activities associated with HVHF including utility corridors (including gathering lines), compressor facilities, and access roads associated with compressor facilities. However, the construction of gathering lines, compressor facilities and the access roads associated therewith is not required to be addressed in the SWPPP. The GP and the required SWPPP contents should be revised to include construction and stormwater discharges related to gathering lines, compressor stations and associated access roads, as well as those facilities currently listed under this section.

Comment 13:

C.1. Disturbance of more than five (5) acres – If phased construction is planned, with a maximum of five acres disturbed in any phase, the permitting of greater disturbance may be permissible under the SPDES HVHF GP as it is currently written.

Recommendation: The SPDES HVHF GP should be revised to require approval when the soil disturbance activities will result in more than five acres of disturbance at any one time, or more than five acres of disturbance over the life of the project.

Recommendation: The SPDES HVHF GP should be revised to effectively cover all areas not in AA, AA-Special, or FAD areas.

Part IV CONTENTS OF SWPPP

Comment 14:

A. What the Construction SWPPP Must Achieve –The SPDES HVHF GP requires well sites to be *designed to minimize environmental impacts* through the minimization of clearing and grading; and avoidance of sensitive areas such as erodible soils, steep areas, and critical habitats. However, the SPDES HVHF GP does not indicate how the permittee will achieve this.

Recommendation: The SPDES HVHF GP should be revised to clearly indicate how sensitive areas will be identified in permittee submission packages and require the identification to be done so at a mapping scale adequate to clearly identify all potential sensitive areas to ensure clearing and grading will be minimized accordingly. This requirement also applies to setback requirements around waterbodies. (See additional comments under Part IV.C.1. and Part IV.A.)

Comment 15:

B.1.b. and e. Effluent Limitation Requirements – The SPDES HVHF GP requires compliance with erosion and sediment controls to *minimize the discharge of pollutants,* specifically the control of stormwater and sediment discharges, but does not require supporting calculations to be submitted.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit calculations supporting any claim of compliance with mandatory control of stormwater, sediment, or other pollutant discharges.

Comment 16:

C.1.b. Erosion and sediment control components - The SPDES HVHF GP requires a site map/construction drawing(s) that include information vital to erosion and sediment control considerations, including wetlands, potentially affected surface waters, existing and final slopes, and location(s) of stormwater discharges. However, there is no maximum scale identified for this requirement. It is possible that sensitive features may be overlooked and steep slopes unidentified if mapping is at too large a scale.

Recommendation: The SPDES HVHF GP should be revised to require mapping at a maximum scale no greater than 1" = 100' to ensure adequate identification of features to be avoided or protected during construction.

Comment 17:

C.1.i. Erosion and sediment control components – The inspection schedule, as well as the corresponding inspection reports should be made available with the SWPPP for Department access. At a minimum, the inspection schedule should be made available to the public and include a Department contact where concerns may be reported.

Comment 18:

D.1.b. Post-construction stormwater management practice component - The SPDES HVHF GP requires a well site map/construction drawing(s) that include information vital to post-construction stormwater management practice evaluation, including the specific location and size of each post-construction stormwater management practice. However, there is no maximum scale identified for this requirement. It is possible that the regulatory review of post-construction stormwater management practices may be inadequate if mapping is at too large a scale.

Recommendation: The SPDES HVHF GP should be revised to require mapping at a maximum scale no greater than 1" = 100' to ensure adequate identification and evaluation of proposed post-construction stormwater management practices.

Comment 19:

D.1.e. Post-construction stormwater management practice component - The SPDES HVHF GP requires a hydrologic and hydraulic analysis for all structural components of the stormwater management control system. However, the SPDES HVHF GP does not require supporting calculations to be submitted in support of these analyses. Without supporting calculations, regulators will be limited in the ability to effectively review the appropriateness of the proposed system.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit calculations supporting the hydrologic and hydraulic analysis of all structural components of the proposed stormwater management control system. All calculations and information should be available to the public upon request.

Comment 20:

D.1.f. Post-construction stormwater management practice component – The SPDES HVHF GP requires a detailed summary of the sizing criteria that were used to design all post-construction stormwater management practices *including calculations* to be submitted with the SWPPP. The SPDES HVHF GP requires the summary to address, at a minimum, the required design criteria from applicable chapters of the 2010 New York State Stormwater Management Design Manual.

However, the SPDES HVHF GP does not indicate that the calculations are site specific. Given the variability of site conditions throughout any given project, it is essential that the post-construction stormwater management practices be designed to address the unique considerations of both the site conditions and the functional practicality of any proposed post-stormwater management practice.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit site-specific calculations supporting the design of all proposed stormwater management practices to ensure they are appropriate for site-specific conditions.

Comment 21:

E. Enhanced Phosphorous Removal Standards – The SPDES HVHF GP requires post-construction stormwater management practices to be designed in conformance with the Enhanced Phosphorous Removal Standards included in the 2010 New York State Stormwater Design Manual. However, the SPDES HVHF GP does not require permittees to submit documented implementation of this requirement.

Recommendation: The SPDES HVHF GP should be revised to require permittees to document the implementation of the Enhanced Phosphorous Removal Standards within the SWPPP as part of their permit application package.

Part V-CONSTRUCTION OF WELL SITE – INSPECTION, MAINTENANCE, AND RECORDKEEPING REQUIREMENTS

Comment 22:

D. Recordkeeping – The SPDES HVHF GP requires all inspection reports to be maintained on the *well site* with the *Construction SWPPP*. Without a requirement to submit inspection reports or, at a minimum, a list of violations and corrective actions required, to the Department, the inspection reports may not serve their intended purpose. Regardless of limitations to staff and funding, the Department should maintain responsibility for ensuring compliance with applicable regulations. The utilization of *qualified inspectors* is only one part of ensuring compliance and should be supplemented with quality control checks by the Department, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of inspection reports or, at a minimum, a list of violations and correctives actions required, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of inspection documents to ensure compliance is being achieved.

Part VI CONSTRUCTION PHASE COMPLETION

Comment 23:

B. Inspections – The SPDES HVHF GP requires from qualified inspectors, by signature, a statement certifying achievement of final site stabilization. However, the SPDES HVHF GP does not require any documentation supporting this certification.

Recommendation: The SPDES HVHF GP should be revised to require documentation, specifically time/date-stamped digital photographs, to support certification of final stabilization.

Part VII HVHF SWPP

Comment 24:

Part VII General comment – Would an applicant be permitted to submit one generic document to be applied at multiple sites? If so, it is unlikely that all relevant issues will be adequately addressed.

Recommendation: The SPDES HVHF should be revised to require a site-specific SWPPP as described in previous comments to ensure adequate protection and mitigation measures are proposed.

Comment 25:

A.5. Development of the HVHF SWPPP – The SPDES HVHF GP requires the HVHF SWPPP to be developed by someone knowledgeable in the principles and practices of stormwater management and groundwater protection associated with the HVHF Phase and the Production Phase. The SPDES HVHF GP specifically mentions a Professional Engineer. However, the principles and practices of groundwater protection are often best performed by a Professional Hydrogeologist.

Recommendation: The SPDES HVHF GP should be revised to reference the appropriate professional disciplines necessary to adequately address both stormwater management (Professional Engineer) and groundwater protection (Professional Hydrogeologist).

Comment 26:

A.11 Development of the HVHF SWPPP – The SPDES HVHF GP allows the Department to issue an immediate stop work order upon a finding of significant non-compliance of the HVHF SWPPP or violation of the GP.

Recommendation: The ability to issue a stop-work order is a great option for the Department and should be supplemented by random quality control reviews performed as described in previous comments.

Part VIII HVHF OPERATION REQUIREMENTS

Comment 27:

A.1. and 2. General Requirements – The SPDES HVHF GP requires owners and operators to develop and evaluate alternatives for HVHF Phase fluid additives and to maintain a list of all HVHF Phase fluid additives on-site. The Department must make clear that propriety information must not be excluded from this list.

Comment 28:

A.4. General Requirements – The SPDES HVHF GP requires qualified inspectors to sign a statement certifying achievement of final site stabilization prior to initiating the HVHF Phase. However, the SPDES HVHF GP does not require any documentation supporting this certification.

Recommendation: The SPDES HVHF GP should be revised to require documentation, specifically time/date-stamped digital photographs, to support certification of final stabilization.

Comment 29:

A.6. General Requirements – The SPDES HVHF GP requires Department inspector verification of partial site reclamation. However, the SPDES HVHF GP does not address the procedures necessary if partial site reclamation is not sufficient.

Recommendation: The SPDES HVHF GP should be revised to detail the process for addressing sites where the requirements for partial site reclamation are insufficient.

Part IX CONTENTS OF THE HVHF SWPPP

Comment 30:

A.2. HVHF General SWPPP Requirements – The SPDES HVHF GP requires a site map that includes information critical to adequately review and evaluate the HVHF

SWPPP. Specifically, the SPDES HVHF GP cites a *USGS quadrangle or other map.* While a USGS quadrangle map may be adequate for showing general site location, it is not appropriate for showing detailed information. It is possible that the regulatory review of the HVHF SWPPP may be inadequate if mapping is at too large a scale.

Recommendation: The SPDES HVHF GP should be revised to require mapping at a maximum scale no greater than 1" = 100' to ensure adequate identification and evaluation of proposed post-construction stormwater management practices. Specifically, this section of the SPDES HVHF GP should be revised as follows:

b. Directions of stormwater flow should be shown on a contoured map with contours shown at minimum 5-ft intervals.

e. The scale for maps showing the locations of items listed in this section should be mapped at an appropriate <u>defined</u> scale (e.g. 1"=50' maximum). This section should also include the location of gathering lines.

g. Drainage area maps and stormwater outfall locations should be submitted on a separate stormwater map, attached to the site map, to ensure correct documentation.

i. The procedure for determining areas with significant potential for causing erosion should be defined or, if already defined in other documents, referenced.

<u>Comment 31:</u>

A.4. HVHF General SWPPP Requirements – This section requires the name, classification, and distance from the nearest edge of the well pad to the nearest receiving water(s). Submission of this information in narrative form may be sufficient, but an appropriately scaled map with labeled features would also provide an easily-verifiable document.

Recommendation: The SPDES HVHF GP should be revised to require a map showing the name, classification, and distance from the nearest edge of a well pad to the nearest receiving water(s) at a legible scale.

<u>Comment 32:</u>

A.7. HVHF General SWPPP Requirements – The inclusion of gravel is important when considering the total imperviousness of the well site. The compaction of subsoils and clogging with fine sediment within gravel areas has been shown to function as an impervious surface with regard to stormwater runoff.

<u>Comment 33:</u>

A.7. HVHF General SWPPP Requirements – This section includes an equation for estimating the total imperviousness of a well site as:

> Area of Roofs + Area of Paved and Other *Impervious* Surfaces, including gravel and roads = Total Area of *Well site.*

This equation should be revised as follows:

> Area of Roofs + Area of Paved and Other *Impervious* Surfaces, including gravel and roads = Total <u>Impervious Surface</u> Area of *Well site.*

<u>Comment 34:</u>

A.11. HVHF General SWPPP Requirements – The SPDES HVHF GP requires a summary of discharge sampling data to be maintained on the well site. Without a requirement to submit sampling data to the Department, it is possible that discharges in violation of the SPDES HVHF GP may be overlooked. Regardless of limitations to staff and funding, the Department should maintain responsibility for compliance and enforcement through quality control checks.

Recommendation: Quality control checks should be performed by the Department and facilitated by the submission of sampling data to the Department electronically. Checks should then be verified through cross-checking submitted sampling data against Department-collected sample data. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments.

Comment 35:

A.13. HVHF General SWPPP Requirements – In addition to identifying the proposed sources or any water to be used at the well site, an estimate of proposed volume to be withdrawn from each source will assist in tracking any pollutants found in that water.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit estimated volumes to be withdrawn from each identified water source.

Comment 36:

A.16. HVHF General SWPPP Requirements – The SPDES HVHF GP requires the HVHF SWPPP to include a description of stormwater management controls appropriate for the *well site*. However, the SPDES HVHF GP does not indicate that this description will include site specific sizing calculations. Given the variability of site conditions throughout any given project, it is essential that stormwater management controls be designed to address the unique considerations of both the site conditions and the functional practicality thereof.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit site specific sizing calculations supporting the design of all proposed stormwater management controls to ensure they are appropriate for site-specific conditions. Site-specific stormwater management controls should be evaluated for design and performance through inspection reporting and quality control as described in previous comments.

Comment 37:

A.18.k. HVHF General SWPPP Requirements – The SPDES HVHF GP requires the HVHF SWPPP to include information about partial site reclamation, including a requirement that reclaimed areas be seeded and mulched after topsoil replacement and reestablishment of vegetative cover. Standards for acceptable seeding, maintenance of seeded areas, and soil restoration should be defined in order to ensure reclamation, revegetation, and continued stabilization are achieved.

Recommendation: The SPDES HVHF GP should be revised to include by definition or reference standards for acceptable seeding, maintenance of seeded areas, and soil restoration.

Comment 38:

B.1.p. Required Non-Structural BMPs - The SPDES HVHF GP requires the owner or operator to use absorbents for dry cleanup whenever possible. However, the SPDES HVHF GP does not address the disposal of used absorbents.

Recommendation: The SPDES HVHF GP should be revised to address the disposal of used absorbents in accordance with NYS and EPA guidelines.

Comment 39:

C. Required Structural BMPs – The SPDES HVHF GP requires the HVHF SWPPP to "describe the traditional stormwater management practices…that currently exist or that are planned." However, the SPDES HVHF GP does not require calculations supporting the capacity of existing stormwater management practices to manage additional stormwater from newly constructed well sties, nor does the SPDES HVHF GP require supporting calculations for design of proposed stormwater management practices. Without a thorough review prior to issuance of the GP, it is possible that stormwater management practices will be inadequate to effectively address stormwater runoff from well sites.

Recommendation: - The SPDES HVHF GP should be revised to require the submission of calculations supporting the capacity of existing stormwater management practices and the design of proposed stormwater management practices to effectively manage stormwater runoff resulting from the construction and operation of a well site.

Part X ACTIVITIY-SPECIFIC STRUCTURAL AND NON-STRUCTURAL BMPs AND BENCHMARK MONITORING REQUIREMENTS

Comment 40:

A.5. General – The SPDES HVHF GP states that "if the [HVHF] activities are conducted for less than one (1) calendar year, all stormwater monitoring requirements must be satisfied during the period of activity. If no qualifying storm event occurs during the period of activity, or no qualifying storm event results in a *discharge*, monitoring requirements must be completed during the first qualifying storm that results in a *discharge*." However, the SPDES HVHF GP does not define the term "qualifying storm event." To ensure adequate monitoring of stormwater resulting from HVHF activities, the monitoring and sampling requirements must be clearly defined in order for permittees to satisfy the conditions of the permit.

Recommendation: The SPDES HVHF GP should be revised to include a clear definition of the term "qualifying storm event."

Comment 41:

D. Vehicle and equipment cleaning areas – The SPDES HVHF GP states that "discharge of vehicle and equipment wash waters … are not authorized by the SPDES HVHF GP and must be covered under a separate SPDES permit or discharged to a sanitary sewer in accordance with applicable industrial pretreatment requirements or transported off-site for proper disposal." The intent of the SPDES HVHF GP was to streamline and condense the permitting process for HVHF activities. Requiring a separate permit for the discharge of vehicle and equipment wash waters seems redundant in light of the ability of the SPDES HVHF GP to cover all other HVHF activities.

Recommendation: The SPDES HVHF GP should be revised to incorporate all the provisions necessary to meet New York State permitting requirements within a single permit, including the provisions necessary to authorize discharges from vehicle and equipment wash waters or require off-site transportation for disposal.

Comment 42:

J. Piping/conveyances – The SPDES HVHF GP requires the HVHF SWPPP to include and describe measures that prevent or minimize the contamination of surface runoff from spills and leaks from piping/conveyance systems used for transferring "fresh water, *flowback* water, *production brine*, well *stimulation* water, sanitary, and other wastewaters." However, the SPDES HVHF GP does not address this requirement for piping/conveyance systems used for transferring the gas produced by each well site. Failure to address the piping/conveyance systems used for gas transmission may result in inadequate protection of surface waters in the event of a leak or spill of gas.

Recommendation: The SPDES HVHF GP should be revised to address all piping/conveyances, including gas transmission systems.

Comment 43:

J.2.p. Piping/conveyances – The SPDES HVHF GP states, "pipelines buried under stream crossings shall be buried below the scouring depth and may require other permits." The SPDES HVHF GP does not require the submission of supporting calculations for determination of scour depth, nor does it clearly define the conditions under which "other permits" may be required. Furthermore, it seems that NYSDEC does not require stream crossing permits for activities other than silviculture. This lack of oversight may result in significant impacts to surface waters due to the potential thousands of crossings at headwater streams to facilitate HVHF activities.

Recommendation: The SPDES HVHF GP should be revised to require submission of calculations supporting the determination of scour depth for the placement of buried pipeline stream crossings.

Recommendation: The SPDES HVHF GP should be revised to clearly define which “other permits” may be required and the conditions under which those “other permits” are applicable.

Recommendation: NYSDEC should examine current stream crossing requirements and develop more robust regulations to ensure proposed crossings are constructed and maintained appropriately and do not impact water quality.

Comment 44:

M. Freshwater Surface Impoundments and Reserve Pits – The SPDES HVHF GP states, “a closed-loop tank system must be used instead of a reserve pit to manage drilling fluids and cuttings for any of the following: a) horizontal drilling in the Marcellus Shale unless an acid rock drainage mitigation plan for onsite burial of such cuttings is approved by the Department; and; b) any drilling requiring cuttings to be disposed of off-site, as provided in Part 360 of this Title, including at a landfill.” However, the SPDES HVHF GP does not define an “acid rock drainage mitigation plan.” The SPDES HVHF GP also does not clearly identify the reference to Part 360 in section (b), above.

Recommendation: The SPDES HVHF GP should be revised to include a section defining an “acid rock drainage mitigation plan” which includes the conditions under which the plan must be developed, the issues which the plan must address (including any necessary supporting calculations), and the contents which must be included in the plan.

Recommendation: The SPDES HVHF GP should be revised to clearly identify the statute included in part (b) of this section which references the off-site disposal of cuttings.

Part XII HVHF PHASE MONITORING

Comment 45:

A. Schedule for Monitoring – The SPDES HVHF GP requires a schedule for visual monitoring and examination of stormwater discharges at each outfall after each qualifying storm that must document observed color, odor, clarity, floating solids, settled solids, suspended solids, foam, and oil sheen. However, the SPDES HVHF GP does not require sampling, even if the visual observations indicate the presence of pollutants.

Recommendation: The SPDES HVHF GP should be revised to clearly define sampling requirements. At a minimum, sampling and laboratory testing should be required if a visual examination indicates the presence of pollutants.

Comment 46:

A. Schedule for Monitoring – The SPDES HVHF GP requires visual examination documents to be maintained on the well site. Also, the SPDES HVHF GP does not require photographic documentation to support visual examination reports. The Department should perform quality control checks, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of visual examination reports, including photos, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of visual examination documents to ensure compliance is being achieved.

Comment 47:

A. Schedule for Monitoring – The SPDES HVHF GP states, “all samples (except snowmelt samples) must be collected from the *discharge* resulting from a storm event that is greater than 0.1 inches in magnitude and that occurs at least seventy-two (72) hours from the previously measurable (greater than 0.1 inch rainfall) storm event. The 72-hour storm interval is waived if the preceding measurable storm did not result in a stormwater *discharge* (e.g., a storm event in excess of 0.1 inches may not result in a stormwater *discharge* at some facilities).” Is this the intended definition of “qualifying storm event?”

Comment 48:

A. Schedule for Monitoring – The SPDES HVHF GP states, “if a visual examination was performed and the storm event was later determined not to be a measurable (greater than 0.1 inch rainfall) storm event, the visual examination should still be included in the *HVHF SWPPP* records.” The inclusion of all visual examination reports in the HVHF SWPPP record should be required.

Recommendation: The SPDES HVHF GP should be revised to state, “if a visual examination was performed and the storm event was later determined not to be a measurable (greater than 0.1 inch rainfall) storm event, the visual examination must still be included in the *HVHF SWPPP* records.”

Comment 49:

A.3.c. Schedule for Monitoring – This section of the SPDES HVHF GP requires samples to be analyzed within ten calendar days after they have been collected.

This information may be more logically located in section A.10.b. which discusses collection and analysis of samples.

Recommendation: The SPDES HVHF GP should be revised to move the above referenced requirement for analysis of samples from Part XII.A.3.c. to Part XII.A.10.b.

Comment 50:

A.3.d. Schedule for Monitoring – This section of the SPDES HVHF GP states, "the benchmark concentrations do not constitute direct numeric effluent limitations and, therefore, an exceedance is not a general permit violation." What is the purpose of benchmark monitoring if exceedance of the benchmark concentrations listed in Part X of the SPDES HVHF GP do not result in a general permit violation?

Recommendation: The SPDES HVHF GP should be revised to omit this sentence from the document. Exceeding benchmark concentrations should immediately result in a violation of the GP to ensure proper corrective action is taken to protect water quality.

Comment 51:

A.3.f. Schedule for Monitoring – The SPDES HVHF GP requires benchmark monitoring results to be documented and maintained on the well site. The Department should perform quality control checks, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of benchmark monitoring results, including corrective actions needed, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of benchmark monitoring documents to ensure compliance is being achieved.

Comment 52:

A.10.b. Schedule for Monitoring – The SPDES HVHF GP states that "sampling requirements must be assessed on an outfall-by-outfall basis." However, there are no criteria upon which sampling requirements are to be assessed. The SPDES HVHF GP also fails to identify the party responsible for directing sampling requirements at each outfall. Sampling requirements should be directed by NYSDEC guidance criteria, to include frequency of collection and analysis requirements.

Recommendation: The SPDES HVHF GP should be revised to clearly identify the Department as the party responsible for directing sampling requirements at each outfall.

Recommendation: The NYSDEC should develop guidance criteria for sampling requirements for HVHF activities. This guidance criteria should address the conditions under which sample collection is required (i.e., when a visual examination indicates the presence of pollution), location of sample collection, frequency of sample collection, and laboratory analysis requirements for collected samples.

Recommendation: The SPDES HVHF GP should be revised to require sampling in accordance with NYSDEC guidance criteria, to include frequency of collection and analysis requirements.

Comment 53:

A.10.b. Schedule for Monitoring – This section of the SPDES HVHF GP does not reference the ten-day time limit for analysis of collected samples.

Recommendation: This section of the SPDES HVHF GP should be revised to include reference to the ten-day time limit for analysis of collected samples included in Part XII.A.3.c.

Comment 54:

A.10.c. Schedule for Monitoring – This section of the SPDES HVHF GP requires owners/operators to provide the date and duration of sampled storm events, rainfall measurements or estimates (in inches) of the storm event that generated the sampled runoff, time between storm events greater than 0.1 inch, and an estimate of volume sampled. A rain gauge/weather station should be required to ensure rainfall greater than 0.1 inch is accurately recorded. This will also ensure visual examination and sampling is completed for events greater than 0.1 inch.

Recommendation: The SPDES HVHF GP should be revised to require rainfall measurements and remove references to rainfall estimates to ensure monitoring and sampling in compliance with the conditions of the permit.

Part XIII HVHF PHASE REPORTING

Comment 55:

A. Discharge Monitoring Reports (DMR) – The SPDES HVHF GP requires the results of laboratory analysis of samples to be submitted to the Department on preprinted DMRs within ten days of their receipt. The required formatting of DMRs lends itself very easily to standardization for electronic submission to the Department, which would allow for faster submission and reduce the costs incurred by both the Department and permittees by eliminating unnecessary paper and paperwork. Furthermore, the Department should perform quality control checks, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of DMRs, in approved format via online forms, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of benchmark monitoring documents to ensure compliance is being achieved.

Part XIV MONITORING FOR THE PRODUCTION PHASE AND TEMPORARY SUSPENSION OF THE HVHF PHASE

Comment 56:

A. Schedule for Monitoring – Please see comments 45, 46, 49, 50, 51, 52, 53, and 54, and the corresponding recommendations as they apply to this section of the SPDES HVHF GP.

Part XVI PRODUCTION PHASE REPORTING

Comment 57:

A. Discharge Monitoring Reports (DMR) – Please see comment 55 and the corresponding recommendation as it applies to this section of the SPDES HVHF GP.

Part XXI. STANDARD GENERAL PERMIT CONDITIONS

Comment 58:

F. Duty to Provide Information – The SPDES HVHF GP states, "the NOI, SWPPP and inspection reports required by this general permit are public documents that the *owner or operator* must make available for review and copying by any person within five (5) business of the *owner or operator* receiving a written request by any such person to review the NOI, SWPPP or inspection reports. Copying of documents will be done at the requester's expense." Many HVHF well sites prohibit access by the general public, and all of the public documents indicated are required by the SPDES HVHF GP to be kept on the well site. In order to expedite requests and eliminate man-hours necessary to escort individuals through restricted areas, as well as provide for the recommendations above, the Department should require the electronic submission of all public documents. These documents should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments.

Recommendation: The SPDES HVHF GP should be revised to allow for the electronic submission of all public documents. These documents should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments.

Attachment A

Technical Information in support of comments:

1. Sediment Loads from Gravel Roads

   The Pennsylvania Center for Dirt and Gravel Road Studies provides information on measures to maintain gravel roads in a manner to reduce the discharge of pollutants and protect water quality. Penn State's Center for Dirt and Gravel Road Studies (Center) recently completed a research project for the Chesapeake Bay Commission (Scheetz, Summary Statement) that begins to quantify sediment production from gravel roads and sediment reductions from several commonly used practices. This study found that:

   > **Runoff Rates from Existing Roads:**
   > *"The five "existing condition" tests done for this study found sediment production rates ranging from 0.7-12.2 pounds of sediment runoff in a single 30 minute, 0.55 inches simulated rainfall. The 0.7 pound event was generated from a flat narrow farm lane with grass growing between the wheel tracks. The 12.2 pound event was generated from a wider, mixed limestone/clay road at a 4-5% slope. This highlights the great variability in erosion rates based on specific site conditions. Using the average sediment runoff rate of 5.6 pounds per event, a single 30 minute 0.55 inch rain event moving across Pennsylvania can be conservatively expected to generate over 3,000 tons* of sediment form the State's 20,000+ miles of public unpaved roads".*

   This research supports that gravel roads can be a significant source of pollutants such as sediment. As discussed in several comments, there is a need for the RDSGEIS to estimate the cumulative impact of gravel road development as a result of HVHF activity.

2. **Water Quality Impacts from Gas Drilling Activities**

   In 2005, the U.S. Environmental Protection Agency (U.S. EPA) awarded a grant to the City of Denton, Texas, to monitor and assess the impact of gas well drilling on stormwater runoff. The results of this effort were published in December 2007 in a report titled "Demonstrating the Impacts of Oil and Gas Exploration on Water Quality and How to Minimize These Impacts Through Targeted Monitoring Activities and Local Ordinances." With regards to the discharge of sediment during construction, this study determined that:

> *"Gas well sites have the potential to produce sediment loads comparable to traditional construction sites.*
>
> - *Total suspended solids (TSS) and turbidity event mean concentrations (EMC = pollutant mass / runoff volume) at gas sites were significantly greater than at reference sites (the median TSS EMC at gas sites was 136 times greater than reference sites).*
>
> - *Compared to the median EMCs of storms sampled by Denton near one of their outfalls, the gas well site median EMC was 36 times greater.*
>
> - *Gas site TSS EMCs ranged from 394 to 9898 mg/l and annual sediment loadings ranged from 21.4 to 40.0 tonnes/hectare/year (tonne = 1000 Kg; hectare = 10,000 square meters), and were comparable to previous studies of construction site sedimentation"*.

This study concludes that "Gas well sites have the potential to negatively impact surface waters due to increased sedimentation rates." (US EPA ID No. CP-83207101-1, page 2).

In addition to the well pad site, roads that are constructed, widened, or altered for vehicle access to and from the well pad site can be a source of sediment and pollutants during both construction and operation. The U.S. EPA Publication "Erosion, Sediment and Runoff Control for Roads and Highways" (EPA-841-F-95-008d) states that:

> Runoff controls are essential to preventing polluted runoff from roads, highways, and bridges from reaching surface waters. Erosion during and after construction of roads, highways, and bridges can contribute large amounts of sediment and silt to runoff waters, which can deteriorate water quality and lead to fish kills and other ecological problems.
>
> Heavy metals, oils, other toxic substances, and debris from construction traffic and spillage can be absorbed by soil at construction sites and carried with runoff water to lakes, rivers,

> and bays. Runoff control measures can be installed at the time of road, highway, and bridge construction to reduce runoff pollution both during and after construction. Such measures can effectively limit the entry of pollutants into surface waters and ground waters and protect their quality, fish habitats, and public health.

This publication (EPA-841-F-95-008d) identifies a number of pollutant types and sources related to Roads and Highways, as identified in Table 1.

Table 1. Typical pollutants found in runoff from roads and highways.

Erosion, Sediment and Runoff Control for Roads and Highways | Polluted Runoff | US EPA

	Pollutant	**Source**
Sedimentation	Particulates	Pavement wear, vehicles, the atmosphere and maintenance activities
Nutrients	Nitrogen & Phosphorus	Atmosphere and fertilizer application
Heavy Metals	Lead	Leaded gasoline from auto exhausts and tire wear
	Zinc	Tire wear, motor oil and grease
	Iron	Auto body rust, steel highway structures such as bridges and guardrails, and moving engine parts
	Copper	Metal plating, bearing and brushing wear, moving engine parts, brake lining wear, fungicides & insecticides
	Cadmium	Tire wear and insecticide application
	Chromium	Metal plating, moving engine parts and brake lining wear
	Nickel	Diesel fuel and gasoline, lubricating oil, metal plating, bushing wear, brake lining wear and asphalt paving
	Manganese	Moving engine parts
	Cyanide	Anti-caking compounds used to keep deicing salt granular
	Sodium, calcium & chloride	Deicing salts
	Sulphates	Roadway beds, fuel and deicing salts
Hydrocarbons	Petroleum	Spills, leaks, antifreeze and hydraulic fluids and asphalt surface leachate

References

1. Center for Rural Pennsylvania “the Impact of Marcellus Gas drilling on Rural Drinking Water Supplies”, October 2011.

2. Entrekin, Sally, et al, “Rapid Expansion of Natural Gas Development Poses a Threat to Surface Waters”, From Frontiers in Ecology 2011; 9(9): 503-511, Oct 2011.

3. Etowah Aquatic Habitat Conservation Plan “Utility Stream Crossings Policy”, July 13, 2006.

4. Handlerof, Stephanie; League of Women Voters of Indiana “Marcellus Shale Natural Gas Extraction Study 2009-2010 Study Guide V: Regulation and Permitting of Marcellus Shale Drilling”, League of Women Voters of Pennsylvania, 2010.

5. Kaplan, Louis, et al “Protecting Headwaters: The Scientific Basis For Safeguarding Stream And River Ecosystems, A Research Synthesis from the Stroud Water Research Center “ 2008.

6. Leopold, Luna B.; “A View of the River”, Harvard University Press, Cambridge, MA, 1994.

7. NYDEC “Stream Crossings Protecting and Restoring Stream Continuity” web page at http://www.dec.ny.gov/permits/49060.html.

8. O’Dell, Patrick M., Professional Engineer in Petroleum Engineering, National Park Service Geologic Resources Division, “Potential for Development of Natural Gas Exploratory Wells to Adversely Affect Water Resources of the Delaware River Basin”, Nov 23, 2010.

9. Reid, Scott M. and Paul G. Anderson “Effects of Sediment released During Open-cut Pipeline Water Crossings, Canadian water Resources Journal Vol. 24, No 3, 1999.

10. Scheetz, Dr. Barry E. and Steven M. Bloser; Center for Dirt and Gravel Road Studies, The Pennsylvania State University, University Park, PA 16802; “Environmentally Sensitive Maintenance Practices for Unpaved Roads: Sediment Reduction Study” Prepared for Chesapeake Bay Commission c/o Senate of Pennsylvania G-05 North Office Building Harrisburg, PA 1712, FINAL REPORT June 30, 2008, Revised August 29, 2008 and Summary Statement

11. United States Environmental Protection Agency "Erosion, Sediment and Runoff Control for Roads and Highways", Office of Water (4503F) EPA-841-F-95-008d, December 1995

12. United States Environmental Protection Agency, Final Report for Catalog of Federal Domestic Assistance Grant Number 66.463 Water Quality Cooperative Agreement for Project Entitled "Demonstrating the Impacts of Oil and Gas Exploration on Water Quality and How to Minimize these Impacts Through Targeted Monitoring Activities and Local Ordinances" and "Summary of the Results of the Investigation Regarding Gas Well Site Surface Water Impacts", ID No. CP-83207101-1, Kenneth E. Banks, Ph.D. Manager, Division of Environmental Quality and David J. Wachal, M.S. Water Utilities Coordinator

13. United States Environmental Protection Agency, Wadable stream assessment: a collaborative survey of the nation's streams, 2006. EPA 841-B-06-002.

14. Letter from James A. Schmid, PhD, Schmid & Company Consulting Ecologists to Scott E. Walters, Chief General Permits Bureau of Waste Management PaDEP, 8 November 2011.

Attachment 7

The Louis Berger Group, Inc.

THE Louis Berger Group, INC.
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Memorandum

TO: Kate Sinding, Natural Resources Defense Council

FROM: Niek Veraart, Louis Berger Group

DATE: January 11, 2012

RE: Technical Review Comments on the 2011 Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program and Proposed High-Volume Hydraulic Fracturing Regulations (Proposed Express Terms 6 NYCRR Parts 550 through 556 and 560)

1.0 Introduction

The Louis Berger Group Inc. (LBG) reviewed the 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS), the proposed Environmental Assessment Form (EAF) and EAF Addendum (RDSGEIS Appendices 5 and 6), the proposed Supplemental Permit Conditions (RDSGEIS Appendix 10) and the proposed High-Volume Hydraulic Fracturing (HVHF) regulations (Proposed Express Terms 6 NYCRR Parts 550 through 556 and 560) for the following topics:

- Noise (RDSGEIS Sections 2.4.13 and 6.10)
- Ground-borne noise and vibration (impacts not addressed in the RDSGEIS)
- Visual impacts (RDSGEIS Sections 2.4.12 and 6.9)
- Land use (impacts not addressed in the RDSGEIS)
- Transportation (RDSGEIS Sections 2.4.14 and 6.11)
- Community character (RDSGEIS Sections 2.4.15 and 6.11)
- Cultural resources (impacts not addressed in the RDSGEIS).
- Aquatic Ecology (RDSGEIS Sections 6.1.1.2, 6.1.1.3 and 6.1.1.4).

For each topic, the following sections address the sufficiency of the RDSGEIS impact analyses and proposed mitigation measures in meeting State Environmental Quality Review Act (SEQRA--6 NYCRR Part 617) requirements. The comments also identify specific improvements and best practice approaches that the New York State Department of Environmental Conservation (NYSDEC) could use to resolve the deficiencies identified and minimize the environmental impacts of High-Volume Hydraulic Fracturing (HVHF) and related development in New York.

2.0 Noise

2.1 Construction Impacts

The 2011 RDSGEIS quantitative construction noise assessment uses information from the Federal Highway Administration’s Road Construction Noise Model to estimate noise levels at various distances from the construction site and represents a substantial improvement over the qualitative analysis in the 2009 Draft Supplemental Generic Environmental Impact Statement (DSGEIS). For quiet rural areas, the results show that construction activities would result in significant adverse impacts under NYSDEC criteria (increase of 6 dBA (A-weighted decibels) or more over existing conditions) at distances exceeding 2,000 feet.

The RDSGEIS provides the requisite construction noise analysis, but fails to appropriately evaluate and discuss the significance of the model results. Instead, a one sentence conclusion is provided: “Such levels would not generally be considered acceptable on a permanent basis, but as a temporary, daytime occurrence, construction noise of this magnitude and duration is not likely to result in many complaints in the project area.”

Contrary to this statement, there is no regulatory requirement that access road construction and site preparation be limited to daytime hours. To mitigate this significant adverse impact, a prohibition on nighttime construction should be included in the HVHF regulations or supplemental permit conditions to avoid annoyance and sleep disturbance of nearby residences, along with other construction noise control best practices (See Section 2.6 infra).

Further, the assertion in the RDSGEIS that construction noise impacts are “temporary” ignores the likelihood of large number of wells and pads being concentrated in certain areas, as well as construction noise from related infrastructure development (pipelines, compressors, etc.). The cumulative construction noise impact has not been addressed.

In addition, noise-related complaints are not the appropriate basis for drawing conclusions about the significance of noise impacts under SEQRA because people (and wildlife) can be adversely affected by noise, but choose not to report it. NYSDEC should evaluate the significance of the construction noise impacts in relation to the duration, quality (tonal purity), time of day and year, background noise present, distance to the source, familiarity with the noise and other factors such as the setting. Studies have shown that each listener’s subjective perception of appropriateness of a noise in a particular setting can be just as important to annoyance as the objective sound level.[1] Given the rural context of the majority of the areas where natural gas development is expected to occur, many residents and visitors to these areas would find heavy construction activity noise to be out of place and annoying. Construction noise adjacent to parks and other sensitive land areas where natural quiet is expected would be especially problematic and would contribute to adverse economic impacts not accounted

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[1] See: Blauert, J. 1986. “Cognitive and Aesthetic Aspects of Noise Engineering.” In *Proceedings of Inter-Noise 86, Cambridge, Massachusetts, July 21–23*, volume 1, 5–13.

Kuwano, S., S. Namba, and H. Miura 1989 “Advantages and Disadvantages of A-weighted Sound Pressure Level in Relation to Subjective Impression of Environmental Noises.”*Noise Control Engineering Journal* 33:107–115.

Carles, J.L., I. Lopez Barrio, J.V. de Lucio 1999 “Sound Influence on Landscape Values.”*Landscape and Urban Planning* 43:191–200.
Ozawa, K., S. Ohtake, Y. Suzuki, and T. Sone 2003 “Effects of Visual Information on Auditory Presence,” Acoustical Letter to Acoustical Science and Technology, 24(2), 97-99.

for in the 2011 RDSGEIS by making areas where gas development is occurring less attractive to visitors.[2]

2.2 Drilling and Fracturing Impacts

2.2.1 Failure to Analyze Multi-Well Pad Impacts

The general approach used in the RDSGEIS quantitative noise impact assessment is reasonable and consistent with the methodology recommended in NRDC's comments on the 2009 DSGEIS for evaluation of the impacts of drilling and fracturing of one horizontal well. However, it fails to analyze the impacts of multi-well pads, which is the primary form of development anticipated. Table 6-59 in the RDSGEIS presents the duration of various construction and operational phases for one well. Each well is estimated to take 28-35 days to drill, while fracturing is assumed to take up to five days. Since drilling or fracking of multiple wells is likely to occur simultaneously, the combined noise levels would be higher than those reported for a single well in the RDSGEIS.

The failure of the RDSGEIS to provide a noise impact assessment for the simultaneous drilling and fracturing of multiple wells is especially problematic because it is inconsistent with the scenario developed for the analysis of transportation impacts (page 6-305). The result of this inconsistency is that the noise impacts of drilling and fracturing are underestimated and do not reflect a reasonably foreseeable worst-case development scenario. The multi-pad horizontal well development scenario in the transportation section of the RDSGEIS assumed three rigs would be operated simultaneously over a 120 day period and that each rig would drill four wells (for a total of 12 wells at the site). With three rigs in operation at the same time, the combined noise level at a distance of 50 feet would be approximately 84 dBA, not 79 dBA as reported for one rig in the RDSGEIS (Table 6.56- Rotary Air Well Drilling).[3]

With respect to the fracturing phase, the RDSGEIS wording is unclear, but appears to suggest sequential fracturing (one well being fractured at a time for a total of 60 days of fracturing noise impacts). The RDSGEIS states "fracturing and completion of the four wells occurs sequentially and tanks are brought in once for all four wells" (page 6-305). This statement is confusing because the scenario being described involves a total of 12 wells, not four wells. If fracturing of multiple wells occurs simultaneously, then the duration of fracturing impacts would be less, but the combined noise level would be higher. For example, fracturing two wells at once would create a combined noise level 3 dBA higher than the fracturing of one well. When drilling and fracturing are occurring at the same time, the total noise level would be entirely driven by the much louder fracturing process (no increase in the total sound level because the difference between the two sound levels is greater than 10 dBA).

At a minimum, NYSDEC should analyze the noise impact from the same multi-pad well development scenario as used in the analysis of transportation impacts. NYSDEC should address the expected number of wells per multi-well site, the timing of drilling and fracturing at each well and the reasonable worst case noise levels that could result from the various combinations of drilling and fracturing at multiple wells on the same site.

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[2] Refer to Susan Christopherson's socioeconomics technical memorandum for more information on impacts to the tourism industry.

[3] Decibels are expressed on a logarithmic scale and thus cannot be added together directly.

2.2.2 Lack of Reasonable Noise Impact Significance Criteria

Similar to the construction impact assessment discussed in Section 2.1, the RDSGEIS presents the model results for the drilling and fracturing noise impacts without a SEQRA-compliant assessment of the significance of the results in various contexts where natural gas development is anticipated. The RDSGEIS does not include noise impact criteria against which the significance of the impacts can be assessed generically or at the site specific review level, which is contrary to the purposes of a GEIS. For information on a recommended framework for developing noise impact criteria, refer to Section 2.8.

The RDSGEIS references NYSDEC's noise policy ("Assessing and Mitigating Noise Impacts,"2001)[4], but this document has a number of significant problems that limit its usefulness in regulating noise. It discusses a 6 dBA increase as potentially significant, but does not define what averaging time period should be used in calculating the increase, does not account for increased sensitivity to noise occurring at night, and does not take into account the total level at the affected receptor. The policy also does not provide a standard for specific highly sensitive land uses, such as passive recreation parks and wilderness areas. The NYSDEC noise policy leaves too much discretion to individual analysts to ensure consistent application of noise control for an activity expected to have widespread and significant impacts across New York. Accordingly, an assessment as to the significance of the potential adverse noise impacts should be made independent of the 2001 policy.

The RDSGEIS acknowledges that drilling and fracturing would take place 24hours per day. People are much more sensitive to noise that occurs at night and interferes with sleep than to noise that occurs only during daytime activities. For this reason, community noise impact assessment metrics such as day-night sound levels (Ldn) apply a 10 dB penalty to sounds occurring at night in determining a 24-hour average energy sound level that better reflects human preferences. Background noise levels are also lower at night, further emphasizing the significance of the increase in sound levels attributable to drilling and fracturing. As noted above in the discussion of construction impacts, non-residential land uses in rural areas vital to the economic health of upstate New York such as parks, recreation areas and campgrounds would be especially sensitive to increases in sound levels.

2.2.3 Fracturing Noise Impacts Exceed Hearing Damage Thresholds

The noise levels associated with the fracturing process are of a relatively short duration on a per well basis (2-5 days), but are of an extremely large magnitude that could adversely affect human health:

- At a distance of 2,000 feet, the fracturing pump truck noise level of up to 72 dBA would be intrusive and interfere with normal conversation.
- At a distance of 500 feet, the fracturing pump truck noise level of up to 84 dBA approaches the level where hearing damage occurs (85 dBA for eight hours).

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[4] http://www.dec.ny.gov/docs/permits_ej_operations_pdf/noise2000.pdf

- At a distance of 250 feet, the fracturing pump truck noise level of up to 90 dBA is in the range of noise levels where no more than 15 minutes of unprotected exposure is recommended to prevent damage to hearing.[5]
- At a distance of 50 feet, the fracturing pump truck noise level of up to 104 dBA is of a similar magnitude to a jet flyover at a distance of 1,000 feet and at a level where unprotected exposure over one minute poses a risk of permanent hearing loss.

For context in understanding the sound levels discussed above, Table 1 provides a summary of the decibel level of common sounds sources and the associated effects.

Table 1
Decibel Levels of Common Sound Sources

Sound	Noise Level (dB)	Effect
Jet Engines (near)	140	
Shotgun Firing Jet Takeoff (100-200 ft.)	130	
Rock Concerts (varies)	110–140	Threshold of pain begins around 125 dB
Oxygen Torch	121	
Discotheque/Boom Box Thunderclap (near)	120	Threshold of sensation begins around 120 dB
Stereos (over 100 watts)	110–125	
Symphony Orchestra Power Saw (chainsaw) Pneumatic Drill/Jackhammer	110	Regular exposure to sound over 100 dB of more than one minute risks permanent hearing loss.
Snowmobile	105	
Jet Flyover (1000 ft.)	103	
Electric Furnace Area Garbage Truck/Cement Mixer	100	No more than 15 minutes of unprotected exposure recommended for sounds between 90–100 dB.
Farm Tractor	98	
Newspaper Press	97	
Subway, Motorcycle (25 ft.)	88	Very annoying
Lawnmower, Food Blender Recreational Vehicles, TV	85–90 70–90	85 dB is the level at which hearing damage (8 hrs.) begins
Diesel Truck (40 mph, 50 ft.)	84	
Average City Traffic Garbage Disposal	80	Annoying; interferes with conversation; constant exposure may cause damage
Washing Machine	78	
Dishwasher	75	
Vacuum Cleaner, Hair Dryer	70	Intrusive; interferes with telephone conversation
Normal Conversation	50–65	
Quiet Office	50–60	Comfortable hearing levels are under 60 dB.
Refrigerator Humming	40	
Whisper	30	Very quiet
Broadcasting Studio	30	
Rustling Leaves	20	Just audible
Normal Breathing	10	

Source: http://www.nidcd.nih.gov/health/education/teachers/pages/common_sounds.aspx

The minimum setbacks in the proposed regulations (currently 100 feet from a residence) must be revised to protect the health and well-being of nearby residents during fracking. Landowners should not have the power to waive the minimum setback requirement. The

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[5] http://www.nidcd.nih.gov/health/education/teachers/pages/common_sounds.aspx

landowners should not be presented with the temptation to trade their family's health for financial gain. An additional problem with granting landowners the ability to waive setback requirements is that tenants of a landowner's property would not have any say in the landowner's decision to waive setback requirements essential for health.

The drilling phase sound levels are substantially lower than the fracturing noise levels, but their duration is much longer (approximately one month of 24-hour drilling per well). Drilling sound levels would drop to below 70 dBA at a distance of 250 feet from the well pad. However, 70 dBA is still 40 dBA greater than the nighttime background sound level in rural areas of 30 dBA, further supporting the need for noise impact criteria and mitigation requirements to protect the soundscapes of rural areas

2.2.4 Other Comments

Tables 6.56, 6.57 and 6.58 are all incorrectly labeled as showing "estimated construction noise levels."

The equipment assumed in the analysis and sound levels associated with each piece of equipment are based on "confidential industry sources." NYSDEC should disclose the basis for the equipment assumptions and sound levels so that these important inputs can be independently validated.

Table 6.57 has footnote "2" for the rig drive motor and generator sound levels, but the explanation for footnote 2 is missing. In addition, it appears that footnote #1 on Table 6.57 should be associated with the "Distance in Feet/SPL (dBA)" portion of the table and not the sound levels associated with the top drive, draw works and triple shaker.

2.3 Transportation Noise Impacts

The RDSGEIS discusses the potential for noise impacts related to truck traffic, but fails to conduct a meaningful analysis of typical transportation noise impacts for various phases of well pad development. This failure is particularly problematic given that the detailed truck trip generation information necessary for conducting a traffic noise assessment was developed for the transportation section of the RDSGEIS.

NYSDEC should use the Federal Highway Administration's (FHWA) Traffic Noise Model (TNM) version 2.5 and the truck trip generation information to fully consider truck traffic noise impacts. While site-specific impacts cannot be assessed, NYSDEC could easily examine a hypothetical, yet realistic development scenario for one well. The analysis could look at one single public road segment from which the well site would be accessed. Receptors at various distances (50 feet to 1,000 feet) would help show the potential extent of the area where impacts could occur. A range of non-natural gas related background traffic on the modeled road could be considered to show how the increase in sound levels would be much higher for local roads with low traffic volumes than for roads with high volumes under existing conditions. Traffic noise impacts for the various receptor distances could be assessed using well established New York State Department of Transportation (NYSDOT) and FHWA criteria.[6]

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[6] FHWA's noise impact assessment and mitigation procedures are defined under 23 CFR 772. NYSDOT's latest noise policy (revised April 2011) for implementing the FHWA requirements is

For the purposes of the SGEIS level of analysis, a number of simplifying, conservative assumptions could be employed in the TNM analysis (assuming flat terrain, no existing barriers, analyze one worst-case peak hour and one worst-case off-peak hour etc.). These assumptions would allow NYSDEC to complete a meaningful traffic noise analysis without extensive cost or delay to the review process.

2.4 Effects on Wildlife

Animals rely on sounds for communication, navigation, avoiding danger and finding food. Industrial and transportation noises associated with natural gas development create noise levels that can interfere with the sounds used by animals, which in turn can affect wildlife behavior and populations. The RDSGEIS acknowledges that noise could contribute to impacts on wildlife (page 6-68), but does not provide any analysis of this issue. NYSDEC should review the available scientific literature on this topic, qualitatively assess impacts and ensure appropriate mitigation measures are implemented. Key references to assist NYSDEC in this aspect of the environmental review are provided below:[7]

FHWA. Synthesis of Noise Effects on Wildlife Populations. http://www.fhwa.dot.gov/environment/noise/noise_effect_on_wildlife/effects/

Barber, J.R., K.R. Crooks, and K. Fristrup. 2010. The costs of chronic noise exposure for terrestrial organisms. Trends Ecology and Evolution 25(3): 180–189. Available at: http://www.sciencedirect.com/

Bayne, E.M., L. Habib and S. Boutin. 2008. Impacts of Chronic Anthropogenic Noise from Energy-Sector Activity on Abundance of Songbirds in the Boreal Forest. Conservation Biology 22(5) 1186-1193. Available at: http://oz.biology.ualberta.ca/faculty/stan_boutin/uploads/pdfs/Bayne%20etal%202008%20ConBio.pdf

Dooling R. J., and A. N. Popper. 2007. The effects of highway noise on birds. Report to the California. Department of Transportation, contract 43AO139. California Department of Transportation, Division of Environmental Analysis, Sacramento, California, USA. Available at: http://www.dot.ca.gov/hq/env/bio/files/caltrans_birds_10-7-2007b.pdf

Francis, C.D., C.P. Ortega and A. Cruz. 2009. Noise Pollution Changes Avian Communities and Species Interactions. Current Biology, Aug 25;19(16):1415-9 10.1016/j.cub.2009.06.052. Available at: http://www.sciencedirect.com/science/article/pii/S0960982209013281

Habib, L, E.M. Bayne and S. Boutin. 2007. Chronic industrial noise affects pairing success and age structure of ovenbirds Seiurus aurocapilla. Journal of Applied Ecology 44: 176-184. Available at: http://oz.biology.ualberta.ca/faculty/stan_boutin/ilm/uploads/pdfs/Habib%20etal%202

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available at https://www.dot.ny.gov/divisions/engineering/environmental-analysis/manuals-and-guidance/epm/repository/4_4_18Noise.pdf

[7] The suggested list of references is adapted from the USFWS paper entitled "The Effects of Noise on Wildlife." Available at: http://www.fws.gov/windenergy/docs/Noise.pdf

007%20JAE.pdf

Schaub, A, J. Ostwald and B.M. Siemers. 2008. Foraging bats avoid noise. The Journal of Experimental Biology 211: 3174-3180. Available at: http://jeb.biologists.org/cgi/content/full/211/19/3174

Swaddle, J.P. and L.C. Page. 2007. High levels of environmental noise erode pair preferences in zebra finches: implications for noise pollution. Animal Behavior 74: 363-368.

2.5 Cumulative Impacts

The RDSGEIS does not address the cumulative noise impacts of the anticipated natural gas development. Key considerations in developing a cumulative impact analysis for noise include the following:

- Analyze the cumulative noise impact of multi-well pads. The RDSGEIS analysis only addresses a single well.
- Analyze the cumulative noise impact from well site construction, drilling and fracturing in combination with the construction of pipelines and the operation of compressor stations. Pipelines and compressor stations are a reasonably foreseeable form of "induced growth" that needs to be considered.
- Examining the Ldn sound levels that would result at residences that are exposed to drilling, fracturing and truck traffic noise. The combination of these sources could result in impacts more significant than any individual source examined separately.
- Discuss regional-scale traffic noise impacts that would result from wide spread natural gas development and related economic development and temporary population growth.
- Discuss regional-scale noise impacts on human beings and wildlife, including the potential for disturbance of noise-sensitive species, such as the ovenbird (*Seiurus aurocapilla*).[8]

2.6 Mitigation

2.6.1 Mitigation for Construction Impacts

Construction noise impact mitigation is not addressed in Section 7.10 of the RDSGEIS. NYSDEC should require the use of construction noise mitigation best practices, such as those outlined in FHWA's Construction Noise Handbook. At a minimum, these measures should include:

- Requiring the use of construction noise control measures in construction contract documents. Specific noise levels can be established to ensure the protection of sensitive receptors.

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[8] http://oz.biology.ualberta.ca/faculty/stan_boutin/ilm/uploads/pdfs/Habib%20etal%202007%20JAE.pdf

- Limitations on the time periods when construction could occur (e.g., prohibiting nighttime construction).
- Requiring the use of less noisy equipment and mufflers.
- Requiring temporary noise barriers when significant impacts cannot be addressed through other means.

2.6.2 Mitigation for Drilling, Fracturing and Transportation Impacts

The general types of noise mitigation measures for drilling, fracturing and trucking suggested in the RDSGEIS are reasonable, but there is no guarantee which measures, if any, will actually be required in specific circumstances. Therefore, it is likely that significant impacts will not be mitigated at the site level. In addition, the RDSGEIS states that detailed noise modeling and consideration of mitigation measures will only be required for receptors within 1,000 feet of the well pad. This requirement is illogical given the impact analysis results that show impacts extending beyond 2,000 feet. Under NYSDEC's proposed 1,000 feet distance for noise modeling, well operators could avoid assessing site specific impacts and mitigation by locating wells just beyond the 1,000 feet threshold. This could result in unmitigated significant adverse impacts for residences between 1,000 and 2,000+ feet from the well pad.

Table 2 summarizes the noise mitigation commitments in the RDSGEIS and shows that many of these commitments were not carried through to the EAF, EAF Addendum or the proposed regulations. The mitigation measures not included in the EAF or regulations are not enforceable.

The proposed supplemental permit conditions (Appendix 10) state that NYSDEC can require noise mitigation "deemed necessary," but this is meaningless without a clear basis for determining when noise impacts that warrant mitigation occur. The proposed supplemental permit conditions do not contain any of the mitigation measures in Table 2 that were not addressed by the EAF or the regulations. The proposed supplemental permit conditions do contain specific requirements to mitigate air quality impacts (Appendix 10, Attachment A), therefore it would be reasonable and consistent to also include many of the site-specific noise mitigation measures in Table 2 as supplemental permit conditions. A few of the mitigation measures in Table 2 are general enough that they should be incorporated in the proposed regulations, rather than as supplemental permit conditions. These are indicated in the "notes" column of Table 2.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate noise impacts at HVHF sites, and use this information to refine the noise mitigation requirements for future permit applications.

Table 2
Noise Mitigation Matrix

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Compliance with regulatory spacing and siting restrictions. (7-128)	No	Yes (553.1)	No	
Unless otherwise required by private lease agreement, the access road must be located as far as practicable from occupied structures, places of assembly, and occupied but unleased property. (7-135)	Yes (A6-6)	Yes (560.6(a))	No	Regulation adds an additional qualifier where this provision potentially does not apply- to avoid bisecting agricultural land.
The well operator must operate the site in accordance with a noise impacts mitigation plan consistent with the SGEIS. (7-135)	Yes (A6-6)	No	No	Applies to all wells, should be in regulations
The operator's noise impacts mitigation plan shall be provided to the Department along with the permit application. (7-135)	Yes (A6-5)	No	No	Applies to all wells, should be in regulations
Additional site-specific noise mitigation measures will be added to individual permits if a well pad is located within 1,000 feet of occupied structures or places of assembly. (7-135)	Partial(A6-5)	No	No	Permit applicants are required to identify mitigation measures in the noise mitigation plan, but there is no regulatory requirement that mitigation is included in permit conditions. Applies to all wells, should be in regulations
Modifying speed limits or restricting truck traffic on certain roads. (7-130)	No	No	No	
Noise modeling for any site within 1,000 feet of a noise receptor. (7-130)	No (noise mitigation plan is required, modeling is not mentioned)	No	No	The 1,000 feet distance is arbitrary and inconsistent with the 2011 RDSGEIS analysis results which show significant impacts out to 2,000+ feet from the well pad. Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Potential site-specific permit condition: Requiring the measurement of ambient noise levels prior to beginning operations. (7-130)	No	No	No	All of the following site specific measures are required "as practicable," but no procedure or criteria for determining practicability is specified.
Potential site-specific permit condition: Specifying daytime and nighttime noise level limits as a permit condition and periodic monitoring thereof. (7-130)	No	No	No	Daytime and nighttime noise limits should be established as part of the SGEIS and regulatory process, not on a permit by permit basis that does not allow for public review. The noise limits should be consistent and included in regulations.
Potential site-specific permit condition: Placing tanks, trailers, topsoil stockpiles, or hay bales between the noise sources and receptors. (7-131)	No	No	No	
Potential site-specific permit condition: Using noise-reduction equipment such as hospital-grade mufflers, exhaust manifolds, or other high-grade baffling. (7-131)	No	No	No	
Potential site-specific permit condition: Limiting drill pipe cleaning ("hammering") to certain hours .(7-131)	No	No	No	
Potential site-specific permit condition: Running of casing during certain hours to minimize noise from elevator operation. (7-131)	No	No	No	
Potential site-specific permit condition: Placing air relief lines and installing baffles or mufflers on lines. (7-131)	No	No	No	
Potential site-specific permit condition: Limiting cementing operations to certain hours (i.e., perform noisier activities, when practicable, after 7 A.M. and before 7 P.M.). (7-131)	No	No	No	
Potential site-specific permit condition: Using higher or larger-diameter stacks for flare testing operations. (7-131)	No	No	No	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Potential site-specific permit condition: Placing redundant permanent ignition devices at the terminus of the flow line to minimize noise events of flare re-ignition. (7-131)	No	No	No	
Potential site-specific permit condition: Providing advance notification of the drilling schedule to nearby receptors. (7-131)	No	No	No	
Potential site-specific permit condition: Placing conditions on air rotary drilling discharge pipe noise, including: -orienting high-pressure discharge pipes away from noise receptors; - having the air connection blowdown manifolded into the flow line. This would provide the air with a larger-diameter aperture at the discharge point; - having a 2-inch connection air blowdown line connected to a larger-diameter line near the discharge point or manifolded into multiple 2-inch discharges; - shrouding the discharge point by sliding open-ended pieces of larger-diameter pipe over them; or -rerouting piping so that unusually large compressed air releases (such as connection blowdown on air drilling) would be routed into the larger-diameter pit flow line to muffle the noise of any release. (7-131)	No	No	No	
Potential site-specific permit condition: using rubber hammer covers on the sledges when clearing drill pipe. (7-131)	No	No	No	
Potential site-specific permit condition: Laying down pipe during daylight hours. (7-131)	No	No	No	
Potential site-specific permit condition: Scheduling drilling operations to avoid simultaneous effects of multiple rigs on common receptors. (7-131)	No	No	No	
Potential site-specific permit condition: Limiting hydraulic fracturing operations to a single well at a time. (7-131)	No	No	No	
Potential site-specific permit condition: Employing electric pumps. (7-131)	No	No	No	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Potential site-specific permit condition: Installing temporary sound barriers (see Photo 7.2, Photo 7.3, and Photo 7.4) of appropriate heights, based on noise modeling, around the edge of the drilling location between a noise generating source and any sensitive surroundings. Sound control barriers should be tested by a third-party accredited laboratory to rate Sound Transmission Coefficient (STC) values for comparison to the lower-frequency drilling noise signature. (7-131)	No	No	No	

2.7 EAF and EAF Addendum

The EAF requires land use information for a distance of one-quarter (1/4) mile around the well pad. This distance is insufficient, as many impacts (including noise and visual) extend far beyond this distance. The EAF should require the identification and mapping of land uses within one mile of the well pad, as well as additional land use mapping along local roads that would be affected by heavy truck traffic (as identified in the required transportation plan) outside the one mile area. The EAF Addendum should specifically require the identification of land uses that are especially sensitive to noise, including protected open space, recreational areas, places of worship, campgrounds, hotels, schools, and healthcare facilities.

The details of the noise mitigation plan required by the EAF Addendum are not sufficiently defined to ensure impacts are mitigated. There is a need for a standardized noise impact assessment procedure and criteria for determining the reasonableness of various levels of mitigation expenditure (e.g., the cost per benefited receptor approach used by DOTs). Without standardized requirements for assessing and mitigating noise impacts, residents in areas affected by gas development will not receive fair or consistent treatment. The NYSDEC noise guidance document does not provide sufficient detail and criteria to ensure appropriate noise analyses conducted at the site level. At a minimum, NYSDEC should provide the detailed requirements of the noise mitigation plan, addressing the following components:

- Scope of study area for the mitigation plan (recommend one-half (1/2) mile around well pad plus sensitive areas adjacent to the local roads that would experience the largest percent increase in truck traffic).
- Methodology for establishing existing noise levels (recommend requiring 24-hour measurements at a few representative receptors).
- Required protocol for assessing noise impacts: what noise metrics should be used (Ldn, Lmax, peak hour Leq, percent time audible etc.); what sources need to be considered (transportation, drilling and fracking); acceptable software modeling packages; and sources of information on appropriate sound emission levels to assume for various types of the equipment.
- Required criteria for determining which impacts are significant and require mitigation and which do not.
- Required criteria for determining how much expenditure on mitigation is reasonable to address significant adverse impacts.

One template for NYSDEC to consider adopting to specify the requirements of noise impact analysis and mitigation plans is the Alberta Energy Resources Conservation Board (ERCB) Noise Control Directive (#38), which is described below in Section 2.8.

2.8 Best Practice Recommendation for Noise Standards and Site-Specific Impact Assessment Protocol

The Alberta ERCB Noise Control Directive was developed through an extensive scientific review process and is recognized as one of the most stringent in the world. The Noise Control directive is based on the calculation of a permissible sound level (PSL) at the worst case receptor in terms of equivalent energy sound level (Leq)[9] for the daytime period and the nighttime period. The PSL calculation takes into account all the important factors that influence human annoyance due to noise:

- Daytime noise is allowed to be higher than nighttime noise, reflecting the greater sensitivity to noise occurring at night.
- Existing noise levels are taken into account based on dwelling unit densities and transportation infrastructure or through ambient monitoring.
- A sliding scale of adjustment factors based on the duration of the noise accounts for the fact that people are more tolerant of a brief period of noisy activity than a noise source that continues for months or years.

As a simple example, the PSL in a low density rural area not near a major transportation corridor would be calculated as follows for the drilling of one well (35 days):

Nighttime Drilling PSL= 40 dBA basic sound level + 5 dBA adjustment due to the duration
Nighttime Drilling PSL= 45 dBA

The daytime PSL for drilling in this simple example would be 10 dBA higher, or 55 dBA.

For five days of fracking, the PSL in a low density rural area not near a major transportation corridor would be calculated as follows:

Nighttime Fracking PSL= 40 dBA basic sound level + 10 dBA adjustment due to the duration
Nighttime Fracking PSL= 50 dBA

The daytime fracking PSL would be 10 dBA higher or 60 dBA. This daytime limit would be exceeded even at a distance of 2,000 feet from the well pad based on the RDSGEIS analysis without mitigation, which estimated 72 dBA at this distance, or approximately twice as loud as the standard.

The Alberta ERCB Noise Control Directive also outlines detailed requirements to standardize the modeling of noise impacts and the preparation and documentation of noise studies that would be appropriate for NYSDEC to consider in regulating noise from HVHF in New York.

3.0 Ground-Borne Vibration and Noise

Page 6-251 of the RDSGEIS acknowledges the potential for ground-borne vibration impacts in the discussion of potential effects on property values: “Gas well development could impact local environmental resources and cause noise and vibration impacts, and trucks servicing the well development could also impact the surrounding areas.” Despite this statement, no vibration impact analysis (or an explanation of why an analysis was not conducted) is presented in the 2011 RDSGEIS. NYSDEC should analyze vibration impacts addressing the following issues:

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[9] Leq refers to the constant sound level that conveys the same energy as the variable sound levels during the analysis period.

- Construction-period vibration impacts for access road and well pad development. Recommended procedures are provided in Section 12.2 of the Federal Transit Administration's *Transit Noise and Vibration Impact Assessment* guidebook. A simple qualitative assessment may be appropriate in this case. While construction activities do not typically create vibration levels capable of damaging most buildings, fragile historic buildings are more sensitive and should be avoided in the siting of access roads and well pads. Ground vibration from construction can also be an annoyance to adjacent land uses.

- Operation vibration impacts associated with drilling and fracking. This assessment should include information on drilling vibration levels from existing natural gas development in New York and other locations. While it is difficult to generalize vibration effects from one area to another due to the effects of local soils and geologic conditions, this information would provide a rational basis for identifying a screening distance for determining when a more detailed vibration impact assessment should be required at the site level. If no receptors are within the screening distance at which perceptible vibration levels could occur, then no vibration assessment would be required in the site level review.

- Operation low-frequency ground-borne noise impacts. Ground vibration can create a phenomenon known as ground-borne noise, a rumble associated with the movement of the interior surfaces of a room.[10] Special considerations apply when assessing low-frequency noise because of the non-linearity of human hearing which causes sounds dominated by low-frequency components to seem louder than broadband sounds that have the same A-weighted level. As a result, even low levels of low-frequency noise (generally defined as the frequency range below 200 Hz) can be perceived as highly annoying and contribute to sleep problems and other health problems caused by sleep disruption. In addition to sleep disturbance and physiological stress, there is strong evidence that noise exposure can contribute to cardiovascular diseases.[11] NYSDEC should assess the potential for the various phases of well development and production to generate ground-borne noise, including any on-site equipment such as condensers that have been anecdotally reported generating high vibration levels in Pennsylvania.

Based on the ground-borne noise and vibration impact assessment conclusions, the NYSDEC should identify ground-borne noise and vibration impact mitigation measures and ensure that information necessary to identify and mitigate ground-borne noise and vibration impacts at the site level is required as part of the EAF Addendum, supplemental permit conditions and/or regulations.

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[10] Both ground-borne noise and vibration are issues associated with the inside of buildings and are generally not annoying outdoors.

[11] See Cardiovascular effects of noise. Noise Health. Vol. 15 Issue 52. http://www.noiseandhealth.org/showBackIssue.asp?issn=1463-1741;year=2011;volume=13;issue=52;month=May-June

4.0 Visual

4.1 Impact Assessment

The RDSGEIS describes in very broad terms the potential direct and cumulative impacts of various phases of natural gas development on NYSDEC-designated visually sensitive resources. The RDSGEIS considers and incorporates information from two studies by others that addressed the visual impact of high-volume hydraulic fracturing.[12] The public disclosure of significant adverse visual resource impacts should be improved by providing the following:

- Discussion of the various viewer groups (local residents, through travelers, tourists, etc.) that would experience changed views as a result of natural gas development and their relative sensitivity. For example, local residents are familiar with local views and may be very sensitive to changes in views they consider important. Tourists visiting an area in part to experience high visual environment quality would also be much more sensitive than general through travelers that would have passing views of natural gas development from roadways while commuting. NYSDEC should describe how natural gas development at the scale anticipated in the socioeconomic impact study would affect viewer perceptions.

- To aid in the identification and understanding of impacts, landscape similarity zones (rural open areas, rural wooded areas, villages, cities, etc.) should be identified statewide and computer modeling conducted to create three dimensional photo simulations of various phases of the well development process at various distances for each zone. NYSDEC would not need to develop this analysis from scratch—significant consultant costs could be saved by using the New York State Office For Technology's "Generic Visual Impact Assessment" prepared for the 2004 Statewide Wireless Network (SWN) DGEIS as a starting point.[13] The SWN Generic Visual Impact Assessment is an excellent example for NYSDEC to follow in comprehensively addressing visual impacts at the GEIS stage. The landscape similarity zones and representative photos selected for photo simulations used in the SWN analysis could likely be used with no to little modification. The main additional work required would be to define the components of a typical well pad development at various phases in sufficient detail and re-run the simulation model.

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[12] Upadhyay and Bu. 2010. Visual Impacts of Natural Gas Drilling in the Marcellus Shale Region. Cornell University, Dept. of City and Regional Planning: CRP 3072 Land Use, Environmental Planning, and Urban Design Workshop

Rumbach, Andrew. 2011. Natural Gas Drilling in the Marcellus Shale: Potential Impacts on the Tourism Economy of the Southern Tier

[13] New York State Office for Technology. 2004. *Draft Generic Environmental Impact Statement for the New York State Statewide Wireless Network*. Cultural Resources Appendix B. Prepared by Environmental Design & Research, P.C. (now EDR Companies)

- Analysis of light pollution impacts of nighttime lighting and flaring. The RDSGEIS analysis focuses on daytime visual impacts and downplays nighttime light impacts as a “temporary impact” that most of the viewing public would not be exposed to (see page 6-281). Light pollution impacts would not be temporary when the duration of drilling, fracturing and production activities is considered for multi-well pads and cumulatively as numerous well pads are added throughout the region over the 60 year development timeframe contemplated in the RDSGEIS. The RDSGEIS ignores the visual impact to local residences that comes with the loss of pristine dark nighttime skies in rural areas. Residences are not even mentioned in the impact assessment. In many cases the nighttime impact will be more significant than the daytime visual impact because the lighting will make the well site a pronounced focal point. In addition to evaluating the visual impact of light pollution on humans, NYSDEC also needs to evaluate the impact of nighttime lighting and flaring on migratory birds.[14]

The photographs of a PA well site below illustrate the dramatic visual impact of natural gas development in a rural residential setting during the day and night.

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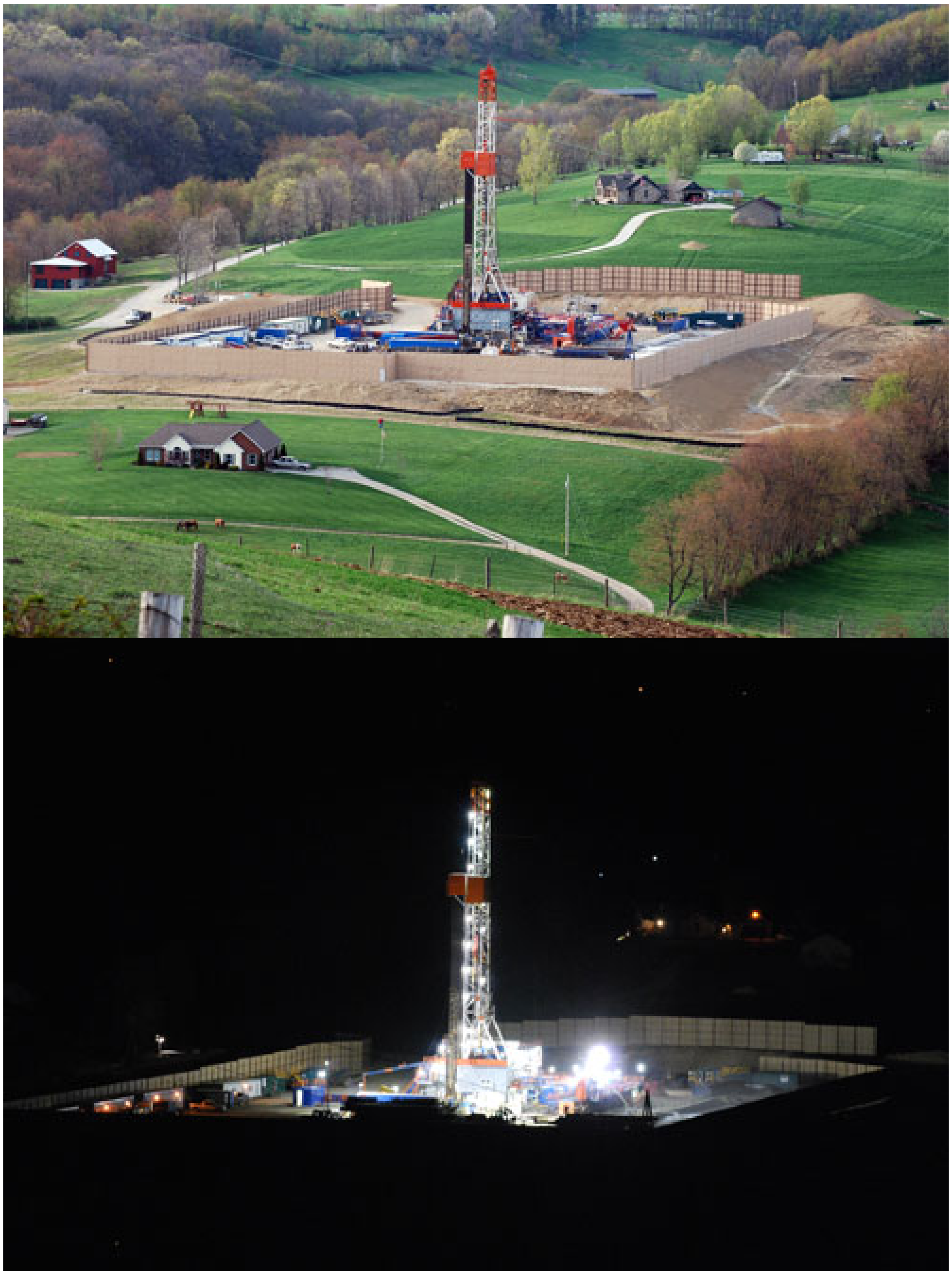
[14] Poot, H., B. J. Ens, H. de Vries, M. A. H. Donners, M. R. Wernand, and J. M. Marquenie. 2008. Green light for nocturnally migrating birds. *Ecology and Society* **13**(2): 47. http://www.ecologyandsociety.org/vol13/iss2/art47/
For background information on light pollution impacts on wildlife see: http://www.darksky.org/index.php?option=com_content&view=article&id=719



Day and Night Views of Chappel Unit 1H-10H in Hopewell Township, Washington County PA. Source: http://www.marcellus-shale.us/Chappel-Unit.htm

4.2 Mitigation

The RDSGEIS mitigation section for visual resources suggests that mitigation measures would only be considered when designated significant visual resources (parks, historic resources, scenic rivers, etc.) are present and within the viewshed of proposed wells. This approach fails to consider visual impacts on nearby residences or tourists in areas where a significant visual resource is not present. In these situations, no mitigation would be required for individual wells to be consistent with the RDSGEIS. NYSDEC should make basic and low-cost mitigation measures mandatory for all well development sites (such as keeping lighting levels at the minimum level required and directing lights downward to minimize light pollution), regardless of whether or not significant visual resources are present. In addition, a broader menu of more sophisticated and costly mitigation measures should be provided for those development sites that do have the potential to impact designated visual resources.

Table 3 summarizes the visual impact mitigation commitments in the RDSGEIS and shows that many of these commitments were not carried through to the EAF, EAF Addendum, regulations or supplemental permit conditions. The mitigation measures not included in the EAF, regulations or permit conditions are not enforceable. The proposed supplemental permit conditions do contain specific requirements to mitigate air quality impacts (Appendix 10, Attachment A); therefore it would be reasonable and consistent to also include many of the visual impact mitigation measures in Table 3 as supplemental permit conditions. A few of the visual impact mitigation measures that are general enough and are applicable to all well sites should be incorporated into the proposed regulations. These mitigation measures are identified in the notes column of Table 3.

Table 3
Visual Impacts Mitigation Matrix

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Prepare visual impacts mitigation plan (A6-6 and Supplemental Permit Conditions).	**Yes**	No	**Yes**	Applies to all wells, should be in regulations
Flaring would only occur during initial flowback at some wells, and the potential for flaring would be limited to the extent practicable by permit conditions, such that the duration of nighttime impacts from flaring typically would not occur for longer than three days. (6-281)	No	No	No	Applies to all wells, should be in regulations
The development of measures to reduce impacts on visual resources or visually sensitive areas would follow the procedures identified in NYSDEC DEP-00-2, "Assessing and Mitigating Visual Impacts." (7-121)	No	No	No	Applies to all wells, should be in regulations
Design and siting measures, as described in NYSDEC DEP-00-2, would typically consist of screening, relocation, camouflage or disguise, maintaining low facility profiles, downsizing the scale of a project, using alternative technologies, using non-reflective materials, and controlling off-site migration of lighting (NYSDEC 2000). (7-122)	No	No	No	Design and siting mitigation measures would be primarily site specific, but some measures could be incorporated in regulations (see the mitigation measure below regarding avoiding ridgelines and minimizing light pollution).
Relocating well sites to avoid ridgelines or other areas where aboveground equipment and facilities breaks (sic) the skyline; and minimizing off-site light migration by using night lighting only when necessary and using the minimum amount of nighttime lighting necessary, directing lighting downward instead of horizontally, and using light fixtures that control light to minimize glare, light trespass (off-site light migration), and light pollution (sky glow). (7-125)	No	No	No	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
The study also recommends the development of a best practices manual for Department staff and the industry, which would provide information on what is expected by the Department in terms of well siting and visual mitigation, and the identification of instances where visual mitigation may be necessary. (7-126)	No	No	No	
Develop a feedback mechanism in the project review process to confirm the success of measures to avoid, minimize, or mitigate visual impacts, based on the analysis of results for prior projects. (7-126)	No	No	No	
The maintenance activities described in NYSDEC DEP-00-2 should be implemented to prevent project facilities from becoming "eyesores." Such measures would typically consist of appropriate mowing or other measures to control undesirable vegetation growth; erosion control measures to prevent migration of dust and/or water runoff from a site; measures to control the off-site migration of refuse; and measures to maintain facilities in good repair and as organized and clean as possible according to the type of project. (7-126)	No	Partial- mostly related to stormwater and erosion control	Partial- SWPPP required	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
The decommissioning activities described in NYSDEC DEP-00-2 should be implemented when the useful life of the project facilities is over; these activities would typically occur during the reclamation phase for well sites. Such activities would typically consist of, at a minimum, the removal of aboveground structures at well sites. Additional decommissioning activities that may also be required include: the total removal of all facility components at a well site (aboveground and underground) and restoration of a well site to an acceptable condition, usually with attendant vegetation and possibly including recontouring to reestablish the original topographic contours; the partial removal of facility components, such as the removal or other elimination of structures or features that produce visual impacts (such as the restoration of water impoundment sites to original conditions); and the implementation of actions to maintain an abandoned facility and site in acceptable condition to prevent the well site from developing into an eyesore, or prevent site and structural deterioration. (7-127)	Partial- site reclamation plans required, but no specific measures are required.	Partial (560.7 Reclamation)	Partial (reclamation plans required)	
The offsetting mitigation described in NYSDEC DEP-00-2 should be implemented when the impacts of well sites on visual resources or visually sensitive areas are significant and when such impacts cannot be avoided by locating the well pad in an alternate location. Per guidance in NYSDEC DEP-00-2, offsetting mitigation would consist of the correction of an existing aesthetic problem identified within the viewshed of a proposed well project. (7-128)	No	No	No	

4.3 EAF and EAF Addendum

There are a number of problems with the EAF and EAF Addendum requirements as currently drafted that will result in significant unmitigated adverse visual impacts if not corrected.

The EAF does not require sufficient information to properly identify receptors that would experience views of proposed wells. The EAF requirement is to identify the distance to the closest occupied building or outdoor facility. The EAF Addendum requires identification of "[a]ll residences, occupied structures or places of assembly within 1,320 feet." This is not a sufficient distance for assessing visual impacts and does not take into account the fact that the closest structures may not be the most impacted depending on local vegetation and topography patterns.[15] A more reasonable distance for identifying sensitive resources and receptors in most instances would be one mile.[16] The EAF addendum should require a visibility analysis to determine where the well site facilities would be visible from public roadways, parks, residences and other sensitive receptors. The number of viewers exposed and the activities viewers would typically be engaged in during exposure needs to be evaluated to determine the extent of visual impacts and the need for mitigation at the site level. NYSDEC has developed excellent guidance on this topic ("Assessing and Mitigating Visual Impacts") and a useful visual EAF addendum. These best practice approaches to visual impact assessment and mitigation should be required as part of the EAF for proposed well development sites.

Unlike the noise and traffic mitigation plans, a visual impacts mitigation plan is not a required component of the submittals to NYSDEC with the permit application, EAF and EAF Addendum. The visual impacts mitigation plan does not even have to be prepared prior to issuance of the well drilling permit and is not subject to prior approval by NYSDEC. The only apparent requirement is that the visual resource mitigation plan is prepared by the applicant in conformity with the SGEIS and made available to the NYSDEC on request. This procedure offers no opportunity for public review or even notice to affected local residents. A visual resources mitigation plan that is not subject to public review and that does not require NYSDEC approval is not an adequate mitigation measure.

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[15] The RDSGEIS acknowledges that on-site equipment would be a prominent landscape feature at distances of up to double 1,320 feet used in the EAF Addendum. Page 6-274: "On-site equipment would be the most visible sign of fracturing activity and, when viewed from relatively short distances (i.e., from 1,000 feet to 0.5 miles) are relatively prominent landscape features."

[16] Although drilling activity during the daytime would be most prominent within ½ mile, a one mile distance is reasonable to account for areas with topography that could make well sites prominent features for more distant views and to address nighttime lighting impacts (which could be prominent at greater distances than the physical appearance of the well site equipment during the day.

5.0 Land Use

5.1 Impact Assessment

The RDSGEIS fails to provide any analysis of the reasonable foreseeable cumulative land use impacts that would result if high-volume hydraulic fracturing was permitted in New York. To comply with SEQRA, NYSDEC should provide the following information:

- An overview of statewide existing land uses patterns and land use planning framework. Much of this information and mapping could be adopted directly from Section 3.3.2.2 of the 2004 Statewide Wireless Network DGEIS and associated appendices. This would provide an appropriate baseline to use in assessing potential land use impacts.

- A quantitative analysis of potential land cover change at the county level. This analysis could use readily available GIS land cover data for existing conditions and assume that well development would impact land cover proportionate to the existing percentage of land cover types in each county (excluding water and developed land). Impacts could be assessed using the average 7.4 acres of disturbance per multi-well pad used in the RDSGEIS (page 5-6) and an estimate of the number of well pads by county consistent with the economic impact study county-level estimates. Cumulative impacts associated with existing trends and known major development proposals should be evaluated, taking into account the lack of capacity of rigorous land use regulation throughout most rural areas of the Southern Tier.

- A qualitative assessment of the compatibility of natural gas development with various adjacent land uses, taking into consideration impacts associated with truck traffic, noise and visual impacts. Appropriate buffer zones should be recommended between natural gas development and incompatible land uses such as residences, parks and schools to minimize impacts.

- A qualitative assessment of the consistency of natural gas development with local and regional plans. Specific land use plans and zoning regulations could not be analyzed in detail in a GEIS, but generalized planning areas common to many areas of the Marcellus shale region could be considered (e.g., rural residential, agricultural, commercial, etc.). Natural gas development should not be permitted to undermine local land use laws, especially planning in rural areas that emphasizes resource protection, open space, and scenic quality. Potential inconsistencies with plans prepared pursuant to New York's Local Waterfront Revitalization Program should be specifically considered in this assessment.

The failure of the RDSGEIS to analyze land use impacts is inconsistent with the scope for the SGEIS, which included a commitment to conduct an "[e]valuation of whether any aspect of multi-well site development or high-volume hydraulic fracturing of shale wells could be expected to change the GEIS's conclusion that major long-term changes to land use patterns, traffic and the need for public services are not anticipated as the result of gas well development. This will include review of the compatibility of shale gas development with other land uses such as agriculture, tourism, and alternative energy development."[17] The RDSGEIS is deficient because it does not contain a land use impact assessment addressing compatibility with agriculture, tourism, and alternative energy development.

5.2 Mitigation

The RDSGEIS fails to provide any discussion of mitigation measures for land use impacts. Based on the additional analyses of land use impacts recommended above, mitigation measures such as buffer distances for incompatible land uses should be described and incorporated into enforceable regulations or supplemental permit conditions, as appropriate. The RDSGEIS should make it clear that such mitigation measures are intended to supplement any local zoning or other land use planning addressing the location of industrial uses, including gas development.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate land use impacts at HVHF sites, and use this information to refine the land use mitigation requirements for future permit applications.

5.3 EAF and EAF Addendum

The topic of consistency with local plans was not addressed in the EAF and EAF Addendum in the 2009 DSGEIS. The addition of a requirement related to the review of local plans and assessment of consistency as part of the EAF Addendum in the RDSGEIS is an improvement. The term "land use plan" should be broadly defined in the EAF Addendum to ensure it encompasses comprehensive plans, zoning ordinances, subdivision regulations, site plan review requirements, hazard mitigation plans, open space plans, agricultural/farmland protection plans, Local Waterfront Revitalization Program plans, historic districts/historic resource protection plans, economic revitalization and tourism plans, ecological and water resource protection/restoration plans etc.

With respect to the avoidance of land use compatibility impacts, the requirements of the EAF Addendum in the RDSGEIS remain extremely vague. Permit applicants are required to attest that "[u]nless otherwise required by private lease agreement, the access road will be located as far as practical from occupied structures, places of assembly and unleased property." There are no definitional or other criteria for determining what is "as far as practical" concerning location of the access road in relation to occupied structures, places of assembly and unleased property. Nor is there any required explanation by the applicant to support its affirmation or submission of a map showing such structures and uses in relation to the access road. Nor is there any required hierarchy in determining which uses of land require greatest distance from the access road in the event that movement of the access road away from one use would bring it closer to another. All that is required of the applicant is a bare affirmation that it has located the access road.

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[17] NYSDEC. 2009. *Scope for the 2009 Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program*. Page 41

The EAF Addendum requires the identification of "[a]ll residences, occupied structures or places of assembly within 1,320 feet." However, as noted previously, there is evidence that significant impacts (such as noise) extend beyond 1,320 feet. In order to comply with SEQRA, NYSDEC must require that the applicant identify all land uses within one mile of a proposed well. These land uses should include, but not be limited to hospitals, senior citizen residences, schools, places of worship, and residential uses.

6.0 Transportation

6.1 Impact Assessment

Additional analysis is provided in the RDSGEIS regarding truck trip generation (e.g., the number of truck trips to and from the well site at varies stages), but the impact on roadway congestion and safety has not been adequately addressed. The impacts of a typical multi-well development on congestion and safety should be analyzed in detail, as well as a cumulative traffic effects analysis using a reasonable worst case development scenario. The reasonable worst case development scenario for regional traffic impacts should include indirect traffic generation associated with increased economic development and population growth attributable to natural gas extraction and related industries. Finally, the statewide impact on vehicle miles traveled (VMT) should be reported, taking into account the long distance truck trips that would be required to haul produced water and brine waste out of state for disposal.

6.1.1 Traffic Congestion and Safety Impacts of a Typical Multi-Well Pad

The detailed analysis of the traffic congestion and safety impacts of one typical multi-well pad development serves an important purpose in terms of disclosing the general types of impacts that could occur in many similar locations, but also in terms of creating an analysis template for permit applicants to follow in developing their transportation plans for specific development proposals. A hypothetical well site could be identified in the area where the greatest drilling is expected (Region A) or an actual well site in an area of Pennsylvania representative of similar areas in New York could be analyzed. Once the hypothetical or actual well site is located, the following tasks should be undertaken:

- Identification of the project area where transportation impacts would be most likely based on actual or hypothetical information on trip origins and routes for workers, equipment and water deliveries to the site.
- Characterization of existing conditions in the project area using NYSDOT traffic counts, local data and additional traffic counts as needed. Topics to be addressed should include traffic volumes, intersection level of service, crash rates, etc.
- Analysis of impacts on traffic volumes, intersection congestion and safety consistent with the 2010 Highway Capacity Manual, NYSDOT procedures for traffic impact assessment and good transportation engineering practice.
- Development of mitigation measures to address significant impacts, such as changes in signal timing, temporary traffic signals, limitations on the routes used by water trucks, etc.

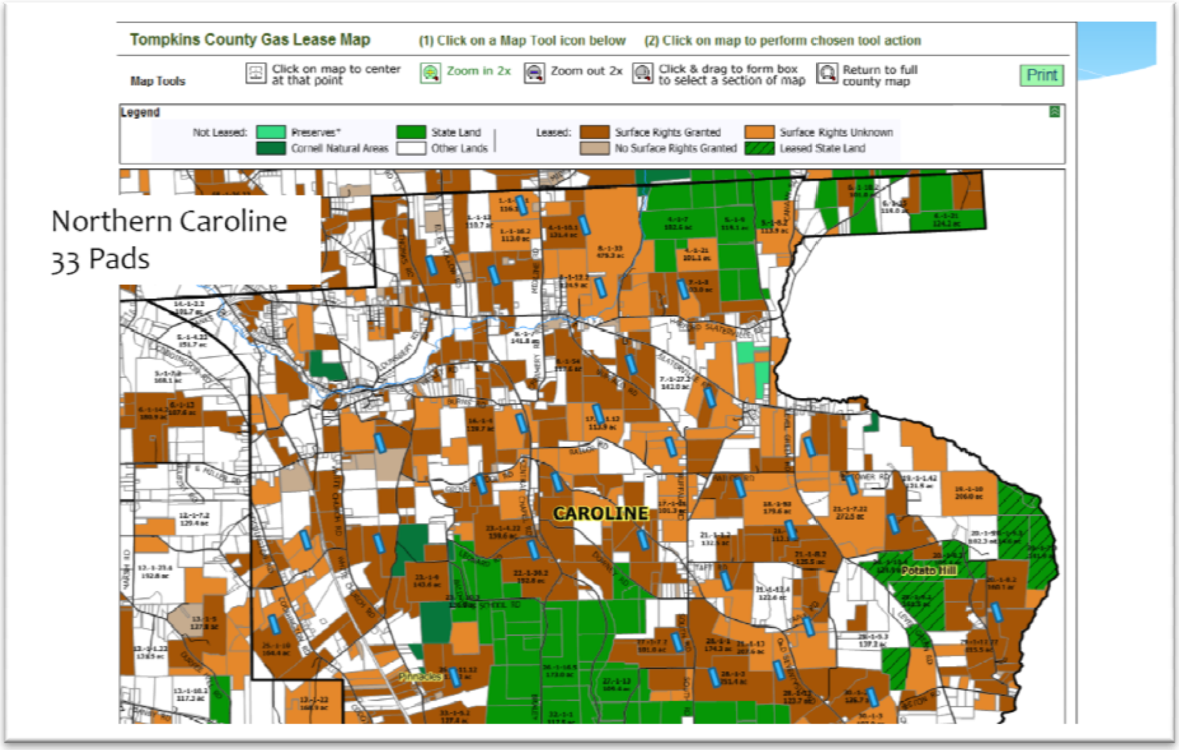
6.1.2 Regional Traffic Congestion and Safety Impacts

In addition to analyzing one well site in detail, it is important for NYSDEC to analyze regional cumulative impacts because these types of impacts will not likely be considered at the site level in the review of individual permits. The regional analysis would consider changes in traffic volumes on major roadways and the resulting potential for increased congestion and crashes from the combined effects of truck traffic to individual wells, as well as traffic related to additional employment and population growth. One methodology for conducting a meaningful regional analysis would be to use an existing travel demand model within the Marcellus and Utica shale regions. Unfortunately, neither New York State nor the Metropolitan Planning Organizations (MPOs) in Region A have a statewide or regional travel demand model. However, there are still several possible options for NYSDEC to conduct a meaningful regional scale transportation modeling analysis.

One option would be to use an analysis of Tompkins County as a surrogate for similar regional scale impacts that could occur in other places. There are several advantages to this approach:

- The Ithaca-Tompkins County Transportation Council (ITCTC) has an existing travel demand model that covers all of Tompkins County.

- The Tompkins County Council of Governments Task Force on Gas Drilling has identified realistic scenario of potential well locations for Tompkins County based on a GIS analysis and information from the 2009 DSGEIS.[18] An example map output from this analysis is provided in the figure below.



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[18] http://www.tompkins-co.org/tccog/Gas_Drilling/Focus_Groups/Mapping.html

Example of Well Pad Placement Assessment for the northern portion of the Town of Caroline, Tompkins County. Source: http://www.tompkins-co.org/tccog/Gas_Drilling/Focus_Groups/Mapping%20Minutes/Section%203%20-%20TC%20Mapping%20Analysis.pdf

The travel demand model could be run for multiple scenarios but, at a minimum, future no action and action (peak year of traffic generation) scenarios should be run. Key considerations in setting up the model should include identifying the traffic analysis zones that would experience increased population and employment and appropriately defining the trips attracted to well sites and other important destinations, such as hypothetical water source areas and waste disposal areas. These parameters could easily be established by a team composed of a travel demand modeling expert and a person familiar with hydraulic fracturing well site development stages and trucking needs (making the assumptions available for public review). A cooperative study in partnership with the ITCTC could be particularly beneficial to take advantage of their familiarity with local conditions and the existing model.

Once the model runs are complete, the results should be post-processed and used to develop an informative impact analysis and mapping (e.g., link volume change maps, volume/capacity ratio maps, etc.). This type of regional analysis is routinely conducted by MPOs as part of the long-range transportation planning process. There are numerous examples and guidance sources available to NYSDEC on how to conduct regional transportation analyses for planning that are equally applicable to generic regional traffic impact analysis.[19]

6.1.3 Statewide Vehicle Miles Traveled Impact

Vehicle miles traveled (VMT) is a key indicator used in transportation planning to compare various future scenarios and investment decisions. Increases in heavy truck VMT provide a basis for drawing general conclusions about the effects of HVHF on the transportation system, as well as effects on air pollutant emissions from mobile sources. While information on the number of trips is discussed in the transportation impacts section of the RDSGEIS, VMT impacts are not addressed. The failure of the transportation section to address VMT impacts is especially problematic because statewide VMT estimates were developed for the air quality analyses in the RDSGEIS (see page 6-176). As discussed in further detail below, the RDSGEIS VMT estimates for air quality should be revised to take into account out-of-state waste disposal and incorporated into the transportation impact assessment section, as well as the air quality section.

As discussed in Glenn Miller's accompanying technical memorandum, the waste disposal requirements for produced water and brines cannot be met at any existing disposal facilities in New York. This means that a significant number of long-distance heavy truck trips would be needed to move wastes out of state for disposal. VMT information for the RDSGEIS air quality analyses was generated using average truck trip

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[19] See: NCHRP Report 546: Incorporating Safety into Long-Range Transportation Planning.

FHWA. 2003. "Tools for Assessing Safety Impacts of Long-Range Transportation Plans in Urban Areas."

length information provided by the industry.[20] The industry data was from Bradford County, PA. The data collection methodology and the number of well sites upon which the industry average truck trip length estimates were developed were not disclosed in the RDSGEIS or the industry memo providing the estimates to NYSDEC. Industry estimated 100 truck trips for produced water disposal from each horizontal well, with each waste disposal truck traveling an average distance of 24 miles (one-way).[21] While supporting calculations are not provided to ascertain how the distance of 24 miles was computed, it would appear that the industry's data set was weighted heavily towards well sites where produced brine was reused at other nearby wells. This does not take into account the final disposal transportation impacts. A review of Pennsylvania Department of Environmental Protection (PADEP) waste reports[22] for Bradford County show two primary final disposal sites for brines from wells in the county:

- Pennsylvania Brine and Treatment, Inc. in Franklin, PA (approximately 200 miles from Bradford County municipalities such as Troy).
- Waste-Treatment Corporation in Warren, PA (approximately 140 miles from Bradford County municipalities such as Troy).

The 24-mile trip average distance for waste disposal provided by industry does not reflect the long distance waste hauling that occurs in Bradford County and would be expected to occur in New York. To correct this deficiency, NYSDEC should independently reevaluate the average trip length information provided by industry and develop revised truck trip length estimates that take into account final waste disposal transportation impacts. The assumptions used in generating the average truck trip length estimates should be disclosed for public review. This will allow for a more realistic assessment of the potential transportation and air quality impacts that will result from the statewide increase in VMT.

6.2 Mitigation

The majority of the transportation mitigation discussion in the RDSGEIS is focused on damage to roadways and road use agreements. While this remains an important issue, the RDSGEIS does not give sufficient attention to traffic impact mitigation measures. A list of generic mitigation measures for traffic impacts is provided (Section 7.11.3), but it is not clear when specific mitigation measures would be required because no impact criteria have been defined. For example, at what level of predicted intersection level of service would mitigation have to be considered? NYSDEC should make clear what traffic impact criteria would trigger the need for mitigation measures and include a process for local government and public review of the transportation plans for proposed well sites before NYSDEC issues a permit.

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[20] March 16, 2011 Letter from ALL Consulting to IOGA New York, obtained through a FOIL request. The footnote referencing this letter (footnote #100) was missing from the RDSGEIS.

[21] See Exhibit 19A in the March 16, 2011 ALL Consulting letter

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[22] Pennsylvania Oil and Gas Well Statewide Waste Report by Reporting Period. Jan - Jun 2011 (Marcellus Only, 6 months) https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/DataExports/DataExports.aspx

Table 4 summarizes the transportation mitigation commitments in the RDSGEIS and shows that many of these commitments were not carried through to the EAF, EAF Addendum, regulations or supplemental permit conditions. The mitigation measures not included in the EAF, regulations or permit conditions are not enforceable. The proposed supplemental permit conditions do contain specific requirements to mitigate air quality impacts (Appendix 10, Attachment A); therefore it would be reasonable and consistent to also include many of the transportation mitigation measures in Table 4 as supplemental permit conditions. Other mitigation measures are general enough to apply to all well sites and should be incorporated into regulations as described in the “notes” column of Table 4.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate transportation impacts of HVHF, and use this information to refine the transportation mitigation requirements for future permit applications.

Table 4
Transportation Impacts Mitigation Matrix

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Development of Transportation Plans, Baseline Surveys, and Traffic Studies. (7-136)	Yes	Yes (560.3)	Yes- transportation plan must be approved by NYSDEC and is “incorporated by reference” into the permit	The details of the transportation plan related-requirements should be described in greater detail in the EAF Addendum, along with an example transportation plan to provide clear guidance to industry on the level of data collection and analysis NYSDEC and NYSDOT expect.
Municipal Control over Local Road Systems. (7-137)	N/A	N/A	N/A	This is a mitigation measure that cannot be implemented by NYSDEC- it relies on municipalities with very limited planning resources to be proactive in protecting their roads.
The owner or operator should attempt to obtain a road use agreement with the appropriate local municipality; if such an agreement cannot be reached, the reason(s) for not obtaining one must be documented in the Transportation Plan. The owner or operator would also have to demonstrate that, despite the absence of such agreement, the traffic associated with the activity can be conducted safely and that the owner or operator would reduce the impacts from truck traffic on local road systems to the maximum extent feasible. (7-138)	Partial- copy of road use plan must be submitted if there is one.	No	Partial- copy of road use plan must be submitted if there is one.	Applies to all wells, should be in regulations
Route selection to maximize efficient driving and public safety, pursuant to city or town laws or ordinances as may have been enacted under Vehicle and Traffic Law §1640(a)(10). (7-138)	No	No	No	Applies to all wells, should be in regulations
Avoidance of peak traffic hours, school bus hours, community events, and overnight quiet periods, as established by Vehicle and Traffic Law §1640(a)(20). (7-139)	No	No	No	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Coordination with local emergency management agencies and highway departments. (7-139)	No	No	No	Applies to all wells, should be in regulations
Upgrades and improvements to roads that will be traveled frequently for water transport to and from many different well sites, as may be reimbursable pursuant to ECL §23-0303(3). (7-139)	No	No	No	Refers to provision of ECL that allows municipalities to request from NYSDEC "funds from the oil and gas fund to reimburse the municipality for costs incurred in repairing damages to municipal land or property. Such requests shall include such explanatory material and documentation as the commissioner may require."
Advance public notice of any necessary detours or road/lane closures. (7-139)	No	No	No	Applies to all wells, should be in regulations
Adequate off-road parking and delivery areas at the site to avoid lane/road blockage.(7-139)	No	No	No	Provision of large parking and delivery areas may increase the footprint of the well development sites, increasing ecological and water quality impacts.
Use of rail or temporary pipelines where feasible to move water to and from well sites. (7-139)	No	No	No	
Prior to site disturbance, the operator shall submit to the Department and provide a copy to the NYSDOT of any road use agreement between the operator and local municipality. (7-139)	Yes	No	Yes	Applies to all wells, should be in regulations
The operator shall file a transportation plan, which shall be incorporated by reference into the permit; the plan will be developed by a NYS-licensed Professional Engineer in consultation with the Department and will verify the existing condition and adequacy of roads, culverts, and bridges to be used locally. (7-139)	Yes	Yes	Yes	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Mitigating Incremental Damage to the State System of Roads. (7-141)	N/A	N/A	N/A	Damage to the state road system is identified in the RDSGEIS as an unmitigated impact. The Final SGEIS and HVHF regulations should include a transportation fee on permit applications to compensate for the costs of repairing HVHF-related damage to the state road system.
Limiting truck weight, axle loading, and weight during seasons when roads are most sensitive to damage from trucking (e.g., during periods of frost heaving and high runoff). (7-141)	No	No	No	
Requiring the operator to pay for the addition of traffic control devices or trained traffic control agents at peak times at identified problem intersections or road segments. (7-141)	No	No	No	
Providing industry-specific training to first responders to prepare for potential accidents. (7-141)	No	No	No	
Road use agreements limiting heavy truck traffic to off-hour periods, to the extent feasible, to minimize congestion. (7-141)	No	No	No	
Providing a safety and operational review of the proposed routes, which may include commitments to providing changes to geometry, signage, and signaling to mitigate safety risks or operational delays. (7-141)	No	No	No	
Avoiding hours and routes used by school buses. (7-141)	No	No	No	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
1.0 Where appropriate the Department would impose specific construction windows within well construction permits in order to ensure that drilling activity and its cumulative adverse socioeconomic effects are not unduly concentrated in a specific geographic area. Those 2.0 measures, designed to mitigate socioeconomic impacts and impacts on community character, can also be employed to minimize operational and safety impacts where such impacts are identified. (7-142)	No	No	No	The effectiveness of this measure is difficult to assess because the RDSGEIS does not explain what criteria would trigger a limitation on well permits within a specific area. Applying an adaptive management approach is logical, but it requires substantial resources and planning to monitor well development pressures at the local level. NYSDEC has not explained how such a monitoring system would be implemented, and thus this mitigation measure is likely to be ignored or forgotten once NYSDEC starts issuing permits.
Reducing trucking through different technology, such as on-site treatment. (7-142)	No	No	No	
The operator will provide specific information on the types and quantities of hazardous materials expected to be transported through the jurisdictions that they will be operating in and brought on site as part of the permitting process. (7-142)	Yes	Yes (560.3)	Yes	
All fracturing fluids and additives are transported in “DOT-approved” trucks or containers. (7-142)	N/A	N/A	N/A	This measure cannot be enforced by NYSDEC- depending on federal or NYSDOT oversight of hazardous material movement.
First responders and emergency personnel would need to be aware of hazardous materials being transported in their jurisdiction and also be properly trained in case of an emergency involving these materials. Permit conditions may require the operator to provide first responder emergency response training specific to the hazardous materials to be used in the drilling process if a review of existing resources indicates such a need. (7-143)	No	No	No	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Transportation plans may provide that sensitive locations be avoided for trucks carrying hazardous materials. (7-143)	No	No	No	To make this mitigation measure meaningful, it would be helpful for NYSDEC to identify the specific categories of sensitive facilities that permit applicants must identify and avoid in developing trucking routes (bridges over drinking water supply reservoirs for example).

6.3 EAF and EAF Addendum

A transportation plan is a required component of the EAF Addendum. The scope of the transportation plan is discussed in RDSGEIS Section 7.11.1.1 and includes "the number of anticipated truck trips to be generated by the proposed activity; the times of day when trucks are proposed to be operating; the proposed routes for such truck trips; the locations of, and access to and from, appropriate parking/staging areas; and the ability of the roadways located on such routes to accommodate such truck traffic." NYSDEC should provide details on the scope of the specific analyses that should be performed for the transportation plan to ensure a uniform approach is used.

7.0 Community Character

7.1 Impact Assessment

Community character is an amalgam of various elements that give communities their distinct "personality." These elements include a community's land use, architecture, visual resources, historic resources, socioeconomics, traffic, and noise (CEQR Tech. Manual). The community character impact assessment portion of the RDSGEIS lists some of the community character impacts that could be expected (focused on demographic and economic impacts), but does not analyze the significance of these impacts or draw conclusions on how proposed new natural gas development in the Marcellus and Utica shales would affect community character in the short-term and long-term. The impact assessment does not mention the contribution of visual, land use or historic resource impacts to community character. The discussion of traffic and noise impacts is superficial (two sentences each).

The community character impact assessment in the RDSGEIS appears to be based on the *Impacts on Community Character of Horizontal Drilling and High Volume Hydraulic Fracturing in Marcellus Shale and Other Low-Permeability Gas Reservoirs* report prepared by NTC Consultants for NYSERDA. To the extent the analysis in the RDSGEIS derives from or relies upon this report, it is significantly flawed in that for the most part it considers a few of the elements of community character individually (visual, noise, traffic), without drawing conclusions on the cumulative impact of all the changes associated with the expected level of new development. Much of the cumulative impact discussion in the report focuses on attempting to explain why a regional cumulative impact assessment based on a reasonable worst case development scenario is not necessary or helpful. The report also states:

> "The approach for addressing regional cumulative impacts is to focus on the proactive siting of well pads as discussed in previous sections of this report. If the location and construction of each well pad is based on 'Best Practices' (See Appendix A) then the potential impacts will be lessened and/or eliminated. **When applications are reviewed, it is recommended that DEC examine any negative issues that have occurred on adjacent well pads to determine if there is a potential problem in the area that needs further scrutiny**." Page 38. Emphasis added.

The suggested approach is to let the impacts occur and then do something about those impacts if there is a problem. NYSDEC adopted this approach in the form of the vague mitigation commitment to monitor the pace of well development and respond through limits on permits in specific areas to minimize cumulative socioeconomic impacts (see page 7-120). This is contrary to SEQRA, the intent and spirit of which is to consider impacts *before* making a decision to approve the proposed action. NYSDEC must address regional cumulative community character impacts and not defer the issue to the future after the impacts have occurred. An adaptive management framework to addressing HVHF impacts is useful (as discussed further below), but this does not excuse the omission of a complete community character impact assessment in the RDSGEIS.

7.2 Mitigation

The community character mitigation section of the RDSGEIS focuses on the EAF Addendum requirement related to consistency with local plans. There is also a mitigation commitment requiring site-specific review and additional mitigation measures of disturbance of 2.5 acres or more within an agricultural district. However, the agricultural district mitigation commitment is not enforceable because it is not included in the EAF Addendum, regulations or supplemental permit conditions.

The community character mitigation section also references the visual, noise, transportation and socioeconomic mitigation commitments in Chapter 7. However, as noted in the other sections of this review, enforceable mitigation has not been provided for those topics, which means that the unmitigated impacts in those subject areas will contribute to unmitigated community character impacts.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate community impacts of HVHF, and use this information to refine the community impacts mitigation requirements for future permit applications. NYSDEC contemplates such a similar approach in the discussion of mitigation for socioeconomic impacts (page 7-120), but the details of how this monitoring system would work need to be defined and circulated for public review and comment.

7.3 EAF and EAF Addendum

Community character impacts are not addressed as a distinct topic in the EAF or EAF Addendum.

8.0 Cultural Resources

8.1 Impact Assessment

Cultural resources, also referred to as historic properties, link a community with its past. These are finite resources and are provided protections through local, state, and federal authorities. In the 1992 GEIS, cultural resources were addressed as one of the major environmental issues. In GEIS Chapter 6, a background of these environmental resources and a review of the then-existing authorities (in addition to SEQRA) was provided, noting “the revised, shortened and simplified EAF should still remain as an attachment to the drilling permit application form (FGEIS page 31).” The simplified EAF includes cultural resources and offers the New York State Office of Parks, Recreation, and Historic Preservation (OPRHP, the State Historic Preservation Office) as a source for information along with the DEC Division of Construction Management-Cultural Resources Section and the DEC Division of Regulatory Affairs-Regional Office. There was limited discussion of the potential cultural resource issues beyond that identified on pages 6-16, 7-7, and 16-11 through 16-12. Further, although the 1992 GEIS highlighted the need for consultation between NYSDEC and the OPRHP, there was no formal process for consideration of cultural resources outlined.

Despite the length of time since the 1992 GEIS was issued, the 2009 DSGEIS and the RDSGEIS provide no update or reaffirmation of the authority-driven procedures for taking potential impacts to cultural resources into account beyond referring back to the 1992 GEIS. For example, how will tribal consultation be addressed given the 2009 DEC policy, *Contact, Cooperation, and Consultation with Indian Nations*:

> “’Affecting Indian Nation interests’ means a proposed action or activity, whether undertaken directly by the Department or by a third party requiring a Department approval or permit, which may have a direct foreseeable, or ascertainable effect on environmental or cultural resources of significance to one or more Indian Nations, whether such resources are located on or outside of Indian Nation Territory.”

In the RDSGEIS there is limited new discussion of cultural resource issues despite comments provided during the scoping process by the New York Archaeological Council (NYAC) dated December 11, 2008, outlining the potential loss of valuable scientific information should no consideration be given to these finite resources. NYAC reinforces the direct impacts to archaeological deposits that can result from any ground disturbing activity and offers comments on potential indirect impacts, such as vibration from drilling and increased vehicular traffic that could impact fragile archaeological deposits, or the potential for loss or degradation of the information that could be gleaned from specialized analyses of archaeological features that may result from changes to the soil matrix with the introduction of chemical additives as well as the potential for indirect (visual, vibration) impacts to historic architectural resources. Despite the availability of these comments, the additions to the RDSGEIS focus solely on the potential for visual impacts but disregard NYAC’s other recommendations, a notable deficiency in the 1992 document.

In \RDSGEIS Chapter 3, there is no mention of cultural resources relative to SEQRA beyond the reference back to the 1992 findings. In Chapter 6, there is no discussion of cultural resources; while the 1992 document and its findings are incorporated by reference and this chapter is intended to address new issues, this is a missed opportunity to consider potential impact to cultural resources. Consider the potential situation where a cultural resource, such as the remnants of an old water-powered mill complex that once was the economic hub for a small community or what remains of an historic vessel scuttled during a military skirmish, is submerged or partially submerged in an anaerobic environment. With a reduction in stream flow there is the potential to degrade the resource, rendering it subject to deterioration and potential loss. Without consideration of a broadly defined area of potential effect at the outset when the siting application and all its associated contingencies (e.g., well pads, gathering lines, distributions lines, access roads, resource or water needs, etc.) is reviewed, there is the potential to impact cultural resources.

The RDSGEIS does note in Chapter 8, Table 8.1, that OPRHP has a role in “well siting” and in “new in-state industrial treatment plants” but these are shown with an asterisk, with the caveat “role pertains in certain circumstances.” On page 8-6, it is noted that “[i]n addition to continued review of well and access road locations in areas of potential historic and archeological significance, OPRHP will also review locations of related facilities such as surface impoundments and treatment plants.” On page 8-37, the State Historic Preservation Act (SHPA) is brought into play with respect to dam safety permitting criteria and thresholds for resource consideration. And in Appendix 14 (Department of Public Service Environmental Management & Construction Standards and Practices –Pipelines), cultural resources are listed under the portion of the checklist for “Procedures for the Identification and Protection of Sensitive Resources.”

Thus, the big issue that has not been adequately outlined and addressed is how cultural resources will be handled in the overall permitting process; in particular, what is the procedural means and proposed agency coordination for cultural resources identification, and impact evaluation, minimization, avoidance, mitigation?

8.2 Mitigation

The RDSGEIS mitigation section for visual resources suggests that mitigation measures would be considered when designated significant visual resources associated with historic resources are present and within the view shed of proposed wells. However, in order to determine whether there is a view shed impact on a historic resource the resource itself must be identified, and evaluated before a determination of impact can be made. Because the RDSGEIS does not, as noted, indicate how this will be done, it is impossible to evaluate whether the process for impact identification and mitigation pursuant to SEQRA will be adequate.

The same can be said for ***all*** potential cultural resource impacts, such as those to archaeological sites which are rarely visible on the surface – mitigation measures would be considered once any resources have been identified, evaluated for significance, and a determination made that the impact cannot be avoided or minimized. It is expected that this process is to be undertaken during consideration of well siting applications (which should take into account gathering and distribution lines, access roads, all potential ground-disturbing impacts as well as potential indirect impacts [i.e., vibration, chemical, visual, etc.]). Unfortunately, this approach does not allow the public adequate review of possible mitigation efforts.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate cultural resource impacts of HVHF, and use this information to refine the cultural resource mitigation requirements for future permit applications.

8.3 EAF and EAF Addendum

As noted above, the process for addressing potential cultural resource impacts is not fully developed beyond the EAF checkboxes and DEC review of the application.

9.0 Aquatic Ecology

The assessment of aquatic ecology issues focused on the following items:

- Potential for impairment of the “best use” classifications of the State’s surface waters due to cumulative impacts.
- Potential for the alteration or degradation of critical aquatic habitat for aquatic species with limited distributions and sensitivity to water quality, such as trout and salamanders (e.g., the common mudpuppy (*Necturus maculosus*).
- Potential for aquatic habitat fragmentation (i.e., the isolation of existing populations).

LBG’s review of Sections 6.1.1.2, 6.1.1.3 and 6.1.1.4 of the RDSGEIS indicates that the document does not fully characterize the potential environmental impacts leading to the potential degradation of a stream’s best use classification, and the alteration of aquatic habitats and ecosystems due to direct and cumulative impacts. The RDSGEIS inadequately addresses the potential for the regulated development of high-volume hydraulic fracturing to alter critical aquatic habitat for sensitive species, specifically trout and salamanders, and no provisions are made in sections 7.1 and 7.4 to require standard mitigation measures to ensure degradation is avoided.

Pursuant to NY State Environmental Conservation Law regulations, Chapter X - Division of Water, Article 2, Part 701, all fresh surface water classes have a general condition that does not allow the discharge of wastes to impair the best usage of the receiving water, and all surface water use classifications “shall be suitable for fish, shellfish, and wildlife propagation and survival.” The regulations provide for further discharge restrictions to surface waters that occur within the RDSGEIS study area, including:

- Part 701.20: c.2 – waters that contain “critical aquatic habitat for fishes, amphibians, or aquatic invertebrates listed as endangered, threatened, or of special concern in Part 182 of this Title”; d.3 “small trout spawning streams;”
- Part 701.25 a. – waters that are labeled with the symbol (T) are “classified waters in that specific item are trout waters. Any water quality standard, guidance value, or thermal criterion that specifically refers to trout or trout waters applies;” and,
- Part 701.25 b. – waters that are labeled with the symbol (TS) are “classified waters in that specific Item are trout spawning waters. Any water quality standard, guidance value, or thermal criterion that specifically refers to trout, trout spawning, trout waters, or trout spawning waters applies.”

The purpose of the discharge designations is to provide further protection to these waters by defining their best use as the maintenance of aquatic species diversity and populations of sensitive or diminishing species that are sensitive to the degradation of water and habitat quality. The combined land use changes caused by well pad development, roadway network improvements and expansion, and supporting infrastructure should be described within the RDSGEIS at a watershed scale that is practical to the management of aquatic resources.

To assist in defining a potential scale, LBG prepared maps that depict the frequency, spatial distribution and arrangement of discharge restricted sensitive aquatic environments (trout streams) at two watershed scales (See Figures 1 and 2). Figure 1 shows the distribution of streams with NYSDEC discharge designations for trout within the Unadilla river watershed, a large tributary to the Susquehanna River with a 520 square mile watershed. Figure 1 shows the number of and connectivity between patches of existing stream habitat and populations of trout, and presumably other sensitive aquatic species. Figure 2 shows the Lower Butternut Creek watershed at the Hydrologic Unit Code (HUC) 12 level, with a 52.16 square mile watershed. Lower Butternut Creek is a tributary of the Unadilla River. At this scale, Figure 2 can be used as a planning level tool to depict aquatic habitat cores, islands, and corridors for a single or multiple populations of aquatic species. The scale is also practical for relating well pad and ancillary features with potential impacts and mitigation considerations. In the RDSGEIS, NYSDEC should use similar planning tools to evaluate more thoroughly potential impacts to aquatic habitat.

Table 5 below summarizes the watershed features of size, length of trout supporting (T) and trout spawning (TS) designated waters, and length of existing roads for both figures.

Table 5
Watershed Statistics

Watershed	Watershed Size (sq. miles)	Non-Trout Waters (miles)	Trout Supporting/ Trout Spawning Waters (miles)	Existing Roads (miles)
Unadilla River	520	587.63	461.85	1488
Lower Butternut Creek	52.16	88.26	49	134

Construction of well pads, access roads and supporting infrastructure may impact two major watershed processes which could have multiple cumulative effects on surface waters.

The first process is the increase in concentrated runoff from construction sites due to precipitation or snow melt through the re-routing and concentrating of diffuse overland sheet flow into roadside ditch networks, and the reduction in soil infiltration and permeability due to land development (or changes in water supply distribution) (Rosgen 2006, Forman et al. 2003, Leopold and Langbein 1960).

Second, the increase in sediment from the introduction of miles of new access roads with a gravel base, unpaved shoulders, and/or unconsolidated drainage conveyances/ditches, and stream crossings is a process that can lead to changes in sediment supply. Gravel roads, even when properly constructed and maintained, provide a source of sediment, especially during high traffic periods (Rosgen 2006, Forman et al. 2003, Reid and Dunne 1984). Each of these items is discussed below.

9.1.1 Land Use

Sections 5.1.1, 5.1.2 and 5.1.3 of the RDSGEIS describe the extent of land disturbance during the drilling and fracturing stage for a well pad and ancillary features (access roads, utility corridors, compressor stations, etc.). The average total disturbance was estimated at 7.4 acres for a multi-well pad and 4.6 acres for a single well pad.

Section 5.1.4.2 of the RDSGEIS states that the spacing of disturbances from horizontal wells with multiple wells drilled from common pads is "up to 640 acres," which is approximately one well pad per square mile. An "on average" spacing estimate is not provided; therefore, a typical disturbance footprint spacing has not been quantified. Analyses of cumulative impacts at a watershed scale require a practical spacing or range of spacing to better evaluate the need for regulatory limitations on well pad densities. If truly representative of the affected acreage, a single 7.4 acre multi-well pad represents approximately 1.5 percent of the area within a square mile.

A common component of construction is the clearing, grading and compaction of land within the disturbance footprint. These actions impact the naturally occurring drainage patterns outside of the disturbance footprint by re-routing and concentrating diffuse overland sheet flow produced by precipitation or snow melt (Leopold and Langbien, 1960; Leopold, 1994), re-directing this water through surface conveyances such as a ditch network (Foreman et al. 2003), which can change the timing and path of water supplied to surface waters within the watershed (Rosgen, 2006) or the hydrologic regime (Poff et al., 1997). The RDSGEIS does not specifically address these processes or address potential mitigation measures for inclusion as permit conditions within the regulatory program.

In reference to partial reclamation of the well pad, Section 5.16.1 states that "[s]ubsequent to drilling and fracturing operations, associated equipment is removed. Any pits used for those operations must be reclaimed and the site must be re-graded and seeded to the extent feasible to match it to the adjacent terrain. Department inspectors visit the site to confirm full restoration of areas not needed for production."
The intention of partial reclamation of a pad during the production phase is to further reduce the footprint of the disturbance. However, this section does not describe details about how long each phase lasts, does not provide a reclamation time table, or performance standards. Therefore, it is difficult to classify the disturbance as a temporary or permanent impact. The section provides insufficient elaboration or methods and does not define the industry standards or success criteria for reclamation activities and the environmental benefits they may provide; therefore, the value of reclamation as mitigation is also unclear.

Land use restrictions using impervious area thresholds are used to maintain brown trout populations in suburban watersheds in Delaware, Maryland and Pennsylvania (Kauffman and Brant, 2000) which is based on limiting impervious surfaces to less than 10% coverage of a watershed. Brook trout populations, the very species associated with T and TS stream designations in NY have become extirpated in watersheds with impervious land uses above 4% coverage, and stress upon brook trout populations was inversely related to impervious watershed coverage (Stranko et al., 2008). Brook trout population presence is shown to have a positive relationship with forested watershed coverage above 68% (Hudy et al. 2008). Collectively, this information demonstrates that cumulative watershed land use changes induced by HVHF that impact forested land and increase impervious cover is likely to cumulatively impact NY State designated trout and trout spawning waters which could well lead to the loss of the waters' best use designations. NYSDEC should address these issues in the RDSGEIS. In addition, related impacts to tourism are not discussed here but should be as these impacts are an indirect effect of natural habitat degradation and natural habitat is an established State tourism asset.

9.1.2 Access Roads

Section 5.1.1 of the RDSGEIS states “industry estimates an average access road size of 0.27 acre, which would imply an average length of about 400 feet for a 30-foot wide road. Permit applications for horizontal Marcellus wells received by the Department prior to publication of the 2009 DSGEIS indicated road lengths ranging from 130 feet to approximately 3,000 feet.” The Executive Summary, Chapter 2 summary of the RDSGEIS states “the Department has determined, based on industry projections, that it may receive applications to drill approximately 1,700 - 2,500 horizontal and vertical wells for development of the Marcellus Shale by high-volume hydraulic fracturing during a ‘peak development’ year. An average year may see 1,600 or more applications. Development of the Marcellus Shale in New York may occur over a 30-year period. Those peak and average levels of development are the assumptions upon which the analyses contained in this RDSGEIS are based.” Based only on the averages considered in the RDSGEIS, an average of 1,600 wells annually, each requiring 400 feet of new road, according to the RDSGEIS would result in over 121 miles of new, likely gravel, roads annually. This would be over 3,600 miles of new roads over 30 years. The RDSGEIS does not address the potential impact of the additional roads on aquatic resources, especially streams with sensitive species.

Stream drainage density relative to road density across a watershed is indicative of the interconnectivity of the roadway drainage system with the stream ecosystem (Foreman et al. 2003). In a regional study of the distribution of brook trout in their native range, average road densities of 3.2 km/sq. km was shown to be a predictor of watersheds that are not likely to support intact brook trout habitat (Hudy et al. 2008). Road density within the lower Butternut Creek watershed is 2.57 miles/sq. mile and the stream density is 2.63 miles/sq. mile. Within the lower Butternut Creek watershed, the stream network is less likely to be designated as Trout or Trout Spawning in areas where roads cross the stream more frequently. For instance, the stream network is designated as Trout or Trout Spawning stream segments are crossed by roads 38 times, and non-trout where stream segments are crossed by roads 54 times or more (Figure 2). While other land use factors can be at play here, road density within a watershed is positively correlated with stream habitat condition. The RDSGEIS should exam available literature on this topic to aid in the assessment of potential long term impacts to trout populations within affected watersheds due to watershed level changes. It is likely that some watersheds currently supporting trout populations are at or near the tipping point of trout sustainability. The RSDGEIS does not address how future HVHF development may affect native trout populations and other sensitive aquatic species.

Road crossings have been identified as a source of habitat fragmentation within linear aquatic systems by forming barriers to fish passage and altering the continuity of fluvial processes (e.g. sediment transport and disconnecting a stream from its floodplain) (Foreman, 2003). Road crossing structures can also change the transport of Large Woody Debris (LWD) (Foreman et al. 2003). LWD is important as an indicator of trout habitat quality (Flebbe and Dolloff, 1995) and in routing, storing and sorting sediment in fluvial landforms (Fisher et al. 2010, Lassettre and Harris 2001, Gomi et al. 2001 and Montgomery et al. 1995).

The alteration of fluvial processes caused by watershed development includes increased peak flows and mobilization of sediment from watershed and stream channel sources (Leopold 1994). Gravel roads, particularly construction and repair of gravel roads, have been shown to be a source of sediment in watersheds (Rosgen 2006) and contribute to habitat degradation (Logan, 2003). Heavy vehicle traffic on gravel roads, up to four heavy vehicles per day, has been shown to contribute up to 130 times more sediment to streams than paved roads (Reid and Dunne, 1984). The drilling and fracturing process can require tens to hundreds of trips by heavy vehicles each time a new well is constructed, thus increasing the likelihood of new sediment loadings to the local stream. Currently New York State provides no regulatory guidance for stream crossing design which maintains Aquatic Organism Passage (AOP). Vermont Department of Environmental Conservation, Watershed Management Program has developed stream crossing design guidance and stream crossing assessment tools which support AOP and natural channel morphology (The Vermont Culvert Geomorphic Compatibility Screening Tool, 2008 and The Vermont Culvert Aquatic Organism Passage Screening Tool, 2009). These tools can be used to design habitat sensitive crossings at new roads and find mitigation through retrofit or replacement of existing non-habitat sensitive crossings. The Massachusetts Department of Environmental Protection has developed guidance for maintaining gravel roads, ditch networks and stabilizing cut slopes to prevent erosions and reduce sediment inputs to the watershed (The Massachusetts Unpaved Roads BMP Manual, 2001). The adoption or incorporation of these practices as standard BMP measures within the regulatory program should be addressed within the RDSGEIS as a means to minimize potential impacts.

Section 6.4.3 of the RDSGEIS provides an incomplete characterization of potential environmental impacts to endangered and threatened species. While Chapter X, Part 701.20: c.2 states “critical aquatic habitat for fishes, amphibians, or aquatic invertebrates listed as endangered, threatened, or of special concern in Part 182 of this Title” includes discharge designations for waters with species of special concern, the RDSGEIS does not adequately recognize critical habitats for aquatic species of special concern, nor does it provide a complete list of species of special concern that are dependent on aquatic habitats as part of their natural life cycle. There is insufficient evaluation of species of special concern and potential cumulative impacts to threatened, endangered or special concern species within the RDSGEIS.

9.1.3 Recommendations

Based on the review of the RDSGEIS, LBG has found that the document does not adequately address the potential direct and cumulative impacts of HVHF on aquatic resources, New York State designated trout and trout spawning waters, and the potential for the loss of the waters’ best use designations. Recommendations to address the deficiencies of the RDSGEIS are provided below.

1. The RDSGEIS should provide a technically supported evaluation method to assess the anticipated changes to land use and road networks at a watershed level and the potential impact to aquatic habitat and sensitive aquatic species.

2. The RDSGEIS should define the restoration standards and success criteria for well pads, access roads and other short term and long term disturbances,

and timelines so that the temporal impacts of these activities and the environmental benefits of site reclamation are clearly defined.

3. Currently New York State does not provide regulatory guidance for stream crossing design which maintains Aquatic Organism Passage (AOP).The adoption or incorporation of these practices as standard BMP measures within the regulatory program should be addressed within the RDSGEIS as a means to minimize potential impacts.

9.1.4 Aquatic Ecology References

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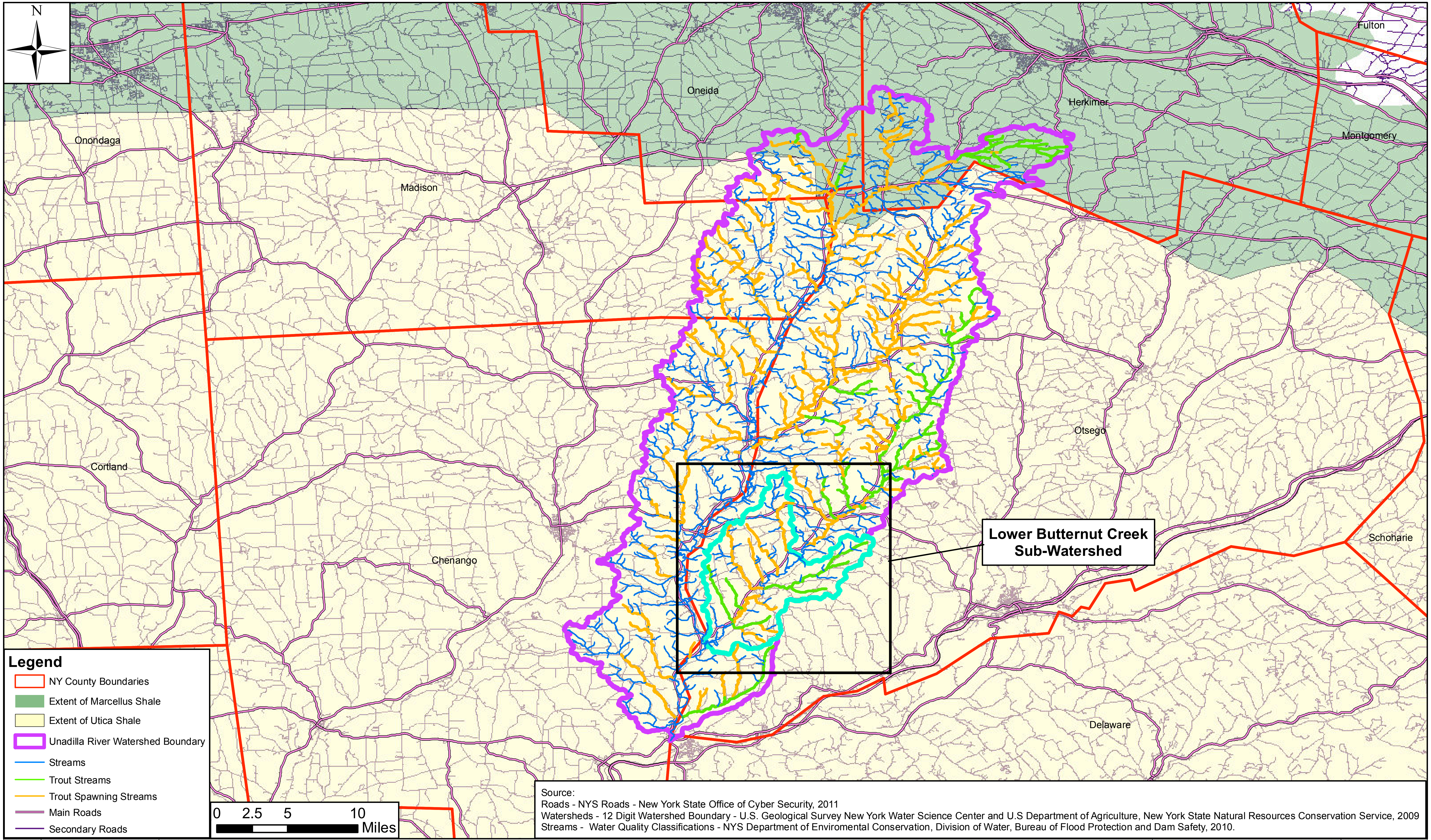


Source:
Roads - NYS Roads - New York State Office of Cyber Security, 2011
Watersheds - 12 Digit Watershed Boundary - U.S. Geological Survey New York Water Science Center and U.S Department of Agriculture, New York State Natural Resources Conservation Service, 2009
Streams - Water Quality Classifications - NYS Department of Enviromental Conservation, Division of Water, Bureau of Flood Protection and Dam Safety, 2010.

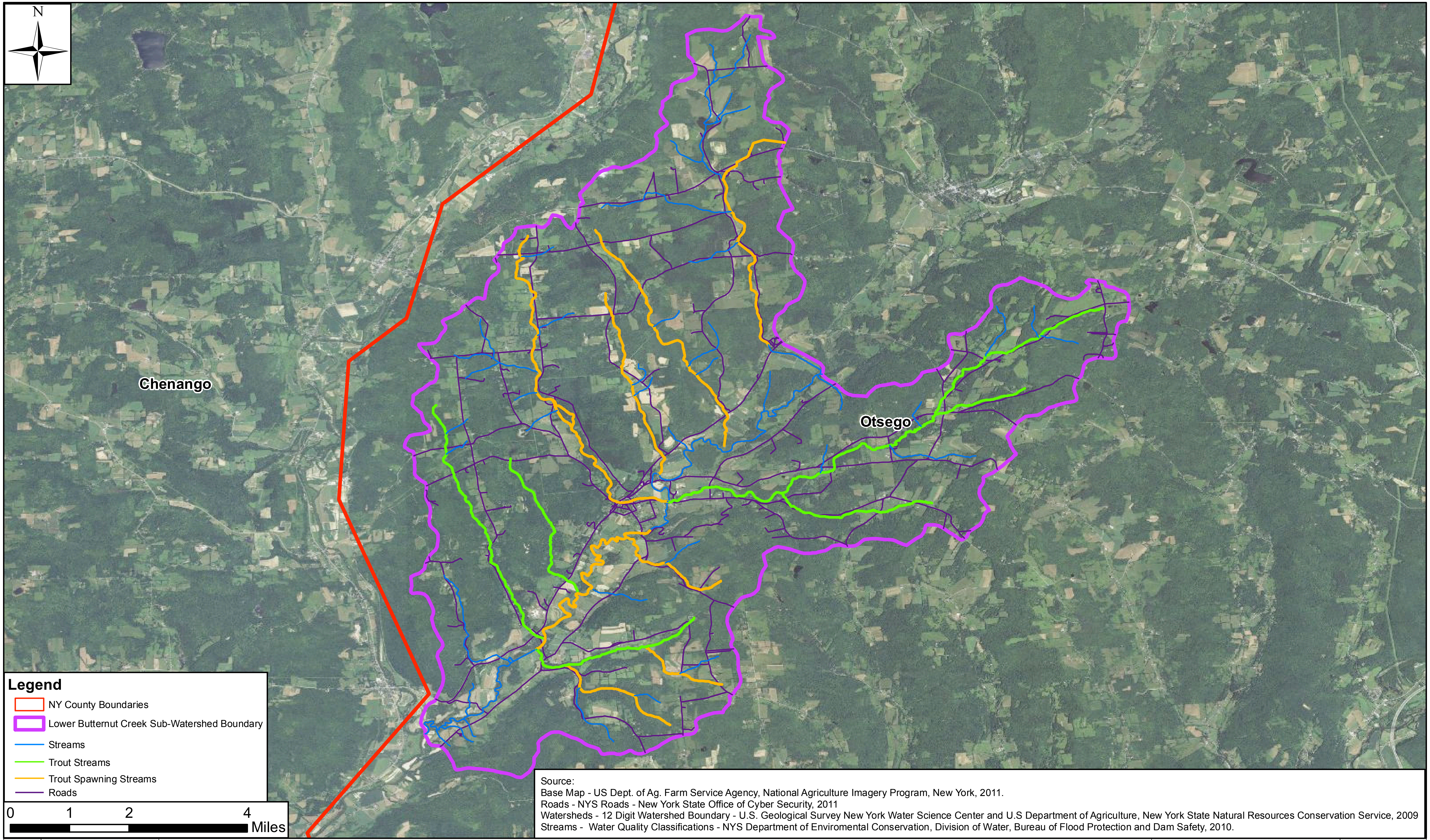
Natural Resources Defense Council

UNADILLA RIVER WATERSHED MAP

NEW YORK

The Louis Berger Group, Inc.
412 Mt. Kemble Ave
Morristown, NJ

FIGURE 1



Source:
Base Map - US Dept. of Ag. Farm Service Agency, National Agriculture Imagery Program, New York, 2011.
Roads - NYS Roads - New York State Office of Cyber Security, 2011
Watersheds - 12 Digit Watershed Boundary - U.S. Geological Survey New York Water Science Center and U.S Department of Agriculture, New York State Natural Resources Conservation Service, 2009
Streams - Water Quality Classifications - NYS Department of Enviromental Conservation, Division of Water, Bureau of Flood Protection and Dam Safety, 2010.

Natural Resources Defense Council

LOWER BUTTERNUT CREEK SUB-WATERSHED MAP

NEW YORK

The Louis Berger Group, Inc.
412 Mt. Kemble Ave
Morristown, NJ

FIGURE 2

Attachment 8

Kevin Heatley, M.EPC LEED AP

Professional Review & Comment

on

Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (Revised September 7, 2011)

January 5, 2012

Prepared for:

Delaware Riverkeeper Network

Prepared By:

Kevin Heatley, M.EPC LEED AP

Restoration Ecologist

EXECUTIVE SUMMARY

This review of the New York State Department of Environmental Conservation (NYDEC) revised draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas and Solution Mining Regulatory Program (issued September 7, 2011) was prepared in response to a request by the Delaware Riverkeeper Network to provide expert opinion on issues of terrestrial and restoration ecology. The ecological health and integrity of the forested landscapes located within watersheds has a direct bearing on both the water quality and the biotic composition of the streams and aquatic resources of the Delaware River and other major drainages of the Marcellus and Utica region. Mitigation of land disturbance impacts, such as those associated with unconventional fossil fuel extraction, is critical to ecological sustainability.

The NYDEC recognizes in section 1.2 of the RDSGEIS that it is required by NY state law to "conserve, improve and protect its natural resources and environment . . ." However, the agency openly, and correctly, acknowledges that this mandate cannot be achieved for terrestrial habitats and wildlife resources in the state under the proposed RDSGEIS mitigation recommendations. According to section 7.4.1, "Significant adverse impacts to habitats, wildlife, and biodiversity from site disturbance associated with high-volume hydraulic fracturing in the area underlain by the Marcellus Shale in New York will be unavoidable." The agency presents no mitigation option, such as aggressive region-wide restrictions on the spatial and/or temporal scale of this land disturbance sufficient to negate the undesirable ecological impacts of shale gas development.

The RDSGEIS identified four major areas of concern with respect to ecosystems and wildlife:

1. Fragmentation of habitat
2. Potential transfer of invasive species
3. Potential impacts on endangered and threatened species
4. Use of certain state-owned lands

While the RDSGEIS correctly emphasizes the importance of habitat fragmentation on terrestrial vertebrate species (in particular avian organisms) it fails to document the long term ecological consequences of fragmentation, deforestation, increasing forest edge and reduced surface permeability on desirable forest regeneration, surface water quality, soil chemistry, biodiversity, and sustainable ecosystem services.

Unfortunately, the mitigation measures proposed fail to fully address fragmentation and landscape connectivity issues for the majority of the affected ecosystems. In addition, the proposed invasive species best management practices lack the following key components:

- Quantifiable control metrics
- Latent seed bank management
- Forest edge management

The RDSGEIS also fails to provide any effective regulatory guidance and/or mandates regarding the final ecological restoration of ecosystem structure and function to well pads, pipelines, access road sites, and other related infrastructure upon cessation of natural gas extraction activities.

As written, the revised draft RDSGEIS presented by the NYDEC assures that widespread, dramatic changes in both the current integrity, and the future successional trajectory, of the watersheds and forests in the Marcellus and Utica regions will occur should the anticipated level of landscape industrialization occur. Changes in the successional trajectory (the type of tree species regenerating in the forest understory and that will ultimately comprise the forest canopy) will cause cascading ecological consequences. These changes are likely to result in an undesirable diminution of the ecosystem benefits and services currently provided by these biotic communities. Cascading ecological effects and consequences are probable and will require costly management interventions of significant spatial and temporal scale in order to achieve system restoration.

DISCUSSION

A careful review and analysis of the draft NYDEC RDSGEIS reveals a number of areas of concern with respect to the maintenance of the ecological integrity of terrestrial ecosystems and the corresponding impacts upon aquatic resources. In particular the RDSGEIS does not adequately provide for the protection and sustainable regeneration of critical headwater forests within the Delaware River drainage. Forested ecosystems are the dominant land cover type (57%) within the areas of potential shale gas extraction in the State of New York. This canopy cover is of extreme importance to both the quality and quantity of water that flows within the Delaware River drainage.

Forests filter contaminants, moderate stream temperatures and buffer flow volumes associated with precipitation events. They are the structural foundation upon which the ecological integrity and health of the basin's biological resources are built. The link between percent forest cover and water quality is clearly established in the scientific literature. As an example, reductions in forest cover are directly correlated with negative changes in water chemistry, such as increases in nitrogen, phosphorus, sodium, chlorides, and sulfates, and with reductions in stream macroinvertebrate diversity (Jackson and Sweeny 2010).

A healthy, viable forest canopy creates tangible economic value that accrues directly to local and regional communities. This value comes both from forest-dependent industries and from the ecosystem services (air filtration, climate regulation, water purification, etc.) that the forest provides. For instance, a 2002 survey of 27 water suppliers found that for every 10% increase in forest cover within a municipal watershed, the costs of water treatment and purification decreased by approximately 20% (Ernst, Caryn, Gullick and Nixon 2004). In New York State, forest-dependent industries are estimated to generate nine billion dollars of economic activity on an annual basis (North East State Foresters Association 2001).

Forest fragmentation as a result of anthropogenic landscape modification is well recognized within biogeographic theory and conservation biology as a leading cause of local species extinctions (extirpation). It can also cause dramatic shifts in the floral and faunal composition of woodland communities. Sub-lethal impacts to floral and faunal populations (population isolation, reduced genetic fitness and diversity) have also been associated with disruptions to forest connectivity (Clark, et.al. 2010).

Species dependent upon large, intact areas of interior, or “core” forest and those with limited dispersal abilities are at particular risk from forest fragmentation. A large body of scientific literature associated with neotropical migratory birds clearly links the survival of many of these species to the preservation and restoration of core forest habitat. The Cerulean warbler *(Dendroica cerulean*), a species of special concern in New York State, is a prime example. These populations are already in decline due to massive reductions in the amount of intact core forest. Even if the remaining interior forest habitat is preserved, the extensive fragmentation of the rest of the forested landscape will effectively preclude these areas from reconnection and restoration as interior forest habitat.

As pointed out by Semlitsch and Bodie (2003), the long-term persistence of many amphibian populations depends on the availability of vernal (seasonal) woodland pools and the surrounding, connective forest habitat. The ability of local populations to safely disperse is critical for the survival of these species. For instance, while many species of salamanders return to where they hatched to breed and lay eggs, it has been shown that they will use other vernal pools for breeding if their vernal pool of origin has been disturbed (if it is within their migration distance capacity). Linear disturbance corridors such as roadways and pipeline right-of-ways can create impermeable barriers to movement and effectively isolate populations of these organisms from alternative breeding sites. Isolated populations are at greater risk for extirpation (local extinction). The Jefferson salamander (*Ambystoma jeffersonianum*), another species of special concern in

New York, is an example of an amphibian that will be at risk should significant forest alterations occur.

The development of shale gas infrastructure in the New York and Pennsylvania region will have profound forest fragmentation impacts. Recent modeling work performed by the Pennsylvania Chapter of The Nature Conservancy indicates that approximately 2/3rds of the Marcellus well pads to be built in Pennsylvania will be located in what is currently forested habitat (TNC 2010). Coupled with the associated connective infrastructure of access roads and pipeline right-of-ways (ROWs), disruption of vital ecological processes is assured.

Fragmentation creates an increase in the amount of forest edge (the interface between forest and non-forest). This transitional zone or "ecotone" is fundamentally different in structure and functionality from an interior forest system. Edge habitat is characterized by increased light levels on the forest floor, reduced soil moisture, and a high degree of biological invasion from non-native invasive organisms. Dramatic changes can occur in the soil chemistry and associated micro biota. The top layer of the soil profile, the rich organic duff, begins to dry out and the primary decomposition community begins to shift from fungal to bacterial. Changes in the soil micro biota will result in shifts in the macro biotic community structure. The regeneration of desirable tree species (the successional trajectory) will be affected, potentially impacting the level of valuable ecosystem benefits supplied by the forest. These changes have direct economic implications to both landowners and society. Invasive species, for instance, have been estimated to cost the U.S. economy approximately $120 billion dollars per year (Pimintel et al. 2004).

Invasive organisms within terrestrial forest environments tend to be early successional species that respond favorably to site disturbance. Disruption of native plant cover and the exposure of the forest floor to sunlight provide an opportunity for these organisms to establish satellite populations. These populations eventually radiate out into the adjacent forest, displacing native species and retarding desirable tree regeneration (Bennet et al. 2011). Dispersal (vectoring) mechanisms and/or corridors are required in order for these non-native species to colonize new locations and the access roads, pipelines, and vehicular traffic associated with natural gas extraction are ideally configured to serve this function. Long beyond the point when wells are decommissioned, the landscape legacy of forest edge spreading outward from pipeline corridors, access roads, well pads, and related infrastructure will continue to disrupt ecosystem functioning as non-native organisms repeatedly colonize exposed areas and impede desirable tree regeneration.

Invasive species suppression and the eventual restoration of these disturbed sites to forested systems will require resources of a significant financial and temporal scale. While published information is scarce, it is in the professional experience of restoration practitioners in this region that the reasonable reconstruction of forest canopy and understory diversity can cost between $4,000 and $10,000 per acre. The suppression of invasive plant species is also a major, recurring expense with the initial years' treatment often costing between $1,000 and $2,500 per acre. Invasive treatment in subsequent years typically drops in cost by approximately 50% per year during the first three years of suppression. Treatment and monitoring will need to continue on an annual basis until forest canopy closure is re-established and the resulting changes in light penetration and soil conditions begin to favor native species.

As the effects of forest fragmentation may not immediately manifest themselves following the disturbance, monitoring is often suggested as a methodology to balance and modify the level of fragmenting activity in accordance with the conservation of forest-related ecosystem services. Unfortunately, these effects may not be linear in nature and thus are not always amenable to an adaptive management approach. Biological systems may possess thresholds that provide little indication of impending adverse impacts until sudden system collapse.

It is from within this conceptual framework that a review of the NYDEC Revised Draft RDSGEIS was undertaken and the following concerns identified:

Infrastructure Density-related Ecological Impacts -

- While mandatory unitization of production areas is in effect in New York, this spacing regime is geared toward maximization of gas extraction and not natural resource protection. Preliminary research results already point towards pad density as a significant indicator of potential landscape level impacts to water quality (Academy of Natural Sciences 2011). The RDSGEIS makes no mention of utilizing ecological planning units (such as the sub watershed) or ecological carrying capacity models. This is necessary to assure the industrial development pattern is consistent with the maintenance of ecological integrity.

- Density of infrastructure is also directly correlated to percent impermeable surface within subwatersheds. Increased impermeable surface area will disrupt both surface and subsurface hydrologic regimes within currently forested systems resulting in shifts in species composition and functional benefits. For instance, it is widely accepted among watershed managers that negative changes in water quality and quantity become clearly evident when impermeable surface begins to exceed 10% of a given watershed area. The RDSGEIS-proposed mitigation strategies do not address allowable levels of impermeable surface within ecological planning units such as the subwatershed.

Forest Fragmentation

- While the requirement for ecological assessments and site-specific mitigation measures on well pads placed in grasslands of greater than 30 acres (in grassland focus areas) and for forest patches of greater than 150 acres (in forest focus areas), is helpful this approach is, in essence, ironically fragmented. It completely fails to address the importance of landscape connectivity between patches. As such, it will not protect the landscape-level ecological processes that maintain regional forest integrity. It will also fail to protect connective corridors vital to the movement of plant and animal populations in response to climate change. A preferable methodology would be to set maximum allowable levels of deforestation and fragmentation based upon ecological planning units such as the subwatershed.

- It is strongly recommended that a comprehensive, ecosystem-based plan guide the decision-making and permitting process in place of the piecemeal approach to land use planning and the protection of watershed resources set forth in the RDSGEIS. Setting maximum thresholds and spatial parameters for percent forest cover loss and forest connectivity would assure that density levels and cumulative impacts of natural gas extraction do not exceed the ability of the regional ecosystem to absorb these activities.

- The RDSGEIS correctly emphasizes the importance of minimum patch sizes and landscape connectivity in protecting terrestrial wildlife habitat and/or the human recreation associated with such wildlife. However, no discussion or analysis is present regarding the impact that fragmentation and increasing edge habitat will have upon long term forest successional trajectory and associated biodiversity.

- No analysis has been presented in the RDSGEIS regarding the potential diminution of critical ecosystem services associated with the disruption of forest cover and soils (carbon sequestration and storage, air filtration, watershed flow rates and volume, surface water quality and thermal condition).

- Section 6.4.1.2 estimates that a mere 7% of the forest cover underlain by the Marcellus Shale in NY occurs on State-owned land. However, section 7.4.4 proposes a ban on surface disturbance within state forests and state wildlife management areas only. It is important to understand that this prohibition is not based upon any substantive <u>ecological</u> differences between forests under different ownership.

- Section 7.4.4 gives several reasons for prohibiting surface disturbance on State-owned land including: “Increased light and noise levels would be likely to have significant impacts on local wildlife populations, including impacts on breeding, feeding and migration” and “The local wildlife populations could take years or even decades to recover." These concerns are equally applicable to privately-owned forests, yet full mitigation of these identified impacts to wildlife is not addressed for the remaining 93% of the forest cover in the state. In particular, noise reduction strategies are entirely omitted from section 7.4.1.1 (BMPs for Reducing Direct Impacts at Individual Well Sites).

- Section 7.4.1.1 requires full cutoff (downward) lighting only during bird migration periods. As the ecological impacts of artificial night lighting across a range of species are well documented in the scientific literature, this requirement should be extended year-round.

- Section 7.4.1.1 fails to address BMPs for placement and maintenance of gathering pipelines. As this infrastructure is fundamental to well pad development, and has the potential to disrupt a greater net acreage than the actual pad, BMP recommendations should be developed.

- Section 7.4.1.1 fails to address BMPs for placement and mitigation of compressor station impacts.

- Section 7.4.1.2 indicates that for forest patches of 150 acres or more (within Forest Focus Areas) where the DEC issues a disturbance permit after reviewing the required Ecological Assessment, "enhanced monitoring of forest interior birds during the construction phase of the project and for a minimum period of two years following the end of high-volume hydraulic fracturing activities (i.e., following date of well completion) would be required." While this is an important recommendation, such enhanced monitoring should be extended to less mobile species sensitive to the radical changes in forest floor light and moisture levels that forest fragmentation will cause. Forest-dwelling amphibian species are at a particular risk of extirpation (local extinction) following the loss of interior forest conditions given their limited ability to traverse across linear landscape barriers such as roadways and pipeline ROWs.

- As connectivity between forest patches is critical to allowing for species migration, dispersal, and the continued genetic fitness of terrestrial species, mitigation strategies protective of this landscape level feature should be required. The RDSGEIS does not presently address protection of landscape connectivity and mitigation of disruptions to connective corridors.

- Definition of a disturbed area – clarification should be made as to the minimum size that defines a disturbed area.

- Section 7.4.1.3, *Monitoring Changes in Habitat* recommends, on parcels meeting the threshold criteria in grassland and forest focus areas, that monitoring of disturbance effects should occur during the drilling process and for a minimum of two years following well completion. While monitoring is indeed a valuable tool, effective implementation of operational changes (adaptive management) following and in response to ecosystem disruption is not always possible. Ecosystem response to disturbance may not follow a linear pattern as previously unknown tolerance thresholds may be crossed. Sudden system collapse and the loss of valuable structural and functional features of an ecosystem may occur even in the absence of discernible advance indicators of stress. A more appropriate response would be to apply the precautionary principle and study the likely impacts prior to widespread, and potentially irreversible, landscape modification.

Invasive Species Introduction & Management

- It is recommended that section 6.4 be expanded to include an analysis of the threat potential to forest health from the inadvertent introduction and facilitation of the spread of invasive terrestrial invertebrates and pathogens. The current analysis only considers invasive plants and aquatic organisms.

- The construction of infrastructure necessary to develop the Marcellus and Utica shales will entail the movement of large fleets of vehicles and equipment from various sections of North America. It will also entail the movement of large numbers of transient laborers and technical personnel from across the United States. This activity carries an inherent risk of acting as a vectoring mechanism for a number of threats to forest health. The RDSGEIS should review this potential mechanism of invasive threat and propose mitigation strategies.

- Section 6.4 should also be expanded to include an analysis of the impact that massive increases in forest edge habitat will have upon the incursion and establishment of invasive plant species. Edge habitat is inherently attractive to the type of plant species that display invasive characteristics. Invasive plants tend to be early successional species adapted to disturbed sites. The ecotone between forest and grassland is an area generated by recent disturbance and thus presents ideal conditions for these opportunistic, rapidly-reproducing species. Periodic re-infestation of edge habitat by invasive plant species is also highly probable given the high light levels and frequent deposition of wind-borne and bird-deposited seeds in such areas. The creation of edge habitat on the scale anticipated by natural gas infrastructure is likely to result in chronic, regional infestations of undesirable species that will require regular, and expensive, control interventions. The creation of forest edge is, in and of itself, an important precursor to biological invasion.

- Section 7.4.2.1 fails to include compressor stations and pipeline ROWs in the requirements for invasive species best management practices.

- Section 7.4.2.1 indicates that an invasive species survey “should be conducted by an environmental consultant familiar with the invasive species in New York.” It is recommended that the word “should” be replaced by “must”.

- It is recommended that the invasive species survey required under section 7.4.2.1 stipulate that percent aerial cover be classified <u>for each</u> identified invasive plant species on the site. Identification of baseline infestation levels is critical to determining target levels of cover reduction and control.

- Section 7.4.2.1 fails to provide any measurable metric, such as percent cover reduction from pre-disturbance levels, for quantifying levels of invasive control. The recommendation strategy that, “Any new invasive species occurrences found at the project location should be removed and disposed of appropriately” should be qualified to include the latent seed bank in the soil.

- Section 7.4.2.1 fails to define the temporal timeframe of responsibility for invasive suppression. The seeds of many invasive plant species can lie dormant in the soil for years. This latent seed bank creates a reservoir for future outbreaks following soil disturbance. It is critical that a long term monitoring and treatment program be implemented for all sites and associated infrastructure. Monitoring and suppression treatments should continue until final site reforestation and effective closure of the tree canopy.

- Section 7.4.2.1 fails to provide a spatial framework for the area of invasive species control responsibility. Invasive species are highly mobile and akin to a wildfire in their dispersal from initial point of infestation. At a minimum, site developers should be required to manage invasive infestations within all forest edge environments surrounding new pads, pipeline ROWs, and newly constructed access roads. Failure to do so will result in migration of these species off-site and the transfer of the financial burden of control onto adjacent property owners.

- As prevention is more cost effective than control, requirements should be adopted mandating independent site inspections by a qualified ecologist on no less than a semiannual basis until final reforestation and canopy closure occurs. Failing to provide for frequent site inspections assures compliance will be minimal.

Site Restoration

- The RDSGEIS fails to provide any meaningful guidance regarding the ultimate restoration of well pads, pipeline ROWs and access roads to full ecosystem functionality upon decommissioning. Effective restoration requires a comprehensive, site-level assessment of the existing plant community prior to disturbance and the use of local reference ecosystems as templates for restoration. Ecological restoration is based upon the concept of rebuilding degraded areas such that they are structurally and functionally similar to pre-disturbance conditions. Reclamation is NOT restoration. Grassy fields neither function in a biologically similar manner as a forest nor supply the ecosystem benefits of a forest system. The replacement of a decades-old, complex assemblage of woodland species with a simple mix of grasses is not "restoration". It may retard erosion but it does not replace the original functionality and structure of the displaced ecosystem.

- Restoration objectives and planning should be integrated into best management practices and developed based upon a landscape-level analysis. Re-establishing forest connectivity should be a primary goal.

- As the service life of gas extraction infrastructure such as transmission pipelines may extend for decades, mitigation banks and sites where restoration of previously degraded systems might off-set the disturbance for the interim period should be utilized. This will help assure that no net loss of ecosystem benefits occurs within the region.

- Requirements for an independent, qualified restoration ecologist to oversee and inspect site restoration should be developed in order to assure effective compliance.

Summary

As currently proposed, the NYDEC RDSGEIS does not provide an adequate assessment of likely impacts associated with the rapid conversion of forested and rural ecosystems to industrial sites. It also fails to recommend potential mitigation strategies and options that would offset and reduce the "significant" impacts anticipated for native terrestrial ecosystems. Protection of these terrestrial ecosystems is critical to the continued health of the regions' aquatic resources. Inadequate attention has been given to the following vital considerations: density related impacts of infrastructure, forest fragmentation, invasive species, and site restoration. Should the RDSGEIS be adopted in its current form, widespread disruption to forest ecosystems within the upper Delaware River Basin and other watersheds underlain by the Marcellus and Utica formations will occur. Restoration of these systems following the eventual cessation of natural gas extraction will be a monumental cost incurred by both the taxpaying public and adjacent private property owners. It is strongly recommended that the NYDEC consider a more comprehensive approach to protecting the integrity of the forested landscapes in New York. Setting maximum thresholds and spatial parameters for percent forest cover loss, forest connectivity, and core forest integrity within ecological planning units, such as the subwatershed, would assure that density levels and cumulative impacts of natural gas extraction do not exceed the ability of the regional ecosystem to absorb these activities.

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Attachment 9

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January 8, 2012

Re: Comments on the RDSGEIS on NY Marcellus Shale Natural Gas Hydraulic Fracturing

These comments are submitted regarding the Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) governing high-volume, hydraulic fracturing as a method of natural gas drilling in the Marcellus Shale and similar formations in New York State.

I am Senior Scientist in the Health and Environment Program at the Natural Resources Defense Council in New York City, and Assistant Clinical Professor in the Department of Environmental Health Sciences at the Mailman School of Public Health of Columbia University. I received my doctorate in Public Health from Columbia University, and much of my research considers the effects of climate change on human health (my CV is attached). These comments relate to climate change and public health concerns raised by the information described in the RDSGEIS.

Although the RDSGEIS describes greenhouse gas emissions that would be generated by Natural Gas Hydraulic Fracturing operations in the Marcellus and other shale formations in NY State (sec. 6.6), and the means to reduce those health-harming emissions (sec. 7.6), the RDSGEIS lacks critical information about the exacerbating effect climatic changes will have on the uncertainties of drilling operations. Further, climate change is likely to increase the risk to public health from HVHF operations if these operations are conducted without regard to the effects of climate change on the environmental context of drilling operations.
Climate change is likely to increase several key uncertainties in shale gas natural gas hydraulic fracturing operations which are not addressed in the RDSGEIS, yet should be. Several of these climate change and public health-relevant omissions are described below:

1. **More frequent extreme rainfall events.** The public health risks of drill pad operations and waste fluid disposal are likely to be affected by more frequent extreme rainfall events in New York State, as climate change continues. These events and the flooding they can cause need to be factored into the RDSGEIS. Measured changes in the heaviest precipitation events in the Northeastern US increased 67% over the period 1958-2007; and the trend toward heavier precipitation is projected to increase into the 2090s.[1] In New York State in the last 60 years from 1948 to 2006, there has been a statistically significant 56% increase in the most extreme rainfall events, according to the a 2007 study by Environment America.[2] As climate change continues, these extreme rainfall events are projected to continue to occur more frequently.[3] The New York Panel on Climate Change (or NPCC), an expert group of university researchers and climate modelers, investigated climate change's effects on New York City and the surrounding region, and projected that annual precipitation in the New York region will "more likely than not" increase, with mean annual precipitation increasing up to 5% by the 2020s, 10% by the 2050s, and

5-10% by the 2080s.[4] The New York State Climate Action Council's Nov. 2010 *Climate Action Plan Interim Report* noted in its Executive Summary (ES) that, "Summertime rain is expected to fall more often as heavy downpours, leading to more flooding; at the same time, the periods between these rainstorms are likely to be drier, leading to droughts. … Public and private entities will need to assess whether new investments in infrastructure, particularly long-lived infrastructure like power plants and transportation, will be consistent with a low-carbon future, both in terms of GHG emissions and in terms of vulnerability to a changing climate. We should avoid investments that are not highly adapted to a modified climate, such as infrastructure sited in low-lying floodplains."[5] ***DEC should act consistently with the recommendations of the New York Climate Action Plan Interim Report by prohibiting HVHF operations and infrastructure in low-lying areas***.

2. **Changes in floodplain location.** The locations of 50-, 100- and 500-year floodplains are likely to change in New York State, owing to the effects of climate change. Extreme rainfall events are becoming more frequent in the US.[6] This trend was also noted in the recently-released NY State ClimAID report: "Intense precipitation events (heavy downpours) have increased in recent decades, and are likely to increase in future."[7] These extreme precipitation events are occurring in tandem with a long-term increase in annual average precipitation of 0.37 inches per decade since 1900.[8] The advent of extreme precipitation events taken together with a general increase in average precipitation is likely to alter the location and size of floodplains. Altered floodplain locations could dramatically compromise the siting and safety of drilling operations, as well as waste disposal and transport. With the trend to heavy downpours over the past 50 years projected to continue, an increase in localized flash flooding in hilly regions across the state is expected. "Flooding has the potential to increase pollutants in the water supply and inundate wastewater treatment plants and other vulnerable development within floodplains."[9] The most recent state of the science on the effects of climate change on the extent of local floodplains should be applied in the RDSGEIS's consideration of the potential impacts of proposed new drilling in NY State.

   Because increasingly frequent and extreme rainfall events could threaten drilling infrastructure, operations and disposal, such investments should be avoided without a full, detailed mapping of areas at greatest risk from storm and flood damage. This is in line with the Nov. 2010 recommendations of the NY State Climate Action Council in their Climate Action Interim Report.[10] Floodplain maps must be fully updated to include the latest information on how climate change will affect local flood plain locations, taken from downscaled climate model projections.[11]

   Although DEC proposes prohibiting surface disturbances in 100-year floodplains[12], this approach is problematic for several reasons. First, DEC should also prohibit subsurface activity in these areas. Second, the prohibition should apply to additional matters involved in HVHF, such as the siting of pipelines and other potentially sensitive infrastructure, the construction of impoundment ponds, the location of temporary waste storage tanks, etc. Third, not only does DEC acknowledge that FEMA is currently updating Flood Insurance Rate Maps (FIRMs) in several high-flood areas in the state,[13] but the Department also admits that the increased frequency and magnitude of flooding has raised a concerns regarding the reliability of the existing FIRMs in the Susquehanna and Delaware River basins.[14] Given this acknowledgment, DEC should extend this prohibition to 500-year floodplains. In general, ***no permits should be issued anywhere in the state before updated floodplain maps are in place for the entire region and these maps are reflected in DEC's environmental review and regulations***. These maps should be reflective of anticipated changes that may result from climate change, namely the increase in frequency and severity of storm events. To permit any activities before properly mapping prohibited areas is inconsistent with SEQRA.

3. **Potential changes in groundwater flow patterns.** Hydrological assumptions about groundwater flow patterns through the Marcellus and other shale formations could be altered by water demands from drilling activities, if coupled with increasingly frequent seasonal drought and/or flood periods in NY State, as climatic instability increases. More frequent alternation between periods of extreme wet and dry periods could, over time, result in changes in groundwater flow patterns[15] and unanticipated movement of production fluids and other groundwater in subsurface fractures and fissures. While challenging to predict, such migration could threaten drinking water supplies. Subsurface hydrological modeling studies have been undertaken to account for some of these climate change effects,[16] yet such studies were ignored by the RDSGEIS. ***No permits to drill near groundwater resources should be issued until climate change-based subsurface hydrological modeling studies have been incorporated into the DEC's review and regulations***.

4. **Changing seasonal precipitation patterns.** Increasing temperatures have already caused spring snowmelt to occur earlier in the year, and climate change will continue to bring changing patterns of seasonal precipitation across the state, with more annual precipitation falling as rain rather than snowfall.[17] This could affect the frequency, intensity and timing of overland flooding events at drill pad sites. In 2011, Hurricane Irene caused extensive flooding across the Catskills and upstate NY, in part because the soils were already so saturated from record-breaking heavy precipitation during the summer. As the USGCRP 2009 report attests, "…water-saturated soils can generate floods with only moderate additional precipitation."[18] In addition to prohibiting water withdrawals during low stream flow, ***the RDSGEIS should explicitly address shifting precipitation patterns resulting from climate change, increased flooding risks, and the public health issues they may create***.

5. **Increasing temperatures could exacerbate chemical volatilization and fugitive emissions from drill sites.** Ambient temperatures are projected to increase across NY State, due to the warming climate.[19] Volatilization of fracking chemicals and fugitive emissions may increase due to higher evaporation rates from higher temperatures. Exposures to workers and the community could increase, exacerbating associated health risks. ***Adverse human health impacts resulting from increased volatilization of fracking chemicals and fugitive emissions should be explicitly addressed in the RDSGEIS.***

6. **Conflicting demands on water use during drought periods are likely to be exacerbated by climate change.** Hydrofracking operations will require enormous quantities of water in drilling, in operations, and as wastewaters are disposed of. Marcellus development is projected over a thirty-year life cycle.[20] The average year would see 1,600 or more wells.[21] The amount of water consumed in each well is projected between 2.4 and 7.8 million gallons,[22] and the average well consumes 4.2 million gallons of water.[23] Based on these numbers, approximately 201,600,000,000 gallons of freshwater will be permanently removed from New York State surface and groundwater sources for the purpose of HVHF operations. The effect of these freshwater diversions in light of predicted climate change impacts to water supplies was not analyzed in the RDSGEIS. Because climate change is likely to disrupt the timing of precipitation's seasonality, the enormous water demands from hydrofracking operations could periodically conflict, during periods of local drought, with those of populations who rely on local surface and groundwater sources for drinking, domestic, municipal, business and agricultural uses. ***The potential for conflicts between HVHF operators and the public over dwindling water supplies resulting from climate change, including the adverse environmental and human health impacts associated with unprecedented freshwater diversions, should be examined in the RDSGEIS, and operators should be prohibited from consuming water from underground, surface, and municipal sources if doing so would exacerbate local drought conditions.***

7. **Nitrous oxide is an extremely potent GHG that the RDSGEIS fails to properly analyze.** Even in its current discussion of greenhouse gases (GHG) generated during drilling operations, the RDSGEIS lacks sufficient information in Sec. 6.6.2 about nitrous oxide (N_2O) as a greenhouse gas (GHG) of concern. The RDSGEIS states that because N_2O is produced in small quantities it need not be explicitly discussed in terms of its treatment or disposal.[24] However, N_2O has a global warming potential 289 times greater than carbon dioxide (CO_2), and an atmospheric lifetime 114 times longer than CO_2.[25] It is injudicious to entirely negate N_2O's effect on climate change in the RDGEIS without fuller discussion of the volumes that would be generated, from what sources, and potential treatment methods. ***The RDSGEIS should identify the impacts associated with N_2O emissions and proposed mitigation measures to curb these emissions.***

8. **Public health impacts.**. Climate change impacts can jeopardize the safety of drilling operations and exacerbate the consequences of HVHF operations on New York State, leading to adverse environmental human health impacts. ***DEC should conduct a comprehensive Health Impact Assessment (HIA) as part of the state's environmental review*** in order to evaluate potential risks to human health from gas development in New York, including the dynamic between HVHF operations (impacts on water quantity and quality, waste runoff, air pollution, etc.) and climate change (water shortages, floods, temperature rise, etc.). ***To assist in the review of comments received, at least one Public Health professional should sit on the team who evaluates the comments received by DEC on the RDGEIS***. Their expertise would be helpful in assessing other potential areas of significant health concern, ranging from air quality, water quality, worker exposure, waste management, etc...

Based on the foregoing, the RDSGEIS is incomplete in its current form. The RDSGEIS is deficient because it does not ever come to grips with the challenges to safe HVHF operations posed by climate change: it does not consider changes in the frequency of extreme rainfall events, changes in floodplain location, changes in groundwater flow patterns, changes in seasonal precipitation patterns, changes in average temperature, potential water use conflicts, the effects of nitrous oxide on climate change, or the public health impacts of climate change in association with HVHF operations. The RDSGEIS fails to include current information relevant to climate change's potential effects on New York State, which will pose potentially significant adverse environmental and public health threats in conjunction with HVHF operations that should be identified and mitigated to the maximum extent possible.

Thank you for consideration of these comments.

Respectfully,

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[8] ClimAID Report (2011), p.81 sec. 4.2.2.

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[9] Nov. 2010 *Climate Action Plan Interim* Nov. 2010 Report, Overview, p.10.

[10] NY State Climate Action Council, 2010. Climate Action Interim Report, Overview, pp.10, 43, and 48.

[11] Cooney CM 2012. Downscaling Climate Models: Sharpening the Focus on Local-Level Changes. *Environ Health Perspect* 120:a22-a28. http://dx.doi.org/10.1289/ehp.120-a22.

[12] 2011 RDSGEIS, Additional Precautionary Measures, Section 1.8, p. 1-18.

[13] 2011 RDSGEIS, Flood Zone Mapping, Section 2.4.9.2, p. 2-33.

[14] *Id*.

[15] USGRCP (2009), Water sector report, pp. 46-47.

[16] Goderniaux P, Brouyere S, Fowler HJ, et al. 2009. Large scale surface-subsurface hydrological model to assess climate change impacts on groundwater reserves. *Journal of Hydrology* 373:122-138.

[17] ClimAID (2011), Sec. 4.2.1, p.81.

[18] USGCRP (2009), Water Sector report, p.45.

[19] ClimAID (2011), Ch.1, pp.30-36.

[20] 2011 RDSGEIS, Cumulative Water Withdrawal Impacts, 6.1.1.7, p. 6-6.

[21] 2011 RDSGEIS, Description of Proposed Action, Chapter 2, p. 2-1.

[22] 2011 RDSGEIS, Hydraulic Fracturing Procedure, 5.9, p. 5-93.

[23] 2011 RDSGEIS, Cumulative Water Withdrawal Impacts, 6.1.1.7, p. 6-10.

[24] 2011 RDSGEIS, Emissions from Oil and Gas Operations, 6.6.2, p. 6-188.

[25] 2007 Intergovernmental Panel on Climate Change (IPCC), Fourth Assessment Report (AR4), Working Group 1 Technical Summary, Chapter 2, p.212, "Changes in Atmospheric Constituents and Radiative Forcings."

Attachment 10

Gina Solomon, M.D., M.P.H

MEMORANDUM

TO: Kate Sinding
FROM: Gina Solomon, M.D., M.P.H., Senior Scientist, NRDC; Clinical Professor of Health Sciences, UCSF
DATE: January 9, 2011
RE: NRDC Comments on RDSGEIS, NY Marcellus Shale Natural Gas Hydraulic Fracturing relative to Public Health concerns and Health Impact Assessments

Numerous health concerns have been associated with natural gas development using hydraulic fracturing, including air pollution, potential contamination of groundwater or surface water that may be used for drinking or recreation, toxicity of chemicals used in fracturing fluids, safety concerns such as fire or explosion, increased vehicle traffic, altered social conditions, and the health effects of noise, vibration, and light at night. The RDSGEIS addresses some aspects of a subset of these health issues, but fails by (1) omitting several important health issues entirely, (2) addressing only some aspects of other issues such as air, water quality and traffic without fully considering the health impacts in those areas (Note: this issue is addressed more fully in comments on those sections of the RDSGEIS submitted as part of this package), and (3) failing to consider health issues as a group in a formal Health Impact Assessment (HIA), including the interactive effects on the health of local residents and communities.

The failure to conduct a full HIA as part of the RDSGEIS is an important omission because the health effects of numerous chemicals used and emitted in the course of natural gas development have been well-described.[1] In addition, there are already numerous reports of health complaints among people who live near natural gas drilling and fracturing operations in other states. These health complaints have received coverage in the media,[2] and some cases have been investigated by researchers or government agencies.[3] Reported health issues in residents near natural gas drilling operations include: eye irritation, dizziness, nasal and throat irritation, sinus disorders, bronchitis and other respiratory symptoms, depression, nausea, fatigue, headaches, anxiety, difficulty concentrating, and a range of other symptoms.[4] Just last week, the nation's top environmental health expert

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[1] Colborn, T.; Kwiatkowski, C.; Schultz, K., and Bachran, M. Natural gas operations from a public health perspective. Human & Ecological Risk Assessment. 2011; 17(5):1039-1056. http://www.endocrinedisruption.com/chemicals.journalarticle.php. Accessed January 9, 2011; Witter R, Stinson K, Sackett H, et al. Potential Exposure-Related Human Health Effects of Oil and Gas Development: A White Paper. University of Colorado Denver, Colorado School of Public Health, Denver, Colorado, September 15, 2008. Witter R, Stinson K, Sackett H, et al. Potential Exposure-Related Human Health Effects of Oil and Gas Development: A Literature Review (2003-2008) University of Colorado Denver, Colorado School of Public Health, Denver, Colorado, August 1, 2008. http://docs.nrdc.org/health/hea_08091702.asp. Accessed January 9, 2011.

[2] See eg. ProPublica. Science Lags as Health Problems Emerge Near Gas Fields. http://www.propublica.org/article/science-lags-as-health-problems-emerge-near-gas-fields/single. Accessed January 3, 2012.

[3] See eg. ATSDR Health Consultation. Garfield County. http://www.atsdr.cdc.gov/hac/pha/Garfield_County_HC_3-13-08/Garfield_County_HC_3-13-08.pdf. Accessed January 3, 2012; Subra W. Health Survey Results of Current and Former DISH/Clark, Texas Residents. Earthworks, Dec 17, 2009. http://www.earthworksaction.org/library/detail/health_survey_results_of_current_and_former_dish_clark_texas_residents/. Accessed January 3, 2012.

[4] Ibid.

affirmed his view that more research is necessary regarding the impacts of natural gas drilling on human health.[5] Although much research needs to be done to investigate specific associations between the reported symptoms and nearby gas extraction operations, there is sufficient information on health issues associated with the chemicals and other environmental stressors at these sites to demand performance of a full HIA.

> *Health impact assessment is a systematic process that uses an array of data sources and analytic methods and considers input from stakeholders to determine the potential effects of a proposed policy, plan, program, or project on the health of a population and the distribution of those effects within the population. Health impact assessment provides recommendations on monitoring and managing those effects.*
>
> National Research Council, 2011

Rationale for a Health Impact Assessment in New York State

In September 2011, the National Research Council of the National Academies of Science (NAS) issued a report entitled: *Improving Health in the United States: The Role of Health Impact Assessment*. The report recommended the greater use of HIA in decision making in the United States, saying that: "systematic assessment of the health consequences of policies, programs, plans, and projects is critically important for protecting and promoting public health; as indicated, lack of assessment can have many unexpected adverse health (and economic) consequences."[6]

According to the Centers for Disease Control and Prevention (CDC), the HIA framework is used to bring potential public health impacts and considerations to the decision-making process for plans, projects, and policies that fall outside of traditional public health arenas, such as transportation and land use.[7] The National Environmental Policy Act (NEPA) requires federal agencies to consider the environmental impact of their proposed actions on social, cultural, economic, and natural resources prior to implementation. In New York, the State Environmental Quality Review Act (SEQRA) regulations [see 617.2(l)] define Environment as: "…the physical conditions that will be affected by a proposed action, including land, air, water, minerals, flora, fauna, noise, resources of agricultural, archeological, historic or aesthetic significance, existing patterns of population concentration, distribution or growth, existing community or neighborhood character, and *human health*" (emphasis added).[8]

In the United States, HIA is a rapidly emerging practice. HIA is also regularly performed in Europe and Canada. Some countries have mandated HIA as part of a regulatory process. In the U.S., some version of an HIA is arguably required by NEPA and by many state "mini-NEPAs,"[9] including most explicitly, the New York SEQRA,

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[5] CDC scientist: tests needed on gas drilling impact. Associated Press. January 4, 2012. http://online.wsj.com/article/AP8338b702930849f49d22a5d96b7d1b2d.html. Accessed January 5, 2012.

[6] National Research Council. Improving Health in the United States: The Role of Health Impact Assessment. Washington, DC: The National Academies Press, 2011, pp. 4-5.

[7] Centers for Disease Control and Prevention. http://www.cdc.gov/healthyplaces/hia.htm. Accessed January 3, 2012.

[8] See also Environmental Conservation Law § 8-0103(5) ("…it is the intent of the legislature that the government of the state take immediate steps to identify any critical thresholds for the health and safety of the people of the state and take all coordinated actions necessary to prevent such thresholds from being reached).

[9] Bhatia, R and Wernham, A. Integrating Human Health into Environmental Impact Assessment: An Unrealized Opportunity for Environmental Health and Justice. Environmental Health Perspectives. 2008;116(8): 991-1000.

which clearly specifies the mandate for a full characterization of the effects on human health. The National Academies of Science committee on HIA recommended: "improving the integration of health into EIA under NEPA and related state laws…[to] serve the mission of public health and the goals of HIA….[In order t]o ensure reasonable priority of health issues under NEPA, public-health agencies should be afforded a substantive role in the scoping and oversight of health-effects analysis in EIA, and health-effects analysis must be afforded resources commensurate with the task.[10]

There is precedent for performing formal HIAs for drilling activities. In 2007, an HIA of proposed oil and gas development projects in Alaska's North Slope was performed by the local government.[11] The HIA evaluated predicted impacts on fish and wildlife and the consequences for diet and health in the local population. It also identified potential social changes such as drug and alcohol use. The HIA led to new requirements for air quality analysis and monitoring of any oil-related contaminants in subsistence foods, and to a new requirement for worker education on drugs, alcohol and sexually transmitted diseases.

A draft HIA was done in Colorado for a proposed gas drilling development in Battlement Mesa. This draft HIA identified eight major areas of health concern (stressors) associated with natural gas development and production: air emissions, water and soil contaminants, truck traffic, noise/light/vibration, health infrastructure, accidents and malfunctions, community wellness, and economics/employment.[12] Several physical health outcomes linked to potential exposures were considered, including respiratory, cardiovascular, cancer, psychiatric, and injury/motor vehicle-related impacts on vulnerable and general populations in the community. The study concluded: "The key findings of our study are that [the] health of the Battlement Mesa residents will most likely be affected by chemical exposures, accidents or emergencies resulting from industry operations and stress-related community changes."[13] The researchers went on to recommend a set of mitigation measures to reduce the health threats to local residents. Although the Battlement Mesa HIA was halted by the local Board of County Commissioners, apparently for political reasons,[14] it demonstrated the feasibility and utility of HIA for evaluating risks to the health of local residents from hydraulic fracturing and natural gas drilling operations.

In October of 2011, hundreds of health professionals signed a letter to Governor Cuomo specifically requesting that the draft SGEIS be "supplemented to include a full assessment of the public health impacts of gas

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[10] National Research Council. Improving Health in the United States: The Role of Health Impact Assessment. Washington, DC: The National Academies Press, 2011, p. 111-113.

[11] Wernham A. Building a Statewide Health Impact Assessment Program: A Case Study from Alaska. Northwest Public Health. Fall/Winter 2009; Health Impact Project. Case Study: Oil Development of Alaska's North Slope. http://www.healthimpactproject.org/resources/case-study-oil-development-of-alaskas-north-slope. Accessed January 5, 2011.

[12] Witter R, McKenzie L, Towle M, et al. Health Impact Assessment for Battlement Mesa, Garfield County Colorado. Colorado School of Public Health, University of Colorado, Denver, September 2010. http://www.garfield-county.com/public-health/documents/1%20%20%20Complete%20HIA%20without%20Appendix%20D.pdf. Accessed January 4, 2012.

[13] Battlement Mesa Health Impact Assessment (2nd Draft). March 1, 2011. http://www.garfield-county.com/public-health/battlement-mesa-health-impact-assessment-draft2.aspx. Accessed January 4, 2012.

[14] Vote Ends work on Battlement Mesa HIA. May 4, 2011. http://www.healthimpactproject.org/news/in/vote-ends-work-on-battlement-mesa-hia. Accessed January 4, 2012.

exploration and production."[15] The letter pointed out that, "there is a growing body of evidence on health impacts from industrial gas development," and specifically stated that: "A comprehensive Health Impact Assessment (HIA) would be the most appropriate mechanism for this work." The Director of the Agency for Toxic Substances and Disease Registry (ATSDR), Dr. Christopher Portier, also supports more thorough assessment of the health impacts of gas drilling, stating: "Studies should include all the ways people can be exposed, such as through air, water, soil, plants and animals."[16]

In summary, the requirements of SEQRA and recommendations of the National Academies of Science argue strongly for the need for a New York HIA of the health impacts of gas drilling and hydraulic fracturing. A similar investigation in Colorado revealed a set of potentially significant human health impacts associated with chemical exposures, accidents, and stress-related community changes, all of which were insufficiently considered in the New York RDSGEIS. Without a full assessment and mitigation of the impacts of the risks, the health of New York State residents and communities is likely to suffer.

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[15] Abramson A, Abrams J, Alexander M, et al. Letter to The Honorable Andrew M. Cuomo. October 5, 2011. http://www.psehealthyenergy.org/resources/view/198813. Accessed January 5, 2012.

[16] CDC scientist: tests needed on gas drilling impact. Associated Press. January 4, 2012. http://online.wsj.com/article/AP8338b702930849f49d22a5d96b7d1b2d.html. Accessed January 5, 2012.

Attachment 11

Briana Mordick

January 10, 2012

To: Kate Sinding

From: Briana Mordick

Subject: Technical analysis of hydraulic fracturing-induced seismicity provisions in the New York State Revised Draft Supplemental Generic Environmental Impact Statement On the Oil, Gas & Solution Mining Regulatory Program

Introduction

The following report is a technical review and analysis of the hydraulic fracturing-induced seismicity provisions of the New York State (NYS) 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas & Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs. This report includes recommendations for properly managing the risks associated with induced seismicity.

Analysis

The RDSGEIS fails to require operators of HVHF wells to consider the risk of induced seismicity when siting wells and designing hydraulic fracture treatments, concluding that,

"There is a reasonable base of knowledge and experience related to seismicity induced by hydraulic fracturing. Information reviewed indicates that there is essentially no increased risk to the public, infrastructure, or natural resources from induced seismicity related to hydraulic fracturing. The microseisms created by hydraulic fracturing are too small to be felt, or to cause damage at the ground surface or to nearby wells. Accordingly, no significant adverse impacts from induced seismicity are expected to result from high-volume hydraulic fracturing operations."[1]

Since the RDSGEIS was written, hydraulic fracturing has been confirmed to have caused induced seismicity strong enough to be felt at the surface. In a report commissioned by United Kingdom-based Cuadrilla Resources, researchers concluded that a series of earthquakes in Lancashire, UK were likely caused by hydraulic fracturing. Two relatively large earthquakes, with magnitudes 2.3 and 1.5, and 48 smaller events occurred in the hours after several stages of the Preese Hall 1 well were fracked.[2] A separate report written by a seismologist at the Oklahoma Geological Survey concluded that a swarm of about 50 earthquakes in Garvin County, Oklahoma, ranging in magnitude from 1.0 to 2.8, could also have been induced by hydraulic fracturing.[3]

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[1] Revised Draft SGEIS 2011, Executive Summary, Page 19

[2] de Pater, C.J., and Baisch, S., 2011, *Geomechanical Study of Bowland Shale Seismicity: Synthesis Report*, prepared for Cuadrilla Resources Ltd, 71p., available at: http://www.cuadrillaresources.com/cms/wp-content/uploads/2011/12/Final_Report_Bowland_Seismicity_02-11-11.pdf

[3] Holland, A., 2011, *Examination of Possibly Induced Seismicity from Hydraulic Fracturing in the Eola Field, Garvin County, Oklahoma*, Oklahoma Geological Survey, Open-File Report OF1-2011, 31p., available at: http://www.ogs.ou.edu/pubsscanned/openfile/OF1_2011.pdf

The RDSGEIS concedes that, "There are no seismic monitoring protocols or criteria established by regulatory agencies that are specific to high volume hydraulic fracturing,"[4] and recognizes that, "It is important to avoid injecting fluids into known, significant, mapped faults when hydraulic fracturing."[5] However, instead of developing such protocols and requiring operators to demonstrate that they have accounted for seismic risks in the siting of wells and design of hydraulic fracture treatments, the RSDGEIS assumes that, "Generally, operators would avoid faults because they disrupt the pressure and stress field and the hydraulic fracturing process,"[6] and, "It is in the operator's best interest to closely control the hydraulic fracturing process to ensure that fractures are propagated in the desired direction and distance and to minimize the materials and costs associated with the process."[7]

To justify why no additional analysis or monitoring is required to prevent induced seismicity, the RDSGEIS states, "The routine microseismic monitoring that is performed during hydraulic fracturing serves to evaluate, guide, and control the process and is important in optimizing well treatments,"[8] and, "Monitoring beyond that which is typical for hydraulic fracturing does not appear to be warranted, based on the negligible risk posed by the process and very low seismic magnitude."[9] However, earlier in the document, NYSERDA's consultant ICF International concludes that, "…fracture monitoring by [microseismic fracture mapping] is **not regularly used** because of cost…"[10] So in fact, seismic monitoring would rarely be employed during a routine hydraulic fracture treatment.

The RDSGEIS further assumes that no additional analysis of seismic risk is needed due to the fact that, "The locations of major faults in New York have been mapped (Figure 4.13) and few major or seismically active faults exist within the fairways for the Marcellus and Utica Shales."[11] There are two fatal flaws with this assumption. First, in both the UK and Oklahoma incidents, the earthquakes likely occurred due to slippage on minor, sub-seismic faults. Therefore, knowing the locations of only "major faults" is not sufficient to assess the potential risk of induced seismicity from hydraulic fracturing. Second, it is precisely the injection of fluids which induces previously inactive faults to become active. Therefore, whether a fault is currently or even recently seismically active is not sufficient to predict whether it could become active due to human activity – the definition of induced seismicity. A paper on earthquake hazards from deep well injection prepared by the U.S. Geological Survey for the U.S. Environmental Protection Agency concludes that predicting and mitigating seismic hazard risks in the Eastern United States is particularly problematic, as the causes of natural earthquakes and location of faults are not well understood.[12]

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[4] Revised Draft SGEIS 2011, Page 6-322
[5] Id.
[6] Id.
[7] Revised Draft SGEIS 2011, Page 6-323
[8] Revised Draft SGEIS 2011, Page 6-323
[9] Revised Draft SGEIS 2011, Page 6-328
[10] Revised Draft SGEIS 2011, Page 5-88, emphasis added
[11] Revised Draft SGEIS 2011, Page 6-327
[12] Nicholson, C., and Wesson, R., 1990, *Earthquake Hazard Associated With Deep Well Injection – A Report to the U.S. Environmental Protection Agency*, U.S. Geological Survey Bulletin 1951, 86p., available at: http://pubs.usgs.gov/bul/1951/report.pdf

Induced seismicity could result in unwanted and dangerous consequences, depending on the size and location of the earthquake. Fault movement may potentially endanger groundwater by creating or enhancing migration pathways between the zone being hydraulically fractured and underground sources of drinking water. Seismicity can also compromise wellbore integrity. The induced seismicity event in the UK caused ovalization of the production casing over hundreds of feet, with more than a half-inch of ovalization occurring over an approximately 250 foot length.[13] Such damage could compromise the cement bond, allowing methane or fluids to migrate up the back side of the casing to groundwater.

Even a relatively small earthquake could cause damage over a large area. The USGS report cited above states that, "Earthquakes in the Central and the Eastern United States typically cause damage over much larger areas as compared to earthquakes of the same size in the Western United States. This is primarily the result of the lower attenuation of seismic waves in the East versus the West, but other factors also may be involved."[14] Earthquakes could cause property damage including to private homes and public buildings and could also put at risk the aqueducts, tunnels, and infrastructure that deliver the New York City drinking water supply. In a report prepared for the New York City Department of Environmental Protection, environmental engineering firm Hazen and Sawyer concluded that, "…liner cracks can be anticipated to develop as the tunnels age, due to normal geologic activity (e.g., seismic activity), and to changes in subsurface conditions associated with widespread hydrofracturing, gas reservoir depletion/withdrawal and injection well operation," and, "Detrimental effects [to tunnel liners] could include liner cracks, which would facilitate infiltration of pressurized fluids."[15] In addition to natural seismic activity, induced seismicity could also be expected to create additional liner cracks. The authors also concluded that, "Hydraulic fracturing operations in proximity to the naturally occurring fracture systems that intersect DEP tunnels will increase the risk of (a) contaminating drinking water with drilling and fracturing chemicals and poor quality formation water; (b) methane accumulation around and within DEP subsurface infrastructure; and (c) tunnel liner structural failure. Mitigation of risks to drinking water quality and infrastructure integrity will require revision of current setback provisions to reflect the occurrence of laterally extensive subsurface faults, fractures, and brittle structures."[16] If earthquakes are induced along faults that intersect the DEP tunnels, these risks could be further exacerbated.

Even in the absence of actual damage, induced seismic events will have financial and manpower costs associated with the investigation of the causes and effects of the earthquake and from the suspension of operations until such studies are completed.

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[13] Id. at 2

[14] Id. at 13

[15] Hazen and Sawyer, 2009, *Impact Assessment of Natural Gas Production in the New York City Water Supply Watershed: Final Impact Assessment Report,* prepared for New York City Department of Environmental Protection, 100p., available at: http://www.nyc.gov/html/dep/pdf/natural_gas_drilling/12_23_2009_final_assessment_report.pdf

[16] Id., Appendix D

The RDSGEIS provides insufficient analysis and scientific evidence to support its conclusion that regulations to reduce the risk of induced seismicity from hydraulic fracturing are not necessary.

Recommendation

The RDSGEIS should require operators to provide a site-specific analysis of the risk of induced seismicity due to hydraulic fracturing. This should include a detailed analysis of the geology, including the locations of known faults and an assessment of the seismic history of the region. Operators should be required to provide an analysis detailing the maximum magnitude of an earthquake that could be triggered based on anticipated injection volume and the probability that such an earthquake may occur based on site-specific geologic and geophysical parameters such as fault and fracture density, lithology, minimum horizontal stress, and anticipated pore pressure as a result of fluid injection.[17] Operators should then be required to use this data to properly design their hydraulic fracture treatment to reduce the risk of triggering induced seismicity. Operators should be required to perform seismic monitoring during hydraulic fracturing to ensure that any seismicity that occurs is within design parameters.

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[17] See, e.g., Shapiro,S. A., C. Dinske, and J. Kummerow (2007), Probability of a given magnitude earthquake induced by a fluid injection, Geophys. Res. Lett., 34, L22314, doi:10.1029/2007GL031615.

Attachment 12

Expert Resumes

Harvey Consulting, LLC.

- Susan Harvey

Tom Myers, Ph.D.

Glenn Miller, Ph.D.

Ralph Seiler, Ph.D.

Meliora Design, LLC.

- Michele Adams, P.E.
- Ruth Sitler, P.E.

The Louis Berger Group, Inc.

- Niek Veraart, AICP, ASLA
- Raed EL-Farhan, Ph.D.
- Hope Luhman, Ph.D., RPA
- Edward Samanns, PWS, CE
- Leo Tidd
- Dane Ismart

Kevin Heatley

Kim Knowlton, DrPH

Gina Solomon, M.D.

Briana Mordick

HARVEY CONSULTING, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

Susan L. Harvey, Owner

Susan Harvey has 25 years of experience as a Petroleum and Environmental Engineer, working on oil and gas exploration and development projects. Ms. Harvey is the owner of Harvey Consulting, LLC, a consulting firm providing oil and gas, environmental, regulatory compliance advice and training to clients. Ms. Harvey held engineering and supervisory positions at both Arco and BP including Prudhoe Bay Engineering Manager and Exploration Manager. Ms. Harvey has planned, engineered, executed and managed both on and offshore exploration and production operations, and has been involved in the drilling, completion, stimulation, testing and oversight of hundreds of wells in her career. Ms. Harvey's experience also includes air and water pollution abatement design and execution, best management practices, environmental assessment of oil and gas project impacts, and oil spill prevention and response planning. During Governor Knowles Administration, Ms. Harvey headed the Industry Preparedness Program for the Alaska Department of Environmental Conservation, Division of Spill Prevention and Response; she was responsible for oil spill prevention and response oversight of all Alaska industry operations that produce, store or transport hydrocarbons. Ms. Harvey taught air pollution control engineering courses at the University of Alaska in the Graduate Engineering Program.

Education Summary:

Environmental Engineering **Masters of Science** University of Alaska Anchorage	Petroleum Engineering **Bachelor of Science** University of Alaska Fairbanks

Consulting Services:

- ☐ Oil and gas, environmental, regulatory compliance advice and training
- ☐ Oil spill prevention and response planning
- ☐ Air pollution assessment and control

Employment Summary:

2002-Current	Harvey Consulting, LLC., Owner
2005-Current	Harvey Fishing, LLC., Co-owner
2002-2007	University of Alaska at Anchorage Environmental Engineering Graduate Level, Adjunct Professor
1999-2002	State of Alaska, Department of Environmental Conservation Environmental Supervisory Position
1996-1999	Arco Alaska Inc. Engineering and Supervisory Positions held
1989-1996	BP Exploration (Alaska), Inc. Environmental, Engineering, and Supervisory Positions held
1987-1989	Standard Oil Production Company *(purchased by BP in 1989),* Engineering Position
1985-1986	Conoco, Production Engineer and New Mexico Institute of Mining and Technology Petroleum Research & Recovery Center, Laboratory Research Assistant

Harvey Consulting, LLC
PO Box 771026 Eagle River, Alaska 99577
Email:sharvey@mtaonline.net; Phone: (907) 694-7994; Fax: (907) 694-7995

Employment Detail:

2002-Current	**Harvey Consulting, LLC.** Owner of consulting business providing oil and gas, environmental, regulatory compliance and training to clients.
2005-Current	**Harvey Fishing, LLC.** Co-owner and operator of a commercial salmon fishing business in Prince William Sound Alaska.
2002-2007	**University of Alaska at Anchorage** Environmental Engineering Graduate Level Program, Adjunct Professor Air Pollution Control.
1999-2002	**State of Alaska, Department of Environmental Conservation** **Environmental Supervisory Position** Industry Preparedness and Pipeline Program Manager, Alaska Department of Environmental Conservation, Division of Spill Prevention and Response. Managed 30 staff in four remote offices. Main responsibility was to ensure all regulated facilities and vessels across Alaska submitted high quality Oil Discharge Prevention and Contingency Plans to prevent and respond to oil spills. Staff included field and drill inspectors, engineers, and scientists. Managed all required compliance and enforcement actions.
1996-1999	**Arco Alaska Inc.** **Engineering and Supervisory Positions held** Prudhoe Bay Waterflood and Enhanced Oil Recovery Engineering Supervisor. Main responsibility was to set the direction for a team of engineers to design, optimize and manage the production over 120,000 barrels of oil per day from approximately 400 wells and nine drill sites, from the largest oil field in North America. Responsible for six concurrently operating drilling and workover rigs. Prudhoe Bay Satellite Exploration Engineering Supervisor for development of six new Satellites Oil Fields. Main responsibility was to set the direction for a multidisciplinary team of Engineers, Environmental Scientists, Facility Engineers, Business Analysts, Geoscientists, Land, Tax, Legal, and Accounting. Responsible for two appraisal drilling rigs. Lead Engineer for Arco Western Operating Area Development Coordination Team. Lead a multi-disciplinary team of engineers and geoscientists, working on the Prudhoe Bay oil field.
1989-1996	**BP Exploration (Alaska), Inc.** **Environmental, Engineering, and Supervisory Positions held** Senior Engineer Environmental & Regulatory Affairs Department. Main responsibilities included: air quality engineering, technical and permitting support for Northstar, Badami, Milne Point Facilities and Exploration Projects. Senior Engineer/Litigation Support Manager. Duties included managing a multidisciplinary litigation staff to support the ANS Gas Royalty Litigation, Quality Bank Litigation and Tax Litigation. Main function was to coordinate, plan and organize the flow of work amongst five contract attorneys, seven in-house attorneys, two technical consultants, eight expert witnesses, four in-house consultants and twenty-two staff members.

Senior Planning Engineer. Provided technical, economic, and negotiations support on Facility, Power, Water and Communication Sharing Agreements. Responsibilities also included providing technical assistance on recycled oil issues, ballast water disposal issues, chemical treatment options, and contamination issues.

Production Planning Engineer. Coordinated State approval of the Sag Delta North Participating Area and Oil Field. Resolved technical, legal, tax, owner and facility sharing issues. Developed an LPG feasibility study for the Endicott facility.

Reservoir Engineer. Developed, analyzed and recommended options to maximize recoverable oil reserves for the Endicott Oil Field through 3D subsurface reservoir models, which predicted fluid movements and optimal well placement for the drilling program. Other duties included on-site wellbore fluid sampling and subsequent lab analysis.

Production Engineer. North Slope field engineering. Duties included design and implementation of wireline, electric line, drilling and rig completions, well stimulation, workovers and well testing programs.

1987-1989 **Standard Oil Production Company, Production Engineer**

Production Engineer. North Slope field engineering. Duties included design and implementation of wireline, electric line, drilling and rig completions, well stimulation, workovers and well testing programs.

Engineering Internship, Barry Waterflood Oklahoma City OK.

1986 **Conoco, Production Engineer**

Production Engineer. Engineering Internship, Hobbs New Mexico.

1985-1986 **New Mexico Institute of Mining and Technology**
Petroleum Research & Recovery Center

Laboratory Research Assistant, Enhanced Oil Recovery, Surfactant Research.

Harvey Consulting, LLC, Major Projects and Publications

Northeast Natural Energy, LLC. and Enrout Properties, LLC vs. The City of Morgantown, West Virginia, technical support to The City of Morgantown, 2011.

Arctic Oil and Gas Project, technical support to Pew Charitable Trust, 2010-2011.

Stockport Mountain Corporation, LLC vs. Norcross Wildlife Foundation, Inc., technical support to Norcross Wildlife Foundation, Inc., 2011.

Nikaitchuq Oil and Gas Development Project, technical review and advice to North Slope Borough, 2011.

Valdez Marine Terminal, Oil Spill Prevention Audit, report prepared for Prince William Sound Regional Citizens Advisory Council, 2011.

Great Bear Petroleum Exploration Oil Spill Prevention and Response Plan, technical review and comments prepared for North Slope Borough, 2011.

Recommendations to Improve the December 9, 2010 Delaware River Basin Commission (DRBC) Proposed Natural Gas Development Regulations, report prepared for Delaware Riverkeeper Network, 2011.

Oooguruk Oil and Gas Development Project, technical review and advice to North Slope Borough, 2011.

Trans-Alaska Pipeline Oil Discharge Prevention and Contingency Plan, technical review and comments prepared for North Slope Borough, 2011

Shell Beaufort Sea Exploration Plan, technical support to North Slope Borough, 2007-2011.

Canadian National Energy Board, Offshore Drilling Review, technical support to WWF-Canada, 2011.

Shell Chukchi Sea Exploration Plan, technical support to North Slope Borough, 2010-2011.

SINTEF Behavior of Oil and Other Hazardous and Noxious Substances (HNS) spilled in Arctic Waters (BoHaSA) Report, technical review and advice to WWF, 2011.

Milne Point Oil & Gas Project, technical review and advice to North Slope Borough, 2011

National Commission Report on the BP Deepwater Horizon Oil Spill and Offshore Drilling, the Challenges of Oil Spill Response in the Arctic, technical analysis and recommendations prepared for Pew Charitable Trust, 2010.

Appeal of U.S. Forest Service Plan of Operations Denial for Wolcott Gold Mining Operation, technical report and appeal filing for Wolcott Gold Mining, 2010.

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Curriculum Vitae

Objective: To provide diverse research and consulting services to nonprofit, government, legal and industry clients focusing on groundwater modeling, hydrogeology, environmental forensics and compliance, NEPA analysis, federal and state regulatory review, fluvial morphology and environmental and water policy.

Education

Years	Degree	University
1992-96	Ph.D. Hydrology/Hydrogeology	University of Nevada, Reno Dissertation: Stochastic Structure of Rangeland Streams
1990-92		University of Arizona, Tucson AZ Classes in pursuit of Ph.D. in Hydrology.
1988-90	M.S. Hydrology/Hydrogeology	University of Nevada, Reno Thesis: Stream Morphology, Stability and Habitat in Northern Nevada
1981-83		University of Colorado, Denver, CO Graduate level water resources engineering classes.
1977-81	B.S., Civil Engineering	University of Colorado, Boulder, CO

Special Coursework

Years	Course	Sponsor
2011	Hydraulic Fracturing of the Marcellus Shale	National Groundwater Association
2008	Fractured Rock Analysis	MidWest Geoscience
2005	Groundwater Sampling Field Course	Nielson Environmental Field School
2004	Environmental Forensics	National Groundwater Association
2004 and -5	Groundwater and Environmental Law	National Groundwater Association

Professional Experience

Years	Position	Duties
1993-Pr.	Hydrologic Consultant	Surface, groundwater and systems modeling, hydrogeology studies, stream restoration design, watershed modeling studies and expert testimony for industry, nonprofit groups, and government agencies.
1999-2004	Great Basin Mine Watch Executive Director	Responsible for reviewing and commenting on mining projects with a focus on groundwater and surface water resources, preparing appeals and litigation, writing reports about mining, fundraising, organizational development, supervision and personnel management.
1992-1997	University of Nevada, Reno Research Associate	Research on riparian area and watershed management including stream morphology, aquatic habitat, cattle grazing and low-flow and flood hydrology.
1990-1992	University of Arizona, Tucson Research and Teaching Assistant	Research on rainfall/runoff processes and climate models. Taught lab sections for sophomore level "Principles of Hydrology". Received 1992 Outstanding Graduate Teaching Assistant Award in the College of Engineering
1988-1990	University of Nevada, Reno Research Assistant	Research on aquatic habitat, stream morphology and livestock management.
1983-1988	US Bureau of Reclamation, Boulder City, NV Hydraulic Engineer	Performed hydrology planning studies on topics including floodplains, water supply, flood control, salt balance, irrigation efficiencies, sediment transport, stream morphology, flood frequency, rainfall-runoff modeling and groundwater balances.
1981-1983	Faulkner-Kellogg and Assoc., Lakewood Co Design Engineer	Basic drainage, grading and subdivision design. Flood control studies.

Representative Reports, Presentations and Projects

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Myers, T., 2009. Technical Memorandum, Review and Analysis of the Hydrology and Groundwater and Contaminant Transport Modeling of the Draft Environmental Impact Statement Blackfoot Bridge Mine, July 2009. Prepared for Greater Yellowstone Coalition, Idaho Falls, Idaho.

Myers, T., 2008. Hydrogeology of the Carbonate Aquifer System, Nevada and Utah With Emphasize on Regional Springs and Impacts of Water Rights Development. Prepared for: Defenders of Wildlife, Washington, D.C.. June 1, 2008.

Myers, T., 2008. Hydrogeology of the Muddy River Springs Area, Impacts of Water Rights Development. Prepared for: Defenders of Wildlife, Washington, D.C. May 1, 2008

Myers, T., 2008. Hydrogeology of the Santa Rita Rosemont Project Site, Numerical Groundwater Modeling of the Conceptual Flow Model and Effects of the Construction of the Proposed Open Pit, April 2008. Prepared for: Pima County Regional Flood Control District, Tucson AZ.

Myers, T., 2008. Technical Memorandum, Review, Record of Decision, Environmental Impact Statement Smoky Canyon Mine, Panels F&G, U.S. Department of the Interior, Bureau of Land Management. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno NV.

Myers, T., 2007. Groundwater Flow and Contaminant Transport at the Smoky Canyon Mine, Proposed Panels F and G. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno NV. December 11, 2007.

Myers, T., 2007. Hydrogeology, Groundwater Flow and Contaminant Transport at the Smoky Canyon Mine, Documentation of a Groundwater Flow and Contaminant Transport Model. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno NV, December 7, 2007.

Myers, T., 2007. Review of Hydrogeology and Water Resources for the Final Environmental Impact Statement, Smoky Canyon Mine, Panels F and G and Supporting Documents. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno, NV. December 12, 2007.

Myers, T., 2007. Hydrogeology of the Powder River Basin of Southeast Montana Development of a Three-Dimensional Groundwater Flow Model. Prepared for Northern Plains Resource Council. February 12 2007.

Myers, T., 2007. Hydrogeology of the Santa Rita Rosemont Project Site, Conceptual Flow Model and Water Balance, Prepared for: Pima County Flood Control District, Tucson AZ

Myers, T., 2006. Review of Mine Dewatering on the Carlin Trend, Predictions and Reality. Prepared for Great Basin Mine Watch, Reno, NV

Myers, T., 2006. Hydrogeology of Spring Valley and Effects of Groundwater Development Proposed by the Southern Nevada Water Authority, White Pine and Lincoln County, Nevada. Prepared for Western Environmental Law Center for Water Rights Protest Hearing.

Myers, T., 2006. Potential Effects of Coal Bed Methane Development on Water Levels, Wells and Springs of the Pinnacle Gas Resource, Dietz Project In the Powder River Basin of Southeast Montana. Affidavit prepared for Northern Plains Resource Council, April 4 2006.

Myers, T., 2006. Review of Hydrogeology and Water Resources for the Draft Environmental Impact Statement, Smoky Canyon Mine, Panels F and G, Technical Report 2006-01-Smoky Canyon. Prepared for Natural Resources Defense Council.

Myers, T., 2006. Review of Nestle Waters North America Inc. Water Bottling Project Draft Environmental Impact Report / Environmental Assessment. Prepared for McCloud Watershed Council, McCloud CA.

Myers, T., 2005. Hydrology Report Regarding Potential Effects of Southern Nevada Water Authority's Proposed Change in the Point of Diversion of Water Rights from Tikapoo Valley South and Three Lakes Valley North to Three Lakes Valley South. Prepared for Western Environmental Law Center for Water Rights Protest Hearing

Myers, T., 2005. Review of Draft Supplemental Environmental Impact Statement, Ruby Hill Mine Expansion: East Archimedes Project NV063-EIS04-34, Technical Report 2005-05-GBMW. Prepared for Great Basin Mine Watch.

Myers, T., 2005. Hydrogeology of the Powder River Basin of Southeast Montana, Development of a Three-Dimensional Groundwater Flow Model. Prepared for Northern Plains Resource Council, Billings, MT in support of pending litigation.

Myers, T., 2005. Nevada State Environmental Commission Appeal Hearing, Water Pollution Control Permit

Renewal NEV0087001, Big Springs Mine. Expert Report. Prepared for Great Basin Mine Watch, Reno NV.

Myers, T., 2005. Potential Effects of Coal Bed Methane Development on Water Levels, Wells and Springs In the Powder River Basin of Southeast Montana. Prepared for Northern Plains Resource Council, Billings, MT.

Myers, T., 2004. An Assessment of Contaminant Transport, Sunset Hills Subdivision and the Anaconda Yerington Copper Mine, Technical Report 2004-01-GBMW. Prepared for Great Basin Mine Watch.

Myers, T., 2004. Technical Memorandum: Pipeline Infiltration Project Groundwater Contamination. Prepared for Great Basin Mine Watch.

Myers, T., 2004. Technical Report Seepage From Waste Rock Dump to Surface Water The Jerritt Canyon Mine, Technical Report 2004-03-GBMW. Prepared for Great Basin Mine Watch.

Myers, T., 2001. An Assessment of Diversions and Water Rights: Smith and Mason Valleys, NV. Prepared for the Bureau of Land Management, Carson City, NV.

Myers, T., 2001. Hydrogeology of the Basin Fill Aquifer in Mason Valley, Nevada: Effects of Water Rights Transfers. Prepared for the Bureau of Land Management, Carson City, NV.

Myers, T., 2001. Hydrology and Water Balance, Smith Valley, NV: Impacts of Water Rights Transfers. Prepared for the Bureau of Land Management, Carson City, NV

Myers, T., 2000. Alternative Modeling of the Gold Quarry Mine, Documentation of the Model, Comparison of Mitigation Scenarios, and Analysis of Assumptions. Prepared for Great Basin Mine Watch. Center for Science in Public Participation, Bozeman MT.

Myers, T., 2000. Environmental and Economic Impacts of Mining in Eureka County. Prepared for the Dept. Of Applied Statistics and Economics, University of Nevada, Reno.

Myers, T., 1999. Water Balance of Lake Powell, An Assessment of Groundwater Seepage and Evaporation. Prepared for the Glen Canyon Institute, Salt Lake City, UT.

Myers, T., 1998. Hydrogeology of the Humboldt River: Impacts of Open-pit Mine Dewatering and Pit Lake Formation. Prepared for Great Basin Mine Watch, Reno, NV.

Peer-Reviewed Publications

Myers, T., in review. Potential contaminant pathways from hydraulically fractured shale to aquifers. *Ground Water*.

Myers, T., 2009. Groundwater management and coal-bed methane development in the Powder River Basin of Montana. *J Hydrology* 368:178-193.

Myers, T.J. and S. Swanson, 1997. Variation of pool properties with stream type and ungulate damage in central Nevada, USA. *Journal of Hydrology* 201-62-81

Myers, T.J. and S. Swanson, 1997. Precision of channel width and pool area measurements. *Journal of the*

American Water Resources Association 33:647-659.

Myers, T.J. and S. Swanson, 1997. Stochastic modeling of pool-to-pool structure in small Nevada rangeland streams. *Water Resources Research* 33(4):877-889.

Myers, T.J. and S. Swanson, 1997. Stochastic modeling of transect-to-transect properties of Great Basin rangeland streams. *Water Resources Research* 33(4):853-864.

Myers, T.J. and S. Swanson, 1996. Long-term aquatic habitat restoration: Mahogany Creek, NV as a case study. *Water Resources Bulletin* 32:241-252

Myers, T.J. and S. Swanson, 1996. Temporal and geomorphic variations of stream stability and morphology: Mahogany Creek, NV. *Water Resources Bulletin* 32:253-265.

Myers, T.J. and S. Swanson, 1996. Stream morphologic impact of and recovery from major flooding in north-central Nevada. *Physical Geography* 17:431-445.

Myers, T.J. and S. Swanson, 1995. Impact of deferred rotation grazing on stream characteristics in Central Nevada: A case study. *North American Journal of Fisheries Management* 15:428-439.

Myers, T.J. and S. Swanson, 1992. Variation of stream stability with stream type and livestock bank damage in northern Nevada. *Water Resources Bulletin* 28:743-754.

Myers, T.J. and S. Swanson, 1992. Aquatic habitat condition index, stream type, and livestock bank damage in northern Nevada. *Water Resources Bulletin* 27:667-677.

Zonge, K.L., S. Swanson, and T. Myers, 1996. Drought year changes in streambank profiles on incised streams in the Sierra Nevada Mountains. *Geomorphology* 15:47-56.

Selected Abstracts, Magazine and Proceedings Articles

Myers, T., 2006. Modeling Coal Bed Methane Well Pumpage with a MODFLOW DRAIN Boundary. In MODFLOW and More 2006 Managing Ground Water Systems, Proceedings. International Groundwater Modeling Center, Golden CO. May 21-24, 2006.

Myers, T., 2006. Proceed Carefully: Much Remains Unknown, *Southwest Hydrology 5(3)*, May/June 2006, pages 14-16.

Myers, T., 2004. Monitoring Well Screening and the Determination of Groundwater Degradation, Annual Meeting of the Nevada Water Resources Association, Mesquite, NV. February 27-28, 2004.

Myers, T., 2001. Impacts of the conceptual model of mine dewatering pumpage on predicted fluxes and drawdown. In MODFLOW 2001 and Other Modeling Odysseys, Proceedings, Volume 1. September 11-14, 2001. International Ground Water Modeling Center, Golden, Colorado.

Myers, T., 1997. Groundwater management implications of open-pit mine dewatering in northern Nevada. In Kendall, D.R. (ed.), Conjunctive Use of Water Resources: Aquifer Storage and Recovery. AWRA Symposium, Long Beach California. October 19-23, 1997

Myers, T., 1997. Groundwater management implications of open-pit mine dewatering in northern Nevada. In Life in a Closed Basin, Nevada Water Resources Association, October 8-10, 1997, Elko, NV.

Myers, T., 1997. Uncertainties in the hydrologic modeling of pit lake refill. American Chemical Society Annual Meeting, Las Vegas, NV, Sept. 8-12, 1997.

Myers, T., 1997. Use of Groundwater modeling and geographic information systems in water marketing. In Warwick, J.J. (ed.), Water Resources Education, Training, and Practice: Opportunities for the Next Century. AWRA Symposium, Keystone, Colo. June 29-July 3, 1997.

Myers, T., 1995. Decreased surface water flows due to alluvial pumping in the Walker River valley. Annual Meeting of the Nevada Water Resources Association, Reno, NV, March 14-15, 1995.*

Select Testimony in Litigation and Administrative Hearings

Northeast Natural Energy LLC v. City of Morgantown, Monongalia Circuit Court, Civil Action No. 11-C-411. 2011. Submitted to Deposition. Case dismissed on constitutional grounds.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s 53987-53992, 54003-54021. September 26 through November 14, 2011, Spring Valley, Cave Valley, Dry Lake and Delamar Valley. Testimony on behalf of protestants Great Basin Water Network, Confederated Tribes of the Goshute Reservation.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s 53987-53992, Cave Valley, Dry Lake, and Delamar Valley, NV. February 4 through February 14, 2008. Testimony on behalf of protestant Great Basin Water Network.

Cole et al v. J.M.Huber Corp. and William DeLapp. U.S. District Court for the District of Wyoming. Case No. 06-CV-01421. Written evidence reports and deposition. Case settled.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s, 54003-54021, Spring Valley, NV. Testimony on behalf of protestant Great Basin Water Network. September 11-26, 2006.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s, 54003-54021, Spring Valley, NV. Testimony on behalf of protestant Great Basin Water Network. September 11-26, 2006.

Montana 22nd Judicial District Court, Big Horn County. Diamond Cross Properties, LLC, and Northern Plains Resource Council, and Tongue River Water Users Association v. State of Montana, Pinnacle Gas Resources. Civil Cause No. DV 05-70. Affidavit provided.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s 72787 – 72797, Tickaboo/Three Lakes Basin. Testimony on behalf of Sierra Club, Indian Springs. November 28 – 30, 2005.

Earlier, several cases before the Nevada State Environmental Commission, on behalf of Great Basin Mine Watch.

CURRICULUM VITAE

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Born November 17, 1950

Education:

University of California, Santa Barbara, CA	B.S. Chemistry	1972
University of California, Davis, CA	Ph.D. Agricultural Chemistry	1977

Employment:

Univ. of Nevada, Reno	Aug-2009-present	Professor, and Director of the Graduate Program in Environmental Sciences
	2008-2009	On leave for 11 months serving as Manager, Environmental Exposure Assessment, Valent USA Corporation, Walnut Creek CA
	2007-2008, 2010-present	President UNR Nevada Faculty Alliance
	1995-2006	Director, Graduate Program in Environmental Sciences and Health
	1998-2004	Director, Center for Environmental Science and Engineering
	1989-	Professor
	1983-89	Associate Professor
	1979-83	Assistant Professor
	1978-79	Lecturer
Environmental Protection Agency	1977-78	Research Chemist

Professional Societies:

American Chemical Society, Agrochemicals Division and Environmental Division
American Association for the Advancement of Science
Society of Environmental Toxicology and Chemistry
Sigma Xi

Awards:

Thornton Peace Prize (1982)
Junior Faculty Research Award (1982)
UNR Foundation Professor (1991)
Conservationist of the Year, Nevada Wildlife Federation (1995)
College of Agriculture Researcher of the Year (1998)
Friend of the Lake Award, League to Save Lake Tahoe (2001)

Other Professional Activities

Environmental Protection Agency: Competitive Grants Review Panel 1985-1995
Environmental Protection Agency: Advisory Committee on Mining Waste 1991-1993
Environmental Protection Agency: Stakeholder Advisory Committee on Commodity Mercury 2007
Nevada Division of Environmental Protection: Technical Advisory Committee on the Carson River Superfund Site 1991-1994
American Chemical Society, Division of Environmental Chemistry: Chair of the Student Awards Committee 1988-1992
American Chemical Society, Division of Environmental Chemistry: Chair of the Awards Committee 1997-2002
UNR Environmental Studies Board: Chairman 1987-1991
UNR Environmental Science and Health Graduate Program: Director 1995-2006
Consultant to various public interest organizations, companies and law firms
Hydrology/Hydrogeology Graduate Faculty: Member 1989-present
Reviewer for numerous environmental chemistry journals
Co-owner and vice-president: Nevada Environmental Laboratories (Las Vegas and Reno) 1990-1999
Manager, Environmental Exposure Assessment, Valent USA Corporation 8/2008- 8/2009

Courses Taught

Humans and the Environment: Environment 100
Environmental Toxicology: NRES 432/632
Environmental Chemicals: Exposure, Transport and Fate: NRES 433/633
Analysis of Environmental Contaminants: NRES 430/630
Risk Assessment, NRES 793C
Global and Regional Issues in Environmental Science: NRES 467/667

Community and Conservation Service Activities

City of Reno, Charter Review Commission: Chairman 1990-93
Peavine Grade School PTA: Co-President 1990-1992
Sierra Club Mining Committee (national): Co-Chair 1989-1992
League to Save Lake Tahoe Board of Directors: 1986-1999
Mountain and Desert Research Fund: 1987-present
Dupont-Conoco Environmental Leadership Award in Mining Committee: 1989-1994
Nevada Interagency Reclamation Award Committee: 1990-1992
Washoe County School District Science Advisory Board: 1992-2000
  Chairman, 1993-94
Earthwords: Board Member 1999-present
Tahoe Baikal Institute: Board Member 1998-present, Chair 2002-2003
Environmental Law Alliance Worldwide Board Member: 2000-present, Chair:2009
Great Basin Mine Watch: Board Member 1994-present, Chair 2001-2006
Center for Science in Public Participation: Board Member 1998-present
Great Basin Institute, Board Member 2000-present, Chair 2001-present
United Nations Environmental Program Committee for Development of a Code for Use of Cyanide in Mining: 2000-2002
Mining, Minerals and Sustainable Development, Assurance Group Committee Member, 2000-2002
National Research Council committee on Methyl Bromide: 1999-2001
National Research Council committee on Mining Technology: 2000-2002

National Research Council committee on USGS Mineral Resources Program, 2000-2003
US Environmental Protection Agency Committee on Management of Mercury Stores in the U.S. 2007

Research Interests: Remediation of mine waste contamination. Mining pit lake water quality. Fate and transport of organic compounds in soils and the atmosphere. Methods of remediation of gasoline contaminated soils; Photochemical transformation of organic contaminants on soil surfaces. Instrumental development of chromatographic systems.

Grants Received: (1982-present)

$ 14,550 "Atmospheric Photolysis of Pesticides," A Junior Faculty Research Award from the UNR Research Advisory Board, 1982.

$ 3,000 "Photolysis of CGA-41065," CIBA GEIGY Corporation, 1982.

$ 4,000 "Chemotaxonomy of Sagebrush Using High Performance Liquid Chromatography," Intermountain Research Station USDA, 1984.

$ 83,000 "Analysis of Bovine Tissue for Chlorinated Hydrocarbons," Environmental Protection Agency, 1984-85.

$ 18,300 "Photooxidation of Sulfide Containing Pesticides on Soil Surfaces," Western Regional Pesticide Impact Assessment Program, 1984.

$ 2,500 "Identification of Sagebrush Taxa Based on Liquid Chromatographic Analyses of Phenolics" Research Advisory Board, 1986.

$235,500 "Factors Affecting the Photolysis of Dioxins on Soil Surfaces," U.S. Environmental Protection Agency, 1986-89.

$ 15,160 "Vapor Phase Photolysis of Phorate," American Cyanamid Corporation, 1987.

$ 2,500 "Identification of Sagebrush Taxa Based on Liquid Chromatographic Analyses of Phenolics," UNR Research Advisory Board, 1987.

$ 48,792 "Upgrading Municipal Wastewater Effluents for Urban Water Reuse through Phytochemical Oxidations: System Development and Operational Criteria," U.S. Geological Survey, State Water Research Institute Program (Co-P.I. with Richard Watts), 1986-88.

$ 17,200 "Vapor Phase Photolysis of Malathion," American Cyanamid, 1988.

$ 16,460 "Aging Groundwater: A comparison of the Fluorocarbon Method to the Tritium Method," U.S. Geological Survey, State Water Research Institute Program (Co-P.I. with K. Sertic), 1988-89. (Competitive Grant, State of Nevada) Terminated 6-89.

$206,000 "In Situ Treatment of Organic Hazardous Wastes in Surface Soils Using Fenton's Reagent." U.S. Environmental Protection Agency (Co-P.I. with Richard Watts), 1988-89. (Competitive Grant, national)

$ 23,200 "Evaporation of Gasoline from Soils," Nevada Division of Environmental Protection Co-P.I. with Susan Donaldson), (Contract).

$ 50,000 "Photolysis of Pesticides on Soils," American Cyanamid Corporation (Unrestricted Grant, noncompetitive)

$ 15,600 "Vapor Phase Photolysis of Diazinon and Methyl Parathion" Western Region Pesticide Impact Assessment Program (USDA) (competitive) 1989-90

$ 30,000 "Interface for a Capillary electrophoresis Effluent and a Mass Spectrometer" Linear Corporation 1989-90. (Co P.I. with Murray Hackett) (contract)

$ 15,000 "UV-Gas Chromatographic Dectector" Linear Corporation 1990. (Co P.I. with Murray Hackett) (Noncompetitive grant)

$153,000 "Enhancement of Photodegradation of Pesticides in Soil by Transport Upward in Evaporating Water" (USGS Competitive) 1991-94

$ 50,000 "Pit Water from Precious Metal Mines" U.S. Environmental Protection Agency, 1992-94

$ 91,000 "Remediation of Acid Mine Drainage at Leviathon Mine" Lahontan Water Quality Control Board. (Contract, Co P.I. with Tom Wildman, Colorado School of Mines) 1992-94.

$159,000 " Ecological Toxicology of Metam Sodium and it Derivatives in the Terrestrial and Riparian Environments of the Sacramento River" California Fish and Game, 1992-1995 (G.C. Miller project, part of a larger project with George Taylor at the Desert Research Institute)

$43,092 “Atmospheric Transport and Deposition of Organophosphates and Other Pesticides as Input to Sierra Nevada Surface Waters” USDA-NRI. 1995-98. Co-P.I. with P.I. James N. Seiber. Task 2.

$80,427 “Linked Techniques for Contaminant Removal from Soil in Arid/Semiarid Environments” Dept. of Energy. 1993-96. Co.P.I with James N. Seiber.

$107,000 “Chemical Environmental Problems Associated with Mining” NIEHS 1993-96. Core B portion. This was a project of a larger Superfund Grant to UNR. James N. Seiber, P.I.

$36,900 “Protocol for Evaluation of Pesticide Photodegradation” Dow-Elanco. 1995-97. (Contract)

$45,000 “Photolysis of Pesticides” Dupont Chemical Company. 1995-98. Unrestricted gift to support ongoing research.

$275,000 “Remediation of Acid Mine Drainage at the Leviathan Mine”. Nevada Division of Environmental Protection. 1996-99

$5000 “Evaluation of Limnology and Water Quality of a Porphyry-Copper Pit Mine Lake” Public Resource Associates 1996.

$767,000 Geochemical, Biological and Economic Impacts of Arsenic and Related Oxyanions on a Mining-Impacted Watershed” NSF-EPA, 1997-01

$46,000 “Remediation of Acid Mine Drainage at the Leviathan Mine”. Lahontan Regional Water Quality Control Board, 2000-2001

$30,000 "Use of Sulfate-Reducing Bioreactors to Remove Zinc in Mine Drainage" Placer Dome Corporation. 2000-2001

$50,000 “Release of Gasoline Constituents from Marine Engines to Lake Tahoe” Lahontan Regional Water Quality Control Board, 1998-1999

$70,000 "Impact of Marine Engine Exhaust on Pyramid Lake" U.S. Environmental Protection Agency, in cooperation with the Pyramid Lake Paiute Tribe. 2000-2001.

$570,000 "An Environmental Assessment of the Impacts of Polycyclic Aromatic Hydrocarbons in Lake Tahoe and Donner Lake" California Regional Water Quality Control Board, Lahontan Region. 2001-2003.

$126,000 "Operation of a Bioreactor at the Leviathan Mine" Contract with ARCO, 2001-2002

$75,000 Trifluroacetic Acid in Antarctic Ice, National Science Foundation 2001-2004

$190,500 “Mercury Deposition Associated with Mining, U.S. Environmental Protection Agency, 2002-2004

$53,000 Passivation of Acid Generating Rock at the Golden Sunlight Mine, Placer Dome Corporation 2002-2003

$520,000 “Operation of a Bioreactor at the Leviathan Mine" Contract with ARCO, 2003-2007

$250,000 “Risk Assessment and Fate of Polyacrylamide and Acrylamide in Irrigation Canals and Receiving Water” A subcontract from the Desert Research Institute on a project from the U.S. Bureau of Reclamation. 2004-2008

$55,000 Passivation of Acid Generating Rock, Freeport McMoran, 2009-2010

$75,000 Biofuel crops on arid lands, Co-P.I. U.S. Department of Energy, 2010-2011

<u>Publications:</u>

G.C. Miller and D.G. Crosby, "Photodecomposition of Sustar^{R} in Water." J. Agric. Food Chem. 26:1316 (1978).

G.C. Miller and R.G. Zepp, "Effects of Suspended Sediments on Photolysis Rates of Dissolved Pollutants." Water Research 13:453 (1979).

G.C., Miller, M.J. Miille, D.G. Crosby, S. Sontum and R.G. Zepp, "Photosolvolysis of 3,4-Dichloroaniline in Water: Evidence for an Aryl Cation Intermediate." Tetrahedron 35:1797 (1979).

G.C. Miller and R.G. Zepp, "Photoreactivity of Pollutants Sorbed on Suspended Sediment." Environ. Sci. Technol. 13:860 (1979).

G.C. Miller, R. Zisook and R.G. Zepp, "Photolysis of 3,4-Dichloroaniline in Natural Waters." J. Agric. Food Chem. 28:1053 (1980).

G.C. Miller, R.G. Warren, K. Gohre and L. Hanks, "A Gas Chromatographic Method for Determining Strychnine Residues in Alfalfa." J. Assoc. Off. Anal. Chem. 65:901 (1982).

G.C. Miller and W.W. Miller, Eds. "Effect of Sewage on the Truckee River." A symposium published by the University of Nevada, College of Agriculture (1982).

G.C. Miller and R.G. Zepp, "Extrapolating Photolysis Rates from the Laboratory to the Environment." Residue Reviews 85:89 (1983).

G.C. Miller and D.G. Crosby, "Pesticide Photoproducts: Generation and Significance." J. Clin. Toxicol. 19:707 (1983).

G.C. Miller, W.W. Miller, J.W. Warren and L. Hanks, "Soil Sorption and Alfalfa Uptake of Strychnine Applied as an Agricultural Rodenticide." J. Environ. Quality 12:526 (1983).

G.C. Miller and D.G. Crosby, "Photooxidation of 4-Chloroaniline and N-(4-Chlorophenyl)-Benzene-sulfonamide to Nitroso- and Nitro-Products." Chemosphere 12:1217-1227 (1983).

K. Gohre and G.C. Miller, "Singlet Oxygen Generation on Soil Surfaces." J. Agri. and Food Chem. 31:1104-1108 (1983).

R.G. Zepp, P.F. Schlotzhauer, M.S. Simmons, G.C. Miller, G.L. Baughman and N.L. Wolfe, "Dynamics of Pollutant Photoreactions in the Hydrosphere." J. of Fresenius Z. Anal. Chem. 319:119-125 (1984).

K. Gohre and G.C. Miller, "Photochemical Generation of Singlet Oxygen on Non-transition Metal Surfaces." J. Chem. Soc. Faraday Trans. I 81:793-800 (1985).

R.V. Tamma, G.C. Miller and R. Everett, "High-Performance Liquid Chromatographic Analysis of Coumarins and Flavonoids from Section Tridentatae of ***Artemisia***." J. Chromatography 322:236-239 (1985).

K. Gohre, R. Scholl and G.C. Miller, "Singlet Oxygen Reactions on Soil Surfaces." Environ. Sci. Technol. 20:934-938 (1986).

K. Gohre and G.C. Miller, "Photooxidation of Thioether Pesticides on Soil Surfaces." J. Agric. Food Chem. 34:709-713 (1986).

B.R. Smith, G.C. Miller, R.W. Mead and R.E.L. Taylor, "Biosynthesis of Asparagine and Taurine in the Freshwater Prawn, ***Macrobrachium rosenbergii*** (De Man)." Comp. Biochem. Physiol. 87B(4):827-831 (1987).

B.R. Smith, G.C. Miller and R.W. Mead, "Taurine Tissue Concentrations and Salinity Effect on Taurine in the Freshwater Prawn ***Macrobrachium rosenbergii*** (De Man)." Comp. Biochem. Physiol. 87A(4):907-909 (1987).

G.C. Miller and V. Hebert, "Environmental Photodecomposition of Pesticides." In: University of California publication - Fate of Pesticides in the Environment (J.W. Biggar and J.N. Seiber, eds.) Chapt. 8, p. 75-86 (1987).

G.C. Miller and R.G. Zepp, "2,3,7,8-Tetrachlorodibenzo-p-dioxin: Environmental Chemistry." In: Solving Hazardous Wastes Problems: Learning from Dioxins (J.H. Exner, ed.) American Chemical Society Symposium Series 338, Chapter 6, pp. 82-93 (1987).

C.R. Blincoe, V.R. Bohman, G.C. Miller, R.L. Scholl, W.W. Sutton and L.R. Williams, "Excretion and Tissue Concentration of Pentachlorophenol Following Controlled Administration to Cattle." J. Animal Sci. 65 Supplement #1 (1987).

G.C. Miller, V.R. Hebert and R.G. Zepp, "Chemistry and Photochemistry of Low-Volatility Organic Chemicals on Environmental Surfaces." Env. Sci. Tech. 21:1164-1167 (1987).

V.R. Bohman, C.R. Blincoe, G.C. Miller, R.L. Scholl, W.W. Sutton and L.R. Williams, "Biological Monitoring Systems for Hazardous Waste Sites." EPA Final Report #CR 809 787 (1988).

F.M. Wilt, G.C. Miller and R.L. Everett, "Monoterpene Concentrations of Litter and Soil of Singleleaf Pinyon Woodlands of the Western Great Basin." Great Basin Naturalist 48:228-231 (1988).

K. Mongar and G.C. Miller, "Vapor Phase Photolysis of Trifluralin in an Outdoor Chamber." Chemosphere 17(11):2183-2188 (1988).

G.C. Miller, V.R. Hebert and W.W. Miller, "Effects of Sunlight on Organic Contaminants at the Atmosphere - Soil Interface." In: Reactions and Movement of Organic Chemicals in Soils (B. Sawhney, ed.) SSSA Special Publication No. 22, pp. 99-110 (1989).

G.C. Miller, V.R. Hebert, M.J. Miille, R. Mitzel and R.G. Zepp, "Photolysis of Octachlorodibenzo-p-Dioxin on Soils: Production of 2,3,7,8-TCDD." Chemosphere 18(1-6):1265-1274 (1989).

G.C. Miller, "Choosing an Analytical Lab" Nevada Waste Reporter Spring, 1989. (Publication of the Nevada Small Business Development Center).

N.L. Wolfe, U. Mingelgrin and G.C. Miller, "Abiotic Transformation Processes in Water, Sediments and Soils." In: B. Spencer and H.H. Cheng, eds., Pesticides and Other Toxic Organics in Soils, Soil Science Society of America, pp. 103-168 (1990).

S. Donaldson, G.C. Miller and W.W. Miller, "Extraction of Gasoline Constituents from Soil." J. Assn. Off. Anal. Chem. *73:*306-311 (1990)

V.R. Hebert and G.C. Miller, "Depth Dependence of Direct and Indirect Photolysis on Soil Surfaces." J. Agric. Food Chem. 38:913-918, (1990)

J.M. Basey, S.H. Jenkins and G.C. Miller, "Food Selection by Beavers in Relation to Inducible Defenses of Quaking Aspens" Oikos 59:57-62 (1990).

S. Donaldson, G. C. Miller, and W.W. Miller, "Volatilization of Gasoline Constituents from Soil. In: Proceedings of the Fourth National Outdoor Action Conference on Aquifer Restoration, Ground Water Monitoring and Geophysical Methods, Las Vegas NV May, 1990.

G.C. Miller, "Nevada's Environmental Commission: Changes Needed for the 1990's" in F. Ballister, Ed. The Nevada Environmental Commission, Published by Claremont College 1991.

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Ralph L. Seiler

PROFESSIONAL EXPERIENCE

Hydrologist

1979-2010 (retired) U.S. Geological Survey Carson City, NV

- Principal investigator for numerous water-quality investigations of surface water and groundwater, including identifying sources of phosphorus in the Carson River, sources of nitrate and bacteria in groundwater, and sources and distribution of TCE in groundwater near a landfill on an Air Force Base in Utah.
- Principal investigator for USGS Fallon leukemia investigation of ground-water quality which involved working closely with CDC, ATSDR, and the State of Nevada. Participated in many public meetings with State and Federal Agencies to explain results of findings related to the presence of arsenic, tungsten, uranium, and polonium-210 in Fallon area groundwater.
- Author of journal articles describing geochemical processes that result in exposure of the public to toxic trace elements and radionuclides.

PUBLICATIONS

Seiler and Wiemels, *in review at Environmental Health Perspectives*. Occurrence of ^{210}Po and biological effects of low-level exposure: The need for research.

Seiler, 2011a, Physical setting and natural sources of exposure to carcinogenic trace elements and radionuclides in Lahontan Valley, Nevada. Chemical-Biological Interactions [Epub ahead of print DOI:10.1016/j.cbi.2011.04.004]

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EDUCATION

Ph.D. Environmental Chemistry

1996-1999 University of Nevada, Reno Reno, NV

B.S./M.S. Biology

1969-1975 University of Utah Salt Lake City, UT

Michele C. Adams, P.E.
LEED AP
Principal Water Resources Engineer

Meliora Environmental Design, LLC

Relevant Experience

Ms. Adams is a Principal Engineer and founder of Meliora Environmental Design. For more than 25 years, her work has encompassed environmentally sensitive site design and sustainable water resources engineering. Building on a multi-disciplinary approach, her work includes both master planning and design for campuses, urban restoration projects, commercial, industrial and residential installations, public facilities, and environmental education centers. In all her work, Ms. Adams seeks to combine sound engineering science with an understanding of natural systems. She is a frequent lecturer and educator on the topics of water and sustainability, and has provided technical expertise to clients ranging from watershed advocacy organizations to corporations. Ms. Adams was one of the principle authors of the Pennsylvania Stormwater Manual, and serves on the U.S. Green Building Council's Technical Advisory Group for Sustainable Sites. She frequently serves as an expert witness with regards to stormwater and water quality issues. Current design projects in which Ms. Adams is engaged include the following:

Stormwater Management for Green and Public Properties, City of Philadelphia: Led a team of engineers, landscape architects, and planners in developing stormwater designs for the City of Philadelphia public properties. The stormwater and landscape designs are intended to reduce impacts to the City's combined sewer system, provide economic cost savings, and promote green infrastructure. Projects have included parks, schools, recreation facilities, and "green streets". A number of projects have been documented through construction and are being (or have been) built.

Purdue University Stormwater Plan: Development of a Stormwater Plan for retrofitting an urban campus to implement an LID approach and incorporate green infrastructure to improve water quality and reduce stormwater runoff volumes. Protection and recharge of drinking water source (groundwater) and water quality protection is a key component of recommendations.

Purdue University Site and Stormwater Improvements at the Mackey Football Fields and Ross-Ade Stadium Parking Lot, West Lafayette, IN: Design of nearly 3 acres of infiltration beds located beneath the Purdue Boilmaker's football practice fields to manage stormwater for the upper campus athletic complex. At the Ross-Ade Stadium, design of bioretention systems to pre-treat runoff from the parking lot and bordering roadways, a drainage area of nearly 6 acres, before the system connects to the infiltration beds under the adjacent football practice fields.

Stroud Water Research Center Environmental Education Center, Academy of Natural Sciences, Avondale, PA: For one of the nation's premier water research and education facilities, provided sustainable site design engineering related to stormwater management including rain gardens, water reuse, and green roof.

U.S. Botanic Garden Bartholdi Park, Washington, D.C.: Designing stormwater management measures in the landscape to serve as demonstration sites as well as to demonstrate compliance with the new Federal Regulations for stormwater management as part of Section 438 of the Energy Independence and Security Act. The project is also seeking certification from the Sustainable Sites Initiative.

High Performance Landscapes, New York City Parks and Recreation: Ms. Adams served as one of four authors in development of the New York City's *High Performance Landscapes* document, specifically addressing water issues. This publication will be the third in the series that began with *High Performance Buildings*.

Special Qualifications

Twenty-five years of experience in civil and water resources engineering.

Sustainable site design engineering, including Stormwater Best Management Practices, Low Impact Development, (porous pavement, bioretention, tree trenches, vegetated roofs, etc) and alternative wastewater treatment systems (wetlands, drip irrigation, recirculating filters). Design for projects seeking LEED certification.

Watershed studies, computer modeling, stormwater sampling, stream flow monitoring, NPDES permit applications, mixing zone analyses, pollution prevention plans.

Professional Credentials

Bachelor of Science Civil Engineering
Pennsylvania State University, State College, PA, 1984

Graduate Coursework Water Resource Engineering
Villanova University, PA
1997-2001

Registered Professional Engineer in Delaware, Pennsylvania, Virginia, Maryland

LEED Accredited Professional

Waterview Recreation Center, City of Philadelphia and Pennsylvania Horticultural Society: For an existing urban recreation center, design of "green infrastructure" stormwater elements to improve community amenities and reduce combined sewer overflows. Elements include stormwater tree trenches, stormwater planter boxes, and a cistern for the community garden. *This project has recently been the subject of a GreenTreks video on stormwater.*

Greenstreets Design, East Falls: Led a team of design professionals (traffic engineers, landscape architects, pedestrian designers, stormwater engineers) in the design of a "complete" street for an urban neighborhood, including two design charettes with regulatory and design professionals from various city and state agencies. The goal was to develop a complete street that addressed stormwater, various transportation modes, and neighborhood greening and revitalization.

University of Pennsylvania Shoemaker Green, Philadelphia: Design of a passive open space on Penn's Campus that captures runoff generated by new and existing impervious surfaces into site and landscape features throughout the site. The project is also seeking certification from the Sustainable Sites Initiative.

Three Groves Ecovillage: Evaluating the Zoning Overlay for the proposed Ecovillage as well as designing the Water system, Wastewater Collection system, and stormwater measures for the site. Consisting of small residential buildings, community greenhouses, community buildings, natural pools, a constructed wetland treatment system, and bioswales, the proposed Ecovillage development is a model sustainable "green" neighborhood.

Philadelphia Zoo Master Plan: Development of water and environmental recommendations for the Zoo Master Plan, with focus on stormwater measures integrated into the Zoo's landscape to address flooding problems while promoting sustainability.

Greening and Stormwater Retrofits for Urban Schoolyards, Philadelphia: For two existing urbanized school yards (Greenfield School and Independence Charter School) that previously consisted only of asphalt, designed elements intended to both capture the first inch of runoff and provide greening, environmental education, and reduce heat island effects. Components include rain gardens, porous asphalt, porous pavers, and vegetated swales. *Greenfield School has recently been the subject of a GreenTreks video on stormwater.*

Stormwater Plans and Environmental Site Design Analysis for Maryland Projects: For the Chesapeake Bay Foundation and Audubon Society, Ms. Adams led an effort to evaluate various project sites in Maryland and provide recommendations and cost estimates for implementing landscape and stormwater measures to achieve the goals of Maryland's ESD process.

Okehocking Nature Center, Willistown Township, PA: Sustainable site design engineering for new Environmental Education Center, including stormwater management and wastewater treatment systems that are integrated with the natural landscape restoration.

Levin Tract Wooded Wetland Park, Radnor, PA: For the urbanized Radnor, PA area, developed a restoration concept design to convert an abandoned vacant parcel into a wooded wetland park area that will improve water quality from a 40-acre urban drainage area by creating a series of low, wooded wetland depressions and planting areas.

Professional Employment History

2007- Present
Principal Engineer and Founder
Meliora Environmental Design
Kimberton, PA

1997- 2007
Principal Engineer
Cahill Associates, West Chester, PA

1991-1997
Project Manager
Roy F. Weston, Inc., West Chester, PA

1984-1991
Project Engineer
Cahill Associates, West Chester, PA

Professional Memberships

U.S. Green Building Council – Sustainable Sites Technical Advisory Committee (SS TAG)

Member, American Society of Civil Engineers, Environmental Water Resources Institute

Member, Pennsylvania Association of Environmental Professionals

Member, American Water Resources Association

Visiting Guest Lecturer; University of Pennsylvania Schools of Architecture and Landscape Architecture; Philadelphia University, and Temple University

East Vincent Planning Commission Chairman

Ralston House, University of Pennsylvania: Design of stormwater elements to support an urban landscape restoration at an existing healthcare facility for the elderly.

Tyler Arboretum Path System: Designed a system of porous asphalt paths through an existing arboretum to improve access and address localized erosion problems.

Hershey Gardens Stormwater Plan: Developed program of rain gardens, wetlands, and restoration measures to address existing erosion and flooding problems.

North 3rd Street Corridor Sustainable Affordable Housing Plan, Philadelphia: With SMP Architects, designing guidelines for sustainable affordable housing, including stormwater measures to reduce combined sewer overflows and meet new City of Philadelphia ordinances.

Hamilton Children's Zoo at the Philadelphia Zoo: Design of site elements, including stormwater elements that provide educational opportunities, such as wetlands, green roofs, porous paths, and cisterns.

Oxford Library: Sustainable site design and engineering for a library addition to an urban library that includes porous pavers, rain gardens, and public outdoor gathering spaces to promote environmental education.

Mount Saint Joseph Academy Stormwater Improvements: With the Pennsylvania Horticultural Society, design of landscape-based restoration measures to improve stormwater management and educational opportunities at an existing school.

Chanticleer Garden: Stream daylighting of buried tributary and floodplain restoration.

Fire Engine 38: Site design of a new Fire Station in Philadelphia to include green roof, bioretention, and landscape restoration. Project will be LEED certified.

John Hopkins Sustainability House: Site design of a building at John Hopkins to create a Sustainability House and define sustainability criteria for University.

Stroud Model My Watershed: Providing technical expertise in the development of an educational watershed modeling tool being developed through funding from the National Science Foundation. Tool will allow interactive evaluation of development impacts on water balance and water quality, and allow alternative designs to be evaluated for benefits of groundwater restoration, stream health, and water quality.

Panther Hollow Watershed Restoration: Developing a watershed restoration plan which includes hydrologic modeling of the natural and existing conditions, using WinSLAMM, and design of two pilot projects to include elements such as an infiltration trench to capture adjacent street runoff, and retentive grading/infiltration berms to manage compacted lawn on a golf course.

For ten years prior to forming Meliora (1997 – 2007), Ms. Adams was a Principal Engineer with Cahill Associates, where she successfully directed and participated in all aspects of a number of projects.

Pennsylvania Stormwater Best Management Practices Manual, Pennsylvania DEP, co-author of State Manual describing structural and non-structural BMPs, Control Guidelines, calculation methodologies, and specifications, including a volume-based approach to stormwater.

Environmental and Stormwater Master Plan, UNC Chapel Hill, NC, Environmental master planning for sustainable stormwater approach to address large university expansion plan. Detailed hydrologic computer modeling performed in US EPA SWMM to evaluate existing infrastructure and recommend stormwater measures. Represented new LID approach in stormwater for UNC and was recognized by Sierra Club as a "Top Ten Building Better II" project.

Grey Towers National Monument, National Forest Service, Sustainable site design, including various stormwater measures for historic gardens, porous pavement, water and wastewater systems.

Washington National Cathedral, D.C., Restorative stormwater measures for Cathedral site and woods, including various infiltration measures (at source of runoff), infiltration for road system, channel stabilization, etc. Second phase included infiltration trenches integrated in to new outdoor amphitheater.

Mill Creek Community Garden and Clark Park Urban Stormwater Projects, Philadelphia, PA, Design of urban stormwater systems that collect runoff from City streets and infiltrate/manage water in urban green spaces such as community gardens and new basketball courts.

Cusano Center at John Heinz National Wildlife Refuge, Tinicum, PA, Sustainable site design for educational center, including various stormwater elements.

Springbrook Low Impact Development, Lebonon County, PA, Design of full LID stormwater system for 247 residential units in karst area, including over 120 individual stormwater systems (vegetated infiltration beds, infiltration trenches, rain gardens, porous pavements, etc.).

Bartrams Garden Master Plan, Philadelphia, PA, Restorative stormwater management recommendations for Master Plan of historic garden.

Regent Square Gateway, Nine Mile Run, Pittsburgh, PA, Concept and schematic design for urban stream and park "gateway".

Ford Rouge Stormwater Management, Dearborn, MI, Stormwater planning and design for major industrial facility re-development (Porous pavement, bioretention swales, vegetated systems).

Woodlawn Library, Wilmington, DE, Design of urban stormwater measures at new public library to reduce stormwater in combined sewers. Porous parking, bioretention, cisterns with re-use, stormwater planter boxes.

From 1991 through 1997, Ms. Adams was a Project Engineer and Project Manager at Weston.
Stormwater Management Programs and NPDES permitting Between 1992 and 1996, Ms. Adams developed and implemented stormwater management and sampling programs at over fifty industrial, commercial, and military facilities throughout the United States, including the Bureau of Engraving and Printing, Philadelphia International Airport, and various industrial facilities. These programs focused on reducing stormwater and water quality impacts from existing facilities.

Hydrologic, Hydraulic, and Mixing-Zone Modeling For a variety of watershed studies including Act 167 Plans, Ms. Adams conducted hydrologic and hydraulic modeling using various mathematical computer models, including USDA TR-20, EPA SWMM, and COE HEC models. Ms. Adams also performed floodway

Expert Testimony within Past Three Years

2010	**Blue Mountain Preservation Association vs Alpine Development Rose Resorts;** Pennsylvania Environmental Hearing Board. Expert witness on behalf of BMPA on issues related to stormwater management and water quality.
2010	**Koziell and Perrini vs Madison Township; Lackawanna Court of Common Pleas;** Expert witness on adverse stormwater impacts of road improvements.
June 2010	**West Vincent Zoning Hearing Board; Flather Property;** Testimony on behalf of Green Valleys Association and PennFuture related to impacts of **water** quality on variance request for stream buffer and wetland setback requirements.
Jan 2010	**West Pikeland Zoning Hearing Board;** Testimony on behalf of Green Valley Association related to impacts of water quality and stream health on variance requests to environmental ordinances.
2009/2010	**Tim and Jamie Lake vs The Hankin Group;** Court of Common Pleas Chester County; Expert witness on stormwater design and flooding.
2008-2009	**Crum Creek Neighbors vs DEP, et al;** Pennsylvania Environmental hearing Board; Expert witness on stormwater design review and impacts on flooding and water quality.
2007-2008	**Glenhardie Condominium vs. Realen Associates; Appeal of NPDES Post-construction Stormwater Management Permit;** Expert witness on behalf of Glenhardie related to stormwater design and flooding. Permit was withdrawn.

Expert Analysis and Comment within Past Three Years

2009/2010	**Pennsylvania Turnpike Expansion Project;** on behalf on National Park Service Valley Forge National Park and Valley Creek Coalition. Expert services related to review and comment of stormwater design and impacts on water quality and stream conditions.
2009/2010	**City of Philadelphia Longterm Control Plan;** on behalf of Natural Resources Defense Council and PennFuture; review of technical reports, policy documents, and draft permit conditions on issues related to stormwater management, water quality, stream health, and compliance with Clean Water Act and EPA Longtern Control Policy.
2010	**City of Chattanooga MS4 Permit**: For City of Chattanooga, providing technical guidance for incorporation of stormwater measures to address and restore impaired streams and meet TMDL requirements. Training sessions for municipal officials and program development.

Publications

Design for Flooding: Architecture, Landscape, and Urban Design for Resilience to Climate Change; By Donald Watson and Michele Adams; Wiley Publishing, Hardcover Nov 2010.

Park Design for the 21st Century: High Performance Landscape Guidelines; New York City Parks Department and NYC Design Trust; Nov 2010.

Porous Asphalt Pavement: 20 Years and Still Working, Michele Adams, Published in Stormwater Magazine May/Jun 2003

Presentations and Conference Proceedings

2010

Nov	Greenbuild USGBC National Conference; New Directions in Stormwater Management and LEED
Nov	AWRA National Conference; New Direction in Water Management
Oct	Delaware Valley Green Building Council; New Directions in Stormwater Management in Philadelphia
Sep	Pittsburgh Parks Conservancy; Michele Adams; "What's Going on in Panther Hollow" and examples of innovative engineering solutions to stormwater impacts on the watershed; Pittsburgh, PA
May	"Sustainable Stormwater Management for Municipal Officials"; Lecture series for municipal officials sponsored by Brandywine Valley Association
Apr	"Stormwater Management in Pennsylvania", Environmental Law Forum, Harrisburg, PA
Apr	"Rainwater Management", Institute for Conservation Leadership
Mar	"How to Challenge a Stormwater Permit and Win: A Look at the Crum Creek Neighbors Decision" Michele Adams, James Schmid, and John Wilmer; Schuylkill Watershed Congress; Pottstown, PA

2009

Dec	"Bio-retention, Vegetative roofs, rain gardens, stormwater management" sponsored by East Nantmeal Township Environmental Council
Oct	"Regenerative Urban Stormwater: Example Projects in the Philadelphia Region" Michele Adams and Susan McDaniels Pennsylvania Stormwater Conference; Villanova, PA
Oct	Housing and Water: Syncing Neighborhood Development, Stormwater Management, and Water; AIA Design on the Delaware
Oct	"Sustainability and Stormwater Management: Green Infrastructure" American Planning Association National Conference
Sept	LID and Stormwater; 16th Annual Erosion Control Conference
May	"Green Infrastructure and Urban Revitalization" Greening the Heartland Conference, Detroit, MI
May	"Protecting Our Natural Resources: Design Leadership for the Next 100 Years" AIA National Conference, San Francisco.
May	"Putting It Into Practice: Low Impact Development And Stormwater Management Training" Pennsylvania Land Conservation Conference
May	"Reconnecting Water, Soils, and Vegetation: Stormwater Management in the Built Environment" ASLA PA/DE Annual Meeting.
Mar	"Water, Soils, and Vegetation: Sustainable Site Design" Purdue University Sustainability Conference
Mar	"Promoting LID Redevelopment in the Anacostia Watershed" Washington, DC

2008

Jan	AIA/DVGBC, Philadelphia; Porous Pavement: How, Why, and When
Mar	DVGBC Best of GreenBuild

2007

Nov	USGBC GreenBuild, Chicago; Michele Adams; UNC Chapel Hill: A Campus-wide approach for Growth and Sustainability

Aug	“Urban Stormwater and LEED”; Michele Adams, Energy Coordinating Agency of Phila; Demystifying LEED for Homes Event.
May	“Low Impact Development: What’s Important and What Should be Monitored”; Michele Adams and Wesley Horner; Tampa; 9th Conference on Stormwater Research & Watershed Management; Fla DEP
May	“Low Impact Development”; Wesley Horner and Michele Adams; ASCE EWRI World Environmental &Water Resources Congress; Conference; Orlando, Fla
April	“Integrating Sustainable Stormwater into the Campus”; Michele Adams and Thomas Cahill; Baltimore, MD; Smart and Sustainable Campuses Conference, EPA/Society for College and University Planning.
April;	“Stormwater Management at UNC Chapel Hill: A Plan for Growth and Sustainability”; Jill Coleman, UNC, and Michele Adams; Wilmington, NC, 2nd National Low Impact Development Conference
April	“Using the BMP Manual to Meet NPDES Requirements”; Michele Adams; State College, PA; Chesapeake Bay Foundation Confluence 2007, Connecting Communities to Creeks.
March	“Porous Pavements”; Michele Adams, Public information session hosted by the City of Wichita

2006

Nov	“Urban Stormwater BMPs: Finding Space for Stormwater in the Urban Environment”, Michele Adams; Baltimore, MD; AWRA 2006 Annual Water Resources Conference
Nov	“Sustainable Site Design”; Michele Adams; Philadelphia, PA; Design on The Delaware AIA Regional Conference
Sept	“Stormwater Site Design: porous Asphalt and Other Innovative Stormwater Techniques”; Michele Adams; Kansas City, MI; American Public Works International Congress and Exposition
Sept	“Sustainable Stormwater Management”; Michele Adams; Pittsburgh, PA; 3 Rivers Wet Weather 8th Annual Sewer Conference
Sept	“Regent Square Gateway Vision for Nine Mile Run”; Marijke Hecht and Michele Adams; University of Pittsburgh, PA
Sept	“The Etowah Habitat Conservation Plan and Runoff Limits”; Michele Adams; Atlanta, GA; Public workshops sponsored by Etowah Watershed Organization and the River Basin Center Institute of Ecology University of Georgia.
June	Blair County LID Workshop; Michele Adams; Hollidaysburg, PA;
June	Penn State Visitor Center LID Design; Michele Adams; State Colege, PA; Penn State Computational Methods in Stormwater Management
May	“Rams Head Extensive Green Roof Design at UNC Chapel Hill”; Andrew Potts and Michele Adams; Boston, MA; Green Roofs for Healthy Cities Conference
May	Penn State Visitor Center LID Demonstration Tour; Michele Adams; Pennsylvania Association of Environmental Professionals.
Mar	“Porous Asphalt Pavement: The Right Choice”; Michele Adams; Orlando, FLA; NAPA World of Asphalt
Jan	“Sustainable Stormwater Management”; Michele Adams; Atlantic City, NJ; NJ ASLA Annual Meeting
	Various Dates and Locations in PA: Stormwater Management Workshops for Municipal Officials and Engineers; Sponsored by the Pennsylvania Environmental Council

2005

Dec	“Sustainable Design in Our Communities”; Michele Adams and Tavis Dockwiller; Sturbridge, MA; presented by Green Valleys Institute
Nov	“Designing Bio/Infiltration Best Management Practices for Stormwater Quality Improvement”; Michele Adams; Madison, WI; University of Wisconsin Professional Development Course
Oct	“Springbrook: Residential LID in a Limestone Area; Andrew Potts and Michele Adams; Villanova, PA; 2005 Pennsylvania Stormwater Management Symposium
July	“Sustainable Site Design”; Michele Adams; Trenton, NJ; AIA NJ Tectonics of Sustainable Design
June	Penn State Visitor Center LID Design; Michele Adams; State Colege, PA; Penn State Computational Methods in Stormwater Management
April	“Urban Stormwater BMPs: Finding Space for Stormwater in the Urban Environment”; Wesley Horner and Michele Adams; Tampa, FLA; 8th Biennial Conf on Stormwater Research & Management.
Mar	“Sustainable Site Design”; Michele Adams and Tavis Dockwiller; sponsored by Fulton County, PA

Ruth Ayn Sitler, P.E.
Water Resources Engineer

Relevant Experience

Ms. Sitler is a Water Resources Engineer at Meliora Environmental Design with over seven years of civil engineering experience that includes low impact development and sustainable stormwater management design. To date, her experience has provided her with a vast multi-disciplinary background from which to draw for innovative design projects of all scopes and sizes, and includes commercial and residential construction, educational facility construction, stream restoration projects, abandoned mine reclamation, and pavement management and design. Ms. Sitler also has experience in environmental permitting as well as local government operations.

Current designs in which Ms. Sitler has been engaged include the following:

Greenstreets Design, East Falls: Part of a team of design professionals (traffic engineers, landscape architects, pedestrian designers, stormwater engineers) in the design of a "complete" street for an urban neighborhood, including two design charettes with regulatory and design professionals from various city and state agencies. The goal was to develop a complete street that addressed stormwater, various transportation modes, and neighborhood greening and revitalization.

Three Groves Ecovillage: Evaluating the Zoning Overlay for the proposed Ecovillage as well as designing the Water system, Wastewater Collection system, and stormwater measures for the site. Consisting of small residential buildings, community greenhouses, community buildings, natural pools, a constructed wetland treatment system, and bioswales, the proposed Ecovillage development is a model sustainable "green" neighborhood.

Panther Hollow Watershed Restoration: Developing a watershed restoration plan which includes hydrologic modeling of the natural and existing conditions, using WinSLAMM, and design of two pilot projects to include elements such as an infiltration trench to capture adjacent street runoff, and retentive grading/infiltration berms to manage compacted lawn on a golf course.

Philadelphia Zoo Master Plan: Development of water and environmental recommendations for the Zoo Master Plan, with focus on stormwater measures integrated into the Zoo's landscape to address flooding problems while promoting sustainability.

Special Qualifications

Seven years of experience in civil and water resources engineering.

Sustainable civil/site design engineering, including Stormwater Best Management Practices, Low Impact Development, (porous pavement, bioretention, etc).

Integrated water resource planning; regional watershed planning; computer modeling; environmental , transportation, and construction permitting; local ordinance development and implementation.

Professional Credentials

Post-Graduate Coursework
Coastal Engineering
Old Dominion University, VA
2012-present

Master of Engineering
Environmental Engineering
Pennsylvania State University, PA, 2007

Bachelor of Science
Civil Engineering Technology
Pennsylvania College of Technology, PA 2004

Registered Professional Engineer in Pennsylvania

Certified Surveyor-in-Training in Pennsylvania

Professional Employment History

2011- Present
Water Resources Engineer
Meliora Environmental Design
Phoenixville, PA

Expert Testimony within Past Three Years

Jan 2012	**London Grove Zoning Hearing Board;** Testimony on behalf of Three Groves Ecovillage Development, L.P., related to site design engineering components and conformance to local ordinance standards for conditional use approval.
2010	**Butler County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Butler County Act 167 Stormwater Management Plan.
2010	**Crawford County Act 167 Stormwater Management Plan Public Hearing;** Expert witness on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Crawford County Act 167 Stormwater Management Plan.
2010	**Mifflin County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Mifflin County Act 167 Stormwater Management Plan.
2010	**Montour County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Montour County Act 167 Stormwater Management Plan.
2010	**Potter County Act 167 Stormwater Management Plan Public Hearing;** Expert witness on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Potter County Act 167 Stormwater Management Plan.
2010	**Venango County Act 167 Stormwater Management Plan Public Hearing;** Expert witness on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Venango County Act 167 Stormwater Management Plan.
2010	**Warren County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Warren County Act 167 Stormwater Management Plan.

2008-2011
Civil Engineer Manager and
Sr. Civil Engineer
Comm. of Pennsylvania:
PA Dept. of Env. Prot.
(Bur. of Aban. Mine Rec.)
(Bur. of Watershed Mgmt.)
PA Dept. of Transportation
(Bur. of Maint. And Oper.)
Harrisburg, PA

2006-2007
Project Manager
Navarro & Wright Consulting
Engineers, Inc.
New Cumberland, PA

2006-2006
Project Designer
Raudenbush Engineer, Inc.
Middletown, PA

2005-2005
Project Designer
Morris & Ritchie Associates
York, PA

2004-2005
Transportation Engineer I
Buchart-Horn, Inc.
York, PA

Professional Memberships

Member, American Society of Civil Engineers, Environmental Water Resources Institute

Expert Analysis and Comment within Past Three Years

2011 **AML-1: The Abandoned Mine Land Inventory Manual;** on behalf of the Pennsylvania Department of Environmental Protection, Bureau of Abandoned Mine Reclamation; Technical review and comment of revisions to the Department of interior, Office of Surface Mining's regulatory standards for addressing abandoned mine lands.

2011 **Alternate Pavement Type Bidding**: on behalf of the Pennsylvania Department of Transportation, Bureau of Maintenance and Operations; Expert analysis of alternate pavement type bidding policies as implemented on highway design projects in Pennsylvania.

Publications

Streambank Stability: Modeling Channel Evolution and Pollutant Transport in an Urban Stream; Ruth A. SItler; Pennsylvania State University, Masters Paper; Dec 2010.

Geographic Variability of Rainfall Erosivity Estimation and Impact on Construction Site Erosion Control Design; Shirley E. Clark, Aigul Allison, and Ruth A. Sitler; *Journal of Irrigation and Drainage Engineering*; American Society of Civil Engineers; July 2009.

Special Experimental Project No. 14 (SEP-14) Alternate Pavement Type Bidding Initial Report; Pennsylvania Department of Transportation and the Federal Highway Administration; Feb 2011.

Porous Asphalt Pavement: 20 Years and Still Working, Michele Adams, Published in Stormwater Magazine May/Jun 2003

Presentations and Conference Proceedings

2011

Sep	Low impact Development Symposium; Ruth A. Sitler; "Impact of the Rainfall Event Method on the Water Capture Quantity Efficieny of Bioretention Devices"
May	2011 World Environment & Water Resources Congress; Ruth A. Sitler and Shirley E. Clark; "Impact of Bioretention Design of the Calculation Method for the 95th Percentile Rain Event"

2009

Mar	"Act 167 Stormwater Management;" Harrison City, PA
May	2009 World Environment & Water Resources Congress; Christine Y. Siu, Shirley E. Clark, Ruth A. Sitler and Katherine Baker; "Looking Upstream and Into the Watershed for the Big Picture of Stream Health"
June	"Act 167 Stormwater Management – Municipal Implementation Models;" Mercer, PA
July	"Introduction to Hydrologic Modeling with HEC-HMS;" Harrisburg, PA "Building a Project and Running a Simulation with HEC-RAS;" Harrisburg, PA
Oct	2009 Pennsylvania Stormwater Management Symposium; Ruth A. Sitler, Aigul Allison, and Shirley E. Clark; "Geographic Variability of Rainfall Erosivity Estimation and Impact on Construction Site Erosion Control Design"

2008

Feb	"Small Watershed Hydrology Modeling with WinTR-55;" Middletown, PA "AutoCAD;" Middletown, PA
Mar	"Erosion Control and NPDES Permitting;" Middletown, PA
Apr	"Introduction to HEC-RAS;" Middletown, PA "HEC-HMS: The Hydrologic Engineering Center's Hydrologic Modeling System;" Middletown, PA
May	"Planning to Protect Water Resources: Stormwater Management;" Hershey, PA
Sep	"Understanding the Regulatory Environment: DEP Headwaters Initiatives and Stormwater BMPs;" Monroeville, PA
Oct	"Integrated Water Resource Planning through Act 167;" Harrisburg, PA
Nov	"Stormwater Management: Act 167 and Its Implementation;" Harrisburg, PA

2007

Mar	"Engineering Overview of Erosion Control and NPDES Permitting in Central Pennsylvania;" New Cumberland, PA
Oct	2007 Pennsylvania Stormwater Management Symposium; Ruth A. Sitler and Shirley E. Clark; "Streambank Stability: Modeling Channel Evolution and Pollutant Transport in an Urban Stream"

NIEK VERAART, AICP, ASLA **Project Manager**

Mr. Veraart is vice president with LBG with more than 20 years of diverse experience in environmental planning, including EIS in accordance with NEPA, SEQRA and CEQR and other environmental statutes. His environmental planning assignments have encompassed a wide range of projects, including transportation infrastructure (airports, highways, ports, rail/transit) industrial facilities (solid waste management, energy, water and wastewater facilities), large-scale development projects (residential, commercial, mixed use, recreational and transit-oriented development), ecological and sustainable development (watershed management, LEED compliance, waterfront restoration, wetland banking) and cultural resources (memorials, tourist attractions, national parks). He is familiar with regulatory requirements at federal, state, and local levels and has integrated such requirements on multilevel environmental documents, including such high-profile assignments as the World Trade Center Memorial and Redevelopment GEIS. Mr. Veraart is especially familiar with construction impacts and assisted federal and state agencies with the development of Environmental performance Commitments (EPCs) for the rebuilding of Lower Manhattan. Mr. Veraart is familiar with upstate watershed issues through his completion of several SEQRA assignments, including an EIS for the Hackensack River in Clarkstown, New York; infrastructure improvements for the Bear Mountain Bridge (for NYSDOS); and the EIS for Kensico Watershed Water Pollution Control Program (for NYCDEP). Mr. Veraart's experience with third-party EIS review is extensive and includes multiple EISs for US Army Corps of Engineers, EIS review for local public interest environmental organizations and for the New York State Public Service Commission.

Several of the projects led by Mr. Veraart have received prestigious state and national awards. Mr. Veraart has presented at national conferences on subjects of environmental planning and his research contributions in the transportation and environmental planning fields have been published by the National Academy of Sciences, Transportation Research Board.

FIRM Louis Berger Group

EDUCATION

- MS, Regional Planning and Land Planning
- BS, Land Planning and Landscape Architecture

REGISTRATIONS / CERTIFICATIONS

- American Institute of Certified Planners
- American Society of Landscape Architects
- American Society of Civil Engineers, Affil.
- International Association for Impact Assessment

YEARS EXPERIENCE 24
YEARS WITH FIRM 16

RELEVANT PROJECT EXPERIENCE

Lower Manhattan Development Corporation (LDMC), GEIS for World Trade Center Memorial and Redevelopment Plan (SEQRA, NEPA EIS), New York, New York. Project director. Mr. Veraart directed LBG's work for the WTC GEIS, which was co-prepared by LBG with another consulting firm. Under Mr. Veraart's direction, transportation analyses were conducted for the redevelopment of the World Trade Center site and construction scenarios were developed for input into the Traffic, Air Quality and Noise analyses. The GEIS process for this high-profile; complex project was completed within a record time of 12 months from the start of environmental review. Mr. Veraart also directed noise, infrastructure, utilities as well as issues of cumulative impacts.

US Army Corps of Engineers New York District, Third-Party EIS, Meadowlands Mills Regional Mall, Bergen County, New Jersey. Project director. Mr. Veraart was Task manager for the independent third-party review of the developer's EIS and preparation of a federal FEIS and Section 404(b) Permit Alternatives Analysis for the development of a 600-acre site for the construction of a mixed use regional mall, office and recreation complex, located three miles from New York City. The project would involve the filling of approximately 200-acres of wetlands and extensive wetland creation and enhancement.

US Army Corps of Engineers New York District, Meadowlands Comprehensive Restoration Implementation Plan Programmatic Environmental Impact Statement, New Jersey. Provided QA/OC review of the Programmatic Environmental Impact Statement (PEIS) for the Meadowlands Comprehensive Restoration Implementation Plan (MCRIP). The PEIS provides an evaluation of environmental, social and economic issues and alternatives to achieve project goals and objectives, while avoiding/minimizing adverse impacts, providing the USACE with the necessary NEPA compliance documentation for MCRIP implementation. The PEIS is a comprehensive document that considers a number of related actions proposed in the MCRIP, including cumulative, direct, and indirect impacts.

New York City Department of Environmental Protection, Kensico Watershed Water Quality Sustainable Management Plan EIS, Westchester County, New York. Project manager. The EIS evaluated the beneficial effects on water quality resulting from several alternative measures, including the development of stormwater Best Management Practices (BMPs), such as wetland basins, streambank stabilization and waterfowl management. Pollutant reductions were subsequently modeled for each of the streams and subwatershed discharging into the Kensico Reservoir. Transport of contributing pollutants within the reservoir and to the water intakes was then modeled. In addition to the evaluation of the effectiveness of various program alternatives, their impact on the environment was assessed, including socioeconomic and ecological impacts.

Metropolitan Transportation Authority New York City Transit, Fulton Street Transit Center NEPA EIS, New York, New York. Project director. Directed the preparation of the FEIS and Section 4(f) for the $1.4B federally funded Fulton Street Transit Center (FSTC) in Lower Manhattan. Mr. Veraart supervised the approach to alternatives analysis and cumulative effects analysis and supervised preparation of technical assessment of environmental impacts, including traffic and transportation, air, noise, socio-economic analyses and the analysis of adaptive reuse of the historic Corbin Building in Lower Manhattan. A key aspect of the analysis was the assessment of cumulative impacts of the FSTC and other Lower Manhattan Recovery Projects. Mr. Veraart presented the analysis of cumulative construction in Lower Manhattan to a National Panel of government agencies under auspices of the FTA.

US Department of Agriculture, Final Environmental Impact Statement (FEIS - SEQRA, NEPA) Gull Hazard Reduction Program, JFK International Airport, Jamaica, New York. Project manager. Managed the preparation of the SEQRA/NEPA EIS for the implementation of the Gull Hazard Reduction Program at JFK International Airport in New York City.

Parcel B EIS Third-Party Review and Environmental Support Services, Purchase Environmental Protection Association, Purchase, New York. Project manager. Analyzed SEQRA documentation submitted for an office development in Purchase, New York. The expert review team lead by Mr. Veraart reviewed all relevant aspects of the analyzed by the developer and identified numerous deficiencies and inaccuracies in the environmental documentation, including historic resources (impacts on Olmstead landscapes and resources listed on the State/National Register of Historic Places), flooding and stormwater management, incompatibility with zoning regulations, density inconsistencies, traffic safety and congestion issues, ecological impacts and direct and indirect wetland impacts.

Dormitory Authority of the State of New York (DASNY), Chenango Countywide 911 Communications Upgrade EIS, Chenango County, New York. Project Director. Led the preparation of the SEQRA EIS. The project included a GIS-based viewshed analysis of tower visibility. The viewshed analysis included the identification of sensitive resources (e.g. parks and historic areas) within five miles of each tower. The project objective was to improve emergency services communication capabilities through the construction of six radio communication antenna towers and ancillary infrastructure, and upgrades to facilities at an additional three sites

US Army Corps of Engineers New England District, South Coast Rail Project Third-party NEPA EIS (in progress), Massachusetts. Project manager. Mr. Veraart is managing the preparation of an Alternatives Analysis and NEPA EIS for new 60-mile transit service between Boston and the south coast of Massachusetts, including New Bedford and Fall River. Alternatives being evaluated include Bus Rapid Transit and rail. Key impact areas addressed included wetlands, water resources, threatened and endangered species, noise and vibration and coordination with Native American tribes.

Township of Randolph, Third-Party Environmental Review and Site Suitability Analysis Services, Randolph, New Jersey. Project manager. Conducted an independent third-party review of the environmental documentation for the 154-acre Nitti Mountain development project in the Township of Randolph, New Jersey. The review assessed all applicable resources including soils, geology, wetlands, hydrology, slopes/engineering, ecology; land use and zoning, landscape and visual, traffic/circulation and access, cultural resources and socioeconomic impacts. The report provided comments and recommendations regarding technical methodologies, data gaps and data quality, compliance with applicable regulations and appropriateness, projected cost and feasibility of proposed mitigation measures.

City of New City, New York, FEIS, Hackensack River Natural Area Improvement and Flood Management Project, Clarkstown, New York. Project director. Mr. Veraart directed the preparation of the FEIS for flood control measures in the Hackensack River. Flood control measures include the construction of backwater prevention berms, dredging of river sediment and widening of the river in order to improve flow.

NYS Bridge Authority, EA (SEQR) Bear Mountain Bridge Rehabilitation, Bear Mountain,

New York. Project director. Directed environmental permitting and regulatory issues for rehabilitation of the Bear Mountain Bridge across the Hudson River.

Port Authority of New York and New Jersey, Newark Liberty International Airport, Terminal A NEPA Draft Environmental Assessment. Newark. New Jersey. Project manager. Preliminary Environmental Assessment for construction of a new Terminal A facility, including a 1.3 million sf. airport terminal building, surrounding site conditions, including streams and wetlands, roadways and airside facilities. The EA was prepared in close coordination with sustainable planning and design efforts ongoing concurrently towards a LEED certified facility.

LMDC and the National September 11 Memorial & Museum, Pedestrian Simulation Modeling - World Trade Center (WTC) Memorial, New York, New York. Project director. Oversaw the development of origin/destination projections for pedestrian travel patterns on the World Trade Center (WTC) Memorial including the plaza, visitor's center, and museum and the entire WTC Site for the opening year and stabilized year of the WTC Memorial on both a weekday and Saturday. Also developed assumptions for the development program, pedestrian profiles, pedestrian itineraries, and site demand projections. The projected pedestrian movements were modeled to determine if adequate space would be provided for pedestrians based upon the site design and site plan

State University of New York at Binghamton. New Student Housing, State. Town of Vestal, Broome County, New York. Project Director. Directed the preparation of a SEQRA EAF and Supplemental Studies for replacing the 40 years old Newing and Dickinson residence buildings with new buildings to accommodate approximately 3,000 students on the East Campus of Binghamton University. The impact assessments focused on a matrix of potentially affected environmental resources, including storm water/wastewater infrastructure, threatened and endangered species, air quality, and noise.

American Marine Rail, LLP, Dredge Permitting, SEQR Environmental Assessment Statement. And Facility Plan Development. American Marine Rail Intermodal Transfer Terminal, Bronx, New York. Project director. Managed the development of facility layout and directed preparation of permits and state and city environmental regulatory review for a 5,200 tons-per-day intermodal barge-to-rail facility solid waste transfer station. Mr. Veraart supervised the preparation of a Title 6 NYCRR Part 360 Solid Waste permit application to the New York State Department of Environmental Conservation (NYSDEC), a Joint Tidal Wetland Permit from the NYSDEC and the USACE and air quality compliance, as well as compliance with other regulatory requirements**.**

South Jersey Transportation Authority (SJTA) Alternative Energy Vehicle Deployment Plan. Project Director. Directed the preparation of an AEV deployment plan for SJTA, pursuant to the SJTA Alternative Energy Management Plan, prepared by The Louis Berger Group for SJTA. Specific four areas included evaluation of Alternative Energy sources for the SJTA fleet and operations, as well as users of SJTA facilities. Alternative energy sources evaluated include electric, Compressed Natural Gas (CNG), biodiesel and hydrogen.

National September 11 Memorial, Economic Impact of National September 11 Memorial. Project director. Directed the study to analyze impact of the National September 11 Memorial operations on the economy of New York City, New York State and the U.S. Impacts are driven by Memorial operational expenditures, employee household spending and visitor spending. Assessed the effect of the Memorial on Lower Manhattan in terms property tax revenues and business revenues.

NYCDOS, Draft Environmental Impact Statement (DEIS - SEQR, CEQR), Fresh Kills Landfill, Staten Island, New York. Project director. Executive responsibility for the preparation of the DEIS for the Fresh Kills Landfill on Staten Island. For the continued operation of the 2,200-acre landfill, NYCDOS applied for a NYCRR Part 360 Permit for a solid waste management facility from the New York State Department of Environmental Conservation (NYSDEC). For this purpose, the NYCDOS submitted an EIS pursuant to both State Environmental Quality Review (SEQRA) and City Environmental Quality Review. The DEIS was deemed complete by NYSDEC prior to the City's decision to close the Fresh Kills Landfill.

RAED EL-FARHAN, PHD **Principal-in-Charge**

Dr. EL-Farhan, vice president of LBGs science and water resources division, has more than 20 years of experience as a consultant, professor, and university researcher. His areas of expertise include water resources, ecosystem restoration, stormwater management, water and wastewater treatment systems, water quality permitting and compliance, aquatic chemistry, and the fate and transport of contaminants in the environment. Dr. EL-Farhan has used this diverse expertise in support of EPA headquarters and its regional offices in their BEACH, EMPACT, and TMDL programs, where he has characterized, assessed, and modeled water quality; wrote and reviewed technical reports; and prepared training materials and workshops. He has worked extensively with various states to provide water resources planning services throughout the Mid-Atlantic region, and continues to support the EPA's Assessment and Watershed Protection Division through the Technical Support for the National Watershed Protection Program. Dr. EL-Farhan is working on multiple assignments with U.S. Army Corps of Engineers, Institute for Water Resources (USACE IWR), Engineer Research and Development Center (ERDC), Districts, Headquarters, and Assistant Secretary of the Army (CE) to provide technical review of feasibility studies, conduct facilitations at USACE strategic sessions, assist the USACE with development of quality of life metrics, evaluate the USACE model certification process, and evaluate and certify models. Dr. EL-Farhan is a member of the American Water Resources Association and participates in national dialogues related to water resources issues. He also serves on the planning committee of the National Conference on Ecosystem Restoration (NCER) where he has worked alongside many of the USACE restoration experts.

FIRM Louis Berger Group

EDUCATION

- PhD, Environmental Engineering
- MS, Environmental Engineering
- BS, Civil Engineering

YEARS EXPERIENCE 21
YEARS WITH FIRM 10

RELEVANT PROJECT EXPERIENCE

USACE Kansas City, Project Initiation and Planning for Programmatic EIS for the Missouri River Recovery/Restoration Plan and the Public Relations Strategy and Internal Communication Plan Needs Assessment for the Missouri River Recovery Program. Director. Dr. EL-Farhan worked closely with the project manager to coordinate the technical leads, experts, academics, and subconsultants. He not only provides management, but also technical support. He is providing technical support and is responsible for the development of the Research Compendium that will serve as the scientific guideline and basis during the alternatives development phase of the project. Also, Dr. EL-Farhan is assisting with the development of the public outreach and communications strategy and plan for implementation for the Missouri River Recovery Program. This includes both an external public relations strategy and an internal communications plan.

USACE Baltimore, Anacostia River Watershed Restoration Plan. Program manager. Managed a comprehensive watershed restoration plan for the Anacostia River Watershed; its objective is to produce a systematic 10-year restoration plan for environmental and ecological restoration within the entire watershed to mitigate the impact of stormwater runoff to the Anacostia River watershed. The plan was conducted under the USACE General Investigations Program. The study was authorized in a resolution of the Committee on Public Works and Transportation, U.S. House of Representatives.

USACE IWR, Analytical and Professional Support Services. Program manager for this $25 million, five-year contract that provides technical and analytical support services that are generally not available within USACE, including the following principal areas: program management, water resources, environmental protection and restoration, navigation, information systems, and homeland security. Under this contract and Dr. EL-Farhan's leadership, LBG is providing technical review of feasibility studies, conducting facilitations at USACE HQ strategic sessions, assisting USACE with development of quality of life metrics, evaluate the USACE model certification process and certifying models.

USACE Mobile District IDIQ for Environmental Studies for BRAC Actions. Program manager. Under $6 million IDIQ contract, Dr. EL-Farhan oversees overall project management, subcontractor management, project scheduling, quality assurance and control, deliverable production, project accountability to USACE Mobile, and maintains the administrative record. Currently working on environmental, engineering, and planning services in preparation of Phase II of the feasibility study and EIS for the ecosystem restoration and flood damage reduction for the 23 square-mile Upper Turkey Creek Basin in Kansas. Scope includes engineering analysis for the plan formulation to accomplish flood protection, environmental restoration, and improve water quality and recreational facilities.

USACE Baltimore, IDIQ for Planning Projects, Various Locations. Program manager. Under $5 million IDIQ contract, LBG is managing multiple task orders, preparing siting and facility studies and other planning documents. Specifically, Dr. EL-Farhan has worked on Potomac

Park Levee–EA and Section 106 project, for design and construction of an improved flood control project within the National Mall and Constitution Gardens in Washington, DC, to address the potential impacts to cultural and environmental resources. Also includes St. Martin Ecosystem Restoration–assisted in the evaluation of the feasibility study for aquatic ecosystem restoration in the St. Martin River Watershed in Maryland, under the authority of Section 206 of WRDA.

EPA Assessment and Watershed Protection Division, Technical Support for the National Watershed Protection Program. As program and project manager, developed dozens of watershed TMDL studies nationwide and has prepared training materials and conducted workshops. For these projects, conducted source assessment and watershed characterization to support watershed simulation and development of allocations. Presented TMDL results at a series public meetings. The Bayou Lafourche TMDLs, Louisiana included a comprehensive water quality monitoring plan, developing and submitting a QAPP for EPA's approval, setting up and calibrating Louisiana's QUAL2E model, and calculating the TMDL for the bayou.

Review of the Upper Mississippi River Illinois Waterway Feasibility Report. To help ensure the adequacy of this recommendation to Congress, Dr. EL-Farhan and the LBG team provided a review of the UMRS Chief's Report, the Rock Island District Commander's Feasibility Report, the NRC Reports on the UMRS, and related documents. The purpose of the review was to evaluate the actions proposed by the Chief of Engineers and District Commander in relation to external reports by the NRC and other parties, as well as prior Assistant Secretary of the Army (CW) correspondence to OMB to determine potential courses of action for the Assistant Secretary of the Army (CW) in transmitting his report to OMB and the Congress. The LBG report highlighted known and unknown information relevant to the ability to recommend an action to Congress, noted any deficiencies in needed information and recommended an appropriate course of action.

Transportation Research Board (TRB) of the National Academies. Senior technical reviewer. Dr. El-Farhan serves as a senior technical reviewer for the Transportation Research Board of the National Academies. He is responsible for reviewing documents and providing recommendations. Dr. El-Farhan will be reviewing papers for consideration as part of the program for the TRB 87th Annual Meeting in January 2008 and publication in the Transportation Research Record.

EPA Region 3, pH TMDL for Buckhannon River, West Virginia. Served as technical support for TMDL development for Acid Mine Drainage. Screened the available water quality data for the Buckhannon River to determine the frequency of water quality standards violation of pH and heavy metals. Reviewed models and methods applicable for predicting instream pH in streams. Developed a mass balance model based on inflow of alkalinity and acidity to predict the instream pH of the Buckhannon River.

HOPE LUHMAN, PHD, RPA Cultural Resources

Dr. Luhman manages LBG's New England and Northeast cultural resource operations from the Albany, New York, office. She is responsible for all archaeological, architectural, and historic preservation planning projects involving historic and precontact resources, as well as general business development. Dr. Luhman coordinates interdisciplinary and multitask studies; interfaces with clients and subconsultants; participates in public outreach and education programs; maintains project schedules; evaluates budgets; prepares technical reports, agreement documents, and special exhibits; and provides expert witness testimony.

FIRM Louis Berger Group

EDUCATION

- PhD, Anthropology
- MA, Anthropology
- MA, Social Relations
- BA, Anthropology

REGISTRATIONS/ CERTIFICATIONS

- Accredited by the Register of Professional Archaeologists

YEARS EXPERIENCE 28
YEARS WITH FIRM 16

RELEVANT PROJECT EXPERIENCE

Immigration and Naturalization Service (INS), Phase I and II Archaeological Survey, INS Border Patrol Station, St. Lawrence County, New York. Principal investigator.

GSA Northeast and Caribbean Region, Photographic Documentation, Phase IB Archaeological Survey, and Data Recovery Investigations, Proposed U.S. Courthouse, Buffalo, Erie County, New York. Project manager/principal investigator.

New York Army National Guard, Cultural Resource Surveys: New York Army National Guard (NYARNG). Project manager/principal investigator. Projects have included Phase IA archaeological surveys for the Rome, Lockport, Jamestown, Dunkirk, Cortland, and Dryden armories; Phase IA and IB surveys for the Walton, Kingston, Leeds, Latham, Orangeburg, Geneseo and proposed Queensbury armories; Phase IB survey for the Auburn Armory; and Phase II and III archaeological investigations for the Kingston Armory.

PARS Environmental for 77th Regional Readiness Command, Phase IB Archaeological Survey, Kerry P. Hein United States Army Reserve Center, Town of Shoreham, Suffolk County, New York. Project manager/principal investigator.

PARS Environmental for 77th Regional Readiness Command, Section 106 Compliance, Rocky Point/Brookhaven Nike Missile Launch Facility, Shoreham, Suffolk County, New York. Project manager/principal investigator.

77th Regional Readiness Command, Phase IA Archaeological Surveys, New York and New Jersey. Project manager/principal investigator.

U.S. Army Corps of Engineers (USACE) Mobile, Phase I Archaeological Survey, Fort Totten BRAC, Queens County, New York. Project manager/principal investigator.

Engineering Field Activity Northeast, Naval Facilities Engineering Command (NAVFAC), Archaeological Monitoring, Palmer Hall Geothermal Loop Field, U.S. Merchant Marine Academy, King's Point, New York. Project manager/principal investigator.

U.S. Military Academy, Cultural Resources Support, Family Housing, USMA, West Point, New York. Project manager/principal investigator.

Engineering Field Activity Northeast, NAVFAC, Archaeological Monitoring, Barry Hall Geothermal Loop Field, U.S. Merchant Marine Academy, King's Point, New York. Principal investigator**.**

Denver Service Center (DSC), Direct Labeling of Artifacts Recovered from the Archeological Excavations Conducted at Fort Stanwix National Monument for Willett Center Construction, Oneida County, New York. Project manager.

Phase I Archeological Survey, Proposed Mongaup Interpretive Center, Upper Delaware Scenic and Recreational River, Lumberland, Sullivan County, New York. Project manager/co-principal investigator and cultural resource task leader.

Archeological Survey for Roosevelt Farm Lane Rehabilitation Project, Home of Franklin Roosevelt National Historic Site, Hyde Park, Dutchess County, New York. Project manager.

Archeological Survey for the Construction Staging, Sediment Dewatering, and Sediment Dispersal Areas, Val-Kill Pond Restoration Project, Eleanor Roosevelt National Historic Site, Hyde Park, Dutchess County, New York. Project manager.

DASNY, Report on the Phase II and III Archaeological Investigations, The DASNY Site, 515 Broadway, Albany, Albany County, New York. Project manager.

DASNY, Phase IA Newing College Dormitory, State University at Binghamton, Broome County, New York. Project manager.

DASNY, Phase IA Archaeological Survey, Chenango Countywide 911 Communications System Upgrade, Chenango County, New York. Project manager.

Ammann & Whitney, and New York State Bridge Authority, Cultural Resource Services, Bear Mountain Bridge Cable Strengthening Study, Rockland and Westchester Counties, New York. Project manager.

Ammann & Whitney, Phase IA Cultural Resource Sensitivity Assessment, Proposed Amsterdam Pedestrian Bridge, City of Amsterdam, Montgomery County, New York. Project manager.

EBI Consulting, Cultural Resource Services for Wireless Carriers, New England. Contract and project management/principal investigator. On-call contract for performance of cultural resource surveys in New York, Massachusetts, New Hampshire, Vermont, Connecticut, Rhode Island, and Maine. Archaeological desk reviews, archaeological resource assessment reports, and reconnaissance/intensive surveys have been conducted throughout New York, Massachusetts, New Hampshire, Vermont, Connecticut, and Rhode Island.

USACE New England, Review of Cultural Resource Investigations, South Coast Rail Project, Southeast Massachusetts. Project manager/principal investigator.

New York State Education Department (NYSED)/New York State Department of Transportation (NYS DOT), Cultural Resource Services. Contract manager. Five-year contract (beginning 2007) to provide cultural resource services primarily associated with NYS DOT Regions 8-11, but may also include other state agency undertakings. Project-specific studies for all phases of archaeological investigations and architectural resource surveys. To date, 28 task orders received; four examples of completed projects are listed below.

- Cultural Resource Reconnaissance Survey, Site Examination and Data Recovery Plan, Shaker/Powell Hotel Site, Route 155 and Old Niskayuna Road Intersection Improvements, PIN 1132.15.101, Town of Colonie, Albany County, New York. Project manager and principal investigator.
- Archaeological and Architectural Reconnaissance Survey, Gorham Street Bridge and Approach Removal, PIN 3805.50.101, Village of Waterloo, Seneca County, New York. Project manager and principal investigator.
- Reconnaissance (Phase I) Survey, Republic Airport Development Aircraft Hangar, PIN 0903.55.101, Town of Babylon, Suffolk County, New York. Project manager and principal investigator.
- Cultural Resource Reconnaissance Survey, Jericho Turnpike, PIN 0042.27.121, Towns of Huntington and Smithtown, Suffolk County, New York. Project manager and principal investigator.

EDWARD SAMANNS, PWS, CE **Aquatic Ecology**

Mr. Samanns is the director of environmental sciences at LBG with more than 20 years of experience managing environmental investigations for a variety of projects and clients. Mr. Samanns specializes in ecological restoration/mitigation and related topics including stream and wetland ecology, permitting, threatened and endangered species studies, invasive species management, and NEPA compliance. Mr. Samanns serves as the project manager/director for several environmental and restoration contracts for public sector clients and was responsible for preparing data collection and analysis protocols, developing and implementing vegetative and hydrology monitoring methodologies, and developing habitat restoration designs. Mr. Samanns is a key member of LBG's ecological restoration unit, a unique assemblage of key scientists and engineers that have been combined to conduct restoration projects including wetland mitigation banks, endangered species habitat enhancement, coral reef creation, and tidal marsh restoration. He was the principal investigator and author of NCHRP Synthesis 302 Mitigation of Ecological Impacts (2002), is currently conducting research for NCHRP on Habitat Fragmentation, and has published/presented several papers on wetland mitigation and wildlife crossings. Mr. Samanns is also a co-author of the USACE, Waterways Experiment Station, Engineering Specification Guidelines for Wetland Plant Establishment and Subgrade Preparation (1998). Mr. Samanns also performs QA reviews of technical reports and restoration designs and provides independent research on environmental topics for clients.

FIRM Louis Berger Group

EDUCATION

- MS, Geography
- BS, Biology

REGISTRATIONS/ CERTIFICATIONS

- Professional Wetland Scientist
- Certified Geologist

YEARS EXPERIENCE 25
YEARS WITH FIRM 23

RELEVANT PROJECT EXPERIENCE

County of Rockland, Minisceongo Creek Nor'easter Repair Project, Rockland County, New York. Project manager. Responsible for overseeing the wetland and stream delineation for the project area and preparation of the Environmental Investigation Report. Also evaluated project for compliance with NEPA CATX requirements of FEMA and coordinated with project engineers to assess project alternatives to stabilize an area of mass wasting and slope failure, protect existing infrastructure from river erosion, re-establish fish passage, and establish self mitigating construction approach. Responsible for ongoing coordination of NYSDEC and ACOE permits for construction.

Marsh Resources, Meadowlands Mitigation Bank Phase 3, Carlstadt, New Jersey. Project director of the permitting, design and upcoming construction of a 60-acre tidal and freshwater wetland mitigation bank in the Hackensack Meadowlands. Responsibilities include federal and state permit application preparation and acquisition, banking instrument preparation, negotiation and approval by the interagency MIMAC, and site concept designs. Analysis has included assessment of on-site resources, functional value assessment, credit determination, innovative designs to minimize wetland fill and control invasive species, tidal data analysis and tide gate assessment. Planting plan also addressed potential treatments for acid soil conditions. Responsible for developing construction and planting plans as a design/build project employing marsh excavation and dredge methods to create enhanced tidal habitat of mud flat and low and high marsh interspersed by tidal channels and upland islands and freshwater forested wetlands.

New York Thruway Authority and NYSDOT, Stewart Airport Access Improvement, Wetland and Vernal Pool Mitigation Site Selection and Design. Project manager. Responsible for conducting a site selection and design study for the creation of 1.5 acres of vernal pool habitats within forested uplands to compensate for wetland habitat losses as requested by the NYSDEC. Evaluated physical features within project area leading to the identification of potential sites. Developed concept plans for each vernal pool site. Also responsible for the design of 15 acres of forested, scrub shrub and emergent wetlands at an off-site location. Prepared full plans and specifications to support bid documents. Additional task included preparation of a Biological Assessment for the Federal and State endangered Indiana bat along the project corridor, and coordination with the USFWS and NYSDEC.

PANYNJ, Goethals Bridge Replacement Project, Staten Island. Project supervisor. Responsible for overseeing the tasks related to the preparation of the natural resource components of a NEPA EIS and the preparation of environmental permits required for issuance of the Record of Decision by the US Coast Guard. Also supervising the wetland mitigation site selection and wetland mitigation design tasks that are necessary to support the preparation of a Mitigation Plan for the Corps permit application. Permit applications include addressing purpose and need, alternatives analysis, coastal zone consistency reviews, EFH assessments, and other topics.

USACE Baltimore District, Integrated Natural Resource Management Plan Environmental Support Services, 99th Regional Readiness Command. Project supervisor. Responsible for overseeing the preparation of an Invasive Species Management Plan and Endangered Species Management Plan as part of an INRMP for use on 184 properties in five states under the command of the 99th Regional Readiness Command. The invasive species management plan was developed to maintain compliance with EO 13112 Invasive Species and the Army Policy Guidance for Management and Control of Invasive Species. The endangered species management plan was updated to maintain compliance with the Endangered Species Act, Bald and Golden Eagle Protection Act, DoD Instruction 4715.3, and AR 200-3. The management plans address existing conditions and habitats, target species and appropriate management actions and estimated costs.

Molly Ann Brook Watershed Management Plan, Passaic County, New Jersey. Project director. Responsible for the coordination and completion of all field studies, meetings, workshops, report preparation, staffing, schedule and budget for this project. The project involves development of a Geodatabase as part of a watershed characterization effort that includes Rosgen stream reach classification, USGS Visual Assessments, and point source locations. Baseline analysis also included collection of hydrologic data and development of stream rating curves, incorporation of fecal coliform and other water quality data, benthic macroinvertebrate data, and assessments of potential nonpoint pollution sources within watershed. Prepared and conducted two public workshops to educate and gather information from interested citizens and public officials. Developed a prioritized list of effective BMP's and prepared a concept design and constructability assessment of the six best candidates for installation.

PANYNJ, Environmental Assessment, Newark Airport, Newark and Elizabeth, New Jersey. Environmental scientist. Responsible for overseeing the preparation of natural resource sections of an FAA Environmental Assessment (EA) for the expansion and modernization of Terminal A at Newark Liberty International Airport. Provided oversight of field investigations and baseline conditions analysis. In addition, provided technical input on options to minimize and mitigation wetland and open water impacts on-site through the use of innovative design options.

Brookhaven Science Associates and US Department of Energy, Peconic River Restoration Project, Brookhaven National Laboratory, Suffolk County, New York. Project manager. Responsible for the development and implementation of a Wetland Restoration Design as part of a three phase remediation of 14,700 linear feet of contaminated stream and freshwater wetlands. Also prepared and obtained NYSDEC wetlands equivalency permits, and long term monitoring plan. Project included developing a habitat assessment for the state threatened Banded Sunfish, developing and implementing protocols for the collection and transplanting of wetland plant material into restored wetlands, and collection and transplanting dormant trees using tree spades.

NYSDOT, Term Agreement for Ecological and Water Resource Studies, and Training. Project manager. Responsible for managing three consecutive four-year on-call services term agreement to provide wetland and water services to NYSDOT Regions 8, 10 and 11, and other upstate regions. Services performed include the delineation of state and federal regulated wetlands, wetland functional assessments, wetland permitting support under the New York State Freshwater Wetlands Act and Section 404 of the Clean Water Act, stream assessments and restoration design, and water quality assessments modeling. Additional services include providing training to NYSDOT staff, evaluating alternative alignments to avoid, minimize and reduce wetland impacts, evaluate wetland mitigation sites, and conducting and preparing wetland mitigation monitoring reports for submission to USACE/NYSDEC. Over one hundred task orders have been completed.

Federal Bureau of Prisons, NEPA EA/EIS Preparation for Proposed Federal Correctional Facilities Nationwide. Team leader. Conducting wetland delineations, wetland assessments, biological inventories, and impact assessments for multiple EAs and EISs for proposed federal prison facilities. Also performed Section 404/State 401 permitting and mitigation site selection and design for several of the projects. Managed staff, subconsultants, and report preparation to complete tasks on time and on budget. Projects are located in over fifteen states and have required interaction with state regulatory agencies and USFWS.

LEO TIDD Noise, Land Use, Indirect and Cumulative Impacts

Mr. Tidd's work at LBG has been focused on conducting environmental analyses for proposed projects and preparing documents to demonstrate compliance with state and federal environmental laws and regulations. He has been lead author and editor of complex EISs required as a result of prior environmental litigation. On these projects Mr. Tidd serves as the primary author, synthesizing the work of various technical specialists into a logical and concise narrative that addresses regulatory compliance and ensures that the lead agency took the requisite "hard look" at environmental issues. In addition, he is responsible for technical environmental analyses on topics that include, noise, indirect and cumulative impacts, air quality, habitat fragmentation/edge effects, wetlands and water resources. Mr. Tidd has completed noise impact modeling for a new connector roadway to the Atlantic City International Airport in New Jersey, as well as comprehensive noise evaluations for off-road vehicle use at the National Park Service (NPS) at Yellowstone National Park and the Lake Meredith National Recreation Area. Mr. Tidd has prepared or contributed to the indirect and cumulative impact assessments for several projects where litigation on indirect and cumulative impact issues occurred in the past or is anticipated, including the Circ-Williston Transportation Project in Vermont, the I-93 Improvements Project in New Hampshire, the Gaston East- West Connector in North Carolina, and the Birmingham Northern Beltline in Alabama. Mr. Tidd is a contributing author of the Legal Sufficiency Criteria for Adequate Indirect Effects and Cumulative Impacts Analysis as Related to NEPA Documents report prepared for AASHTO Standing Committee on the Environment as part of NCHRP Project 25-25.

FIRM Louis Berger Group

EDUCATION

- MPA, Environmental Science and Policy
- BS, Environmental Studies

TRAINING

- Transit Noise and Vibration Impact Assessment, National Transit Institute, 2011
- Highway Traffic Noise: Basic Acoustics, National Highway Institute, 2011
- EPA and FHWA Particulate Matter Quantitative Hot Spot Analysis Training, 2011
- AERMOD Dispersion Modeling Training, Lakes Environmental, 2011
- EPA and FHWA MOVES2010 Training, 2010
- EPA and FHWA Draft MOVES2009 Training, 2009
- Introduction to Transportation Conformity, National Transit Institute, 2008

YEARS EXPERIENCE 6
YEARS WITH FIRM 6

RELEVANT PROJECT EXPERIENCE

Peninsula Corridor Joint Powers Board, Dumbarton Rail Corridor Noise and Vibration Study, California. Task manager. The Dumbarton Rail Corridor Project EIS is being prepared for a proposed new rail service on a corridor spanning San Francisco Bay connecting the existing Caltrain San Jose-San Francisco line alignment in Redwood City, San Mateo County to Newark, Union City and other cities in Alameda County. The noise and vibration study being prepared by Mr. Tidd includes short-term noise monitoring at sensitive receptor locations, train and grade-crossing bell noise impact assessment using Federal Transit Administration procedures, train horn noise impact assessment using Federal Railroad Administration's horn noise spreadsheet program, and a screening analysis of bus noise impacts using FHWA's Traffic Noise Model.

NPS, Yellowstone National Park Winter Use Plan EIS, Wyoming, Montana and Idaho. Planner. Mr. Tidd was the lead author of the EIS chapters addressing the impacts of various levels of snowmobile and snowcoach use on air quality and natural soundscapes as part of the Yellowstone Winter Use Plan Draft EIS. Mr. Tidd summarized the available monitoring data to describe existing conditions in the park, and coordinated extensively with the NPS Natural Sounds program that was responsible for developing the impact thresholds and detailed soundscapes modeling effort. One key challenge addressed by Mr. Tidd was identifying the potential for cumulative impacts to natural soundscapes from actions by others, including oil and gas development in the region, aircraft overflights, and population growth/land development.

NPS, Lake Meredith National Recreation Area Off-Road Vehicle Management Plan EIS, Texas. Planner. Mr. Tidd wrote the EIS chapter describing the existing condition of natural soundscapes within two ORV areas based on monitoring data of percent time audible and sound levels. Mr. Tidd also assisted NPS with the development of soundscapes impact thresholds for the various action alternatives under consideration in the management plan and prepared the soundscapes impact assessment. The purpose of the Lake Meredith National Recreation Area Off-Road Vehicle plan/EIS is to manage ORV use in the national recreation area for visitor enjoyment and recreation opportunities, while minimizing and correcting damage to resources.

South Jersey Transportation Authority, Atlantic City Expressway/Atlantic City International Airport Direct Connector Road Noise and Air Quality Studies, Egg Harbor Township, New Jersey. Task manager. Mr. Tidd prepared air quality screening analyses based on changes in level of service and traffic volumes to address Federal Aviation Administration and conformity requirements for a new roadway and interchange in Egg Harbor Township, New Jersey. Mr. Tidd also conducted traffic noise modeling for the project using TNM2.5 and prepared the traffic noise study technical memorandum. Mr. Tidd developed the noise impact criteria for this project based on FHWA and FAA regulations. The noise modeling effort involved 41 receptor locations. In addition, Mr. Tidd prepared GIS mapping illustrating the location of environmental justice communities in the project area using 2010 U.S. Census data.

Vermont Agency of Transportation (VTrans), Circ-Williston Transportation Project EIS, Chittenden County, Vermont. Deputy project manager. The Circ-Williston EIS is a "fresh look" at a transportation project that was stopped as a result of environmental litigation just prior to construction. Mr. Tidd was responsible for editing the EIS and technical reports, creation of a comment database tracking system and was the lead author of the responses to comments on the Draft EIS and Final EIS. Mr. Tidd coordinated extensively with the various technical discipline specialists and subconsultants involved with the project to ensure a comprehensive and legally sufficient environmental documentation. Mr. Tidd's technical accomplishments on this project have included a detailed analysis of wildlife habitat edge effects and fragmentation, a GIS-based wetland mitigation site search analysis, a project-level greenhouse gas emissions analysis, and a deicing salt loading analysis.

New Hampshire DOT, I-93 Improvements (Salem to Manchester) Supplemental EIS (SEIS), New Hampshire. Deputy project manager. Mr. Tidd was the lead author of the I-93 supplemental environmental impact statement (SEIS), which was prepared in response to a court order requiring analysis of the effects of induced population and employment growth on secondary road traffic and air quality. In addition to editing all components of the SEIS, Mr. Tidd was also responsible for several technical analysis tasks, including a regional emissions sensitivity analysis for ozone precursors, and a cumulative impact analysis assessing the aggregate consequences of the project combined with other reasonably foreseeable projects and forecasted levels of population and employment growth in Southern New Hampshire. The project involves widening I-93 from two-lanes to four-lanes in each direction for a distance of 20 miles between the Massachusetts state line and Manchester, New Hampshire.

USACE, South Coast Rail EIS, Massachusetts. Planner. As part of the third-party review conducted by LBG, Mr. Tidd was responsible for the preparation of technical memorandums reviewing proposed methodologies for assessing indirect and cumulative impacts, and greenhouse gas emissions for the South Coast Rail project. Mr. Tidd was also responsible for editing portions of the DEIS/DEIR, assisting with quality assurance reviews and addressing comments on draft documents.

North Carolina Turnpike Authority, Gaston East-West Connector Indirect and Cumulative Effects Study, North Carolina. Task manager. Mr. Tidd prepared a quantitative indirect and cumulative impact assessment for a proposed toll road extending from I-85 west of Gastonia in Gaston County to I-485 near the Charlotte-Douglas International Airport in Mecklenburg County. As part of this study, Mr. Tidd defined watershed-based study area boundaries and developed metrics to translate household and employment growth into indicators for environmental impacts, such as increases in impervious surface cover and loss of forest cover. Mr. Tidd was responsible for developing and implementing the GIS-based analysis methodology for this project, as well as preparing the final technical report.

DASNY, Chenango Countywide 911 Communications Upgrade EIS, Chenango County, New York. Planner. Assisted in preparation of the SEQRA EAF, scoping document and EIS. Responsible for a GIS viewshed analysis of tower visibility using the ESRI 3D Analyst extension. The viewshed analysis included the identification of sensitive resources (e.g. parks and historic areas) within five miles of each tower. The project objective is to improve emergency services communication capabilities through the construction of six radio communication antenna towers and ancillary infrastructure, and upgrades to facilities at an additional three sites.

DANE ISMART Transportation

Mr. Ismart has 28 years experience with FHWA and 11 years with LBG. While with the FHWA, he served in many capacities including area engineer, research engineer, urban planner, and intermodal team leader. As part of the Office of Environment and Planning, Mr. Ismart specialized in systems transportation planning, intermodal planning, traffic engineering, and policy. He is a nationally recognized expert in transportation planning and models, highway capacity analysis, access management, and site impact analysis. During Mr. Ismart's tenure with FHWA, he conducted and authored the materials for more than 400 short courses on quick response urban planning models, traffic operations, freight planning and models, highway capacity, innovative highway and transit finance, transportation and environmental planning, land use planning, access management, and site impact analysis.

FIRM Louis Berger Group

EDUCATION
- MS, Civil Engineering
- BS, Civil Engineering

YEARS EXPERIENCE 28
YEARS WITH FIRM 17

RELEVANT PROJECT EXPERIENCE

Walmart versus Historic Preservation Society of Civil War Battlefields, Orange County, Virginia. Expert witness. Served as an expert witness for the Historic Preservation Society on the traffic impacts of a proposed Walmart development in Orange County, Virginia on the Wilderness Civil War Battlefield.

I-93 SEIS. Technical analyst. Developed traffic forecasts by using the New Hampshire Statewide Traffic Forecasting Model. Various scenarios are being analyzed and the results are being used for determining how well the projects purpose and scope are being met. As part of this project, an estimate of the potential changes in land use and indirect impacts due to adding capacity to the I-93 corridor are being developed.

Intermodal Terminal Innovative Finance Study. Technical writer. Developed a case study for the NCHRP study evaluating innovative funding techniques for improving access to intermodal facilities. The case study was for the Port of Palm Beach's Sky Bridge over Route 1.

Virginia Research Council. Author and instructor. Developed a financial management of federal aid course for Virginia Research Council.

Highways for Life Leap Not Creep Innovation of Technology Course. Subject matter expert technical advisor and senior instructor. Developed technical material on the application of new innovative techniques for long lasting construction and construction techniques to reduce maintenance of traffic delays and construction impacts.

FHWA, Predictive Performance of Traffic Simulation Models. Project manager. Developed a series of case studies for FHWA to assist transportation planners and traffic engineers in applying traffic simulation models. The case studies included several applications of simulation models forecasting traffic during construction as well as after completion of the projects. A brochure and how-to manual for troubleshooting the application of the simulation models to better replicate actual travel conditions was developed.

FHWA, Access Management Primer and Video. Project manager. Developed the FHWA Primer and Videotape entitled, "Safe Access is Good for Business." The primer discusses in detail methods for improving access to business during construction of corridor access improvement projects.

National Highway Institute. Instructor. Certified NHI instructor for the Federal-Aid 101 Course, Access Management Course, Innovation of Technology Course, and the Highway Capacity Course.

Update of Federal-aid 101. Author. Revised the FHWA Federal-aid 101 Course Material. The material was updated to include the latest planning, finance, construction, and environmental requirements required by SAFTEA-LU. The material and curriculum are used to train FHWA personnel.

FHWA Bottleneck Initiative Workshops. Lecturer/ technical advisor. Conducted Regional workshops and created technical material for the FHWA Bottleneck Initiative. The presentation included techniques for identifying potential corridor bottlenecks due to recurring and non-recurring events and applying innovative solutions for maintaining traffic and reducing delay.

FHWA, Operations CBU Task Order. Key technical task leader. Directed technical teams for a series of FHWA tasks orders involving intermodal planning and policy analysis, freight movements, ITS, and traffic operations.

University of Tennessee, Planning Courses. Instructor. Developed and conducted travel demand forecasting, site impact, access impact, and highway capacity courses for the University of Tennessee and the Tennessee Department of Transportation.

University of Maryland. Instructor and course developer. Developed and conducted site impact, access management, and highway capacity courses for the University of Maryland and the Maryland State Highway Administration.

Central Arkansas Regional Transportation Study. Project manager. Conducted an analysis of the 200-mile freeway system in central Arkansas. The study developed a series of recommendations for improving the freeway system. The study also includes a feasibility study of a fourth bridge crossing over the Arkansas River in Little Rock, Arkansas and a financial plan for funding.

Florida Department of Transportation. Project manager. Conducted a study to evaluate and develop recommendations for improvements to the NHS intermodal connectors of FDOT's District Six.

Klingle Road EIS, Washington, D.C. Traffic technical lead. Conducted the traffic analysis and forecast for the Klingle Road EIS. Using the MWCOG model the project estimated the traffic and traffic patterns if Klingle Road was repaired and open to traffic.

NPS Potomac Boathouse EIS, Arlington County, Virginia. Traffic technical lead. Conducting the traffic analysis to determine the traffic and parking impact for the construction of a new Boathouse facility on the Potomac in Arlington County.

Wisconsin Avenue and Military Road Phase 1 and 2 Corridor Studies, Washington, D.C. Technical director. Conducted a corridor study for the Wisconsin Ave. Corridor and the Military Road Corridor in Washington, D.C. The study developed a series of transportation improvement recommendations for improving the flow of traffic. The study included public meetings and an analysis of future land use development in the corridor.

Washington, D.C., Evacuation Planning Study. Technical model leader. Developed a system-wide traffic forecasting tool to be used in rerouting traffic during man-made and natural disasters that cause corridor or system-wide disruption of traffic.

DC Office of Planning, Washington, D.C. Comprehensive Plan. Model director. Applied the Washington DC COG model as part of the development and evaluation of the Comprehensive Transportation Plan Element.

SHRP 2 R11: Strategic Approaches at the Corridor and Network Levels to Minimize Disruption from the Renewal Process. Principal investigator. Leading the team to create the Work Zone Impact Strategy Estimation (WISE) tool and technical primer. Planning and Operations modules will assist in assessing strategies including economic impact across networks and corridors with user-defined or default value performance measures.

BRAC Bethesda Medical Traffic Study. Traffic engineer. Directing an effort to analyze the impact that the transfer of the Walter Reed staff and patients to the Bethesda Naval Center will have on the access points and internal traffic of the Bethesda Naval Center. A mitigation program to relieve future congestion on the Center is being proposed and developed.

Route 29 Corridor Study, Fauquier County, Virginia. Principal investigator. Analyzing and recommending a series of innovative corridor improvements for Fauquier County, Virginia. A report is being written and improvements such as roundabouts, directional left turns, and restricted access movements are being analyzed.

Kevin Heatley, LEED AP

Employment

2010 – current	Biohabitats, Inc., Baltimore, MD, Senior Scientist
2006 - 2010	Biohabitats Invasive Species Management, Inc., ISM Vice President
2005 - 2006	Penn State College of Technology, Williamsport, PA, Substitute Instructor, Natural Resource Management Department
2005 - 2006	Invasive Plant Control, Inc., Nashville, TN, Director of Development Northeast Region
1997 – 2005	ACRT Inc., Akron, OH, Senior Forester/Regional Manager
1984 – 1994	Bartlett Tree Experts, Lancaster, PA, Area Manager/Arboricultural Consultant

Education

Masters Environmental Pollution Control, Penn State University, Harrisburg, PA, 2006

B.S., Natural Resource Management, Cook College, Rutgers University, New Brunswick, New Jersey 1982

Professional Registration

Certified Arborist #PD-0029, 2000

LEED Accredited Professional for New Construction (USGBC), 2009

Experience

Mr. Heatley has over 20 years of experience in the environmental sector with an extensive background in ecosystem characterization, integrated vegetation management, invasive species suppression and community-based forestry. As a senior ecologist at Biohabitats, Mr. Heatley is responsible for technical and logistical oversight of restoration projects across the continental United States. His work has primarily focused upon the urban/rural interface and on incorporating green infrastructure into sustainable land use planning and management. An expert in the field of invasive species suppression, Mr. Heatley designed the first fully integrated invasive treatment prioritization model in the United States for Fairfax County, Va. He has successfully integrated resource valuation modeling into strategic and budgetary management plans for a variety of land management entities. He has also been instrumental in providing the conceptual design for a leading GIS-based vegetation management software system.

In addition to his technical expertise, Mr. Heatley is skilled at conducting entertaining and informative public speaking engagements and professional workshops. He has lectured on a variety of natural resource topics throughout the United States and the Caribbean.

Representative Project Experience

NPS Revegetation Eastern States IDIQ, Eastern US. Mr. Heatley successfully served as the Biohabitats project manager on a 2.5 million dollar National Park Service Revegetation IDIQ contract. He coordinated and lead project planning and technical assistance services on a wide variety of ecological restoration task orders including revegetation, invasive species control, plant procurement, seeding, plant protection efforts, marsh restoration, and site characterization. Biohabitats has subsequently been awarded a $20 million dollar follow-up contract for National Park Service revegetation services across the Eastern United States and the Caribbean. Mr. Heatley is currently the project manager and technical lead on this contract.

Burgundy Farm Country Day School Ecological Site Assessment, *Alexandria, VA*. Biohabitats Inc. performed an ecological assessment of the campus and developed recommendations for the sustainable use and conservation of the school’s asset. Proactive identification of both ecological assets and landscape challenges enabled the School to cost-effectively integrate site ecology into the master planning process.

Fairfax County Parks Invasive Plant Site Prioritization Model, *Fairfax County, VA.* Biohabitats ISM developed a comprehensive response strategy and site treatment prioritization model as a decision-making tool to be used by the Park Authority to rank the relative value of different sites within their approximately 24,000-acre park system. Based on the principle of "protect the best first" the model shifted the focus in the parks system away from "acres treated" towards "acres restored," allowing the County to maximize the return on its investment in invasive plant control by assuring that treatment sites reflect both the core ecological and cultural values that exist.

Lehigh University, *Bethlehem PA.* Desiring to more fully understand potential atmospheric carbon mitigation opportunities on the college campus, Lehigh University contracted with Biohabitats to undertake an analysis of the direct sequestration and avoided emissions associated with the schools landscape tree cover. Utilizing US Forest Service models, Mr. Heatley performed a comprehensive inventory of 600 acres of naturalized forest and over 220 landscape trees. Information gathered was integrated into strategic recommendations for enhancing this forest benefit and achieving a sustainable level of forest canopy.

Duke University*, Durham NC.* Concerned about the need to understand the ecological processes occurring in a high-visibility, centrally-located stand of campus woodland, Duke University contracted with Biohabitats to undertake an ecological analysis and natural capitol valuation of the campus area known as "Chapel Woods". Mr. Heatley inventoried the vegetation, performed an assessment of the functional benefits, and developed a management plan focused upon forest sustainability. As a function of this effort, Mr. Heatley also performed invasive species suppression within the forest understory.

Valley Road Stream Restoration and Riparian Wetland Creation, *Hagerstown, MD.* Mr. Heatley provided technical recommendations and coordinated invasive plant species suppression in support of the Valley Road Stream Restoration project in Hagerstown, MD. Project involved restoration of an urbanized stream corridor and significant modification of a highly disturbed riparian plant community.

Reforestation Consulting & Invasive Species Suppression, *Rockville, MD.* In order to assure the success of a reforestation effort on a 220 acre tract in Rockville, MD., Fallsgrove Associates, a private development firm, contracted with Biohabitats ISM to oversee tree planting and invasive species suppression. Biohabitats ISM developed and implemented a sampling protocol assessing tree stocking levels and produced biannual reports on supplemental planting levels needed to assure adequate canopy cover. As a component of this effort Biohabitats ISM performed planting contractor coordination and oversight. Biohabitats ISM also created a phased, multi-year, invasive plant suppression strategy. After conducting a comprehensive evaluation of the percent cover for each of the invasive species present on the site, Biohabitats ISM created a target metric for measuring the effectiveness of invasive control efforts. Seasonally selective treatments are currently being undertaken by Biohabitats ISM.

Woodland Restoration of Episcopal High School Alexandria, *Alexandria, VA.* Driven by a desire to integrate a 35 acre woodland resource into the fabric of campus life, the Episcopal High School of Alexandria, Va. contracted with Biohabitats ISM to develop a sustainable campus forest management plan and implement invasive species suppression. This effort involved campus ecosystem characterization, functional benefits modeling, and stakeholder vision sessions. Botanical communities on campus were defined and their respective ecosystem services, in the form of air pollutant interception and carbon sequestration, quantified. Several action items identified during the plan development have subsequently been implemented by Biohabitats including; trail design and construction, ecotone modification, and invasive species suppression. Ecotone modification involved the development of a forest edge planting plan addressing issues of wind vectoring and regeneration. Invasive species interventions have been conducted during 2007 and 2008 in a phased approach designed to enhance native regeneration and minimize opportunities for additional invasive colonization of the woodland.

Episcopal High School, *Baton Rouge, LA.* Recognizing the need to integrate sustainable design principles into future development on their 40 acre campus, the Episcopal High School contracted with Biohabitats (in conjunction with NK Architects) to develop a new Master Plan for the school. Mr. Heatley coordinated Biohabitats participation and involvement in this interactive process. He was directly responsible for developing recommendations and strategies addressing stormwater retrofitting, green infrastructure expansion, and natural capital valuation.

Missionary Ridge Noxious Weed Inventory and Treatment, *Durango, CO.* During the final year of a three year project, Mr. Heatley provided technical oversight and coordinated the GPS/GIS component of the Missionary Ridge invasive species mapping and suppression effort. As part of an adaptive management approach, data collection protocols were modified and additional field staff were hired and trained by Mr. Heatley.

Woodland Management Plan for Episcopal High School, *Alexandria, VA.* Located in the Washington DC metropolitan area, the 150 years of stable land ownership at Episcopal High School has resulted in a significant legacy woodland on the campus. Recognizing the inherent educational, recreational, and inspirational value of their forest, the school contracted with Biohabitats to develop an integrated woodland management plan. The development of this plan involved a GIS-based forest stand delineation, ecological characterization, invasive plant mapping, ecosystem benefits modeling, and stakeholder vision session. As the project manager, Kevin Heatley developed the final document which provides a framework for sustainable management of this green component of the school infrastructure.

Fort Detrick, *Frederick MD.* The US Army operates Fort Detrick on over 1,200 acres of property in Frederick MD. The mixed land use pattern and competing mission objectives create special challenges regarding natural resource management. To aid in understanding field conditions and assist in budgetary justification, Fort Detrick contracted with Mr. Kevin Heatley (in conjunction with Heartwood Consulting LLC.) to undertake a resource analysis and characterization. The primary components of this project included: a GPS Landscape Tree Inventory (with tagging), GIS Database Integration, UFORE Modeling of the Environmental Impact of Forest Stands, and a Five Year Management Plan (with economic tree valuation). Mr. Heatley in addition was contracted with Fort Detrick to undertake a carbon mitigation feasibility analysis. This project examined the potential to use green infrastructure in the mitigation of vehicular greenhouse gas emissions on the base.

Representative Project Experience Prior to Biohabitats

Atkins Arboretum, *Ridgely MD.* Encompassing 400 acres on the Eastern Shore of Maryland, Atkins Arboretum is a unique facility that highlights native plant communities. With strong educational and research objectives as the primary focus of its efforts, the Arboretum enlisted the aid of Kevin Heatley (ACRT Inc.) to develop and implement a GIS-based vegetation database. Mr. Heatley supervised all aspects of the project including; high resolution aerial photogrammetry, GPS mapping of plant communities, the establishment of a thematic research plot layer, and the construction of a multi-thematic, GIS-based, vegetation database.

Tree Preservation Specifications Manual for Association for Zoological Horticulture, *Allison Park, PA.* The Association for Zoological Horticulture, an organization representing the interests of botanists, horticulturalists, and landscape professionals involved with the management of vegetation in zoological parks, contracted with Mr. Heatley for the creation of a set of standard tree preservation specifications. This document was initiated in response to excessive canopy loss during infrastructure construction and renovation projects. It was designed to promote an integrated, comprehensive approach to tree conservation appropriate for vegetation management within the challenging environment of a zoological park. It also contains an extensive specifications section suitable for use as an attachment on construction contracts.

Villanova University Five-Year Canopy Management Plan, *Villanova, PA.* Mr. Heatley as the project manager provided high resolution aerial photogrammetry, GPS/GIS vegetation and infrastructure mapping, and database design, of approximately 250 acres of this historic campus located in Villanova, Pennsylvania.

Swan Point Cemetery Five-Year Canopy Management Plan, *Providence, RI.* Mr. Heatley as the project manager provided GPS/GIS vegetation and infrastructure mapping, “seamless” GIS providing a work tracking database, and budget information of over 300 acres of this historic cemetery located in downtown Providence, Rhode Island.

Professional Associations

Society of American Foresters
International Society of Arboriculture
Society of College & University Planners

Selected Publications, Technical Reports & Presentations

Greater Everglades Ecosystem Restoration Conference, Naples, Fl, July 2010
Land Trust Alliance Annual Rally, Portland , OR, November 2009
Professional Grounds Management Society, Louisville, KY, October 2009
Mid-Atlantic Exotic Pest & Plant Council, Johnstown, PA. July 2009
Society of American Foresters, Western New York Chapter, April 2008
11th Caribbean Urban Forestry Conference, St. Croix, Virgin Islands, June 2006
St. Croix Environmental Association Tree Conservation Workshop, St. Croix, Virgin Islands, June 2006
Southeast Exotic Pest & Plant Council Annual Meeting, Raleigh, NC, May 2006
Association for Zoological Horticulture, *Tree Preservation Specifications Manual* (Industry Standard), 2005
Penn State Invasive Pest, Plants & Weeds Workshop, Luzerne County, PA, October 2005.

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CURRENT POSITIONS

2007-present Natural Resources Defense Council, New York, NY
Senior Scientist, Global Warming and Health Project
Conduct research and offer educational outreach to the public and policymakers on the impacts of climate change on health. Leads NRDC's Global Warming and Health Project. Among the scientists participating in the Intergovernmental Panel on Climate Change 2007 Fourth Assessment Report; published research has looked at heat- and smog-related health problems, climate change's effects on pollen, allergies and asthma, flooding and infectious diseases, especially among vulnerable communities.
(see www.nrdc.org/climatemaps)

2005- present Mailman School of Public Health, Environmental Health Sciences Department
Columbia University's Climate and Health Program
Assistant Clinical Professor
Teaching and research on the health impacts of climate change, and devising strategies to increase societal preparedness to cope with global warming.

2011-present: Co-Convening Lead Author for the Human Health chapter of the 2013 Synthesis of the National Climate Assessment (NCA)

2011-present: Field Editor, Epidemiology, International Journal of Biometeorology

2009-present: Chair, Committee on Global Climate Change & Health, American Public Health Association's Environment Section

EMPLOYMENT HISTORY

2001-2005 Mailman School of Public Health, Columbia University
Post-Doctoral/Doctoral Research Associate
Analyzed health impacts of climate change for the New York Climate and Health Project, multi-disciplinary program linking climate, air quality, and land use change modeling projections.

1998-2001 Queens College/CUNY, Center for the Biology of Natural Systems (CBNS)
Medical Screening Coordinator
Designed/coordinated clinical studies, administration, reporting, and recruitment for the Worker Health Protection Program, medical screening offered to thousands of nuclear weapons workers.

1996-1998 Beth Israel Medical Center, New York, NY
Project Manager
Coordinated CDC study of occupational injuries and illnesses among health care workers.

1996-1997	Office of the New York City Public Advocate, New York, NY **Researcher and co-author** (with S Mattei), *Unhealthy Closure: The Need for a Full Environmental Impact Statement on the Department of Sanitation's Long-Term Plan to Control Pollution from Fresh Kills.*
Sept.1994- Sept. 1996	Radioactive Waste Management Associates, Inc., New York, NY **Research Associate** Provided expertise as geologist and health scientist on reviews of environmental impact statements for radioactive waste disposal and decommissioning projects across the US & Canada.
June 1992- Sept.1994	Natural Resources Defense Council, New York, NY **Environmental Consultant** Researched and wrote a critique of EPA's methods for assessing risks from chemical exposures.
June 1992- Aug. 1992	Los Alamos National Laboratory, Los Alamos, NM **Research Assistant** Provided support on environmental and regulatory reviews of hazardous/radioactive waste issues.
Mar. 1978- May 1979	Colorado State Geological Survey, Denver, CO **Field Geologist** Collected and analyzed samples & conducted field surveys of uranium deposits at former mine sites.

TEACHING EXPERIENCE

2008- present	**Mentor** to Columbia University Earth Institute students on Research Projects on climate change impacts and adaptation in the New York City region, as part of an innovative Climate Change Adaptation Initiative.
2005- present	**Lecturer** on Global Warming and Health, Environmental Health Sciences Core Course, Mailman SPH, Columbia University, New York, NY; as well as at Yale University, New York University, The New School for Social Research, Rutgers University, and the University of California at San Francisco Medical School.
Fall 2006	**Mellon Teaching Fellow,** Barnard College, New York NY: Co-Instructor, "Ecotoxicology;" **Doctoral Seminar Instructor,** The Earth Institute, Columbia University, New York, NY: Public Health Seminar Leader, "Environmental Science for Sustainable Development;" **Mentor** to Barnard undergraduates on their Senior Thesis research projects
Spring 2006- 2007	**Instructor,** Mailman SPH, Columbia University, "Public Health Impacts of Climate Change;" Designed and co-taught with Dr. Patrick L. Kinney a new course offering in the Department of Environmental Health Sciences, which received a Dean's Commendation for Excellence in Teaching; and became the foundation of what has developed into Mailman's new ground-breaking Master's Program in Climate Change & Public Health, lead by Dr. Kinney.
2004- present	**Mentor** to undergraduate research interns who assist on NOAA-funded research.

Fall 2003	**Teaching Assistant**, Mailman SPH, Columbia University, “Topics in Environmental Health Science;” Co-designed and conducted masters seminars in conjunction with Prof. Kinney on climate change and health (*piloted ideas that are now being applied in Spring 2006 course*)
Fall 2002	**Teaching Assistant**, Mailman SPH, Columbia University, “Air Pollution;” helped introduce masters students to concepts of atmospheric structure, air pollution sources, regulation, and health effects

ACADEMIC RESEARCH AND TRAINING

2006-2007	“Profiling Carbon Dioxide, Pollen Concentrations and Asthma in the New York City Region,” as a 2006-2007 APERG Scholar in the Mid-Atlantic States Section of the Air and Waste Management Association (MASS-A&WMA) Air Pollution Educational Research Grant Program (APERG); *Objectives:* to investigate relationships between the timing and length of spring tree pollen seasons and hospital admissions for respiratory illnesses, and to survey spatial and temporal variations in carbon dioxide across the NY metropolitan region
2006-2007	Research investigating differences in greenhouse gas emissions from four different household types, defined by income and urban versus non-urban location
2004-2007	“Climate Variability, Air Quality and Human Health: Measuring Regional Vulnerability for Improved Decision-Making,” funded by National Oceanic and Atmospheric Administration (NOAA); *Objectives*: Assess the degree to which weather and air pollution act independently and/or jointly in contributing to health effects, and to develop and analyze highly resolved exposure and health maps over the state of New York for 1988-2002
2001-2005	“The New York Climate and Health Project: Modeling Heat and Air Quality Impacts of Changing Land Uses and Climate,” funded by US Environmental Protection Agency (EPA); *Objectives*: Develop an integrated modeling framework to assess regional climate and air quality under alternative scenarios of global climate change and regional land use change, and corresponding human health risks.
March 26-April 2 2006	DISsertations Initiative for advancement of Climate-Change ReSearch (DISCCRS) Pacific Asilomar, CA Funded by the National Science Foundation (NSF) to meet challenges in building Successful interdisciplinary careers among recent PhD graduates in climate change impacts. One of 36 fellows selected from doctoral programs throughout the world.
July 2004	NCAR Summer Colloquium on Climate and Health, Boulder, CO (July 2004). Participated in the first summer colloquium on climate and health, held by the Advanced Study Program and Environmental and Societal Impacts Group, National Center for Atmospheric Research.

EDUCATION

October 2005	**Doctor of Public Health, Environmental Health Science** Mailman School of Public Health, Columbia University, New York, NY

Dissertation: “Mortality in Metropolitan New York Under a Changing Climate”

Projections of future climate changes have often been made at the continental scale, yet more finely resolved projections are needed at regional scales in order for local health impacts and adaptive planning options to be evaluated. To meet these needs, a regional health risk assessment was applied to a dynamically downscaled global-to-regional model system for the tri-state New York metropolitan region. The objective was to project climate-related changes in summer heat stress and ground-level ozone concentrations and their impacts on acute mortality from all internal causes, including respiratory and cardiovascular illnesses.

The health risk assessment used model simulations of future temperature conditions and ozone concentrations developed by the New York Climate and Health Project (NYCHP). In the NYCHP model system, the NASA-Goddard Institute for Space Studies (GISS) general circulation model at 4x5° resolution was linked to the Penn State/NCAR Mesoscale Model 5 (MM5) at 36 kilometer (km) resolution to simulate future daily temperatures. The Community Multiscale Air Quality (CMAQ) atmospheric chemistry model at 36 km horizontal grid resolution was linked to the GISS/MM5 model system to simulate future daily ozone concentrations, in five summers of selected future decades across the 31-county New York metro study area. Concentration-response functions from the epidemiological literature were applied to project relative risk of heat- and ozone-related mortality in New York City in each decade. To isolate the effects of climate change on mortality, population was held constant at Census 2000 levels.

Results under the Intergovernmental Panel on Climate Change (IPCC) A2 (relatively fast-growth) scenario assumptions show that summer heat-related mortality could increase 36% by the 2020s, nearly double (95% increase) by the 2050s, and more than triple (250% increase) by the 2080s as compared to the 1990s. There is a median 4.5% increase in ozone-related acute mortality projected across the 31 counties by the 2050s. Synthesizing the heat and ozone results, for a typical summer in the 2050s, projections of additional overall mortality attributable to climate changes are 96% heat- and 4% ozone-related. The downscaled regional projections revealed heterogeneities in the temperature and ozone simulations: relatively dense population areas tend to coincide with relatively high temperatures, and relatively lower population density with relatively high ozone.

A time series analysis of daily summer mortality from 1990-1999 investigated the independent and joint effects of heat and ozone, and whether the relative risk of heat- and ozone-related mortality among urban populations exceeded that of non-urban. Poisson regression modeled daily death counts as a function of same-daily mean temperature and 1-hour daily maximum ozone concentrations averaged over the same and previous day, adjusting for day of week effects and periodic cycles. Results suggest that the heat effect (RR 1.037 per 10°F; 95% C.I. 1.028, 1.047) is less robust than ozone (RR 1.058 per 100 ppb; 95% CI 1.032, 1.085). There is a significant difference in heat-related mortality risk in urban (RR 1.062; 95% CI 1.048, 1.075) vs. non-urban (RR 1.017; 95% CI 1.006, 1.029) counties, but this is not the case for ozone. This type of health risk assessment modeling could be a useful tool for application in other metropolitan areas to evaluate the relative effects of direct (heat) and indirect (ozone) climate-health impacts that are possible under a changing climate.

June 1993	**Master of Science, Environmental & Occupational Health Science** Hunter College, City University of New York, New York, NY
January 1978	**Bachelor of Arts, Geological Sciences** Cornell University, Ithaca, NY

AWARDS

2006-2007	Air Pollution Educational and Research Grant (APERG) Scholarship Program Award recipient, to support research on the relationships between the timing and length of spring tree pollen seasons and hospital admissions for respiratory illnesses, and to survey spatial and temporal variations in carbon dioxide across the NY metropolitan region

2006	Awarded Doctoral Degree with Distinction; I.B.Weinstein Award for Academic Excellence
1993	George H. Kupchik Award, Outstanding Environmental Health Graduate; NIOSH Scholarship Recipient
1973	High School Class Valedictorian; Bausch and Lomb Science Award; NY State Regents Scholarship Recipient

JOURNAL PUBLICATIONS

As lead author:

Knowlton K, Rotkin-Ellman M, Geballe L, Max W, Solomon GM. 2011. Six Climate Change–Related Events In The United States Accounted For About $14 Billion In Lost Lives And Health Costs. Health Affairs 30(11):2167-2176 (Nov. 2011).

Knowlton K, Rotkin-Ellman M, King G, Margolis HG, Smith D, Solomon G, Trent R, English P. 2009. The 2006 California heat wave: impacts on hospitalizations and emergency department visits. *Environmental Health Perspectives* 117:61-67 (January 2009).

Knowlton K, Rotkin-Ellman M, King G, et al. 2009. The 2006 California heat wave: impacts on hospitalizations and emergency department visits. *Epidemiology* 19(6):S323(Nov. 2008).

Knowlton K, Lynn BH, Goldberg R, Rosenzweig C, Hogrefe C, Rosenthal J, Kinney PL. 2007. Projecting heat-related mortality impacts under a changing climate in the New York City region. *American Journal of Public Health* 97:2028-2034.

Knowlton K, Rosenthal JE, Hogrefe C, Lynn B, Gaffin S, Goldberg R, Rosenzweig C, Civerolo K, Ku J-Y, Kinney PL. 2004a. Assessing ozone-related health impacts under a changing climate. *Environmental Health Perspectives* 112: 1557-1563.

Knowlton K, Rosenzweig C, Goldberg R, Lynn B, Gaffin S, Hogrefe C, Civerolo K, Ku J-Y, Solecki W, Small C, Oliveri C, Cox J, Rosenthal J, Kinney PL. 2004b. Evaluating global climate change impacts on local health across a diverse urban region. *Epidemiology* 15 (4): S100-S100 (July 2004).

Knowlton K. 2001. Urban history, urban health. *American Journal of Public Health* 91(12):1944-1946.

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As co-author:

Bell, M.L., Goldberg R., Hogrefe, C., Kinney, P.L., Knowlton K., Lynn B., Rosenthal J., Rosenzweig C., and Patz J. 2007. Climate change, ambient ozone, and health in 50 U.S. cities. *Climatic Change* 82:61-76.

Chavarria G, Knowlton K, Atchley D. 2010. The human-climate-wildlife nexus. *Bulletin of the Atomic Scientists* (January/February 2010):48-56 (DOI: 10.2968/066001007).

Civerolo KL, Hogrefe C, Lynn B, Rosenzweig C, Goldberg R, Rosenthal J, Knowlton K, and Kinney PL. 2008. Simulated effects of climate change on summertime nitrogen deposition in the eastern US. *Atmospheric Environment* 42(9):2074-2082.

Civerolo KL, Hogrefe C, Lynn B, Rosenzweig C, Goldberg R, Rosenthal J, Knowlton K, and Kinney PL. 2007. Estimating the effects of increased urbanization on surface meteorology and ozone concentrations in the New York City metropolitan region. *Atmospheric Environment* 41(9):1803-1818 (Mar 2007).

Hogrefe C. S., B. Lynn, K. Civerolo, J.-Y. Ku, J. Rosenthal, C. Rosenzweig, R. Goldberg, S. Gaffin, K. Knowlton, and P.L. Kinney. 2004. Simulating changes in regional air pollution over the eastern United States due to changes in global and regional climate and emissions. *J Geophysical Res - Atmospheres* 109:D22301 (Nov 17 2004).

Hogrefe C, Rosenzweig C, Kinney P, Rosenthal J, Knowlton K, Lynn B, Patz J, Bell ML. 2004. Health impacts from climate-change induced changes in ozone levels in 85 United States cities. *Epidemiology* 15(4): S94-S95 (July 2004).

Kinney PL, K Knowlton, C Hogrefe, et al. 2007. Melding measurements and models to enrich the study of climate, air quality, and health. *Epidemiology* 18(5):S131(Sept 2007).

Kinney PL, Bell M, Hogrefe C, K Knowlton, et al. 2007. Climate change, air quality, and health: Assessing potential impacts over the eastern US. Epidemiology 18(5):S133(Sept 2007).

Patz JA, Kinney PL, Bell M, Ellis H, Goldberg R, Hogrefe C, Khoury S, Knowlton K, Rosenthal J, Rosenzweig C, Ziska L. 2004. *Heat Advisory: How Global Warming Causes More Bad Air Days*. NY: Natural Resources Defense Council.

Rosenthal JK, Sclar ED, Kinney PL, Knowlton K, Craudereef R, Brandt-Rauf PW. 2007. The links between the built environment, climate and population health: interdisciplinary environmental change research in New York City. *Ann Acad Med Singapore* 97(11):2028-2034.

Sheffield PE, Knowlton K, Kinney PL. 2011. Modeling of regional climate change effects on ground-level ozone and childhood asthma. *American Journal of Preventive Medicine* 41(3):251-257.

Ziska LH, Knowlton K, Rogers CA, Dalan D, Tierney N, Elder MA, et al. 2011. Recent warming by latitude associated with increased length of ragweed pollen season in central North America. *PNAS* 108(10):4248-4251 (March 8, 2011).

BOOK CHAPTERS

As lead author:

Knowlton K. February 10 2011. Globalization and Environmental Health. In: Nriagu JO (ed.) *Encyclopedia of Environmental Health*, vol.2, pp.995-1001. Burlington: Elseveier.

Knowlton K. April 2010 webinar presentation on “Climate Change, Vulnerable Populations and Adaptation” - Chapter 5 on Public Health Adaptation Strategy in CDC/APHA printed guidebook, *Climate Change: Mastering the Public Health Role* (in print April 2011).

Knowlton K, Hogrefe C, Lynn B, Rosenzweig C, Rosenthal J, Kinney PL. 2008. Impacts of heat and ozone on mortality risk in the New York City Metropolitan Region under a changing climate. *In:* Climate Information for the Health Sector. Advances in Global Change Research (Thomson M, Garcia Herrera R, eds.).

Hogrefe C, Ku J-Y, Civerolo K, Lynn B, Werth D, Avissar R, Rosenzweig C, Goldberg R, Small C, Solecki WD, Gaffin S, Holloway T, Rosenthal J, Knowlton K, and Kinney PL. 2004. Modeling the impact of global climate and regional land use change on regional climate and air quality over the northeastern United States. *In:* Air Pollution Modeling and Its Application XVI (Borrego C, Incecik S, eds.). New York: Kluwer Academic/Plenum, pp.135-144.

As co-author:

Kinney PL, Rosenthal JE, Rosenzweig C, Hogrefe C, Solecki W, Knowlton K, Small C, Lynn B, Civerolo K, Ku J-Y, Goldberg R, Oliveri C. 2006. "Assessing Potential Public Health Impacts of Changing Climate and Land Use: The New York Climate and Health Project." *In:* Regional Climate Change and Variability: Impacts and Responses (Ruth M, Donaghy K, Kirshen P, eds.). Cheltenham, UK and Northampton, MA: Edward Elgar, pp.161-189.

Rotkin-Ellman M, Knowlton K, Apatira L, Solomon G. 2011. "Lessons from the Past and Needs for the Future: Place-Based Case Studies of Vulnerability to Climate Change" (book chapter; in press).

Lead author of NRDC Briefing Papers & Fact Sheets on a variety of climate-health topics, including climate change's effects on ground-level ozone smog; pollen, allergies and asthma; heat waves; infectious diseases; harmful algal blooms; and strategies to help prepare to meet these health challenges; available online at: www.nrdc.org/health/globalwarming (2007-present).

PRESENTATIONS

Organizer & Moderator of Sessions on Climate Change and Health, Adaptation in Vulnerable Communities, and Indicators of Vulnerability and Resilience; for the 2011 and 2010 American Public Health Association Annual Meetings.

Organizer & Moderator of Symposia on Climate Change and Health at the 2009 and 2008 American Association for the Advancement of Sciences (AAAS) Annual Meetings.

As presenter:

Session on Climate Change, Air Pollution, and Adaptation in Vulnerable Communities; for the 2010 American Public Health Association Annual Meeting, Denver, Colorado, USA (November 2010).

Capitol Hill Oceans Week, Invited Speaker at Panel on the "Health Impacts of Today's Energy Choices," June 9, 2010, Washington, D.C.

Workshop on Modeling and Mitigation of the Impacts of Extreme Weather Events to Human Health Risks, Rutgers University, June 3, 2010 (Invited Speaker on Heat Wave morbidity, response, adaptation)

International Research Institute for Climate and Society, May 2010 and 2009, Columbia University, New York, NY, Invited Lecturer at Summer Symposium on Climate and Health.

National Environmental Public Health Conference, "Vulnerable Communities & Climate Change: Air Pollution in Metro NY" Centers for Disease Control & Prevention, Atlanta GA, October 26, 2009

National Center for Atmospheric Research Summer Symposium on Climate and Health, Invited Lecturer, July 2009.

American Museum of Natural History, New York, NY, April 2, 2009, "Exploring the Dynamic Relationship Between Health and the Environment" (poster presentation on dengue fever and climate change)

Knowlton K, Rotkin-Ellman M, King G, Margolis HG, Smith D, Solomon G, Trent R, English P. 2008. The 2006 California heat wave: impacts on hospitalizations and emergency department visits. Oral presentation at ISEE/ISEA Joint Meeting, Pasadena, CA, October 15, 2008.

Knowlton K, Kinney PL, Bell ML, Hogrefe C, Rosenzweig C. 2005. Assessing potential health impacts of ozone and $PM_{2.5}$ under a changing climate. Poster P-AQ1.8, US Climate Change Science Program (CCSP) Workshop: Climate Science in Support of Decision Making, November 14-16, 2005, Arlington VA.

Knowlton K, Rosenthal J, Rosenzweig C, Goldberg R, Lynn BH, Gaffin S, Solecki WD, Oliveri C, Cox J, Small C, Hogrefe C, Clverolo K, Ku J-Y, Kinney PL. 2004. Projecting the local impacts of global climate change on public health in New York City. American Public Health Association Annual Meeting, November 6-10, Washington, DC.

Knowlton K, Rosenzweig C, Goldberg R, et al. 2004. Evaluating global climate change impacts on local health across a diverse urban region (poster). ISEE/ISEA Mtg, 1-4 August, New York.

Knowlton K and Rosenthal J. 2004. The New York Climate & Health Project: Global and local environmental change and public health. The New York Academy of Sciences, Environment Section (10 May 2004).

Knowlton K (invited speaker). 6 Mar 2004. "Projecting Local Impacts of Global Climate Change." Long Island Univ Annual Biology Conference: The Scientific, Biological, Social, and Economic Impacts of Fossil Fuels. Brooklyn, NY.

Knowlton K, Rosenthal J, Lynn B, Gaffin S, Kinney P, Hogrefe C, Biswas J, Civerolo K, Ku J-Y, Rosenzweig C, Goldberg R. 2003. Assessing Public Health Impacts of Heat and Air Quality Under a Changing Climate in the NYC Metropolitan Area. Amer Geophysical Union Fall Mtg, 8-12 December, San Francisco. Eos Trans. AGU, 84(46), Fall Meet. Suppl., Abstract U32A-0028.

Knowlton K, Rosenthal JE, Gaffin S, Rosenzweig C, Goldberg R, Lynn B, Kinney PL. Modeling Public Health Impacts of Climate Change in the New York Metropolitan Region. Fifth International Conference on Urban Climate (ICUC-5), 1-5 September 2003, Lodz, Poland.

As co-author:

Civerolo K, Biswas J, Hogrefe C, Rosenthal J, Knowlton K, Lynn B, Ku J-Y, Goldberg R, Rosenzweig C, Kinney PL. 2004. Modeling Future Climate and Air Quality in the New York City Metropolitan Area, Presented at the Symposium on Planning, Nowcasting, and Forecasting in the Urban Zone, 84th AMS Annual Meeting, Jan. 11-15, Seattle, WA.

Hogrefe C, Lynn B, Rosenzweig C, Goldberg R, Civerolo K, Ku J-Y, Rosenthal R, Knowlton K, Kinney PL. 2005. Utilizing CMAQ Process Analysis to Understand the Impacts of Climate Change on Ozone and Particulate Matter. Models-3 Users' Workshop, September 26-28, Chapel Hill, NC. Online: http://www.cmascenter.org/html/2005_conference/abstracts/3_2.pdf.

Hogrefe C, Knowlton K, Goldberg R, Rosenthal J, Rosenzweig C, Lynn BH, Kinney PL. 2005. Integrating observations and MM5/CMAQ predictions to study the link between climate variability, air quality and health in New York State: Project description and initial results. Presented at the NOAA/EPA Golden Jubilee Symposium on Air Quality Modeling and Its Applications, September 20-21, Research Triangle Park, NC.

Hogrefe C, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Solecki WD, Small C, Gaffin S, Knowlton K, Goldberg R, Rosenzweig C, Kinney PL. 2004. Air quality in future decades – determining the relative impacts of changes in climate, anthropogenic and biogenic emissions, global atmospheric composition, and regional land use. Preprints of the 27th NATO/CCMS International Technical Meeting on Air Pollution Modeling and Its Applications, October 25 - 29, Banff, Canada, pp. 158-165.

Hogrefe C, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Knowlton K, Solecki WD, Small C, Gaffin S, Goldberg R, Rosenzweig C, Kinney PL. 2004. Modeling the Air Quality Impacts of Climate and Land Use Change in the New York City Metropolitan Area. Models-3 Users' Workshop, October 18-20, Research Triangle Park, NC. Online:

http://www.cmascenter.org/html/2004_workshop/abstracts/Climate%20Multiscale/Hogrefe_abstract.pdf.

Hogrefe C, Biswas J, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Knowlton K, Goldberg R, Rosenzweig C, Kinney PL. 2003. Climate change and ozone air quality over the eastern United States: A modeling study. Fall Meeting 2003, San Francisco, CA, December 8-12. Eos Trans. AGU, 84(46), Fall Meet. Suppl., Abstract U32A-0027.

Hogrefe C, Biswas J, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Knowlton K, Goldberg R, Rosenzweig C, Kinney PL. 2003. Climate change and ozone air quality: applications of a coupled GCM/MM5/CMAQ modeling system. Proceedings of the 2nd Models-3 Users' Workshop, October 27-29, Research Triangle Park, NC. Online at: http://www.cmascenter.org/2003_workshop/presentations/session2/hogrefe_abstract.pdf.

Kinney PL, Hogrefe C, Lynn BH, Rosenzweig C, Rosenthal J, Knowlton K. 2005. Independent and joint impacts of heat and ozone mortality risk under a changing climate. Wengen Tenth Annual Workshop on Global Change Research, September 12-14, Wengen, Switzerland.

Kinney P, Knowlton K, Rosenthal J, Rosenzweig C, Solecki WD, Hogrefe C, Lynn B, Avissar R. 2003. Heat Stress Modeling in the NYC Metropolitan Area: Estimates for the 2050s Using a Linked Global-Regional Climate Modeling System. 2003 Open Mtg: Human Dimensions of Global Environmental Change, Montreal, Canada, October 16-18.

Rosenthal JR, Kinney PL, Knowlton K. 2004. Reshaping the built environment to reduce public health impacts of the urban heat island effect. American Public Health Association Annual Meeting, November 6-10, Washington, DC.

OTHER OUTREACH, ADVOCACY, MEDIA COVERAGE

Developed NRDC webpages on *Climate-Health Vulnerability* (www.nrdc.org/climatemaps) and *2011 Extreme Weather* (www.nrdc.org/extremeweather)

December 2011 invited presentation on Climate Change, Aeroallergens and Health to the Northern Central Weed Science Society, Milwaukee, WI

2011: Webinars on Climate Change and Health for National Nurses groups for continuing medical education credits; for Faith Community Leadership groups

Nov 2011 presentation at NJ Climate Change Adaptation Workshop at Rutgers University

Oct.29-Nov.3, 2011: presentations at the American Public Health Association Annual Mtg, Washington, DC on communicating climate-health vulnerability; and organizer of two panels, including a Special Session on “Climate Change & Health: The Global Challenge”

Sept 24-25, 2011: invited presentation at workshop on health, economics, and climate change, Boston, MA

May 26-27, 2011: International Research Institute for Climate Change, Columbia University, NY, NY – Climate Change & Health presentations and trainings for international experts and researchers

March 28-20, 2011: Indo-US Heat Vulnerability Workshop, Ahmedabad, India

Invited speaker, April 2010, Barnard College panel with Dr. Mary Robinson on climate change, NYC.

January 2010 Lecture on the health impacts of global warming as part of the *Cambridge Forum* lecture series - one of public radio’s longest running public affairs programs heard on NPR stations across the US - titled, “After Copenhagen,” online at: http://forum-network.org/lecture/health-impacts-global-warming.

Speaking about the impacts of changing climate conditions on infectious diseases like dengue fever in a segment titled, “Outbreak” on *Planet Green* television, October 2009.

Testimony to NYC Council on climate change, infrastructure adaptation and health, May 2008.

CARE International Executive Committee Meeting, New York, NY: *Developing Responses to the Climate Crisis* (7 June 2007).

Testimony to New York City Council (Environment Committee) on climate research findings in support of proposed Local Law No.661 to limit greenhouse gas emissions in NYC (June 2006, June 2005).

The New York Times. Worked with journalists to clarify research issues: "Forecast for New York this century: Hotter and wetter" (*New York Times*, Metro Section, 27 June 2004); "Climate scientists zoom in on changes" (*New York Times*, Metro Section, 9 December 2003).

National Public Radio. "Degrees of Concern: Climate Change and New York City," K Knowlton on West Nile virus and climate variability, broadcast interview on *Living on Earth*, nationally syndicated NPR show, 11 October 2003.

The American Museum of Natural History, Dartmouth College, The 92nd Street Y (NYC), *Science News*, *Greenwire*, *New York Daily News*, *The Poughkeepsie Journal* and *Downtown Express*.

OTHER PROFESSIONAL ORGANIZATIONAL AFFILIATIONS

American Association for the Advancement of Science; American Academy of Allergy, Asthma and Immunology; American Geophysical Union; American Meteorological Society; New York Academy of Sciences; International Society for Environmental Epidemiology.

1/11/2012

GINA M. SOLOMON M.D., M.P.H.

111 Sutter Street, 20th Floor, San Francisco, CA 94104 ♦ (415) 875-6100 ♦ gsolomon@nrdc.org

EMPLOYMENT

Senior Scientist, *Natural Resources Defense Council, 1996 - present*
Conduct research and investigation into priority environmental hazards with a focus on threats to children's health. Advocate for policy changes to improve laws and regulations to protect health. Represent NRDC in the press, legislative and agency hearings, and public fora. Supervise 7 full-time staff and numerous interns and students. Raise and manage an annual budget of over $800,000.

Director, UCSF Occupational and Environmental Medicine Residency Program, *2008-present*
Manage all aspects of the physician training program in occupational and environmental medicine at UCSF, including directing the interview and selection process, shaping the educational requirements, managing the budget, and maintaining funding and accreditation. Supervise an associate director, program coordinator, and 4-7 residents and fellows.

Health Sciences Clinical Professor, *University of California San Francisco, 2011 – present*
Precept occupational and environmental medicine (OEM) residents and fellows in clinic. Teach at journal club, case conference, grand rounds, and summer didactics. Teach Epi 170.16 Environment and Health course for medical and nursing students. Supervise residents from four medical centers for month-long rotations at NRDC.

Associate Director, Pediatric Environmental Health Specialty Unit, *University of California San Francisco, 2003 - Present*

Associate Clinical Professor of Medicine, *University of California San Francisco, 2006 –2011*

Assistant Clinical Professor of Medicine, *University of California San Francisco, 1998 - 2006*

Clinical Instructor in Medicine, *University of California San Francisco, 1996 - 1998*

Consultant, Ergonomics Evaluation Project, *Massachusetts Division of Industrial Accidents, 1996 - 1997*

Fellow, Occupational and Environmental Medicine, *Harvard School of Public Health, 1996*

Clinical Instructor in Medicine, *Harvard University School of Medicine, 1991 - 1995*

Resident, Primary Care Internal Medicine, *Mount Auburn Hospital, 1991 - 1995*

Research Assistant in Environmental Medicine, *Institute of Medicine, Washington DC, 1994*

PROFESSIONAL ACTIVITIES

Science Advisory Board, *U.S. Environmental Protection Agency, 2011-2014*

Editorial Board, *Environmental Health Perspectives, 2010 – present*

Scientific Guidance Panel, *California Environmental Contaminant Biomonitoring Program, 2007-present*

Tracking Implementation Advisory Group, *California Department of Public Health, 2006 - present*

Board of Directors, *San Francisco Bay Area Physicians for Social Responsibility, 2000 – present*

Committee on Human and Environmental Exposure Science in the 21st Century, *National Research Council, 2010 – 2012*

Board of Scientific Counselors, *National Toxicology Program*, *2008 – 2011*

California Adaptation Advisory Panel, *Governor of California*, 2010

Science Advisory Board Drinking Water Committee, *U.S. Environmental Protection Agency, 2004-2010*

Science Advisory Board Acrylamide Panel, *U.S. Environmental Protection Agency, 2007 – 2008*

Reviewer, *American Academy for the Advancement of Sciences* LSDF 09-01: Innovative research programs to improve health and health care, 2009

Committee on Toxicity Testing and Assessment of Environmental Agents, *National Research Council, 2004 -2007*

Childhood Lead Poisoning Prevention Expert Advisory Committee, *California Department of Health Services, 2004 - 2006*

Scientific Advisory Group, Environmental Epidemiology and Biomonitoring, *CA Dept of Health Services Environmental Health Investigations Branch, 2000-2004*

SB702 Expert Working Group on Public Health Tracking, *California Department of Health Services, 2002 - 2004*

Science Advisory Board Trichloroethylene Panel, *U.S. Environmental Protection Agency, 2002*

Strategic Advisory Committee, *National Center for Environmental Health, CDC, 2001 - 2002*

Endocrine Disruptor Screening and Testing Advisory Committee, *U.S. Environmental Protection Agency, 1996 - 1998*

Board of Directors, *Consortium for Environmental Education in Medicine, 1998 - 2000*

Pesticides and Environmental Education for Health Providers Committee, *National Environmental Education & Training Foundation*, *1998 - 2000*

Peer Reviewer: *Journal of the American Medical Association (JAMA); American Journal of Public Health; Climatic Change; Environmental Health Perspectives; Canadian Medical Association Journal; Environmental Science and Technology; Journal of Occupational and Environmental Medicine; Environmental Research; Environmental Geochemistry and Health; Indoor Air; International Journal of Occupational and Environmental Health; Tobacco Control; European Journal of Clinical Nutrition; American Journal of Preventive Medicine; Environmental Pollution; Chemosphere; Journal of Epidemiology and Community Health.*

EDUCATION

Masters in Public Health, *Harvard School of Public Health, 1994*
Doctorate of Medicine, *Yale School of Medicine, 1991*
Bachelor of Arts, Comparative Literature, Magna cum Laude, *Brown University, 1986*

CERTIFICATION AND LICENSING

National Board of Medical Examiners, 7/92
American Board of Internal Medicine, 8/95, Recertified 5/05
American Board of Preventive Medicine, 2/98, Recertified 12/08
California Medical License number: G 083110

AWARDS AND RECOGNITION

CAAT Recognition Award, *Johns Hopkins University Center for Alternatives to Animal Testing, 2009*
Certificate of Appreciation, *Center for Community Action and Environmental Justice, 2007*
Certificate of Appreciation, *California Safe Schools, 2004*
Clean Air Award for Research, *American Lung Association of the Bay Area, 2004*
Ten Women's Health Pioneers, *The Green Guide, 2004*
Environmental Heroes Award, *The Breast Cancer Fund, 2002*
Will Solimene Award for Excellence in Medical Writing, *American Medical Writers Association, 2000*
Occupational Physicians Scholarship Fund Award, *1993, 1995*
Farr Scholarship Award, *Yale Medical School, 1988, 1989*
Phi Beta Kappa, *Rhode Island Chapter, 1986*

SCIENTIFIC PUBLICATIONS

Knowlton K, Rotkin-Ellman M, Geballe L, Max W, Solomon G. Six Climate Change–Related Events in the United States Accounted For About $14 Billion in Lost Lives and Health Costs. Health Affairs. 30(11): 1-10. 2011.

Rotkin-Ellman M, Wong KK, Solomon GM. Seafood Contamination after the BP Gulf Oil Spill and Risks to Vulnerable Populations: A Critique of the FDA Risk Assessment. Environ Health Perspect, 2011. http://dx.doi.org/10.1289/ehp.1103695.

Solomon G, Huddle A, Silbergeld EK, Herman J. Chapter 8. Manganese in Gasoline: Are We Repeating History? In: Clapp R (Ed.). From Critical Science to Solutions: The Best of Scientific Solutions. Baywood Publishing Inc., 2011. ISBN: 978-0-89503-404-5.

Rotkin-Ellman M, Navarro KM, Solomon GM. Gulf oil spill air quality monitoring: lessons learned to improve emergency response. Environ Sci Technol. 44(22):8365-6, 2010.

Solomon G, Janssen SJ. Health Effects of the Gulf Oil Spill. JAMA, 304(10):1118-9, 2010.

Solomon G, Janssen SJ. Communicating with Patients and the Public About Environmental Exposures and Reproductive Risk. In: Woodruff TJ, Janssen SJ, Guillette LJ, Giudice LC (eds), Environmental Impacts on Reproductive Health and Fertility. Cambridge Press, Cambridge, UK, 2010.

Rotkin-Ellman M, Solomon G, Gonzales CR, Agwaramgbo L, Mielke HW. Arsenic Contamination in New Orleans Soil: Temporal Changes Associated with Flooding. Environmental Research, 110(1):19-25, 2010.

Krewski D, Acosta D Jr, Andersen M, Anderson H, Bailar JC 3rd, Boekelheide K, Brent R, Charnley G, Cheung VG, Green S Jr, Kelsey KT, Kerkvliet NI, Li AA, McCray L, Meyer O, Patterson RD, Pennie W, Scala RA, Solomon GM, Stephens M, Yager J, Zeise L. Toxicity testing in the 21st century: a vision and a strategy. Toxicol Environ Health B Crit Rev. 13(2-4):51-138, 2010.

Solomon G, Huang A, Godsel R. Contaminants in the Air and Soil in New Orleans After the Flood: Opportunities and Limitations for Community Empowerment, In: Bullard R, Wright B (eds). Race, Place, and Environmental Justice After Hurricane Katrina. Westview Press, Boulder, CO, 2009.

Solomon G. Physicians' Duty to Be Aware of and Report Environmental Toxins. Virtual Mentor, 11(6):434-442, 2009. http://virtualmentor.ama-assn.org/2009/06/ccas2-0906.html.

Knowlton K, Rotkin-Ellman M, King G, Margolis HG, Smith D, Solomon G, Trent R, English P. The 2006 California Heat Wave: Impacts on Hospitalizations and Emergency Department Visits Environ Health Perspect, 117: 61-67, 2009. http://www.ehponline.org/members/2008/11594/11594.pdf.

Woodruff T, Zeise L, Axelrad D, Guyton KZ, Janssen S, Miller, M, Miller G, Schwartz J, Alexeef G, Anderson H, Birnbaum L, Bois F, Cogliano J, Crofton K, Euling SY, Foster P, Germolec D, Ginsberg G, Gray E, Hattis D, Kyle A, Leubke R, Luster M, Portier C, Rice D, Solomon G, Steinmaus C, Vandenberg J, Zoeller T. Meeting Report: Moving Upstream: Evaluating Adverse Upstream Endpoints for Improved Risk Assessment and Decision Making. Environ Health Perspect, 116:1568–1575 (2008). http://www.ehponline.org/members/2008/11516/11516.pdf.

Humphreys EH, Janssen S, Heil A, Hiatt P, Solomon G, Miller MD. Outcomes of the California Ban on Pharmaceutical Lindane: Clinical and Ecologic Impacts. Environ Health Perspect, 116:297-302 (2008). doi:10.1289/ehp.10668.

Humphries E, Solomon G. Helping Your Patients Manage Asthma: Focus on the Source. Medscape, http://www.medscape.com/viewarticle/572573.

Solomon GM, Janssen S. Talking with patients and the public about endocrine disrupting chemicals. In: Endocrine-disrupting Chemicals: From Basic Research to Clinical Practice. Ed. Andrea C. Gore. Part of "Contemporary Endocrinology," series editor P. Michael Conn, Humana Press, Totowa, NJ, 2007.

Karr C, Solomon GM, Brock-Utne A. Health effects of common home, lawn and garden pesticides. Ped Clin N Am 54(1):63-80, 2007.

Thundiyil J, Solomon GM, Miller MD. Transgenerational exposures: Persistent chemical pollutants in the environment and breast milk. Ped Clin N Am 54(1):81-101, 2007.

Solomon GM, Hjelmroos-Koski M, Rotkin-Ellman M, Hammond K. Air quality in New Orleans, Louisiana after flooding: Mold, endotoxin, and particulate matter, October - November 2005. Environ Health Perspect 114(9):1381-1386, 2006.

Solomon GM, LaDou J, Wesseling C. Environmental Exposures and Controls, in LaDou (Ed.) Occupational and Environmental Medicine. Fourth Ed. Appleton and Lange, Stamford CT, 2006.

McDaniel P., Solomon G, Malone RE. The ethics of industry experimentation using employees: The case of taste-testing pesticide-treated tobacco. Am J Public Health 96(1):37-46, 2006.

McDaniel PA, Solomon G, Malone RE. The Tobacco Industry and Pesticide Regulations: Case Studies from Tobacco Industry Archives. Environ Health Perspect 113(12):1659-1665, 2005.

Bailey D, Solomon G. Pollution Prevention at Ports: Clearing the Air. Environ Impact Assess Review 24:749-774, 2004.

Solomon G, Humphreys E, Miller M. Asthma and the Environment: Connecting the Dots: what role do environmental exposures play in the rising prevalence and severity of asthma? Contemp Pediatrics 21(8), 2004.

Solomon GM, Hawes A, Quintero A, Widess E. Approaches to Occupational and Environmental Law in: Rosenstock L and Cullen M. (Eds.) Textbook of Clinical Occupational and Environmental Medicine, Second Edition. WB Saunders/Mosby/Churchill Livingstone, Philadelphia, 2004.

Solomon GM, LaDou J, Jackson RJ. Environmental Exposures and Controls, in LaDou (Ed.) Occupational and Environmental Medicine. Third Ed. Appleton and Lange, Stamford CT, 2003.

Solomon GM, Balmes J. Health Effects of Diesel Exhaust. Clinics in Occup & Environ Med 3:61-80, 2003.

Miller M, Solomon G. Environmental Risk Communication for the Pediatrician. Pediatrics 112:211-221, 2003.

Miller M, Solomon G. Pesticides, in: Etzel RA and Balk SJ (Eds). Handbook of Pediatric Environmental Health, Second Ed. American Academy of Pediatrics, Elk Grove Village, IL, 2003.

Solomon GM. Rare and Common Diseases in Environmental Health. San Francisco Medicine 75(9):14-16, 2002.

Solomon GM, Huddle AM. Low levels of persistent organic pollutants raise concerns for future generations. J of Epi and Commun Health. 56(11):826-827, 2002.

Solomon GM and Schettler T. Endocrine Disruption. In McCally M. (Ed.) Life Support: The Environment and Human Health. MIT Press, Cambridge MA, 2002.

Solomon GM, Weiss P. Chemical Contaminants in Breast Milk: Time Trends and Regional Variability. Environ Health Perspect 110(6): A339-A347, 2002.

Pandya RJ, Solomon GM, Kinner A, Balmes JR. Diesel Exhaust and Asthma: Potential Hypotheses and Molecular Mechanisms of Action, Environ Health Perspect 110(suppl 1):103-112, 2002.

Chaisson C, Solomon G. Children's Exposure to Toxic Chemicals – Modeling their World to Quantify the Risks. Neurotoxicology 22:563-565, 2001.

Solomon GM, Schettler T. Emerging Issues in Environmental Health: Endocrine Disruption. Canadian Med Assn Journal 163(11): 1471-1476, 2000.

Solomon GM. Hormones, Chemicals, and Public Policy. Chem and Engineering News, 78(32): 66-67, 2000.

Schettler T, Solomon GM, Valenti M, and Huddle AM. Generations at Risk: Reproductive Health and the Environment. Massachusetts Institute of Technology Press, Boston, June 1999.

Milton DK, Solomon GM, Rossiello RA, Herrick RF. Risk and Incidence of Asthma Attributable to Occupational Exposure among HMO Members. Am J Ind Med 33(1):1-10, 1998.

Solomon GM. Reproductive Toxins: A Growing Concern at Work and in the Community. J Occ Env Med 39:105-107, 1997.

Solomon GM, Huddle AM, Silbergeld EK, Herman D. Manganese in Gasoline: Are We Repeating History? New Solutions 7(2):17-25, 1997.

Frumkin H, Solomon GM. Manganese in the U.S. Gasoline Supply. Am J Ind Med 31:107-115, 1997.

Solomon GM, Morse E, Garbo M, Milton DK. Stillbirth after Occupational Exposure to N-Methyl-2-Pyrrolidone: A case report and review of the literature. J Occ Env Med 38:705-713, 1996.

Esswein E, Trout D, Hales T, Brown R, Solomon GM. Exposures and Health Effects: An Evaluation of Workers at a Sodium Azide Production Facility. Am J Ind Med 30:343-350, 1996.

Parker J, Solomon GM. Decades of Deceit: The History of Bay State Smelting. New Solutions 5:80-89, 1995.

REPORTS

Knowlton K, Solomon G, Rotkin-Ellman M. Fever Pitch: Mosquito-Borne Dengue Fever Threat Spreading in the Americas. Natural Resources Defense Council, New York, NY, 2009. http://www.nrdc.org/health/dengue/files/dengue.pdf.

Rotkin-Ellman M, Solomon G. Poisons on Pets II: Toxic Chemicals in Flea and Tick Collars. Natural Resources Defense Council, New York, NY, 2009. http://www.nrdc.org/health/poisonsonpets/files/poisonsonpets.pdf.

Rotkin-Ellman M, Quirindongo M, Sass J, Solomon G. Deepest Cuts: Repairing Health Monitoring Programs Slashed Under the Bush Administration. Natural Resources Defense Council, New York, NY, 2008. http://www.nrdc.org/health/deepestcuts/deepestcuts.pdf.

Wall M, Rotkin-Ellman M, Solomon G. An Uneven Shield: The Record of Enforcement and Violations Under California's Environmental, Health and Workplace Safety Laws. Natural Resources Defense Council, New York, NY, 2008. http://www.nrdc.org/legislation/shield/shield.pdf.

Knowlton K, Rotkin-Ellman M, Solomon GM. Sneezing and Wheezing: How global warming could increase ragweed allergies, air pollution, and asthma. Natural Resources Defense Council, New York, NY, 2007. http://www.nrdc.org/globalWarming/sneezing/sneezing.pdf.

Cohen A, Janssen S, Solomon GM. Clearing the Air: Hidden Hazards in Air Fresheners. Natural Resources Defense Council, New York, NY, 2007. http://www.nrdc.org/health/home/airfresheners/airfresheners.pdf

Solomon GM, Nance E, Janssen S, White WB, Olson E. Drinking water quality in New Orleans: June-October 2006. Natural Resources Defense Council, New York, NY, January 2007. http://www.nrdc.org/health/effects/katrinadata/water.pdf.

Solomon GM, Rotkin-Ellman M. Contaminants in New Orleans Sediment: An Analysis of EPA Data. Natural Resources Defense Council, New York, NY, February 2006. http://www.nrdc.org/health/effects/katrinadata/sedimentepa.pdf.

Solomon GM, Campbell TR, Feuer GR, Masters J, Samkian A, Paul KA. No Breathing in the Aisles: Diesel Exhaust Inside School Buses. Natural Resources Defense Council, New York, NY, 2001. http://www.nrdc.org/air/transportation/schoolbus/schoolbus.pdf.

Solomon G, Ogunseitan OA, Kirsch J. Pesticides and Human Health: A Resource for Health Care Professionals. Physicians for Social Responsibility, San Francisco, CA, 2000. http://www.psrla.org/pahk.pdf

Solomon GM, Mott L. Trouble on the Farm: Growing up with Pesticides in Agricultural Communities. Natural Resources Defense Council, New York, NY, 1998. http://www.nrdc.org/health/kids/farm/farminx.asp.

PUBLISHED ABSTRACTS

Knowlton K, Solomon G, Chavarria G. Preparing for the Health Impacts of Climate Change: Science and Societal Strategies. AAAS Annual Meeting Abstract, 2008.

Janssen S, Solomon G, Chavarria G. Measuring Human Exposures to Hormone-Disruptors: Scientific Tools for Global Health. AAAS Annual Meeting Abstract # 090-096, 2008.

Rotkin-Ellman M, Solomon G. Soil Contamination in New Orleans: Arsenic and Lead Before and After Katrina. APHA Annual Meeting Abstract #163091, 2007.

McDaniel P, Malone R, Solomon GM. The Tobacco Industry and Pesticide Regulations. Society for Research on Nicotine and Tobacco, 10th Annual Scientific Sessions, 2004.

Solomon GM. Mercury and other Persistent Fish Pollutants: Risks to the Fetus and Child. APHA Annual Meeting Abstracts, 2003

Solomon GM. Endocrine Disruptors and Current Science Policy Developments. APHA Annual Meeting Abstracts, 4185, 2000.

Solomon GM. Special Risks to Children in Agricultural Settings. Neurotoxicology, 2000.

Solomon GM, Mott L. Disproportionate Exposures and Susceptibility: Pesticide risks to farm children. Neurotoxicology 20:1, 1999.

Solomon GM, Schettler T, Huddle A, Valenti M. Endocrine Disruptors: A lens on low dose health effects. Epidemiology 9(4): S54, 1998.

Solomon GM, Huddle AM, Schettler T, Valenti M. The Tradition of Statistical Significance: An impediment to prudent public health? Epidemiology 9(4): S75, 1998.

Solomon GM. Protecting Human Health From Endocrine Disruptors: Are toxicology and risk assessment up to the challenge? APHA Annual Meeting Abstracts, 2024, 1998.

Solomon GM. The Reproductive and Developmental Effects of Organic Solvents: The dilemma of identifying a culprit. APHA Annual Meeting Abstracts, 10, 1996.

Solomon GM, Milton DK. The Occupational Asthma Incidence Study: A pilot project. APHA Annual Meeting Abstracts, 177, 1996.

Garbo M, Milton D, Morse EP, Solomon G. From DBCP to NMP: Have we progressed? APHA Annual Meeting Abstracts, 408, 1996.

SELECTED PRESENTATIONS

Congressional Testimony and Briefings:

Cancer and the Environment
Safer Chemicals Healthy Families Congressional Briefing, 4/7/11

Cancer Clusters and the Environment
Hearing of the Senate Committee on Environment and Public Works, Washington, DC, 3/29/11

Reproductive Health and the Environment
Pew Charitable Trusts Congressional Briefing, 6/11/10

Health Effects of the Gulf Oil Spill
Hearing of the House Committee on Energy and Commerce, Subcommittee on Energy and the Environment, Washington DC, 6/10/10

Protecting Children from Environmental Threats
Hearing of the Senate Committee on Environment and Public Works, Washington, DC, 3/17/10

Endocrine Disrupting Chemicals in Drinking Water
Hearing of the House Committee on Energy and Commerce, Subcommittee on Energy and the Environment, Washington DC, 2/25/10

Biomonitoring: A Tool for Public Health Policy
American Chemistry Society Congressional Briefing, 3/09

Health Risks to Children and Communities from Recent EPA Decisions on Air and Water Quality
Hearing of the Senate Committee on Environment and Public Works, Washington, DC, 2/07

Selected TV and Radio Appearances:

Gulf Oil Spill Health Effects
PBS Need to Know, National TV, 6/10
CBS Evening News, National TV, 6/10
CNN Evening News, National TV, 5/10
CBS The Early Show, National TV, 5/10

Cancer Cluster in Fort Chipewyan, Alberta
Canadian Broadcasting Company National Radio, 5/10

Protecting Children from Toxins in the Home
Childhood Matters, KISS-FM Radio, San Francisco, CA, 7/05; 9/07

EPA's Chemical Testing Program
NPR's Living on Earth, 6/07

Protecting the Body from Heat
MarketWatch Special Report: An Investors Guide to Global Warming (Web Video), 5/07

Mold Testing in New Orleans Post-Katrina
National Public Radio, Living on Earth, 11/05
CNN News, 11/05

Diesel Exhaust Inside School Buses
National Public Radio, Science Friday, 2/01

Selected Scientific and Educational Presentations:

Children's Health and the Gulf Oil Spill
Pediatric Academic Societies Annual Meeting, 5/11

Toxicity Testing in the 21st Century
National Academy of Sciences Conference, 5/09

Biomonitoring: A Tool for Public Health Policy
UC Berkeley School of Public Health, 3/09
UCSF School of Medicine, 1/09

Preparing for Climate Change in California
UCSF Continuing Medical Education Course, 11/09
UCSF School of Medicine, 1/08, 3/09
Public Policy Institute of California, 12/08
UCLA School of Public Health, 10/07

Health Effects of Global Warming

Governor's Global Climate Summit, 9/09
Grantmakers in Health Annual Conference, 3/09
UCSF Advances in Internal Medicine Course, 5/08
California Joint Legislative Briefing, Sacramento, CA, 8/06

Health Hazards to Day Laborers
UCSF School of Medicine FCM 184, 12/08, 11/09
Clinica Martin Baro, 3/10

Taking an Environmental History
Kaiser San Francisco Internal Medicine Residents, 10/09
SFGH Internal Medicine Residents, 7/09
UCSF School of Medicine, 1/09
N245 UCSF Nursing School, 2/09
UCSF Family and Community Medicine Residents, 12/08
UCSF Integrative Medicine Course, 5/08

Pediatric Environmental Health "Toolkit" for Pediatricians
San Francisco General Hospital Pediatric Grand Rounds, 10/07
Stanford Lucile Packard Children's Hospital Grand Rounds, Palo Alto, Ca, 4/07
Oakland Children's Hospital, Oakland, CA, 5/07
O'Connor Hospital Combined Grand Rounds, San Jose, CA, 4/07
Kaiser Santa Teresa Hospital, San Jose, CA, 6/07
Kaiser Oakland, Oakland, CA, 10/06

Cancer and the Environment
Institute for Functional Medicine Annual Meeting Plenary Address, 5/10
Northern California Cancer Center, 3/08, 10/08
UCLA Ted Mann Family Resource Center Insights Into Cancer Lecture, Los Angeles, CA, 3/07

Mold Contamination in New Orleans Post-Katrina
UC Irvine Medicine Grand Rounds, 12/07
Stanford Law School, 10/07
CDC National Environmental Public Health Conference, Atlanta, GA, 12/06

Healthy Food in Healthcare
Stanford Medical School, Palo Alto, CA, 10/05, 10/06, 11/09
UCSF Medical Center, San Francisco, CA, 3/06 & 5/06
CleanMed National Conference, Seattle, WA, 4/06
John Muir Medical Center Combined Grand Rounds, Walnut Creek, CA, 3/06

Endocrine Disruptors in the Home and Community
Heinz Conference on Women and the Environment, Boston, MA, 10/06

Controlling Environmental Hazards in Communities of Color
National Legal Aid and Defenders Association Conference, Snowbird, UT, 6/06

Breastfeeding in a Contaminated World
March of Dimes Perinatal Conference, Chicago, IL, 3/06

Mercury and Current Fish Consumption Guidelines for Children
American Academy of Pediatrics Annual Conference, San Francisco, CA, 9/05

Why Should an Internist Care About Environmental Disease?
U.C. Davis Internal Medicine Grand Rounds, Sacramento, CA 7/10
Kaiser Permanente Medical Grand Rounds, San Francisco, CA, 4/04
UCSF Alice Hamilton Memorial Lecture Grand Rounds, San Francisco, CA, 3/04

BRIANA E. MORDICK

PROFESSIONAL EXPERIENCE

NATURAL RESOURCES DEFENSE COUNCIL *Washington, DC*

OIL & GAS SCIENCE FELLOW *September 2010 – Present*

Technical advisor on oil and gas related issues. Provides scientific expertise and analysis in support of advocacy efforts. Engages with and serves as a liaison to the scientific community.

ANADARKO PETROLEUM CORPORATION *January 2005 – September 2010*

Greater Natural Buttes Natural Gas Field, Uinta Basin, UT (June 2009 – September 2010)
Senior Geologist & Team Lead

- Geologist responsible for drilling 50+ wells and selecting 500+ new drilling locations
- Worked to develop new criteria and methods for selecting optimal well locations
- Lead a team of four co-workers who were responsible for two drilling rigs and hundreds of wells; organized and lead meetings; provided weekly updates to management; served as point of contact for extended team members

Salt Creek Field CO_2 Enhanced Oil Recovery Project, Natrona County, WY (Nov 2006 – June 2009)
Geologist II

- Described and analyzed core data to develop full field depositional model
- Analyzed well logs, core, and production data to determine flow pathways of oil and CO_2
- Assisted in construction of digital 3D geologic reservoir model used for oil and CO_2 flow simulation modeling

Ozona Natural Gas Field, Crockett County, Texas (Jan 2005 – Nov 2006)
Geologist I

- Geologist responsible for drilling 100+ natural gas wells, analyzing logs, and recommending zones to be completed for production
- Remapped subsurface geology, resulting in greater predictability of productive zones in wells
- Successfully presented underdeveloped natural gas prospect at the North American Prospect Expo (NAPE) and engaged a partner to develop these prospects

ANADARKO PETROLEUM CORPORATION *The Woodlands, Texas*

GEOSCIENCE INTERN *September 2004 - November 2004*

Evaluated the Baxter shale in active Wyoming oil and gas fields for shale-gas production potential.

EDUCATION

UNIVERSITY OF NORTH CAROLINA AT CHAPEL HILL *Chapel Hill, North Carolina*

MASTER OF SCIENCE, GEOLOGICAL SCIENCES *September 2002 – May 2005*

Thesis: Pyroxene thermobarometry of basalts from the Coso and Big Pine volcanic fields, California

BOSTON UNIVERSITY *Boston, Massachusetts*

BACHELOR OF ARTS, EARTH SCIENCE *September 1998 – May 2002*

Senior Thesis: Provenance of discrete ash layers from the Izu-Bonin Arc system using Laser Ablation-Inductively Coupled Plasma-Mass Spectrometry

BRIANA E. MORDICK

PUBLICATIONS

Mordick, B.E., Glazner, A.F., 2006, Clinopyroxene thermobarometry of basalts from the Coso and Big Pine volcanic fields, California: Contributions to Mineralogy and Petrology, v. 152, no. 1, p. 111-124.

SELECTED PRESENTATIONS

- October 19, 2010:
  - Forum: National Research Council of the National Academies, Board on Earth Sciences and Resources, Committee on Earth Resources
    - Meeting Title: "Meeting Our Nation's Natural Resource Needs: Balancing Risks and Rewards"
    - Presentation Title: "Environmental Impacts of Oil and Gas Production"
- March 11, 2011:
  - Forum: EPA Hydraulic Fracturing Study Technical Workshop
    - Meeting Title: Well Construction and Operations
    - Presentation & Abstract Title: "Risks to Drinking Water from Oil and Gas Wellbore Construction and Integrity: Case Studies and Lessons Learned"
- June 1, 2011:
  - Forum: Environmental Entrepreneurs Monthly TeleSalon
    - Meeting Title: "Natural Gas in the Mix: Finding the Balance"
    - Presentation Title: "Environmental Impacts of Natural Gas Production"

- September 27, 2011:
  - Forum: University of Wyoming Hydraulic Fracturing Forum
    - Meeting Title: Hydraulic Fracturing, A Wyoming Energy Forum
    - Presentation Title: Hydraulic Fracturing Best Practices: Mitigating Environmental Concerns

Draft Report – February 2011

Current and Projected Water Use in the Texas Mining and Oil and Gas Industry

Prepared for
Texas Water Development Board

Bureau of Economic Geology
Scott W. Tinker, Director
Jackson School of Geosciences
The University of Texas at Austin
Austin, Texas 78713-8924

Cover photo: Aggregate facility in Bexar County (courtesy of Google Earth)

Prepared for

Texas Water Development Board

under
Contract No. 0904830939

Jean-Philippe Nicot, P.E., P.G., Anna K. Hebel, Stephanie M. Ritter, Steven Walden[1], Russ Baier[1], Peter Galusky[2], P.E., P.G., James Beach[3], P.G., Richard Kyle[4], P.G., Leigh Symank[3], and Cari Breton

February 2011

Bureau of Economic Geology
Scott W. Tinker Director
Jackson School of Geosciences
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Glossary and Abbreviations

AAPG	American Association of Petroleum Geologists
AF	Acre-foot (1 AF = 325,851 gallons)
Bbbl	Billion barrels
Bcf	Billion cubic feet (1 Bcf = 10^3 MMcf = 10^6 Mcf)
bgs	below ground surface
BTU	British Thermal Unit
CBM	Coal-bed methane
CCS	Carbon capture and storage
EIA	Energy Information Agency
EOR	Enhanced oil recovery
EUR	Estimated ultimate recovery
GAM	Groundwater availability model
GC	Gulf Coast
GCD	Groundwater conservation district
GIP	Gas-in-place
GSA	Geological Society of America
IP	Initial production
ISL	In situ leaching
ISR	In situ recovery
LCRA	Lower Colorado River Authority
LPG	Liquefied petroleum gas
MAF	Thousand acre-feet
MGD	Million gallons per day
Mcf	Thousand cubic feet
MMbbl	Millions of barrels
MMBTU	Million BTU
MMcf	Million cubic feet (1 MMcf = 10^3 Mcf)
NGL	Natural gas liquid
NGW	Natural Gas Week Journal
NOGA	National oil and gas assessments (by USGS)
NORM	Naturally occurring radioactive materials
O&GJ	Oil and Gas Journal
OOGP	Original gas in place
OOIP	Original oil in place
OSHA	Occupational Safety and Health Administration

PBSN	Powell Barnett Shale Newsletter
PGC	Potential Gas Committee
PPA	Pounds of proppant added per gallon of fluid
RRC	Railroad Commission of Texas
RWPG	Regional water planning group
SIC	Standard industrial classification
st	Short ton
TACA	Texas Aggregate and Concrete Association
TCEQ	Texas Commission on Environmental Quality
Tcf	One trillion cubic feet (1 Tcf = 10^3 Bcf = 10^6 MMcf = 10^9 Mcf)
TDS	Total dissolved solids
Th. AF	Thousand acre-feet
TMPA	Texas Municipal Power Agency
TMRA	Texas Mining and Reclamation Association
TOC	Total organic content
TWBD	Texas Water Development Board
TXOGA	Texas Oil and Gas Association
UIC	Underground injection control
USGS	U.S. Geological Survey
VR	Vitrinite reflectance
WAG	Water alternating gas
WCAC	Water Conservation Advisory Council
WUG	Water user group (TCEQ jargon)
WUS	Water use survey (TWDB jargon)

Note to the reader:

In the oil industry m or M stands for 1,000 (one thousand, as in Mcf, one thousand cubic feet) but it means million in the water industry (as in MGD, million gallons per day). We try to spell out numbers or use plain units to limit the confusion.

Acknowledgments

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1 Executive Summary

In the middle of 2009, we undertook a study of water use in the so-called mining industry in Texas, both current and projected for the next 50 years. The study concerned the upstream segment of the oil and gas industry (that is, water used to extract the commodity until it leaves the wellhead), the aggregate industry (sand and gravel and crushed rock operations, washing included but no further processing), the coal industry (mostly pit dewatering and aquifer depressurizing), and other substances mined in a fashion very similar to that of aggregates (industrial sand, lime, etc.), as well as through solution mining. In general we followed the definition of mining according to SIC/NAICS codes. It follows that cement facilities, despite their large quarries, are considered to belong to the manufacturing, not mining, category. The objective of the study, that was essentially prompted by the sudden increase in shale-gas production, was to help in the next cycle of water planning by the state agency in charge of such planning, the Texas Water Development Board (TWDB).

The approach to the study is twofold: (1) to collect water-use data and auxiliary information by contacting actual mining facilities and (2) to interview experts and other knowledgeable individuals in their respective fields to fill in the gaps in water-use data and to understand future development/contraction of water use in the different segments of the mining industry. We surveyed the industry either through formal questionnaires sent to the membership of trade associations (TACA for aggregates; TMRA for aggregate, coal, and uranium; TXOGA and others for oil and gas), through surveys sent to water providers/observers such as GCDs, or through survey results from other organizations (MSHA, RRC, TCEQ, TWDB, USGS), and especially private vendors of the oil and gas industry. We contacted and had in-depth interviews with multiple representatives of every major segment of the mining industry to help us understand how the water is used, how much is recycled, what its source is (groundwater, surface water or something else), whether it is fresh or brackish (saline water use is not tallied in this study), how much is rejected outside of the mining facility, etc.

Results from the surveys were useful but not as extensive as hoped for us to assemble a representative sample of the hundreds of mining facilities in the state, with the exception of the coal industry (a significant water user) and the uranium industry (a minor water user). We were also able to gather relatively accurate data from the stimulation stage when a well is being readied for production (the so-called fracing process), but we are more uncertain about water use for drilling wells and waterfloods. Results of current water use for the aggregate industry relied on previous information somewhat calibrated and updated by survey results. Overall, in 2008 (latest year with complete information), we estimate that the state used ~139 thousand acre-feet (AF) in the mining industry (Figure ES1), including 35.8 thousand AF for fracing wells (mostly in the Barnett Shale/Fort Worth area) and ~21.0 thousand AF for other purposes in the oil and gas industry, although more spread out across the state, with a higher demand in the Permian Basin area in West Texas. The coal industry used 26.7 thousand AF along the lignite belt from Central to East Texas. The 43.0 thousand AF used by the aggregate industry is distributed over most of the state, but with a clear concentration around major metropolitan areas. The remainder amounts to 12.2 thousand AF and is dominated by industrial sand production (~80% of total).

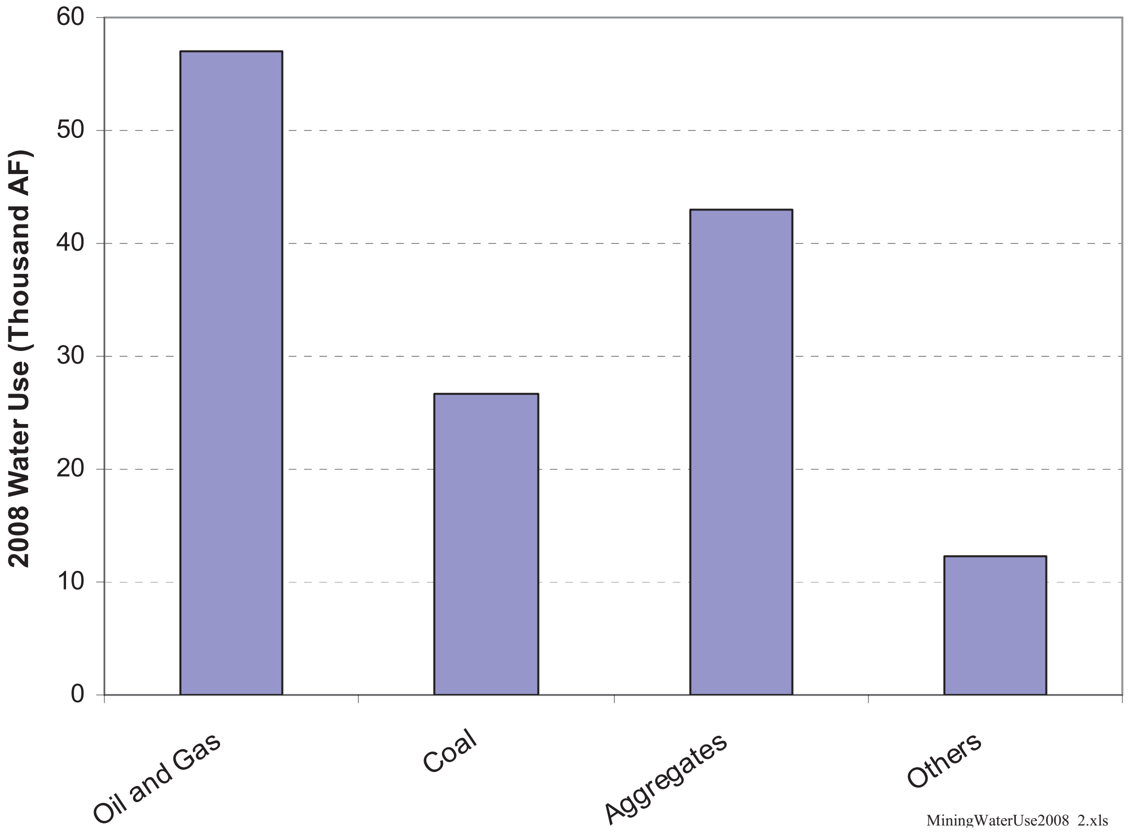

Figure ES1. Summary of estimated water use by mining industry segment (year 2008)

Water is used mostly for drilling wells, stimulating/fracing wells, and secondary and tertiary recovery processes (oil and gas industry); for dewatering and depressurizing pits, with a small amount used for dust control (coal industry); and for dust control and washing (aggregate industry and industrial sand). Reuse/recycling has been accounted for in water-use figures, as well as opportunity usages, such as stormwater collection (aggregates). As such, the numbers represent mostly consumption. Only some of the coal-water use could be construed as nonconsumed withdrawal when groundwater extracted for depressurization purposes is discharged into streams (40–50% of total). The split between surface water and groundwater is difficult to assess, short of having information directly from facilities (such as for coal and some aggregate facilities), especially for exempt use in the oil and gas industry.

Projections for future use were done by extrapolating current trends, mainly for coal (more or less stable) and aggregates (following population growth). Projections for the oil and gas industry were made with the help of various sources by estimating the amount of oil and gas to be produced in the state in the next decades and by distributing it through time. Given the volatility of the price of oil and gas, it is easy to see that the figures provided are only indicative of a possible future. We projected that the state overall water use will peak in the 2020–2030 decade at ~250 thousand AF (Figure ES2), thanks to the oil and gas unconventional resources that will start to decrease in terms of water use around that time. Both coal and aggregates are slated to keep increasing, more strongly for aggregates.

Note (1) that we endeavored to generate results at the county level but, given the uncertainty inherent to future production and to the approach, we estimate that individual counties may be off by a factor of 2 or 3, although a group of counties will have a much lower range of uncertainty; (2) that projections presented in this report are not binding to the facilities cited in the report and are made through integration of many other external factors; and (3) that these figures do not represent official TWDB projections but that they will be used as a tool by TWDB to make official projections for use in the next water-planning cycle.

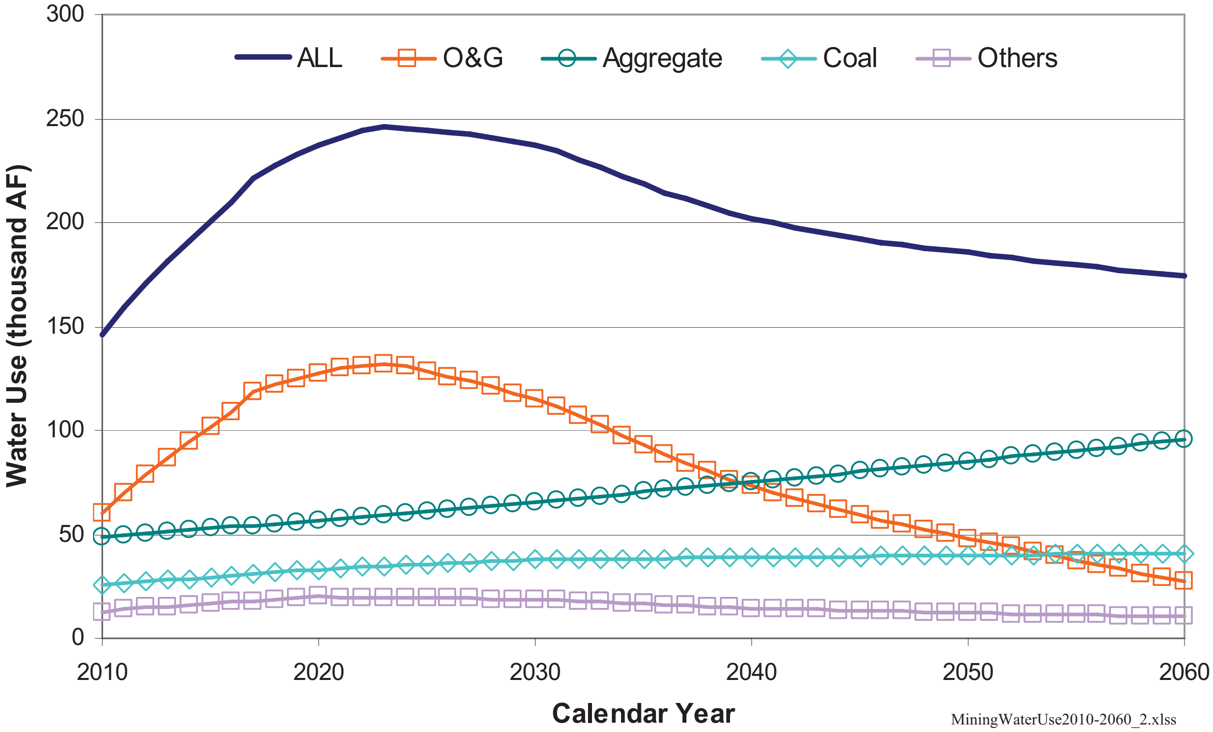

Figure ES2. Summary of projected water use by mining industry segment (2010–2060)

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2 Introduction

The Texas Water Development Board (TWDB) has contracted the Bureau of Economic Geology (BEG) at The University of Texas at Austin to compile information about current water use in the mining industry (to be more thoroughly defined later) and to make water-use projections for the next 50 years to 2060. The project was launched as a response to a Request for Statements of Qualifications on Topic 3 of the 2009 Water Research Study Priority Topics by TWDB Water Resources Planning Division, headed by Dr. Dan Hardin. The present report documents results for the four tasks described in the scope of work of Contract #0904830939: (1) identify major mining operations and analyze water-use patterns, (2) estimate current water use withdrawal and consumption (3) develop long-term water-demand projections at the county level, and (4) report the findings of the study and prepare an electronic database. The project is the result of the collaboration between the Bureau of Economic Geology at The University of Texas at Austin; Steven Walden Consulting, Austin, TX; Texerra, Midland, TX; and LBG-Guyton, Austin, TX. The project also benefited from strong cooperation from major players in the Texas mining industry, particularly the following trade associations: Texas Mining and Reclamation Association (TMRA), Texas Aggregate and Concrete Association (TACA), and Texas Oil and Gas Association (TXOGA).

The report is divided into several sections. In each of them, we successively address oil and gas, coal, aggregates, and other mineral substances. Oil and gas activities are not always necessarily compiled with other mining activities, but they are for the purpose of this report. It is also consistent with the way the federal government catalogs all economic activities (SIC and NAICS codes; more on this later). In the next few paragraphs, we present an overview of the mining industry in Texas and a high-level discussion of its water use. In Section 3, we describe the methodology used to generate figures for current and projected water use. Section 1 describes current water use, whereas Section 5 addresses projected water use. The general approach in the latter section consists of extrapolating historical and current water-use trends and applying some corrections. We think that quantitatively attempting to include new processes or events that might emerge or occur in 50 years is a worthless exercise. The current shale-gas boom, largely unforeseen by industry watchers, is a case in point. It follows that projections are mostly valid in the 5- to 10-year term. We did add a subsection on speculative resources, whose water-use figures were not included in final totals.

2.1 Overview of Mining Activities in Texas and a High-Level Perspective on Water Use in the Industry

2.1.1 Mined Substances

Before water use is discussed in detail, an understanding of the big picture, as well as the mining landscape in terms of operations, might be useful. USGS publishes regular updates to national nonfuel mining activities (http://minerals.usgs.gov/minerals/). The latest USGS (2009) compilation uses data from 2006 (Table 1). Estimated value of nonfuel minerals is \$3.0 billion, 62% of which is related to cement activities. Note that cement is included in the USGS compilation, although neither cement plants nor allied quarrying operations are included in this report. This definition of mining is consistent with previous approaches by TWDB. Oil and gas importance dwarfs that of other minerals in terms of value (>$50 billion) but, as documented in this report, not in terms of water use (Table 1).

Recently BEG (Kyle, 2008) released a factsheet presenting the industrial minerals in Texas consistent with information provided by the USGS. Kyle and Clift (2008) also provided geologic background, explaining in general regional terms why the diverse facilities are located where they are and the uses of these mined substances. In addition to the oil and gas produced over most of the state and to the coal produced within a narrow inland section parallel to the coast, the mining industry, in terms of volume, generates value through sand and gravel, mostly exploited along rivers, and crushed stone, mostly present in the footprint of the Edwards Limestone.

Oil and gas resources are generally sorted into conventional and unconventional categories (Figure 1 and Figure 2). The former represents the archetypal reservoir traps in either sandstones or carbonates and is made up of interconnected pores that allow “easy” communication with the well bore. The latter is generally characterized by the use of advanced technologies and consists of different types of formation and/or extreme environmental conditions (pressure and temperature). In terms of amount produced, unconventional resources have already passed the “conventional” reservoirs (Stevens and Kuuskraa, 2009). Relevant characteristics include low permeability and a need to stimulate the reservoir through hydraulic fracturing. In this study, the unconventional category consists of tight formations, usually “tight gas,” and resource plays such as gas shales and liquid-rich shales. We do not describe the technology in this document; see, for example, King (2010) for a summary. Coalbed methane (CBM), producing mostly gas, could also be added to the list of unconventional reservoirs. Resource plays are generally defined as those plays with relatively predictable production rates and costs and with a lower commercial risk, as compared with conventional plays. Gas-shale plays with their extensive, continuous resources and “no dry well” are examples of resource plays. The challenge for operators is to find those sweet spots that will produce gas at a profit.

Note that the exact terminology to describe hydraulic fracturing as practiced by the oil and gas industry has not been settled yet. We opted for “*frac*”, “*fracing*” and “*fraced*” although “*frack*”, “*fracking*” and “*fracked*” would have been acceptable too. We also refer to “*gas shales*” when the focus is on the formations as a generic term including Barnett, Eagle Ford, etc shales. In contrast, the terms “*shale gas*” or “*shale oil*” suggest that the focus is on the commodity itself not the formation. The term “*oil shale*” is sometimes understood as mostly applicable to those formations in Utah and Colorado which require more efforts and energy to recover the oil. To avoid confusion with common usage, we settled on the term “*liquid-rich shale*”.

Coal is generally ranked as anthracite, bituminous, subbituminous, or lignite, listed in decreasing order of energy content. Low-rank, low-energy coals include lignite and subbituminous coals, and they are the only coals present in Texas in significant amounts (Figure 3). High-rank coals, including bituminous and anthracite coals, contain more carbon and lower moisture than lower-rank coals, and thus have higher energy content. Coal has been produced in Texas since the late 1880’s. At that time the most common mining method was underground mining, but currently only surface mining is utilized. Lignite makes up most of the current coal production and will do so in the near future as well. Whereas bituminous resources are still available, the economically recoverable resources have already been mined. The lignite belt stretches diagonally across Texas from Louisiana to Mexico. It is represented by the Wilcox, Jackson, and Claiborne Formations of the upper Gulf Coast, whereas, farther west, Pennsylvanian and Permian pockets represent bituminous resources. BEG has published many reports on Texas coal (for example, Fisher, 1963; Henry and Basciano, 1979; Kaiser et al., 1980).

Aggregates (Figure 4), as sand and gravel and crushed stone are collectively known, are the most important category in terms of volume and dollar amount, after the oil and gas industry. Crushed stone consists mostly of limestone and dolomite, with many facilities located along the IH35 corridor (San Antonio to the Dallas-Fort Worth metroplex) (Figure 5). Because of important capital costs, those operations tend to be larger than the sand and gravel facilities. The latter are concentrated along streams and on the coast (Figure 6). Allied mined substances include industrial sand and dimension stone. There are other substances but they tend to be mined at only a few locations (Table 2 and Table 3). Note that several mining activities do not require fresh water or even water. Brine production may require fresh water for drilling wells, but its use is nominal, which is equally true for gas wells producing from conventional reservoirs. Another less systemic example is crushed stone operations, which uses water only for occasional dust suppression.

2.1.2 Mining Facilities

The first step of the study, before estimating water use, consisted of determining the actual number of mining facilities. Their spatial distribution and count at the county level represent the next level of complexity as they guide the final mining water use at the county level. Oil and gas operations are present in most Texas counties. Number of traditional mining facilities is given by several sources, the most complete being from the U.S. Census Bureau (USCB). USCB reports survey data every 5 years. The 2002 survey was released in 2005, and the 2007 had not been released at the time this report was written. Disregarding oil and gas wells and other oil- and gas-related facilities, the USCB listed a total of 11 lignite mines, 100+ crushed stone and ~200 sand and gravel operations, many of them small, and ~70 facilities of a different type, neither lignite nor aggregate. Not counting wells tapping the subsurface (solution mining), the vast majority of operations are open-pit operations. USCB (2005) reported six underground mining operations in 2002, all but one (rock-salt operation) being very small.

MSHA (Mining Safety and Health Administration) also manages a database of abandoned and active mines across the country because mines must submit health and safety applications and obtain permits. As of July 2010, 1,869 abandoned and 692 active mines (including cement plants and coal mines) were officially registered in the state of Texas (Table 3). However, the overlap with USCB data is not perfect because the MSHA database includes (1) facilities treating the raw material but not necessarily extracting it locally and (2) nonactive facilities that have not been officially abandoned.

The database for the Source Water Assessment and Protection (SWAP) program, a federally mandated program managed by the Texas Commission of Environmental Quality (TCEQ), contains an inventory of potential sources of contamination (POSC) susceptible to contaminating sources in potable water (both groundwater wells and surface-water intakes). Those sources include a whole range of human activities from cemeteries to gun ranges to dry cleaners, including mining facilities (“Natural Resource Production”). TCEQ cites the Railroad Commission of Texas (RRC), the U.S. Geological Survey (USGS), and BEG as sources for the mining subset of the database. Information that can be depicted on an aquifer map is a more detailed and useful inventory than a listing of facilities (Figure 7, Bastrop and Lee Counties).

2.1.3 Water-Use Overview

Overall, mining water use in Texas represents only a small fraction of total water use in the state, and estimates have varied, given the relatively low priority of this category of water use. Previous water-demand surveys and projections estimated ~280 thousand AF as the demand for water use in mining compared with 17 million AF (1.6%) for total water use in 2000 (TWDB, 2007, Table 4.2), ~250 thousand AF and ~17 million AF (TWDB, 2002, Table 5.2), and ~200 thousand AF and ~16.5 million AF (TWDB, 1997, Table 3.2), both also for year 2000 (Table 4). Those figures represent only fresh water, the generally accepted definition of which is any water with a total dissolved solid content (TDS) <1,000 mg/L. Livestock as well as crops tolerate higher TDS, perhaps as high as 6,000 and 10,000 mg/L, respectively. Some sources define fresh water as water <3,000 mg/L. Inability to reconcile the different definitions adds uncertainty to the final figures provided in this report. Under the Safe Drinking Water Act, any <10,000 mg/L non-exempt aquifer is considered a potential underground source of drinking water. Note that there is no consistency (including in the documents cited in this work) in the definitions of fresh, brackish, and saline water which depend mostly of the context.

The overarching goal of this report is to confirm these figures. We provide some explanation on why results presented in this report differ from previous projections by TWDB, but they are due mostly to a change in accounting and to the impact of shale-gas production. The work presented in this report will not formally be included in the 2012 water plan, but will inform it. An issue of great impact to this work is the split between groundwater and surface water. This information is not always easy to identify, but in the course of this project, we tried to collect as much as possible. Approximately 59% of the water used in the state is groundwater (TWDB, 2007, p. 176), although this statistic is biased because a sizable fraction comes from the Ogallala aquifer in the Texas Panhandle and is used for irrigation. In this area of Texas the groundwater-use fraction is somewhat higher, whereas elsewhere it tends to be smaller. Irrigation is an important category used by TWDB to detail water use in the state and is the largest in terms of volume. Other categories in approximately decreasing volumes are municipal, manufacturing, steam-electric, livestock, mining, and domestic/other.

In addition to efforts at the state level, several federal organizations interpret information flowing from the states. USGS publishes every 5 years (with a lag of a few years relative to data collection) information about all types of water use across the nation. The most recent versions are authored by Kenny et al. (2009) for year 2005 and by Hutson et al. (2005) for year 2000 (Table 5). Sources of data feeding the reports are left to the judgment of local state offices and vary with water-use type and state (Kenny, 2004). For the State of Texas, BEG, RRC, TCEQ, and TWDB are typically contacted. USGS also performs its own survey, although it is not always successful in obtaining comprehensive information from all facilities. USGS typically extrapolates from the information obtained and publishes only aggregated data. For the State of Texas, Kenny et al. (2009, Table 2B) reported a mining-water withdrawal of 102 and 614 thousand AF/yr, respectively, for water of fresh (defined in the USGS report as <1,000 mg/L) and saline (>1,000 mg/L) quality. All saline water was reported as groundwater, whereas only 30 thousand AF of the fresh-water category was reported as groundwater (Kenny et al., 2009, Table 3B and Table 4B). Most of the saline water is counted toward secondary recovery of hydrocarbons (disposal not included). Kenny et al. (2009, p. 35) stated that dewatering operations are included in the water withdrawal total only if the water is put to beneficial use (for example, dust control). The work presented in this report follows a different approach (see section on Methodology). USGS figures for the year 2000 (Hutson et al., 2005, Table 4) are somewhat different and more closely align with those of the TWDB, with a total fresh-water use of 246 thousand AF (144 groundwater and 102 surface water). The total amount of saline water (produced water) at 565 thousand AF is not sizably different. Whereas 1995 (Solley et al., 1998) figures are consistent with those of 2000, the difference between 2000 and 2005 figures corresponds to a change in accounting.

2.2 Overview of Recent Projections

The TWDB Office of Planning provides projection figures to the State Water Plan (e.g., TWDB, 2007). Norvell (2009) represents the latest effort before the work presented in this report. An earlier effort by a consultant on behalf of TWDB (2003) includes manufacturing in addition to mining. Both Norvell (2009) and TWDB (2003) attempted to link economic activity at the county level to water use. In essence, the approach consisted of developing a correlation between historical water use and economic output at the county level and extrapolating future water use from a forecast of economic activity. The correlation was made through so-called water-use coefficients (ratio of water use and gross economic output) determined at the county level. Mining-specific constraints were dismissed and hidden as being part of the overall economic activity (TWDB, 2003, p. 2–3). Overall, results of this approach were not very satisfying for the mining category.

Table 1. Fuel and nonfuel raw mineral production in Texas

Mined Substance	**Quantity**	**Approx. Value (1,000s of $)**
	MMbbl	**~$57/bbl[f]**
Oil[a]	344.5	~19,000,000
	Tcf	**$5/Mcf[g]**
Gas[b]	7.53	~37,650,000
	1000s short tons	**~$18/Short ton[h]**
Coal/lignite[c]	37,099	~668,000
Uranium[d]	Withheld	Withheld
Nonfuel Minerals[e]	**1000s metric tons**	
Cement (overwhelmingly portland)	11,682	1,120,700
Clays (common clay, bentonite)	2,289	14,900
Gypsum	1,430	11,800
Lime	1,650	130,000
Salt	9,570	132,000
Sand and gravel:	99,500	603,000
Industrial sand	1,530	65,600
Crushed stone:	136,000	824,000
Dimension stone	31[i]	12,600
Subtotal		2,902,000
Other: talc, brucite, clays (Fuller's earth, kaolin), helium, zeolites, sulfur		78,000
Total		2,980,000

Source: [a]: http://www.rrc.state.tx.us/data/production/oilwellcounts.php —2009 data;

[b]: http://www.rrc.state.tx.us/data/production/gaswellcounts.php —2009 data;

[c]: http://www.rrc.state.tx.us/industry/_COALPRODthru2009.XLS —2009 data;

[d]: Information withheld for confidentiality (small number of producers)

[e]: USGS (2009) —2006 data;

[f]: 2009 annual average for Texas; http://www.eia.gov/dnav/pet/pet_pri_dfp1_k_a.htm

[g]: 2009 annual average for Texas; http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_STX_a.htm

[h]: 2008 annual average for Texas; http://www.eia.doe.gov/cneaf/coal/page/acr/table31.html

[i]: Seems to be a slow year or underreporting

Table 2. Estimate of the number of mining facilities in the State of Texas in 2002 (USCB)

Industry Type	**Total Number of Establishments**	**>20 Employees**
Crude petroleum and natural gas extraction	2803	286
Natural gas liquid extraction (includes sulfur extraction)	180	57
Total Oil and Gas Extraction	**2983**	**343**
Bituminous coal and lignite surface mining	11	9
Total Coal Mining	**11**	**9**
Fe ore mining	3	0
Au ore and Ag ore	4	0
Cu, Ni, Pb, and Zn ore mining	1	0
U, Ra, V ore mining	5	1
Other metal ore mining	2	0
Total Metal Ore Mining	**15**	**1**
Dimension stone mining and quarrying	18	5
Crushed and broken limestone mining and quarrying	71	23
Granite mining and quarrying	3	0
Other crushed and broken stone mining and quarrying	15	5
Total Stone Mining and Quarrying	**107**	**33**
Construction sand and gravel mining	198	51
Industrial sand mining	19	5
Kaolin and ball clay mining	1	1
Clay and ceramic and refractory minerals mining	11	4
Total Sand, Gravel, Clay, and Ceramic, and Refractory Minerals Mining and Quarrying	**229**	**61**
Potash, soda, and borate mineral mining	1	1
Other chemical and fertilizer mineral mining	6	1
All other nonmetallic mineral mining	19	2
Total Other Nonmetallic Mineral Mining and Quarrying	**26**	**4**
Total Nonmetallic Mineral Mining and Quarrying	**362**	**98**

Source: USCB (2005)

Table 3. Number and diversity of minerals mining operations in Texas (MSHA)

Primary Commodity	# of Fac.	Primary Commodity	# of Fac.
Alumina	2	Dimension sandstone	11
Barite barium ore	7	Dimension stone NEC	47
Bentonite	3	Dimension traprock	1
Cement	12	Fire Clay	7
Clay, ceramic, refractory mnls.	2	Gypsum	8
Common clays NEC	19	Iron ore	6
Common shale	2	Lime	2
Construction sand and gravel	250	Manganese ore	1
Crushed, broken granite	1	Misc. nonmetallic mnls. NEC	1
Crushed, broken limestone NEC	167	Pigment minerals	1
Crushed, broken marble	3	Potassium compounds	1
Crushed, broken sandstone	6	Salt	2
Crushed, broken stone NEC	52	Sand, common	15
Crushed, broken traprock	3	Sand, industrial NEC	10
Dimension limestone	32	Talc	5
Dimension marble	1	Zeolites	1

NEC:
Source: MSHA (http://www.msha.gov/DRS/DRSextendedSearch.asp), data from June 2008

Table 4. Historical projected mining water use (top) and total water use (bottom) for all water uses in Texas by TWDB (MAF)

Water Plan	1990	2000	2010	2020	2030	2040	2050	2060
1997	149 15,729	205 16,586	187 16,867	182 17,135	191 17,489	194 17,900	188 18,354	
2002	149 15,729	253 16,919	246 17,662	245 18,195	252 18,732	252 19,369	244 20,022	
2007		279 16,977	271 18,312	281 19,011	286 19,567	276 20,105	277 20,759	286 21,617

Source: TWDB (1997, 2002, 2007)

Table 5. Historical mining water use in Texas by USGS (thousand AF)

	Fresh	Saline	Total
1995			
Groundwater	143	458	602
Surface water	93	0	93
Total	236	458	694
2000			
Groundwater	144	565	709
Surface water	102	0	102
Total	246	565	811
2005			
Groundwater	30	614	644
Surface water	72	0	72
Total	102	614	716

Source: Kenny et al. (2009), Hutson et al. (2005), Solley et al. (1998)

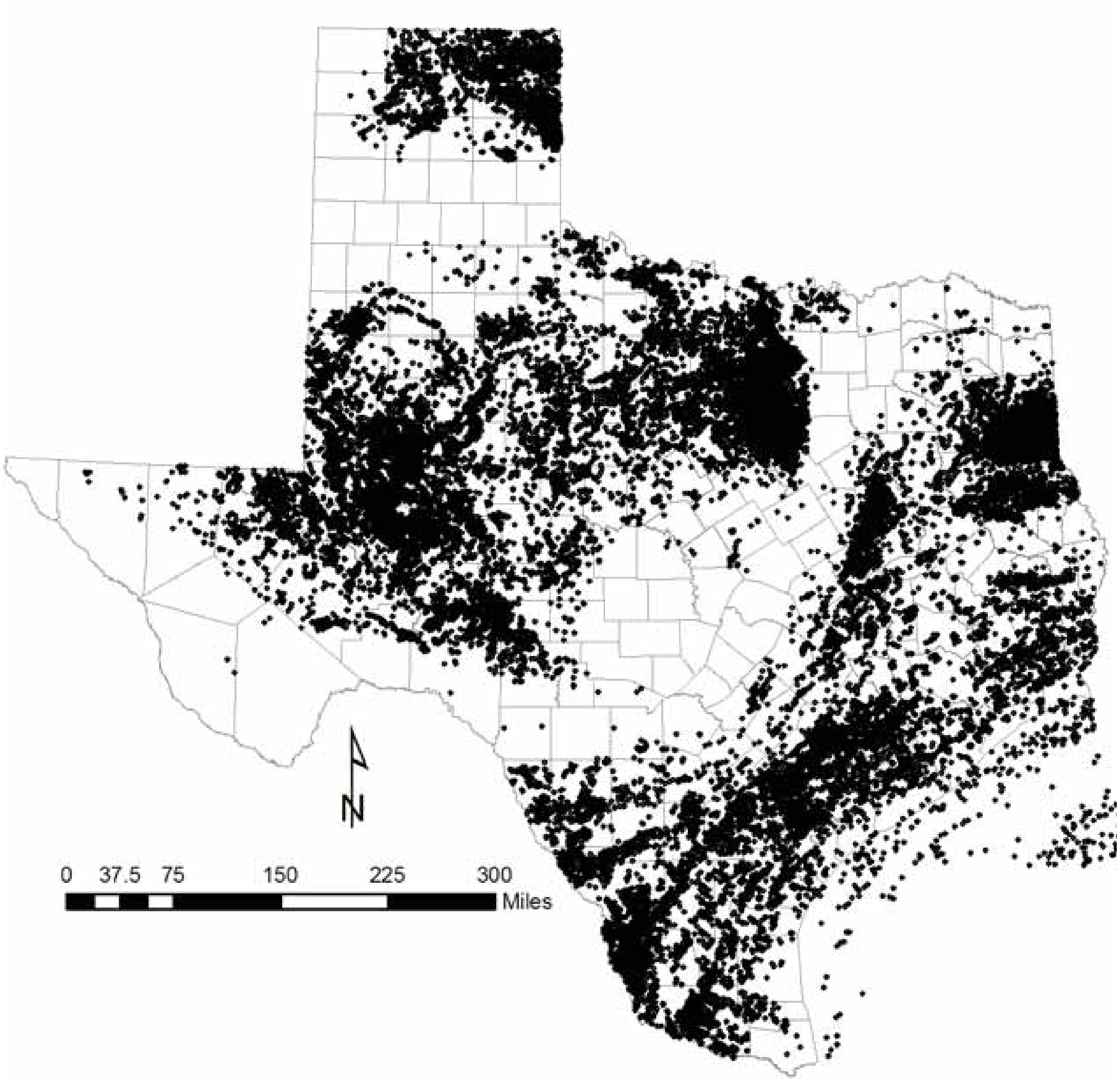
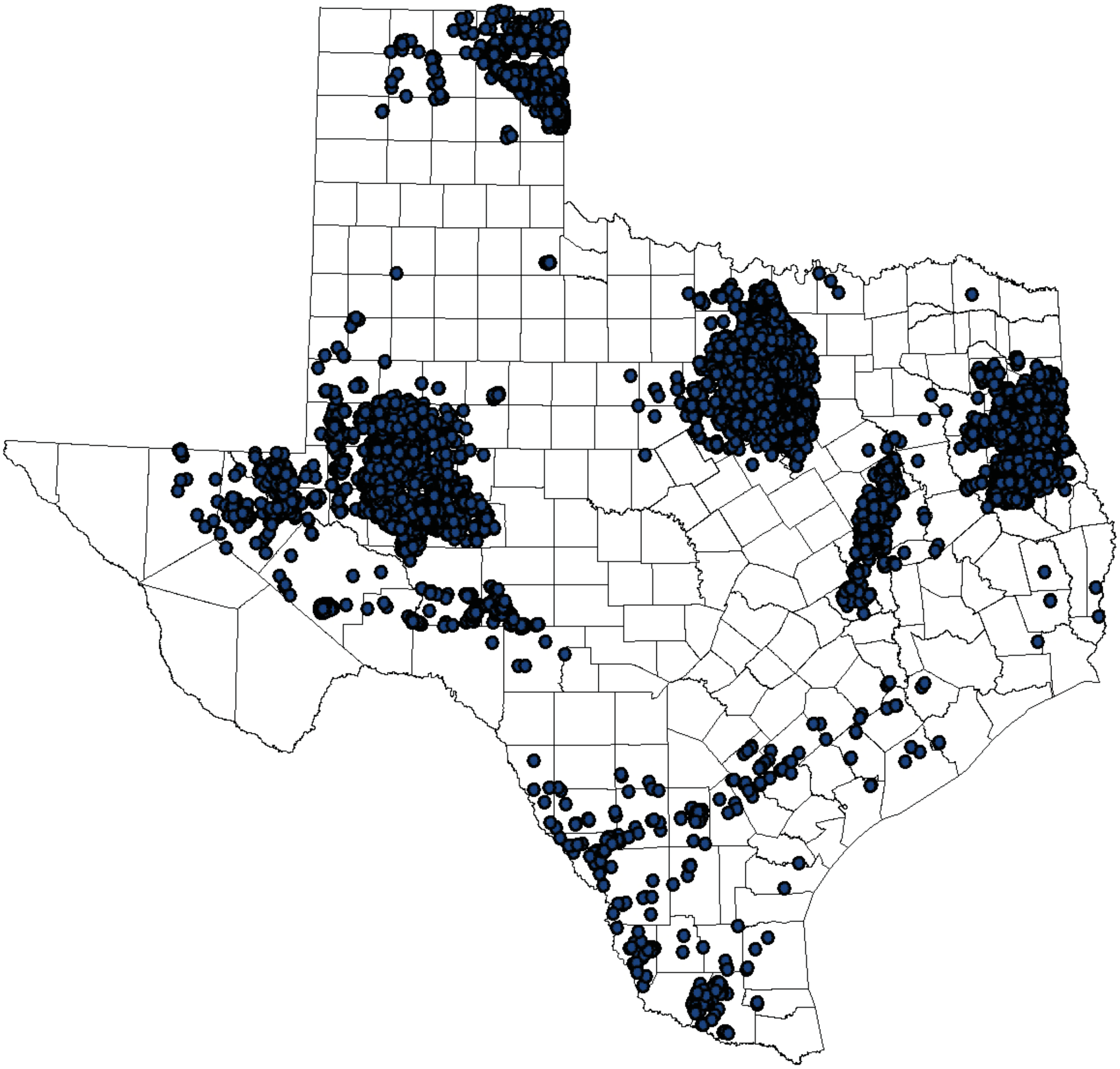


Figure 1. Location map of all wells with a spud date between 2005/01/01 and 2009/31/12 (approximately ~75,000 wells)



Source: IHS database

Figure 2. Map showing locations of all frac jobs in the 2005–2009 time span in the state of Texas. Approximately 23,500 wells are displayed

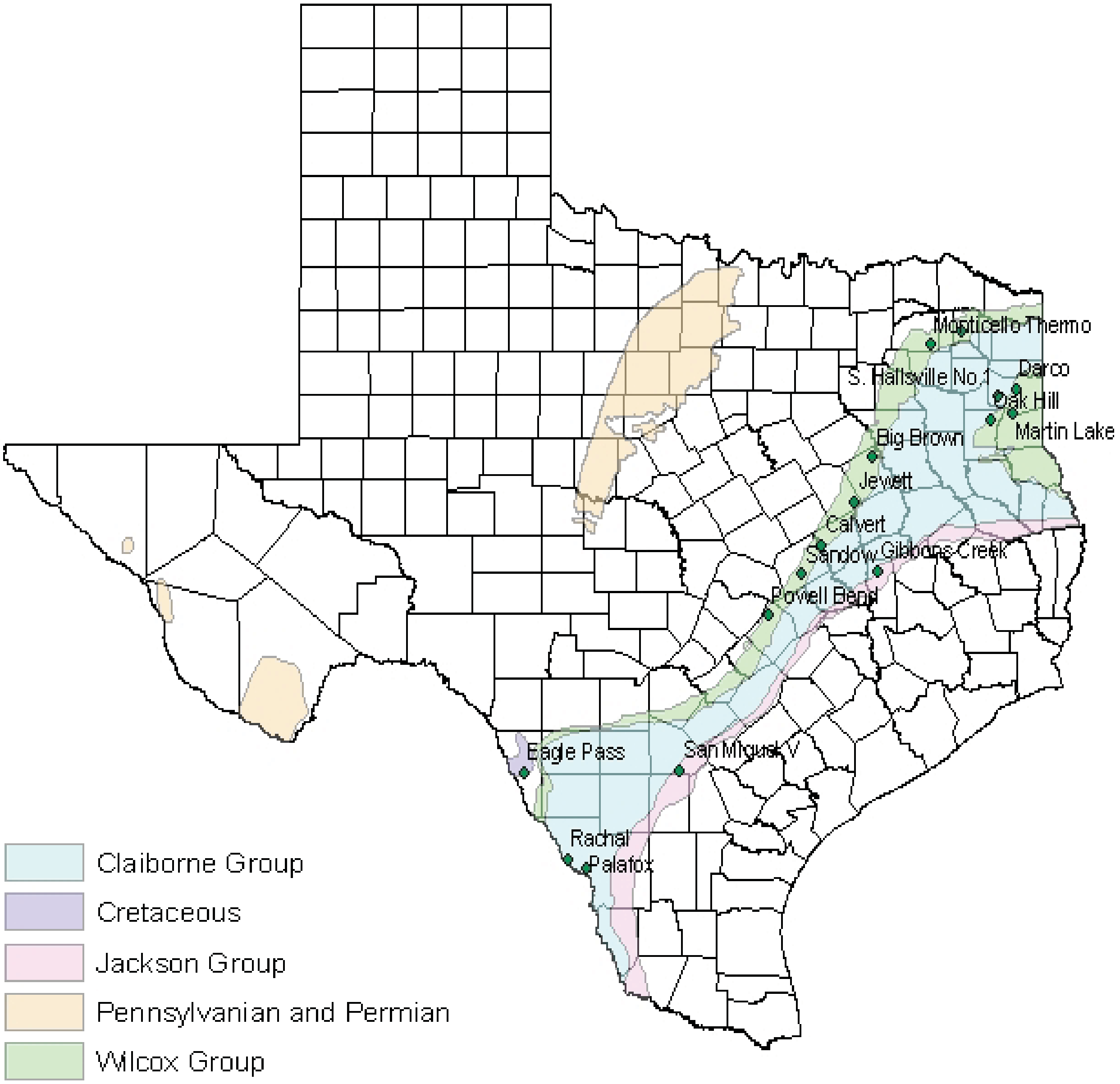
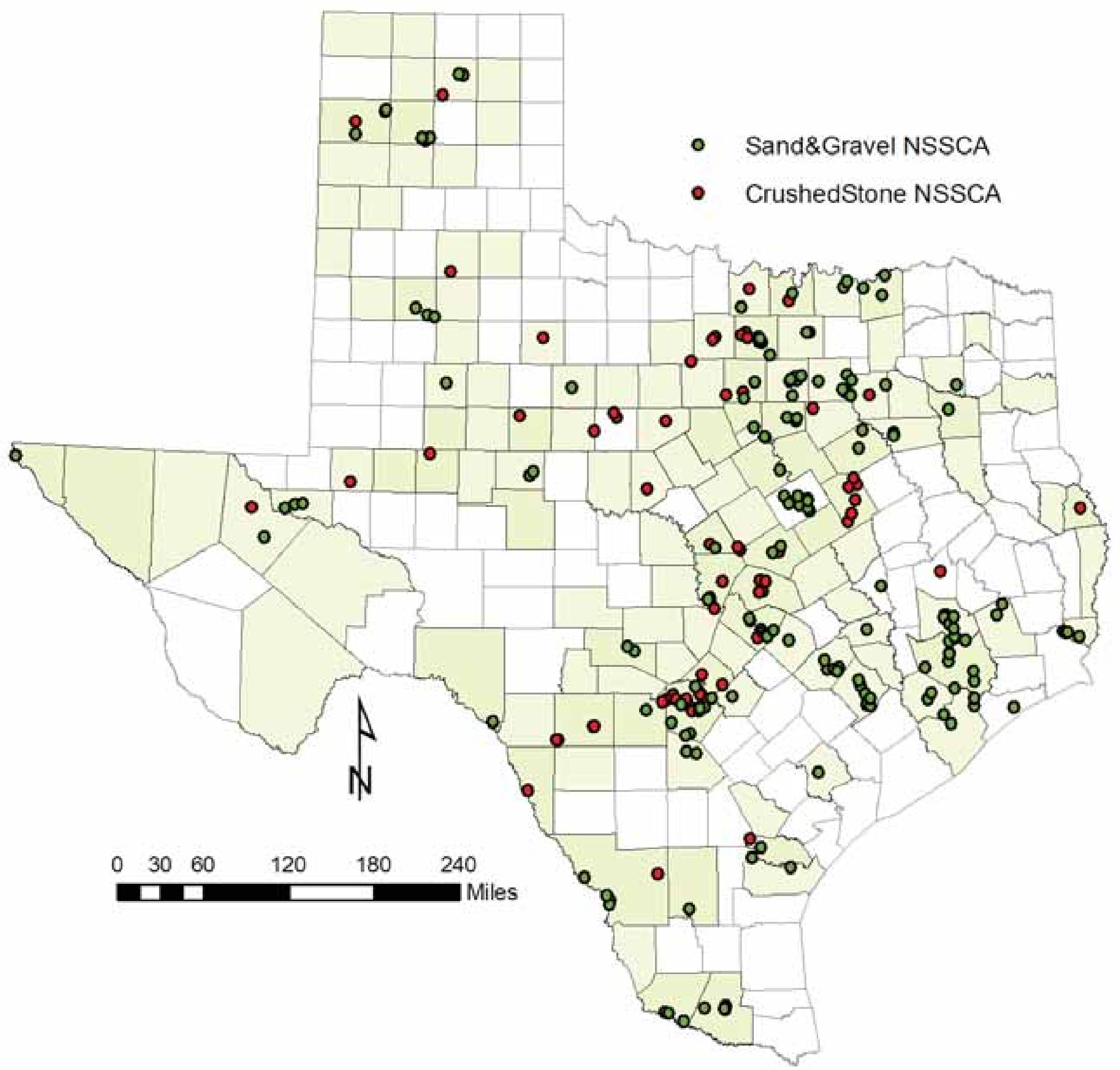


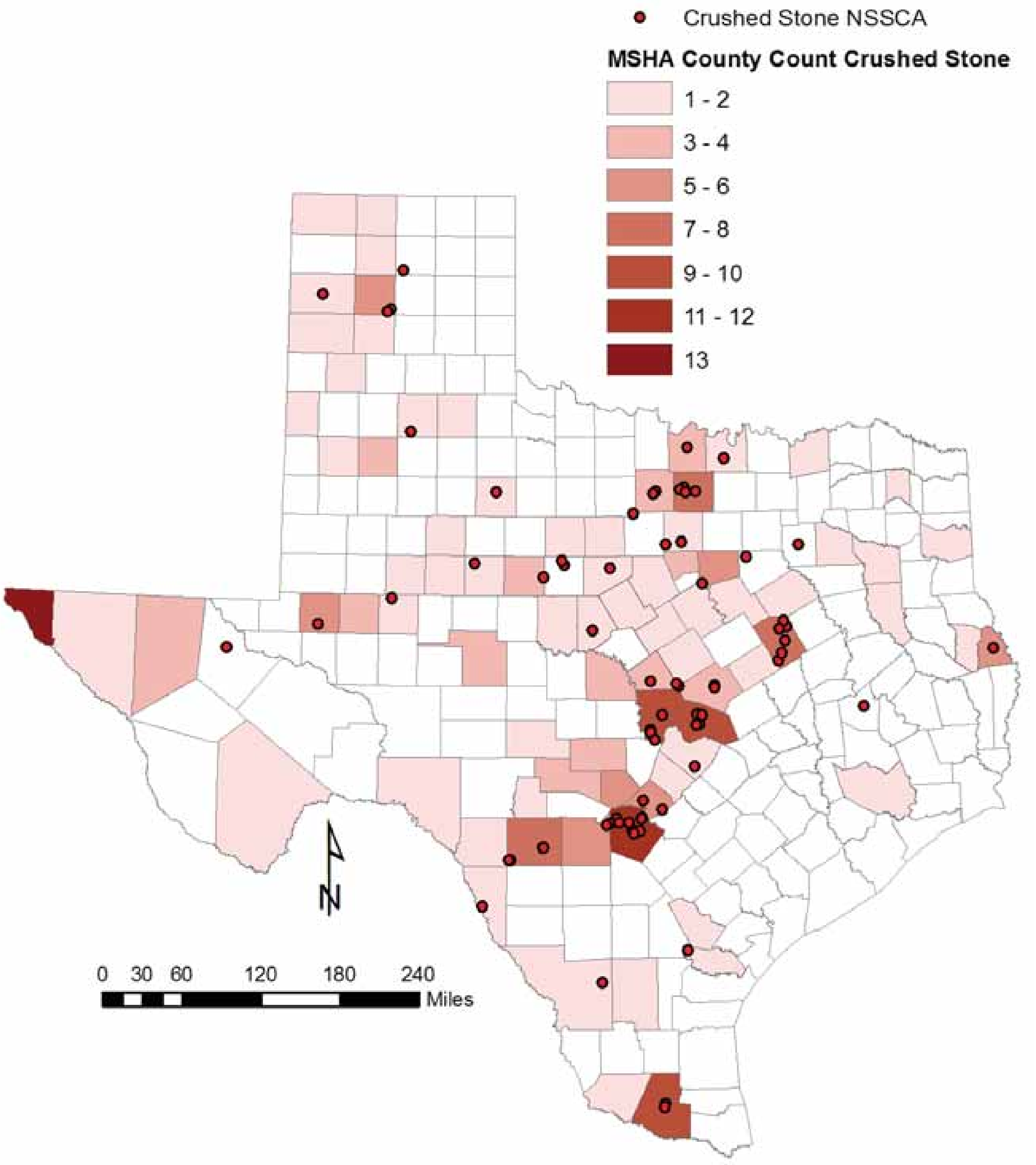
Figure 3. Location map of coal/lignite operations



Source: NSSGA/USGS database and MSHA database

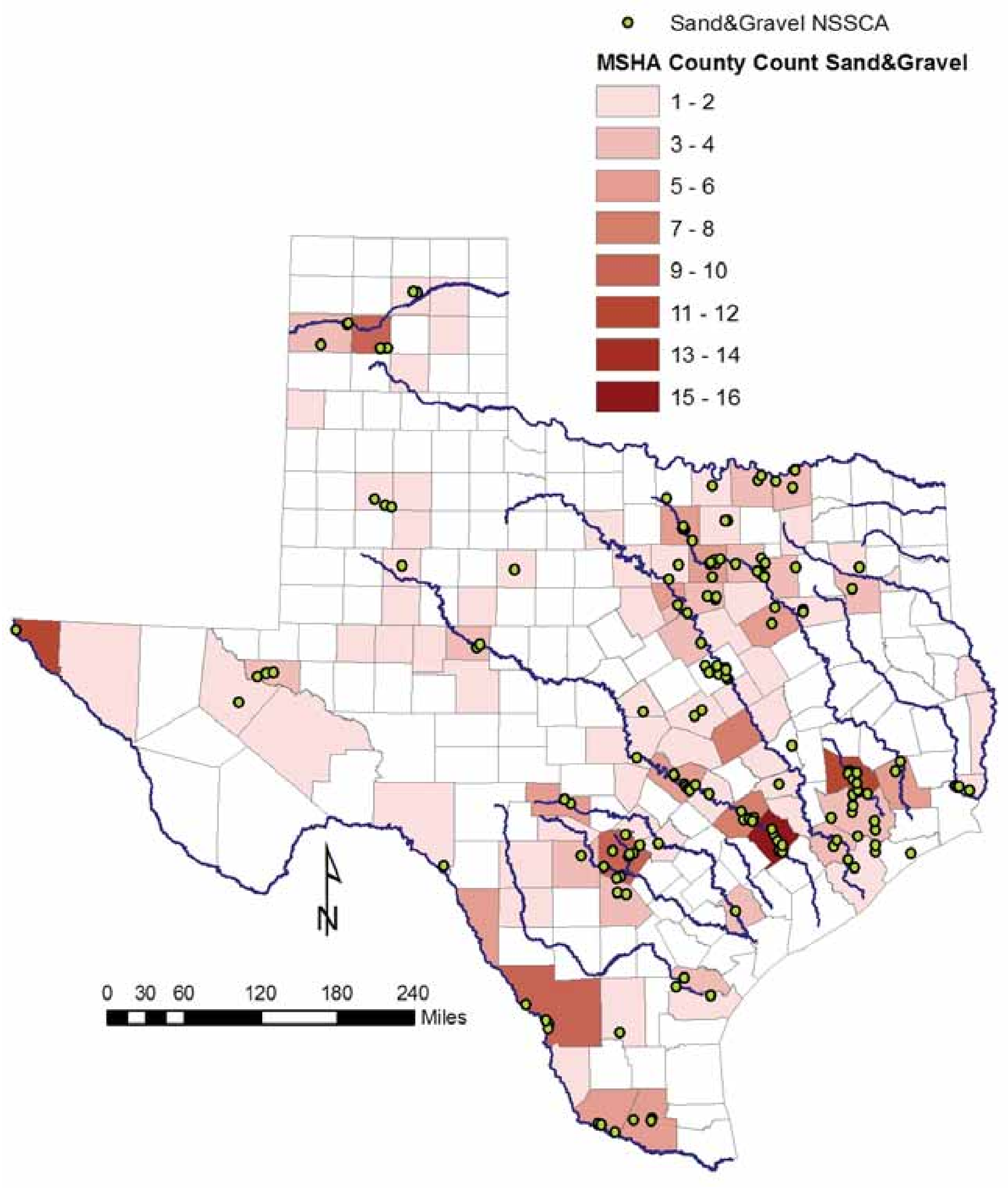
Note: deleted from the NSSGA database were all facilities whose names included “yard,” “asphalt,” “concrete,” or “cement,” as well as plants of well-known cement producers; facilities with “chemical” are treated in the other nonfuel minerals section (Section 4.5)

Figure 4. Location map of aggregate operations from NSSGA database (data points) and MSHA database (selected counties)



Source: NSSGA/USGS database and MSHA database

Figure 5. Location map of crushed-stone operations from NSSGA database (data points) and MSHA database (selected counties illustrating number of operations)



Source: NSSGA/USGS database and MSHA database

Figure 6. Location map of sand and gravel operations from NSSGA database (data points) and MSHA database (selected counties illustrating number of operations)

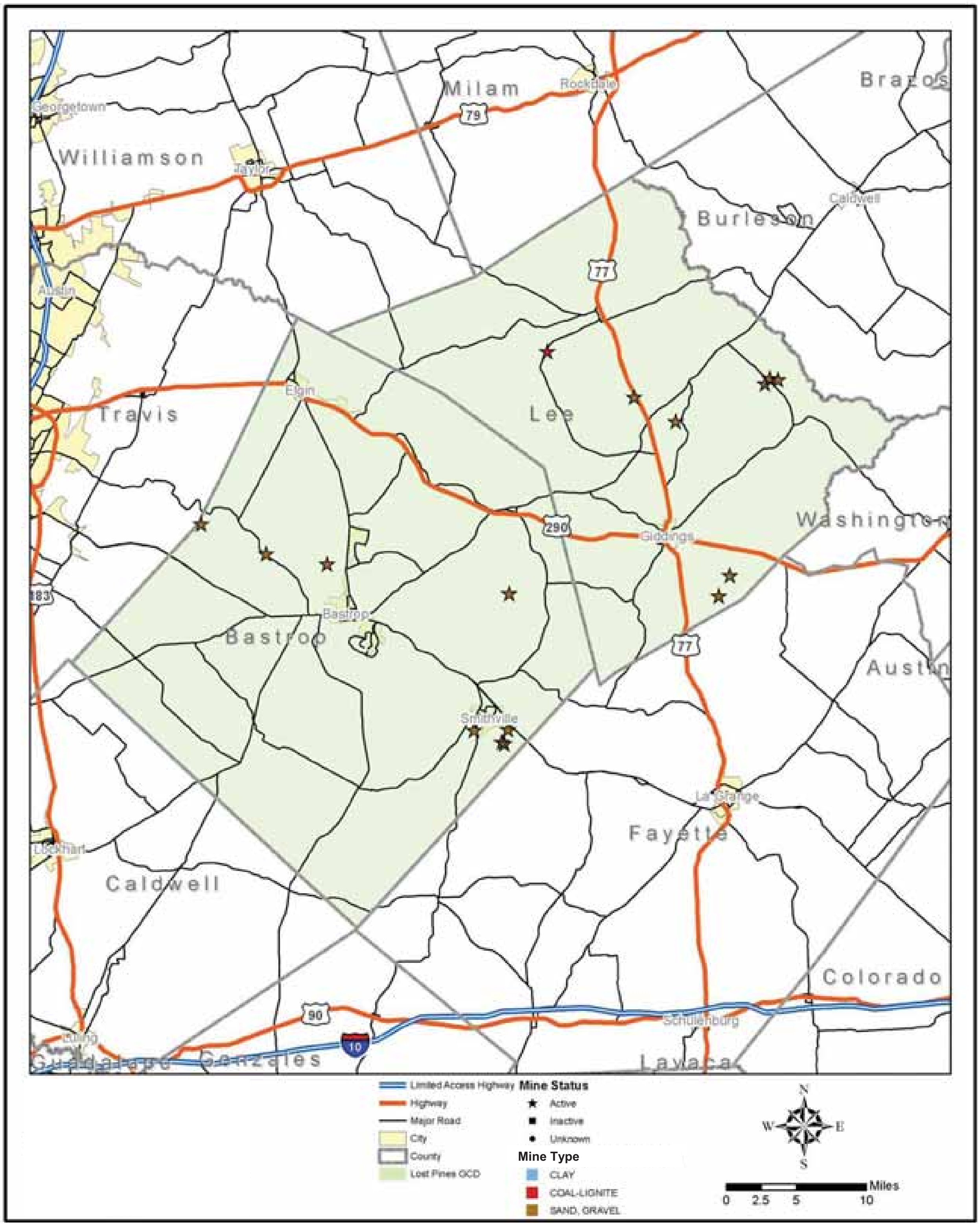


Figure 7. Example or representation provided by the SWAP database

3 Methodology and Sources of Information

With thousands of operations in the state and with no legal requirement to report production and water use (except partly for oil, gas, and coal), some choices had to be made to deliver an acceptable product within the allocated budget. We followed two guiding principles: (1) focus on the biggest users, that is, oil, gas, coal, and aggregates, and (2) if a county has no operations of the previous category, check for any minor mining activity. Several methodologies have been used in the past at the national and state level. Norvell (2009) and TWDB (2003) tried to link economic activity and water use to a black-box approach without including the detailed processes specific to each mining sector. This approach cannot predict groundwater/surface water split.

Another approach calls for the use of water-use coefficients. These coefficients, intensive in nature, are obtained by taking the ratio of two extensive values for a few facilities: (1) water use and (2) commodity production that results in a unit of gallons per weight or volume of the commodity. In a second step, the overall water use for all facilities of that type is computed by applying the water-use coefficient to the overall production for each facility, each county, or across the state. This approach has limitations because 1) the few facilities used to develop the coefficients may not be representative of the overall industry (they are typically chosen because they provided information not because they are representative), and 2) a large state, such as Texas, has considerable climate differences which make it more difficult to apply a single, general coefficient to all facilities. USGS presented in a recent report its approach to estimating mining water use at the national level in 2005 (Lovelace, 2009) and, for the most part, it made use of water-use coefficients. Unfortunately, the specific water-use coefficients are not publicly available. Lovelace (2009, Table 1) gave a broad range in the following general categories that are applicable to the whole nation: metal mining (140 to 1,567 gal/st), coal mining (50 to 59 gal/st), and mining and quarrying of nonmetallic minerals except fuels (30 to 997 gal/st).

This second approach does not work for oil and gas water use because many oil and gas areas use only water to drill and stimulate wells, usages not directly related to hydrocarbon production. A third approach consists of actually obtaining the information directly from the facilities/operators responsible for most of the water use. This approach is particularly effective when databases contain the information, such as in the case of shale gas and oil.

3.1 General Sources of Information

The TWDB Office of Planning obtains material for its projections by regularly collecting data through annual water-use surveys (WUS—http://www.twdb.state.tx.us/wushistorical/) for input into water planning. In Texas, water planning is done through 16 Regional Water Planning Groups (Figure 8; http://www.twdb.state.tx.us/wrpi/rwp/rwp.asp). Data collection by TWDB goes back >50 years to 1955, although the legislature increased the impetus when Senate Bill 1 was passed in 1997, requiring State and local governments to become better informed on how water was utilized in their jurisdiction. Sending back the requested information to TWDB is voluntary, however. TWDB then extrapolates the incomplete information to the whole state. BEG has access to the data collected by TWDB, and the latest water-mining-use information is available is 2007. Unfortunately, the response rate for a given year is low, although through the years many companies have returned surveys.

Overall, during the course of this study, we acquired both soft and hard data. Soft data, such as guesstimates of the future direction of the different mining sectors, were attained mostly through (1) discussion with professionals from the industry and (2) by perusing the web (USGS, EIA, etc.) and other sources of reports and papers (for example, Powell's *Barnett Shale Newsletter*, a weekly newsletter providing information on various gas shales in the U.S.; the *Oil&Gas Journal*; *Energy Intelligence Natural Gas Weekly*; *Texas Drilling Observer*; SPE onepetro database articles, *Fort Worth Oil and Gas Magazine*, and DOE news alerts).

The large amount of knowledge accumulated about production from shales has not fully made its way to the peer-reviewed literature yet, thus requiring us to rely on many noncitable data. As such, this project involved a great deal of interaction with workers in the field, indispensable to locating the latest source of information and to updating it to current knowledge. Fairly complete hard data on water use in the gas industry ("frac jobs") were obtained from IHS Energy, a private vendor compiling all information filed by operators to the RRC (as well as many other governmental entities around the world), and putting it into a format easy to search and retrieve. We also directly used the query tool available from the RRC website. However, not having direct access to the database for custom queries was a handicap. RRC aggregates its data by fields, counties, or districts (Figure 9).

Data on water use for drilling and waterflooding are much harder to obtain because operators do not have to report their water use as such. The latest thorough data collection of water use in the oil and gas industry was the 1995 RRC survey (De Leon, 1996). We updated these 15-year old data by contacting a trade association, TXOGA, and by surveying operators in West Texas, the area with the most waterflooding in the state, which helped constrain current and future water use.

Data on the coal industry were obtained through a survey of Texas coal operators (~100% response rate) and a follow-up with them, consulting with RRC and collecting information from its paper files. Information about the aggregate industry was obtained through surveys we requested from two trade organizations (TMRA and TACA) and discussion with selected operators. For all other operations, we did not gather additional information but relied on published information. Exceptions were a few clay operations, as well as a few uranium operators affiliated with TMRA, from whom we also received survey results. The search was guided by previous work from the TWDB, as well as by published and unpublished documents.

We also sent out, with modest success (see Appendix D), a questionnaire to various water governmental entities for information on mining activities in their jurisdictions. Apart from those mentioned in the body of this report, very few Groundwater Conservation Districts (GCDs) have accurate knowledge on the amount of water used in their areas in the mining category unless the information is readily available (for example, lignite operations) (see Appendix E for details). Figure 10 displays a current map of GCD locations, with active and inactive mine locations superimposed.

3.2 Definition of Mining Water Use for the Purpose in this Report

For consistency with previous estimates and comparison with other studies, we followed the standard classification for economic activities. According to the Standard Industrial Classification (SIC), mining industries are given the following four-digit codes:

Major group 10 (1000 to 1099): metal mining

Major group 12 (1200 to 1299): coal mining
Major group 13 (1300 to 1399): oil and gas extraction
Major group 14 (1400 to 1499): mining and quarrying of nonmetallic minerals, except fuels

These major groups also include *beneficiation*. Operations that take place in beneficiation are primarily mechanical, such as milling–crushing and grinding, washing, dust suppression on service roads, and outdoor machinery. Manufacturing, which includes chemical and more involved processes, is represented by major groups 20 to 59. Major group 32 consists of stone, clay, glass, and concrete products, including cement (3241 is hydraulic cement) and clay products. SIC codes have been superseded by NAICS codes but are still widely in use. The more recent six-digit NAICS code defines "Mining, Quarrying, and Oil and Gas Extraction" as Sector 21. Beneficiation of mined material is included in this category that also includes the following groups: 211xxx oil and gas extraction, 212xx mining (2121xx coal mining; 2122 metal ore mining, 2123 nonmetallic mineral mining, and quarrying), 213xxx: support activities for mining. Similar to the SIC classification, several potential mining products are in an ambiguous position: clay and refractory products, cement (SIC3241 hydraulic cement and 3273xx cement and concrete product manufacturing), and lime manufacturing.

Introduction to the SIC3241 group (hydraulic cement) on the official website states: "*When separate reports are available for mines and quarries operated by manufacturing establishments classified in this major group, the mining and quarrying activities are classified in (…) mining. When separate reports are not available, the mining and quarrying activities (…) are classified herein with the manufacturing operations.*" In this report, we have included small clay pits but have not included cement raw materials, limestone and clay, that are sintered together to make the clinker that will be finely ground to become the main constituent of portland cement. Some cement-producing facilities just grind the clinker and include additives without performing any quarrying activities. More generally, concrete plants of the *ready-mix* or *central mix* type are not included in this study. A rough calculation yields ~125 gal water/st of cement to make concrete or, equivalently, 30 gallons of water per short ton of aggregate. Including concrete manufacturing in the water use of aggregate quarrying operations would inflate mining water use. This distinction seems logical on paper but may be hard to apply in the field, where different water uses may not be tracked separately, or worse, water use for the whole process may be reported as mining. Similarly, asphalt plants and brick manufacturing plants are not included. We also excluded as much as possible water used to convey materials from extraction sites to offsite processing facilities. Thus, water for slurry pipelines and tank farms was not classified as mining water.

The opposite issue occurs with gas plants and other oil and gas facilities located not far from the extraction wells. They are listed with a mining code (SIC 1321) and are excluded from this study. Similarly, some other operations are listed with a mining SIC, for example SIC1459 (clay, ceramic, and refractory minerals), but most of the water is used in manufacturing, not mining activities. The matter can worsen if some of the raw material used in the plant is not locally extracted.

Another important issue is dewatering, especially of coal mines. In agreement with TWDB, we considered aquifer dewatering as consumption because the water is no longer available for other aquifer users. It should be noted, however, that the water could still be put to beneficial use when discharged to local streams and rivers. In other words, some mining operations could be considered as net producers of water, not as users of water, for planning purposes. And yet the position taken in this document is that, as long as there is no directly specifically targeted user, the water must be counted toward consumption.

3.3 Methodology: Historical Water Use

Historical water use was computed using direct data if available (for example, shale gas, coal), with the potential problem of completeness (missing facilities), in which case extrapolations were performed. In other cases, water-use coefficients were used. We used the year 2008 as the reference year because at the beginning of this work, not all 2009 data were yet available and because the year 2009 is likely not representative, owing to the economic slowdown.

3.3.1 Oil and Gas Industry

3.3.1.1 Gas Shales and Other Tight Formations

Gas shales are called resource plays in the sense that most wells will yield some gas over a large regional area, as opposed to conventional oil and gas production that needs to tap actual reservoirs of limited spatial extent (Figure 11). We extracted data from the IHS database relative to all fracing operations from the origins of the technology. We collected names of plays typically fraced by consulting BEG researchers with expertise in this field. Collecting all historical information allows for an understanding of the evolution of the technology—from small-scale fracing to improve permeability around the well bore in relatively permeable oil and gas formations, to medium-scale operations on tight gas to generate fracture permeability required to produce gas, to recent large-scale operations on shales (to recover mostly gas but also more and more oil).

We determined the plays with active frac jobs by downloading from a database provided by a private vendor: IHS Energy. The ultimate source of most of the information was forms submitted to the RRC by operators, but with the added advantage of a powerful querying tool. Before drilling a well, including recompletion, operators must apply to the RRC for a drilling permit (form W-1). Once completed, operators submit a W-1 form (for oil-producing wells) or G-1 form (for gas-producing wells). The two latter forms contain information about well stimulation, including slick-water fracing.

We compiled all wells completed in the 2005–2009 period (5 years) and then selected wells with water use >0.1 Mgal. This threshold is somewhat arbitrary and was used to distinguish true frac jobs from simple well stimulation by fracing and acid jobs. This approach is better than relying on operator classification of acid vs. frac vs. some other IHS category because our experience shows this method to be unreliable. We then compiled all plays with at least one frac job in that period and returned to the IHS database to obtain all wells fraced in these plays (including earlier than 2005). Further processing is detailed later. An additional download of the 2010 data was done in November 2010 to identify recent trends.

Nicot (2009a) and Nicot and Potter (2007) (also in Appendix B of Bené et al., 2007) detailed one of the methodology approaches followed in this current work as applied to the Barnett Shale. Appendix B presents the successful postaudit of the projections made during the 2006–2007 Barnett Shale study. Because of budget constraints, it is not possible to reproduce the finer level of granularity achieved in the previous study, but the general methodology stays identical: (1) gage the eventual level of drilling (and upper bound of ultimate water consumption) at the end of the play history by estimating reserves and prospectivity and (2) distribute water use through time by estimating rig availability for the next few decades and by applying time-varying correcting factors. Many papers emphasize that each play is different and that even wells in close proximity show widely different behavior (Matthews et al., 2007; Chong et al., 2010; King, 2010). However, we assume that, at the county level, most of these differences average out and that it is appropriate to use averages.

The whole process relies on having accurate historical data, which, in this work, are obtained from the IHS database (*header* and *test treatment* options). The first step of the processing is to check the data and fix possible typos (wrong units, additional or missing zeros, etc.). Not paying attention to the typos (generally <10% of the selected portion of the database) could decrease or increase individual well-water use. Typos artificially increasing water use represent the larger risk. The general approach to achieving this goal was to compute proppant loading and water-use intensity for each individual well (not individual stage).

Proppant loading is computed by summing up the amount of proppant mixed and the amount of water used and taking the ratio. Field units are pounds per gallon (ppg or lb/gal). An acceptable value is near 1 (0.5 to 2, e.g., Curry et al., 2010, p. 3; our own statistics). This parameter has to be used with caution because, in past treatments, proppant loadings were at least twice as high but with a smaller water volume. Hamlin et al. (1995, p. 9) mentioned 50,000 to 70,000 gal of gel and 100,000 to 120,000 lb of sand for Canyon Sands in the Val Verde Basin of West Texas. Dutton et al. (1993, p. 45) cited a typical treatment in the Cotton Valley sandstones of 0.4 Mgal and 1.7 million lb of sand. They also indicated (p. 79) that 150,000 gal of x-linked gel and 450,000 lb of proppant were appropriate for the tight sands of the Vicksburg Formation of South Texas.

Water-use intensity is computed by dividing up total amount of water used by length of the productive interval, either vertical length for vertical wells or total lateral length for horizontal wells. Lateral length can be computed from two techniques that generally agree: distance between surface location of the wellhead and bottom-hole location and/or length of total driller depth minus true depth (Figure 12). These are approximations that work well as long as they are applied consistently across a play and as long as most wells are constructed similarly. The so-called directional wells present a challenge, but they are not very numerous in the IHS database and are folded into the horizontal-well category.

Total water use, total proppant amount, water-use intensity, or proppant loading out of the common range create additional scrutiny for that particular frac job. The process is semiautomated because there have been tens of thousands of frac jobs across the state in the past few years. Building a histogram or using the filter feature in Excel are the two ways used to catch these outliers. Many errors can be caught by looking at the consistency of metrics. The decision is then made to fix an obvious typo (for example, barrel unit instead of gallons or tons instead of pounds or an extra zero for water a figure that matches expected water intensity and proppant loading only when it is removed). If no fix is evident, the frac job receives the median water use for that play and year(s). Frac jobs with missing water use are also treated by estimating what they should be from the proppant amount and the median proppant loading for that play and year(s). If neither the water volume nor the proppant amount is given (can be as high as 30% of the data set for a play), the frac job receives the median water use for that play and year(s). The focus is more on the median than on the average, which can be heavily biased (Nicot and Potter, 2007).

Once the selected data set were cleaned up, we used in-house visual basic scripts within Excel to build various histograms and plots for each play: (1) location map and geological information as available, (2) plots of historical number of frac jobs per year in combination with percentiles of water use (for vertical then horizontal wells), (3) comparison of distribution of vertical vs. horizontal wells through time, (4) histogram of water use per vertical well, (5) histogram of water use per horizontal well, (6) histogram of water use intensity for horizontal wells, (7) histogram of proppant amount, and (8) histogram of proppant loading. Historical plots do not include wells with no water-use value, but those wells are added to the 2008 reference year, assuming a median water-use value.

A major assumption is that all makeup water is fresh. Typically, higher TDS water (mostly because of calcium) will increase friction-reducer demand, one of the additives. Hayes (2007) discusses the industry requirements in terms of TDS and ionic makeup. A brackish water (or even saline water, for example, from the underlying Ellenburger Formation in the Barnett Play) could be used if the pressure required to frac the shale is not too high (translating into lower pumping rate and, consequently, less friction reducer). Some higher-TDS water (from reuse of flowback) can be used too, but it is accounted for in the use of a recycling coefficient.

3.3.1.2 Waterflooding and Drilling

RRC neither systematically compiles information on waterflooding and similar recovery processes nor does it collect data about drilling-water use. RRC does post information about injected fluid volumes, but there is no systematic information on the nature of the fluid. Most is likely water, but often there is no indication of the TDS of the water, nor is the groundwater/surface water split well constrained. Fresh-water injection wells need to be permitted as such. Form H-1 asks for the type of injected fluid (saltwater, brackish water, fresh water, CO_2, N_2, air, H_2S, LPG, NORM, natural gas, polymer, and others). For waters other than saltwater, the form requires the applicant to provide information on the source of the injection water "*by formation, or by aquifer and depths, or by name of surface water source*" (fresh-water questionnaire or form H-7) and to demonstrate that no other source water of adequate quality is available nearby. A companion form (form H-1A) requests maximum daily or estimated daily injection rates of each fluid type (including fresh and brackish water when appropriate). Actual water use is reported on form H-10 (http://webapps.rrc.state.tx.us/H10/h10PublicMain.do). A UIC query (http://webapps2.rrc.state.tx.us/EWA/uicQueryAction.do) also provides useful information about individual wells, although no breakdown in type of injected fluids. In addition, the regulatory focus is on the total volume injected and the pressure rather than the type of fluid injected. Experience has shown that H1 forms are only of little use in estimating fresh-water use; rates provided by the applicant largely overestimate actual rates.

Other researchers have also tried to collect waterflood information. Lovelace (2009), in a USGS summary of the approach used to estimate 2005 oil and gas water use across the nation, presented the assumptions made to develop the final figures including into his fresh and saline categories. (1) all water is groundwater; (2) if several water types are indicated in the H10 form, they are assumed to be of equal volume; and (3) because injection volumes are not provided for individual wells, all wells were assumed to contribute equivalent volumes of water. However, the 1995 RRC study (De Leon, 1996) invalidates some of those assumptions; a significant fraction of the water is surface water.

In the end, to gather information about waterflooding, we decided to send quantitative survey forms to ~25 leading oil-producing companies in West Texas, where waterflooding and EOR operations are concentrated (Galusky, 2010). This mailing was followed up with telephone calls and e-mails, and we communicated to them that all of the information and data that they provided would be held in strict confidence by Texerra/P. Galusky, who would submit only an aggregate compilation and summary of key findings in its report to BEG. Additional data and information on drilling activity, oil production, and related parameters were obtained from various publicly (internet) available and private (commercial) data sources.

Drilling-water use is generally not reported, and waterflood reporting combines all water sources from fresh to saline. A logical approach is then to collect information from operators. Drilling-water-use information was collected through informal discussions with practicing field engineers.

3.3.2 Coal/Lignite

Determining the amount of water used within the coal mining industry proves to be a complicated task because no entity currently tracks consumption; however, all coal mine operators must report total pumping rates to the RRC as a requirement for their mine operating permits under Title 16, Part 1, Chapter 12 of the Texas Administrative Code. When a mine operator applies for a new permit, estimates of current conditions and future drawdown must be provided to allow the RRC to determine allowable pumping rates. Once mines are in operation, operators must report their drawdown and pumping rates quarterly for the first 2 year, and then once every year following the 2-year period. The RRC does not restrict the amount of water to be pumped. The agency simply tracks pumping rates and requires documentation of the drawdown impact of mining operations on the surrounding areas (T. Walter, RRC, 2009, personal communication). Dewatering and depressurization totals were collated from each mine from RRC public records with the cooperation of Tim Walter, as well as results from the survey sent to each operator.

To help in the process of collecting data, in-depth literature searches and discussions with industry experts were conducted to help us decide on the best route for determining withdrawal and consumption estimates. We concluded that estimates for specific mining activities, such as hauling or dust suppression, vary for each active mine, depending on climate, location geology, production techniques, and other factors. Therefore, it would be necessary to analyze each mine individually. Fortunately the number of facilities is small, and all of them are large and well documented. We launched a survey in coordination with the Texas Mining and Reclamation Association (TMRA), which was very successful (~100% response rate).

An important question was whether to include pit-dewatering volumes into water consumption/withdrawal. Pit water originates from rain falling into the pit and being captured by its drainage area, as well as seepage from the overburden. The latter can be minimized but never eliminated by pumping groundwater from the formations to be removed before mining. Many mines divert runoff and pit water from precipitation into retention ponds and use it, for example, for dust control. For consistency with the approach followed in the aggregate category, we did not include pit dewatering (strictly defined) in water use.

Aquifer depressurization also lacks the clear-cut classification of some other water uses. Although the amount pumped for depressurization represents a net loss to the aquifer, the water is available for other uses, in particular environmental flow. In addition, in at least one mine, depressurization is put to immediate beneficial use when some wells are turned over to a water supply company (T. Walter, RRC, 2009, personal communication). This amount of water is not counted toward mining so as to avoid double-counting when merging all water uses, although it could bias water-use coefficients (they are not, however, used for coal in this study).

3.3.3 Aggregates

The approach for aggregates is different from that for oil and gas, about which relatively little is known or for coal/lignite, about which a complete data set exists. TWDB already has a working database from past water-use surveys. Various other reference sources and data sets were examined in an effort to determine whether available information could be used to further validate the TWDB water-use estimates and/or to refine our estimates at the county level. Resources examined include

- USGS
- MSHA
- TWDB
- TCEQ
- Interaction with and web search of the largest producers in the state (Martin Marietta Materials, Inc., Vulcan Materials, Inc., and Capitol Aggregates).

Furthermore, we recognized that although most aggregate operations recycle or reuse a large proportion of the water used in their processes, water-use data sometimes reflect the full volumes used and do not account for the recycled volumes. Such an uncertainty may result in inappropriate inflation of the values used for planning purposes. This report also attempts to assess the availability of additional information that may differentiate between water used in aggregate mining and that actually consumed or lost in these processes. A significant effort was made to conduct a survey in coordination with TMRA and TACA to obtain water-use and water-consumption data for a sampling of representative member companies and facilities across the state (survey questionnaires in Appendix D). Despite the cooperation of the two associations and multiple attempts to encourage participation, only seven companies of the many companies contacted responded to the survey request. They provided information for 27 separate facilities with information on location, production, water use, recycling rate, and source water.

These database reviews and survey results were analyzed and compared in order to supplement the information obtained by earlier surveys and planning documents. Results of the survey were highly variable, with some data tending to validate information obtained from earlier work by other agencies and some data suggesting significant differences. The survey highlighted the difficulties in using this approach to gather information on the industrial mineral mining sector. Some of the factors that may have influenced the response include the number, diversity, and relatively small size of many of the mining operations; the concern expressed by many in the mining industry of disclosing competitively sensitive information; the lack of available personnel to compile or calculate data; and the lack of regulatory requirements to collect and report requested information.

Issues we had to overcome or mitigate included (1) information on the types and numbers of industrial mineral mining facilities in Texas obtained from the Mining Safety and Health Administration (MSHA)—681—differed significantly from data from TCEQ—3,125 and (2) water-consumption coefficients, expressed in terms of gallons per ton of product extracted (gal/t) or gallons per dollar of production output (gal/dollar), which have been developed to estimate current and future demands on the basis of population growth or financial forecasts. The coefficients for washed crushed-stone mining derived from the survey were significantly different from those previously determined by either the USGS or the TWDB, whereas the coefficients for construction sand and gravel operations were similar to previous estimates.

Directly useful data in our possession were

1. Production and water-use information for a few facilities (27) from the BEG survey;
2. Water-use information from TWDB WUS survey dating back from 1955, although only recent information was used (26 facilities with some overlap with the BEG survey);
3. List and locations of facilities trying to limit the potential problem of having listed the location of the company headquarters possibly located in a county different from that of the quarry/pit;
4. Generic industry water-use coefficients from other studies;
5. Water-use information at the county level for all mining activities from USGS (year 2005); it is thought that the fresh-water-use data include mostly coal and aggregates;
6. County-level population information from TWDB projections;
7. Annual state production in 2008 (153 million tons crushed stone and 87.7 million tons sand and gravel) and earlier years (for example, 136 and 99.5 million in 2006, respectively)

As noticed by earlier workers, there is no clear correlation between production and water use, an observation again confirmed by the BEG survey. If that were the case, we could simply infer water use from production. However, neither production nor water-use figures are readily available. Actually, production figures are available that are aggregated only at the state level and do not result from direct data compilation. USGS collects production information and does it through surveys (and information collected from state agencies) but is never able to collect comprehensive data and has to rely on extrapolations. TWDB is focused on water use and does similar regular surveys but with limited success. Some companies consistently and voluntarily report their water use, whereas others are less straightforward. Regional Water Planning Groups (RWPGs) (Figure 8) know the reality of their region but are rarely focused on mining, which is typically a small fraction of total water use, and often relies on TWDB figures. Similar to previous USGS and TWDB reports, we elected not to link the data we present later in this report to individual facilities.

We used a two-pronged approach to assess aggregate water use:

1. When water-use figures are known for a given county, they are used.
2. For counties with only partial or no information on water use, we rely on estimated production combined with an estimated water-use coefficient. Water-use coefficients are computed from (1) a BEG survey and (2) generic coefficients from previous work. Estimated production at the county level is computed from local population and number of facilities. A higher number of facilities in a county relative to the population suggest a particularly favorable geology and a higher production per facility.

These detailed steps were used for crushed-stone water use:

1. Derive statistics from BEG survey results.
2. Compare with TWDB WUS and USGS county-level mining-water use.

(3) Compare with generic aggregate water use.

(4) Determine counties with crushed-stone facilities. Sort into two types: (a) of primary importance and listed on the NSSGA/USGS database, potentially deserving markets up to 50 miles away and lasting to the end period of this study and beyond or (b) of secondary importance and listed only on the MSHA database with only local subcounty impact and likely ephemeral in nature (a few years).

(5) Distribute crushed-stone production throughout the state using facility list from NSSGA/USGS; county-level production is anchored by the few counties for which production is known and scaled from the state production according to local population (more details on the mechanics of this in the methodology section for future water use—Section 3.4). Counties with facilities listed in the NSSGA/USGS directory are assigned the population of that county and that of surrounding counties; counties with facilities solely in the MSHA database are not included (Figure 13).

(6) Apply average/generic water use for those counties with no information. Given the large range in water-use coefficients, although likely relatively accurate at the state level, estimated county-level figures may diverge from actual figures if their facilities are more water conscious or less efficient than those of the average facility. USGS uses employment data from MSHA to estimate size of facility. We confirmed the size of some facilities, especially those with seemingly high water use, through Google Earth. Combined with other sources of information, Google Earth could be a good tool for estimating more accurate water use, especially through time, using the historical imager option. Excavation changes through time would help put bounds on production, and pond size and other water features would suggest water use.

Water use in the sand and gravel category follows the same approach except that all production is assumed to be consumed locally within the county; that is, population of surrounding counties does not figure into the calculation. Again, note that we did not include cement or concrete facilities (as far as we can tell by the description given in the databases) in this study. They are part of manufacturing, even if they have quarry operations onsite.

3.3.4 Other Mined Substances

Methodology for other mined substances is done on an ad hoc basis but mostly it is done by collecting information from TWDB WUS. We also collected direct information from some uranium and clay facilities with the survey through TMRA (Appendix D). Specific details are given in the current water-use section (Section 4.5). We included industrial sand operations in the “other” category, although they bear many similarities to the aggregate industry, although the much higher water use coefficient sets them apart.

3.3.5 Groundwater–Surface Water Split

Accessing the source of water used is difficult in most cases. Water use is well documented for some mining-industry segments, such as coal mining, but it varies widely for oil and gas and aggregate-mining segments. Historically the trend in the state has been to rely more and more on surface water. The best source of information is direct surveys, but even knowledge of current sources may have little predictive power. For example, in Louisiana, Haynesville shale frac water initially from the Carrizo-Wilcox aquifer (Hanson, 2009) has switched to alluvial aquifers and, mostly, surface water (Red River) after suggestions by the Louisiana Department of Natural

Resources. And treated wastewater from a paper mill in northern Louisiana has recently been added to the mix of water sources used in the play.

We provided information about the groundwater– surface water split as it became available during the data-collection process but did not try to generalize to the whole mining industry.

3.4 Methodology: Future Water Use

What are the substances currently being mined? How much longer will they be mined? Do any of the substances mined in the past have a credible chance of being exploited again, both in terms of substance and location? What are the new substances that could be mined in the future? Some of these questions are not easy to answer, but overall the main driver of water use in the mining sector is mostly (1) population growth and (2) economic development, especially concomitant energy demand nationally. Population growth relates to resources consumed within the state (aggregates, coal), whereas economic development impacts all substances, including those mostly exported out of the state either in their raw form or transformed. A project such as this includes many levels and types of uncertainties. A tentative comprehensive sampling despite the appearance of completeness can overlook several facilities, although not any one large facility. Operators can make honest mistakes when reporting information or include water-use categories that should not be included. Even more uncertain is extrapolating for long periods of time from a short period of time of a few years, such as for shale gas and oil. Long-term energy projections do not have a very good track record (Figure 14, Figure 15). Figure 14 provides an example of the difficulty of making projections. A natural tendency is to extrapolate trends; projection of U.S. gas consumption made in 1970 is a simple extrapolation of the strong trend of the previous year. Projection for 1972 follows the same model with a smaller growth rate. Year 1974 projection continues to extrapolate, although one of the marking events, energy-wise, of the second half of the 20th century occurred in 1973. Figure 15 demonstrates that, even in the midst of a known energy-paradigm change, shale-gas production (and, by extension, water use) was consistently underestimated. Hindsight or postaudits are a great way to improve the reliability of such scenarios. BEG published an analysis of water use in the Barnett Shale using data from 2005 (Nicot and Potter, 2007), and a comparison to actual water use is presented in Appendix B. The overall conclusion is that projections match recent data but only because of the recent economic slowdown.

We debated having deterministic vs. a range of projections (for example, high, medium, low) and concluded that we would focus on a ***single best-guess scenario,*** with the understanding that uncertainty increases with annual horizon. Although working on a 50-year horizon helps in an understanding of heavy trends, we tried to focus on the next 10 years, the timeframe in which this work could have the most impact. Another concern is higher-frequency changes, again mostly applicable to shale gas, such as the current economic slowdown. A long-term decade-level horizon makes it easier to ignore these high-frequency cycles and to focus on long-term trends. The downside of such an approach is that projections may not be correct in the rate of change of water use from one year to the next but they may be more accurate cumulatively.

Post-mortem analyses of long-term projections show that they often deviate from actual figures because of unpredicted events. A case in point is the rapid development of water-intensive gas production from gas shales. Such events are by nature unpredictable and, although we can develop scenarios, their multiplicity quickly becomes unmanageable: what year does it begin, how fast does it develop, is it permanent or transitory, what is the magnitude of impact, etc.?

Including the uncertainty of abrupt changes in water use, projections would render them meaningless, so our approach has been to ***assume that current trends will continue***. In contrast to abrupt changes, long-term shifts in water use, particularly in the energy sector, can be better tackled. As discussed previously, a large fraction of the mining output is related to energy production (oil, gas, coal). King et al. (2008) discussed future directions of the energy sector in Texas as it relates to water use. For example, development of nuclear power would merely transfer water use from the mining category to the power-generation category, as well as move it to different counties and regions, as would a shift from coal to natural gas. This project does try to predict the unpredictable but always assumes a slow rate of change, such as gas slowly overtaking coal as the major electricity-generating fuel in Texas or the rise and decline of gas production. However, most gas is exported out of state and, because of a projected overall increase in energy consumption, is not denting water use by the coal industry.

Next, we discuss the relationship between three of the major water users in the mining industry: oil vs. gas and gas vs. coal. Oil in terms of energy has always been at a premium relative to gas (for example, Kaiser and Yu, 2010), being sold at a higher price for the same energy content. Natural gas, being a gas at surface conditions, requires more advanced technologies for it to be transported to areas of consumption. The year 2010 has seen a rush toward the oil window, thought to be more profitable, in some so-called gas shales but more accurately described as liquid-rich shales, such as the northern confines of the Barnett Shale or the western section of the Eagle Ford. Such a trend of operators focusing on oil rather than gas, if it persists, will impact water use at the county level, if not at the state level. This focus on oil is analogous to a smaller-scale shift in oil and gas operators' thinking. In this project, we assigned a slightly higher weight to these oil window/combo counties, but on the whole we consider this oil focus a short-term deviation. Another example concerns some gas plays very much in the news 2 or 3 years ago, such as the Pearsall Formation in South Texas or formations of the Palo Duro Basin in the Texas Panhandle, that have since disappeared from the radar, while others such as the Haynesville and, even more so, the Eagle Ford, have exploded in terms of activity. In this ever-changing environment, it is challenging to predict where the gas industry will be active 5 years from now. Another single event with possible repercussions, particularly in terms of legislation, is the Macondo well. On April 20, 2010, a grave accident occurred in the deep offshore Gulf of Mexico. Responding to a likely increase in regulatory scrutiny and, therefore, increased cost, many operators, particularly independents, may redirect their efforts onshore, especially to unconventional oil plays (the Eagle Ford, Barnett Shale oil windows).

Coal and natural gas are used mostly for energy production. Both industries are optimistic about their futures. The Texas energy portfolio consists of mostly coal, nuclear, natural gas, and others, including oil and renewables. King et al. (2008), looking at energy use in Texas by 2060, assumed an annual electricity growth rate of 1.8% in business-as-usual scenarios. These workers also investigated a low-energy-usage case. They described four scenarios combining high/low natural gas prices and implementation (or not) of carbon capture and storage (CCS). In both high-natural-gas-price cases, coal use expands and natural gas use stays steady. However, if natural gas price stays low, coal share decreases even if overall energy consumption decreases. If, in addition, CCS is made mandatory through a hypothetical cap-and-trade or carbon-tax legislation (to deal with climate change, the advantage of natural gas relative to coal is that it releases less CO_2 per unit energy than coal), coal share in the energy mix decreases even faster. However, EIA (2010, p. 79) suggested that lignite production may increase in Texas. Coal mined in Texas is always used locally (mouth-of-mine coal-fired power plants), but a significant fraction of the gas goes into the general market and is exported out of state. For example, 45+% of electricity consumed in the state is produced by natural gas, for a total of ~200,000,000 MWh (equivalent to 0.68×10^9 MMBTU, with 1 MMBTU = 0.2931 MWh). In 2009, natural gas production in the state was 7.66×10^9 Mcf (equivalent to 7.66×10^9 MMBTU, with 1 Mcf =1 MMBTU). Major growth in other parts of the world may boost the gas industry for export, and development of LNG terminals in Texas or the glut of the gas commodity may keep the prices too low for its development to have a major impact on water use (averaged over decades). An authoritative recent study on natural gas (MIT, 2010) suggests that use of natural gas will expand and an earlier study by the same organization (MIT, 2007) acknowledges that coal use is likely to increase overall even if its relative share in the energy mix decreases.

To develop our own understanding of those issues, we collected material from Washington-based think tanks, attended specialized conferences (Nicot, 2009a; Nicot and Ritter, 2009; Nicot et al., 2009; Hebel et al., 2010; Nicot and McGlynn, 2010; Ritter et al., 2010) and discussed the matter with experts. Overall, we decided to use a middle-of-the-road scenario, and because of the mixed signals received from different entities about coal consumption, either up or down, we assumed that it stays at its current level with no sharp increase or decrease in absolute figures (but decreasing in the state energy portfolio), in agreement with discussions with coal producers. Texas gas production is controlled by external factors independently of population growth, whereas aggregate production is controlled entirely by population growth.

Judgment on future water use of nonfuel substances is either more straightforward (aggregate) or less consequential in terms of total water use. Information about future water use was determined not only through direct results of forward-looking survey questions and general understanding of the commodity, but also by scouring Regional Water Planning Group (RWPG) reports. Texas is composed of 16 RWPGs, each of which is charged by law to project water needs and water sources for its own area and to submit information for incorporation into the state water plan. Water Plans (TWDB, 2002, 2007; http://www.twdb.state.tx.us/wrpi/data/proj/demandproj.htm for year 2007) present projections but in general are aggregated at the regional planning level.

3.4.1.1 Gas Shales

The general philosophy of the approach is top-down, that is, distributing estimated overall oil and gas production, as well as water use, across counties, rather than a bottom-up approach, in which a time-consuming and hard-to-get detailed compilation of fields, formations, and local input would be aggregated to deliver county-level figures. This section is untitled gas shales but includes the oil window generally located updip of gas shale proper (liquid-rich shales). As far as water use is concerned, well stimulation does not seem to be approached very differently. Quantitative approaches to future water use in shales fall into two broad categories: (1) production-based approach and (2) resource-based approach. The latter was applied to the Barnett Shale by Nicot and Potter (2007) and Nicot (2009a). In this report, we followed both approaches simultaneously, making sure results were consistent.

A ***production-based approach*** follows five steps, which are further described later in this section:

(1) Determine with the help of BEG experts (or gather from the literature) the total amount of gas/oil contained in the shale, as well as the recoverable fraction and the estimated annual production level. This step also involves recognizing the boundaries of the play.

(2) Decide on (or gather from the literature) the average Estimated Ultimate Recovery (EUR) for a single well.

(3) Compute the total number of wells needed.

(4) Apply the average water use per well (computed from historical data, we have a good handle on water use of many individual wells across many gas plays in the state, as detailed in Section 4.1), possibly corrected by factors accounting for technology advances and increased recycling and, perhaps, additional rounds of well stimulation. Well count for the first few years is estimated, given rig availability, which after a few years becomes irrelevant because the service industry will respond to needs by constructing them.

(5) Distribute through time (expected life of the play) and space (county level) as a function of prospectivity and other parameters. This step is the most uncertain and open to interpretation.

A ***resource-based approach*** follows four steps:

(1) Gather historical data in terms of average well-water use and average well spacing.

(2) Estimate ultimate well density across the play; it is a function of factors, such as geological prospectivity (for example, within play core or not, shale thickness) and cultural features (urban/rural). In this step, ultimate boundaries of the play are identified.

(3) Compute total number of wells needed.

(4) Distribute through time and space, constrained by the assumed number of drilling rigs available (see earlier comment).

As an entity whose strength is applied geology, BEG had the opportunity to develop its own assessment of shale-gas reserves in Texas. Gas accumulations can be biogenic, in which microbes biodegrade organic matter to release methane, or, as in all Texas shale-gas plays, thermogenic. Thermogenic gas is produced by the natural cracking of complex organic molecules into oil and gas, owing to an increase in pressure and temperature, as well as sufficient time at required depths. The deeper the conditions (without some limits), the more advanced the cracking of the organic matter, whose ultimate fate is methane. Some shale plays contain only gas (if they stay in the gas window for long enough)—an example is the Haynesville Shale—others contain both oil and gas either at the same location (a well will produce both oil and gas) in a so-called combo play (for example, the northern section of the Barnett) or spatially distinct oil and gas zones with a mixed transition combo zone (for example, the Eagle Ford Formation). There is a relationship between total organic content (TOC) and potential gas content. Vitrinite reflectance (VR) is a measure of the maturity of the evolved organic matter/kerogen: the higher its value the more likely it is to be in the dry-gas window (VR>~1.5–2). For VR values ranging between 1 and 1.5, the shale is likely to be in the wet gas window. Below a value of 1, oil is produced, whereas if VR<0.6, the sediment is immature, and no commercial accumulations are likely to be found. Combining information about formation thickness, TOC, VR, and a few exploratory wells, specialists can infer gas resources. The core area of a play is subjectively defined as the area where the most favorable combination of thickness, TOC, and VR exists. The core areas of the Barnett and of the Texas portion of the Haynesville consists of each of four counties, whereas they have an additional 20+ whole or not counties and ~10 counties considered noncore, respectively. Core counties have not been defined for other shale-gas plays, including the Eagle Ford Formation, yet. Other known important factors are not used in this study; for example, an emerging model (S. Ruppel, BEG, personal communication, 2010) suggests that margins of shale plays are more prospective because of the influx of carbonate and other clasts with the right combination of organic matter and detrital material, making the setting more favorable.

We decided early on to rely as much as possible on published information rather than developing our own estimates. Nevertheless, knowledge of these parameters helps in determining the prospectivity of an area (county in this case), that is, its attractiveness to operators, which is obviously linked to water use as well as the boundaries of the play. Geological maps and previous drilling and production activity help in constraining the final spatial extent of the play. In practice, prospectivity (maturity, core area) is a positive number ≤1. Each county within a play is assigned a prospectivity factor (generally 1, 0.75, 0.5, or 0.3). This assignment was done in a purely ad hoc manner and in a more cursory manner than in Nicot and Potter (2007), as this parameter is softer than, for example, the play footprint and, owing to a lack of information, includes some guess work relative to where the industry is headed.

Many gas-production projections are published at the national level (EIA, USGS, PGC) aggregated from individual plays and sometimes extrapolated to prospective shale plays. Information about recoverable reserves of individual shale plays (in general, ~30% of OGIP or OOIP) are relatively easy to collect, but unfortunately there is a lack of consistency between the different figures we can gather, mostly because the methodology used to arrive at those figures is not explained in most cases. In the Future Water Use section (Section 5.1), we list figures for all Texas shale plays and explain the choice of the value we used. Another difficulty relates to the fine granularity (county level) we attempt to meet. Projections made at the national level perhaps end up being more accurate because of the low granularity of the system (many oil and gas plays), as opposed to a single state even if it is large because only a few shale plays exist. For example, Appendix B shows that careful work does not necessarily generate accurate predictions at the county level, even though they might be at the multicounty or regional/play level. We expect the same observation to be truer in this higher level study. Results at the county level may be off by a factor or 2 or 3, especially when the time component is added.

Later we focus on the production-based approach because the resource-based approach was already described by Nicot (2009a) and Nicot and Potter (2007). Some published EUR values seem to be problematic. Individual-well EUR can be estimated at 0.5 to 3 Bcf, maybe up to 10 Bcf, in highly profitable wells. Most EUR is derived from limited data, not necessarily in terms of number of wells but in terms of time frame (Figure 16). Reported average EUR values most likely reflect good wells drilled in the core area of a play and might be inflated. Water use computed from number of wells based on EUR and total recoverable gas only is therefore highly uncertain because both can vary substantially. For example, the commonly found EUR value for Barnett wells of 3 Bcf, combined with an assumed <60 Tcf of recoverable gas, yields <20,000 wells. Clearly, even taking into account that many of these wells are vertical wells with a lower EUR, more wells will be drilled in the Barnett. The very first well drilled in the core area of the Barnett in 1982 has produced 1.7 Bcf so far (PBSN, Nov.1, 2010).

Therefore, in the Barnett, either recoverable reserves are underestimated or average EUR is overestimated; that is, production drops faster than currently projected. This report puts more weight on the latter explanation, but without negating the possibility of the former. Actually, there are voices (Shook in NGW, 2009) advocating that shale gas will not carry all the promises put forward by operators. For example, SPEE-Anonymous (2010), Berman (2009), and Wright (2008) suggested that decline curves were too optimistic, but they seem to be in the minority. Their approach has been strongly contested by the gas industry in the literature, as well as in the field, as majors (ExxonMobil, Shell, Total, ENI, Statoil, BP) started investing in shale gas. It seems that with a diversified gas-well portfolio and a statistically sufficiently high number of wells, good producers more than make up for more numerous low-performing, uneconomical wells and render the whole operation profitable for most gas operators. In other words, the viability of a play is determined by its top producers, perhaps the top 10th or 20th percentiles. Note that from a water use standpoint, however, uneconomical wells and good producers consume the same amount of water during fracing. Low-rated wells may even be fraced a second time shortly after the initial frac job in an effort to improve gas production.

A typical play containing 100 Tcf of gas in place, 30% of which is recoverable, translates into 15,000 wells at 2 Bcf EUR, on average. Distributing projected production/water use through time is difficult but is the essence of this project. We relied on several sources in addition to informal information, but particularly Mohr and Evans (2010) and Mohr (2010, Chapter 6), who inventoried all relevant gas shales at the time and summarized available information on projected gas production for the Barnett and Haynesville Shales. They also provided a peak year for gas production (best guess of 2015 and 2031, respectively). Similarly we assigned a peak year for each gas-shale play, which is clearly highly uncertain. Most publications assign a peak year for gas production, which typically comes after the peak year for initial well completion. However, translation from gas production to water use requires the knowledge of the EUR and the details of the production decline curve. It has been commonly observed that production decreases from an "initial production" (IP) (Figure 16). Given the relatively steep decline from IP, new wells must be drilled to sustain production. Information received from informal discussion suggests that 3000+ new wells a year are needed to sustain production at current 2010 production rates.

A commonly circulated IP value in the Barnett is 5 MMcf/d. Overpressured plays, such as the Haynesville, have generally a higher IP—reported value can be as high as 8 or even 20 MMcf/d. More generally, individual gas-well performance is characterized by their IP, how fast they decline from the IP (decline curve), and their cumulative potential (EUR). There is some evidence that pushing production to its max IP is detrimental to the EUR, so most operators throttle production to a rate somewhat lower than the possible maximum. Doing so also makes sense economically when gas prices are depressed. A large body of literature deals with decline curves, which have been a topic of considerable interest in the petroleum industry because they help forecast future performance and production. Two broad families of these mostly empirical curves exist: exponential and hyperbolic (see for example, the classic Arps, 1945; Economides et al., 1994; Ilk et al., 2008; Lee and Sidle, 2010; Valko and Lee, 2010). The former curve model is used when the decline is linear on a semilog plot against time. We tentatively used a simplified version of the Arps decline-curve equations for hyperbolic decline, which is typically faster than exponential decline.

$$q = q_i \exp(-Dt) \quad \text{(exponential decline)} \qquad \text{Equation 1a}$$

$$q = q_i (1 + Dbt)^{-1/b} \quad 0 \le b \le 1 \text{ (hyperbolic decline)} \qquad \text{Equation 1b}$$

Although the parameter b should be ≤ 1 to meet model assumptions, it is often set to values >1 for tight formations (Ilk et al., 2009). This parameter is difficult to assess with the limited information available early in the history of a well. Assuming an average well EUR, a decline curve, and a given life, we can attribute a fraction of the EUR to each year. After some trial and error, we were able to match gas production from Mohr and Evans (2010), assuming an average EUR substantially lower that the most-cited core ones and with input from the resource-based approach. Note that the chosen production model is only one among many, although a middle-of-the-road, defensible one. Exploring all possible production outcomes would entail much larger efforts than available for this study. The fraction produced during the first year is ~45% and ~25% for what we defined as an overpressured *Haynesville type* and a normally pressured *Barnett type*, respectively (Figure 17), over the 30 years of the producing life of a well. The curves displayed in Figure 17 show a drop of 75% and 60% between average production in years 1 and 2 in Haynesville and Barnett types, respectively. Figures are consistent with those presented in Jarvie (2009) that document decrease in the 60–80% range during the first year of production for various shale plays in Texas and elsewhere. Note that the decline curve is just one component in estimating water use, and, although it obviously has a large impact on the production numbers, water use is less sensitive to it, especially when the production-based approach is compared with the resource-based approach.

Spatial coverage density is an important step in the resource-based approach. Figure 19 and Figure 20 display examples of thorough coverage from multiwell pads. Horizontal-well laterals are all oriented in the approximate direction that is perpendicular to minimum local horizontal stress. Nicot (2009a) and Nicot and Potter (2007) used a range of 800– 2000 ft. Generally speaking, 16 40-acre vertical wells ($16 \times 1.7424\times10^6$ ft^2 = 1 square mile) translates into seven 4000-ft-long laterals with 1000-ft spacing that could be all drilled from the same pad with a much larger recovery. There seems to be a relationship between lateral length and lateral spacing (Figure 18).

A limiting factor controlling the number of wells drilled every year in a play is the number of drilling rigs available. Figure 22 illustrates a time snapshot in the distribution of drilling rigs in Texas in June 2010. Rigs typically specialize as gas or oil rigs and are binned as a function of the maximum depth they can reach and the type of well they can drill (horizontal vs. vertical), but this level of detail was not included in the study. We estimate that it takes 3 to 6 weeks to drill a vertical section and a lateral in the Barnett and Haynesville, respectively. An average spud-to-release time in the Haynesville was 44 days in early 2010 (LRNL, 2010). Nicot and Potter (2007) estimated an average spud-to-spud time of 1 month in the Barnett, which is currently down to ~3 weeks. Figure 21 demonstrates the high variability in the number of active drilling rigs. Rigs travel from one play to the next and across state lines, depending on demand and on the perceived or actual potential of a play. Figure 21 shows a rig count increasing at a rate of ~100 rigs/yr between Spring 2002 and Fall 2008, then a sharp drop, and a sharper increase rate at ~375 rigs/yr between June 2009 and June 2010. This steep rate is likely due to rigs mothballed near the new drilling sites and being put back in use quickly. As of December 2010, the Barnett Shale play had ~80 rigs, and that number has varied little since early 2009 (multiple issues of PBSN). Most of the previous year, in 2008, the rig count was at ~180 active rigs. The number of frac jobs (that is, water use) is clearly related to the rig count. Nicot and Potter (2007) underestimated the ability of operators to bring in more rigs to the state. Emergence of more efficient rigs will shorten the rotation time between drilling sites and increase the number of boreholes that a single rig can drill in a year. But again, showing the difficulty of making projections, the industry may run out of trained crews to man the rigs.

Details on recycling, refracing, and other approaches are given in Section 5.1.2. We did not try to resolve the surface water– groundwater split for future decades.

3.4.1.2 Tight Formations

Tight gas (for example, the Cotton Valley Formation in East Texas) or other tight formations containing oil (for example, the Wolfberry play in the Permian Basin) are also subject to hydraulic fracturing. The main difference between them and gas shales, from a practical standpoint, is that (1) these tight formations are conventional resources in the sense that they occur in a discontinuous manner and (2) they are not new plays and have been producing gas/oil for years or even decades for the most part. We applied the same approach to compute future water use, as was employed for the gas-shale category. The approach is particularly similar to that used for the Barnett shale, which already has significant production. At the county or field level, we examined the *burn rate* of the reserves as well as the remaining reserves. Coleman (2009) presented a recent historical overview of gas production from tight sandstones.

3.4.1.3 Drilling and Waterflooding of Oil and Gas Reservoirs

Future water use for drilling was estimated at the state level only by assuming water use for shale-gas wells as provided by the literature for several plays (Section 5.2.2) and assuming an average value for the remainder of the wells. The number of wells to be drilled in the future was computed from (1) the oil subcategory for which we used recent work by Galusky (2010) in the Permian Basin; we then applied a multiplier to account for oil production outside of the Permian Basin; and (2) the gas subcategory, for which we used results from the production-based approach for shale and tight-gas plays, and to which we, in turn, applied a multiplier to account for conventional gas production.

Water use for secondary and tertiary oil production is less dependent on the number of rigs because most of the consumption occurs after drilling and during pressure maintenance or enhanced-recovery operations. We assumed that waterflooding activities occur mostly in the Permian Basin, which is also the world center of CO_2 EOR (a WAG process is typically used, in which water is injected behind slugs of CO_2). Estimates in this category are obtained through a combination of historical data, survey results, and knowledge of the industry.

3.4.1.4 Coal

Energy makeup of the state still relies heavily on coal-fired power plants (although some of the coal is imported from out of state), with nuclear energy as a distant second. The complement comes partly from natural gas and oil. As discussed earlier, we assumed a business-as-usual scenario for the coal industry and accepted figures provided by the comprehensive survey of all operators in the state. The main uncertainty resides in the possibility that the industry will start relying on coal imported from western states to feed the coal-fired power plants instead of relying on local lignite resources. Another uncertainty is the possibility of having most depressurization water volumes captured for municipal use or other beneficial use (for example, fracing), in which case mining water use may be different but not the total water use. Such a development is not accounted for in this study.

3.4.1.5 Aggregates

If some mining activities such as oil and gas are independent of the state population because their products are not necessarily consumed in the state, others, such as aggregates and lignite coal, which have high transportation costs, are consumed mostly locally and depend more strongly on the population level in the state, nearby counties, and economic activity. Future aggregate production (and concomitant future water use) is correlated with population growth. Population of the state is predicted to grow by 20 million people, from ~25 million in 2010 to ~45 million in 2060 (both are estimates). We used TWDB population projections, which are slightly different from those of the U.S. Census Bureau, although differences are well below the level of uncertainty brought about by other parameters.

To estimate future aggregate production we relied on extrapolation from historical data and noted that aggregate production is coupled to absolute population level, but also to its derivative through time (population growth). Numerical details of the analysis are given in Section 5.4 (future water use in the aggregate category), but we based extrapolation of production and population on their changes in the past 20 years. In 2008, the amount of crushed stone produced per capita was ~153 Mt/ 24,000,000 people; that is, ~ 6.5 ton/capita/yr. During the same 1-year period, population growth was ~0.5 million people, that is, ~310 ton/capita growth/yr. A similar analysis yields ~4 ton/capita/yr and ~200 ton/capita growth/yr for the sand and gravel category. Extrapolating solely from gross population numbers seems unrealistic. Norvell (2009) used historical data and determined that over a 20-year span (1982–2003), aggregate production was best predicted by a combination of total population and the state gross product (GDP) related to construction. Population and state GDP were both approximately equally weighted in terms of coefficients, but construction state GDP in billions is about twice the population in millions, so its weight is, in essence, higher. The report states "*coefficients indicate that on average as population grows by 1000 people, aggregate output in Texas rises by 4,800 tons (i.e., about 4.8 tons per person), and every $1 million increase in gross product for the construction industry results in an additional 5,760 tons of aggregate extracted.*" The figure of 4.8 t/capita/yr is somewhat lower than the average of our two figures, although plainly consistent with them. Given the time and budget constraints to develop this report, we assume that population growth is somewhat equivalent to the economic output variable of Norvell (2009) and other economic analyses. As a whole, additional people will need houses, highways, and other facilities at a higher rate than people already living, the state supporting the assumption that population growth has a greater impact on aggregate consumption than the population parameter itself:

$$Aggr.Prod. = 2/3 \times Pop. \times Rate1 + 1/3 \times Pop.Growth \times Rate2 \qquad \text{Equation 2}$$

The population-growth component stays at a stable absolute level because growth rate itself stays stable, whereas the population as a whole component keeps increasing in absolute value and as a fraction of the total.

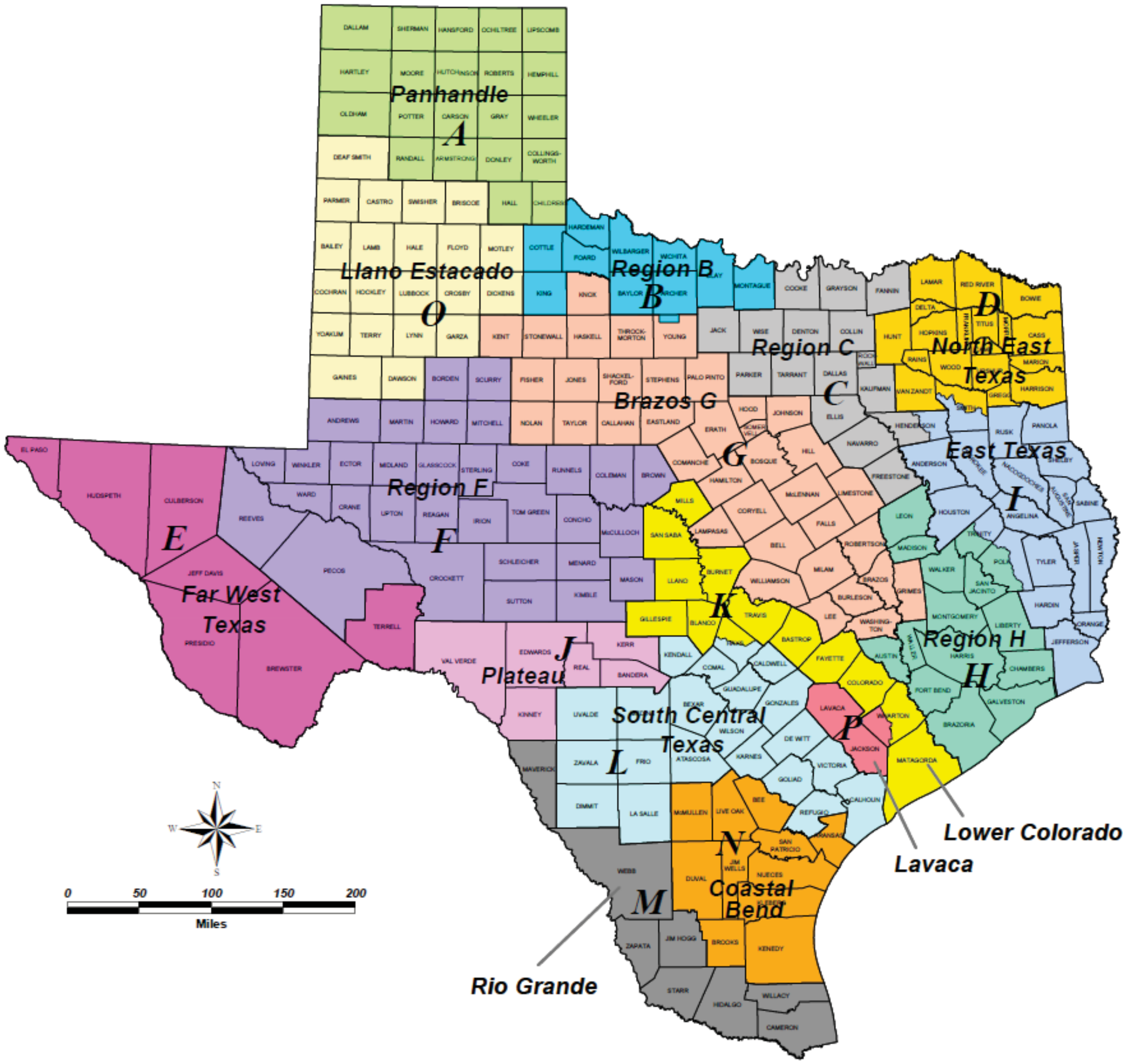
Once aggregate production at the state level has been determined, we could apply water-use coefficients already gathered in the previous phase of the work to obtain aggregate water use at the state level. Difficulties arose when we tried to distribute state-level water use to individual counties. In order to limit distortions due to the impact of artificial administrative boundaries (for instance, large growth in a county next to that of the aggregate facility, as we did for current crushed-stone water use), we used a simplified radius of influence technique (county of interest and neighboring counties) to apportion water use, whereas sand and gravel production is assumed consumed within the county in which it is produced. We also assumed that aggregate production and consumption strictly stay within state lines. Counties on state lines do not take into account growth on the other side of the state line or the possibility of importing aggregate from out of state. Future water used for those few counties for which we have reasonable knowledge of production and water use was extrapolated from current use and county population projection according to Eq. 2, with the caveat presented later for urban counties. The remainder of state-level water use was distributed among the remaining counties. Lack of data on individual facilities compelled us to use this approach involving averages that may not necessarily give accurate results at the county level. This lack of data is made worse by the high variability in reported water use. If need be, when new sources of information update average water use, the figures given in this report can simply be scaled by a more accurate value.

Because we based our projections on population growth, aggregate use will also include aggregate recycling (presumably classified in the manufacturing category) and export/import balance from neighboring states. We assumed that both are small and will stay small. Some aggregate recycling has been estimated at 5% of total consumption in 1998 across the nation (USGS, 2000). More recent figures put the amount at 1.7 million tons (USGS, 2010) in Texas (<1%). In addition, we did not assume more water recycling than is currently done. Nor did we include reclamation and irrigation water use in aggregate water use (at least not explicitly).

We also assumed that the same counties will keep operating the same facilities or their extensions, particularly crushed-stone facilities, because of the difficulty to gain acceptance from the public of new large facilities (Robinson and Brown, 2002, p. 3). The main exception concerns urban counties. These authors stated that "*although development and maintenance of infrastructure in metropolitan areas require a continuing supply of aggregate, aggregate production rates begin to fall in counties when the population density reaches approximately 1000 people per square mile. At population densities of about 2000 people per square mile, production of aggregate in many counties may diminish significantly.*" One of the problems of linking population growth and aggregate output at the county level is that counties with high growth are likely to crowd out mining operations and rely on neighboring counties for their aggregate needs. This scenario is assumed true for Travis County in the crushed-stone category and for Bexar, Dallas, Harris, Tarrant, and Travis Counties in the sand and gravel category.

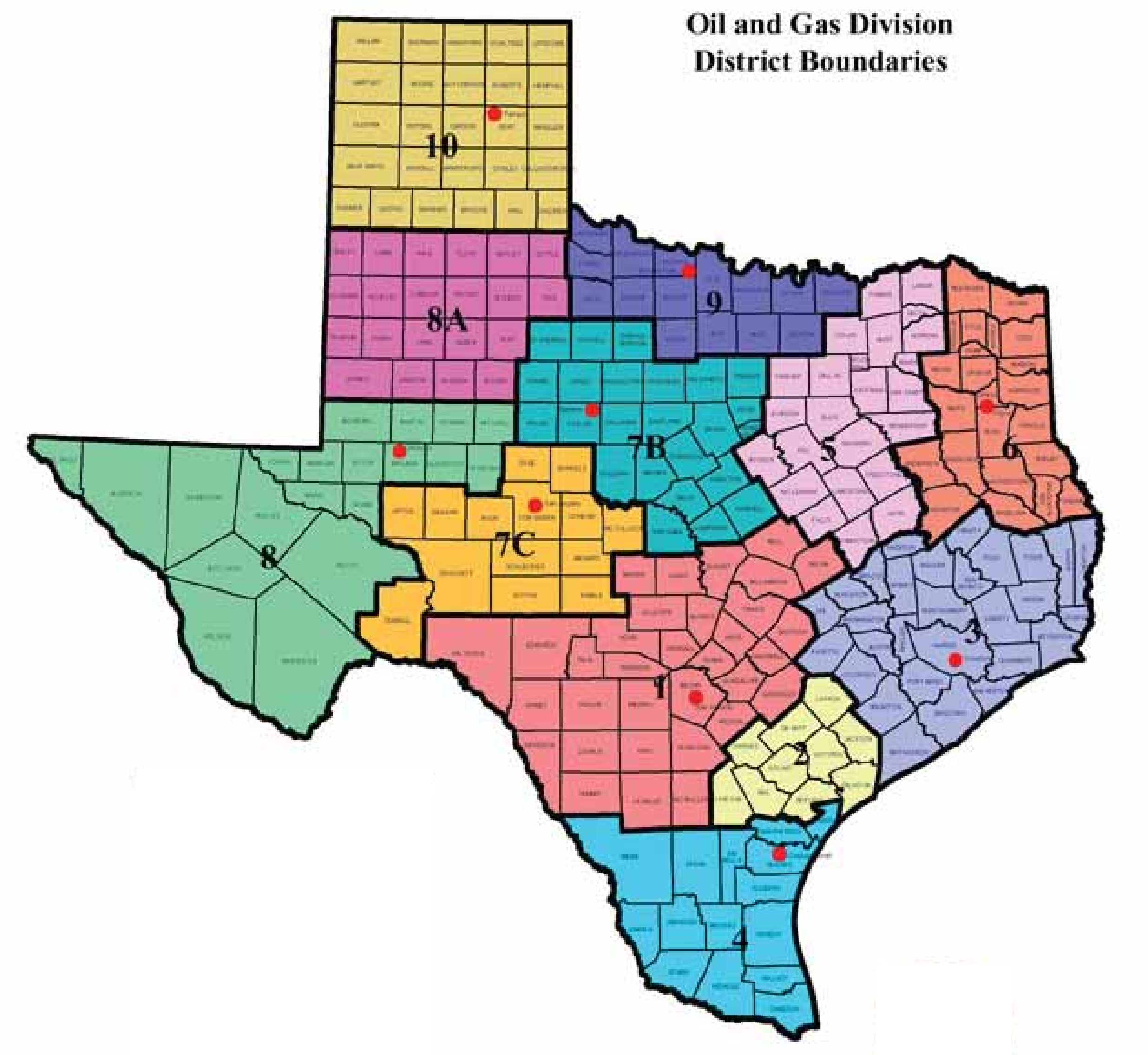
3.4.1.6 Other Mineral Commodities

As was done in the Current Water-Use Methodology Section, future water-use methodology for other mined substances is done on an ad hoc basis. Specific details are given in the Current Water Use section (Section 4.5).



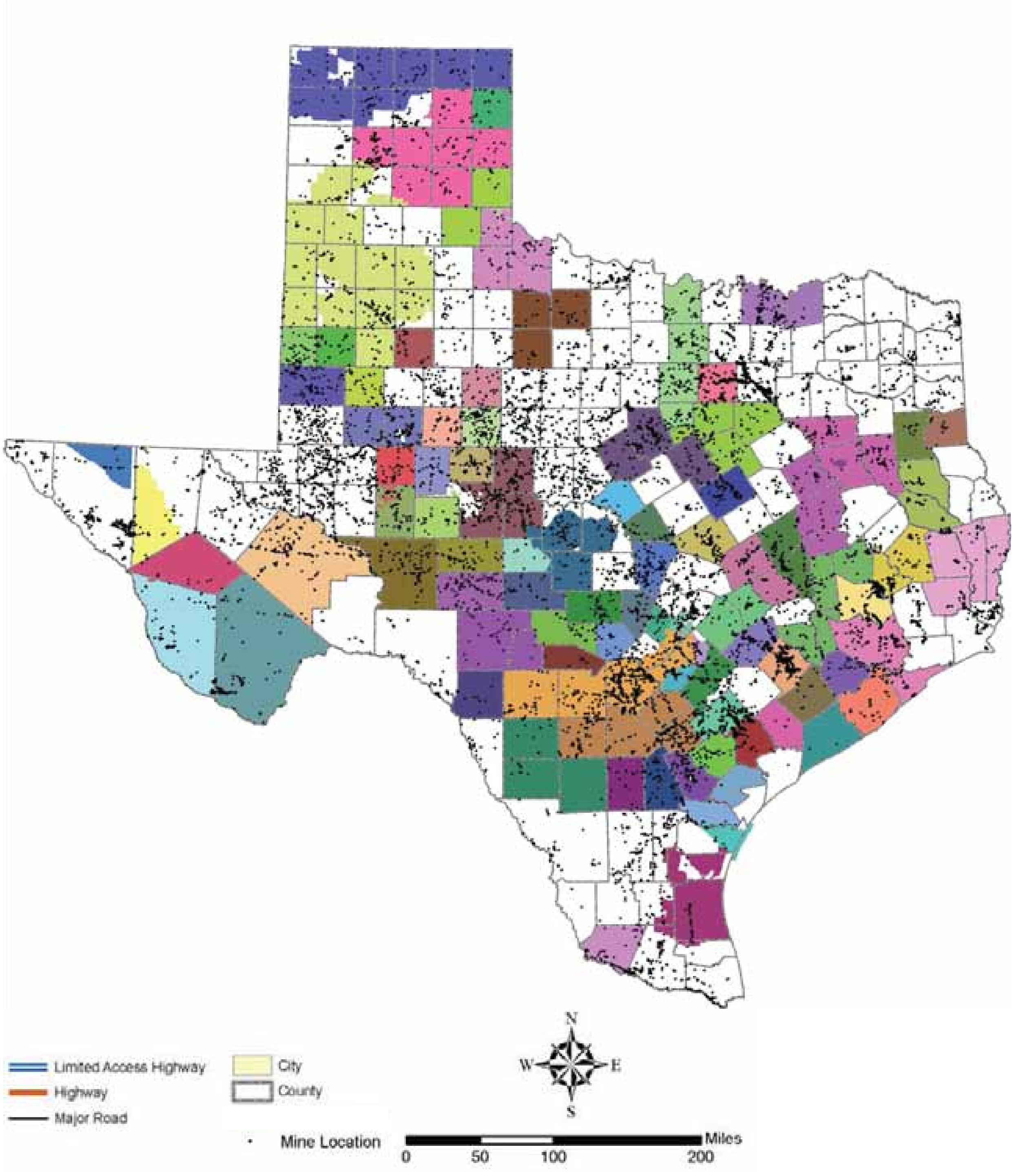
Source: TWDB - http://www.twdb.state.tx.us/mapping/maps/pdf/sb1_groups_8×11.pdf

Figure 8. Map of Regional Water Planning Groups



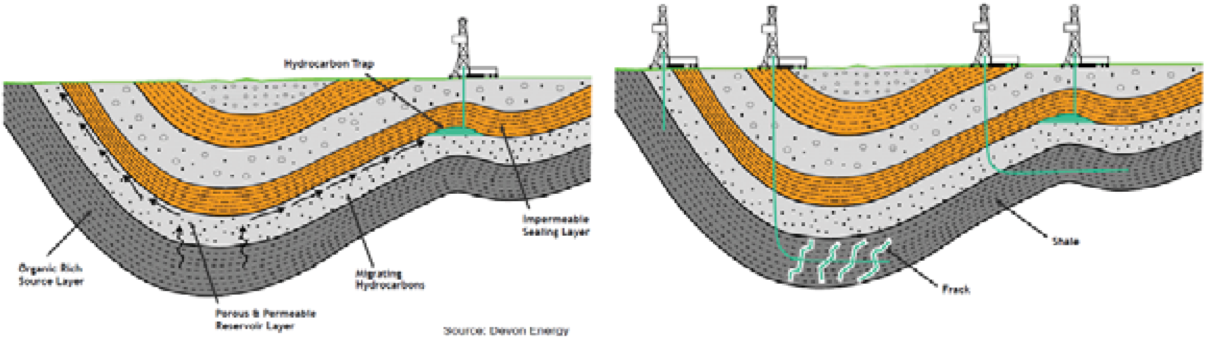
Source: RRC website http://www.rrc.state.tx.us/forms/maps/ogdivisionmap.php

Figure 9. State map of RRC districts



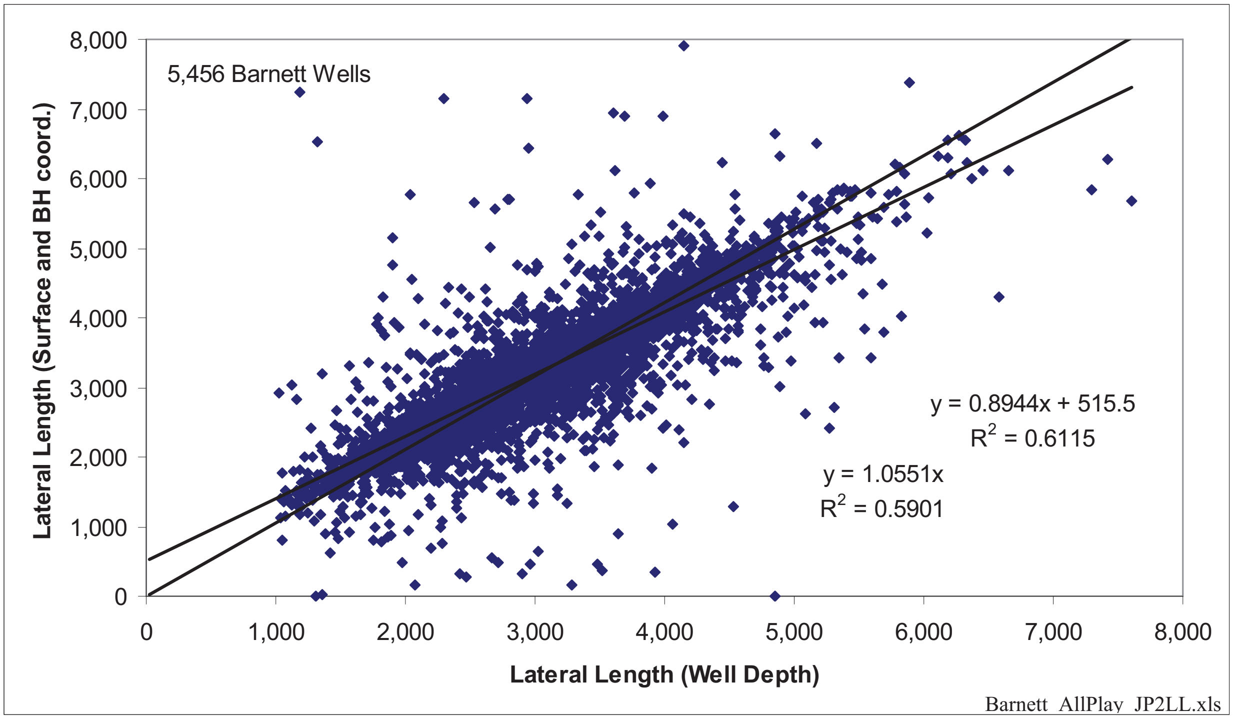
Source: TWDB (GIS coverage of GCDs) and TCEQ SWAP

Figure 10. GCDs and active and inactive mine locations in the TCEQ SWAP database



Source: Devon Energy website

Figure 11. Trap vs. resource play



Note: equation for best fit and fit through the origin are shown. Only those points for which both values are available are shown. Plot also provides estimate of typical and maximum lateral length.

Figure 12. Comparison of the two approaches to compute lateral length

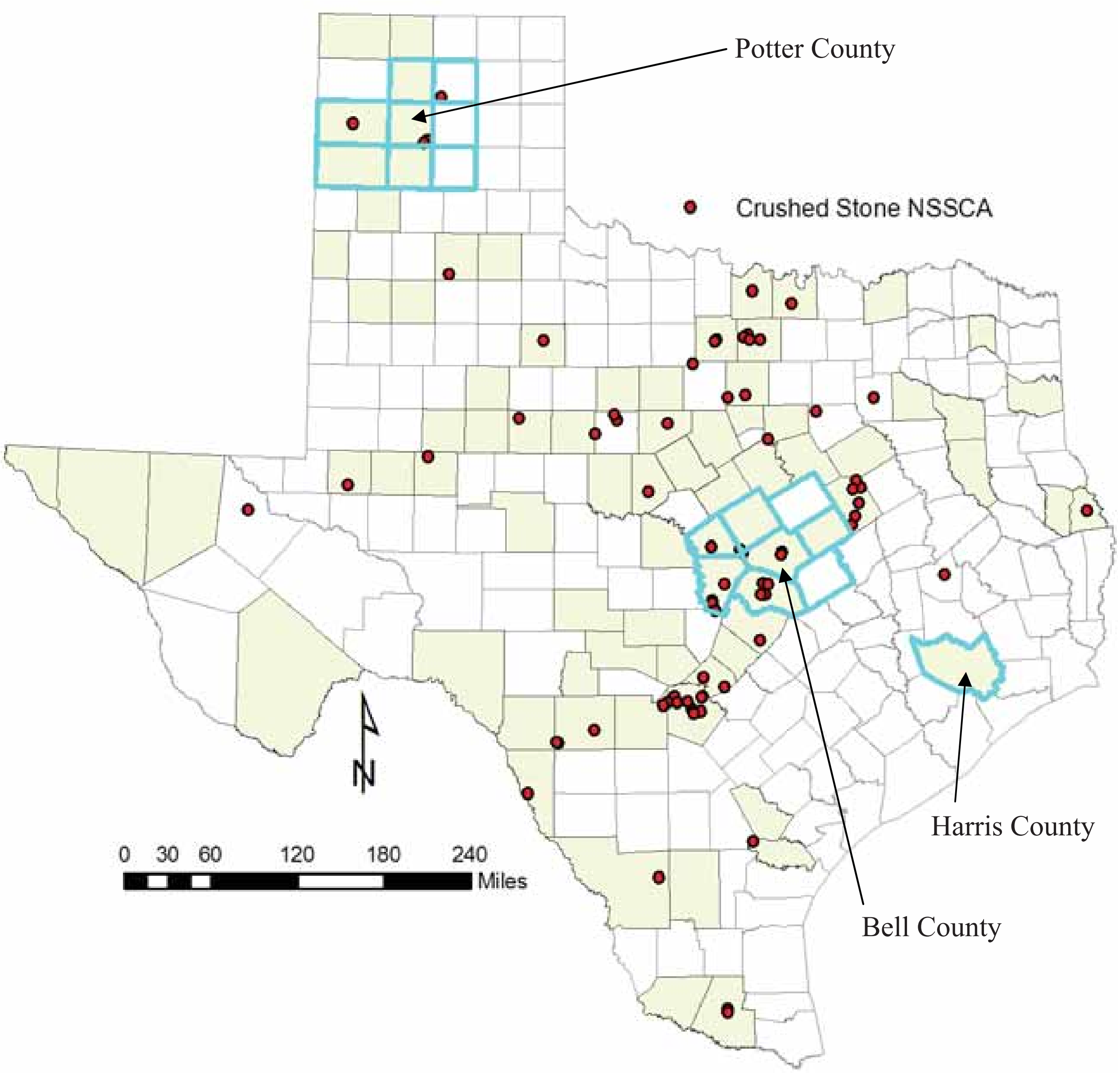
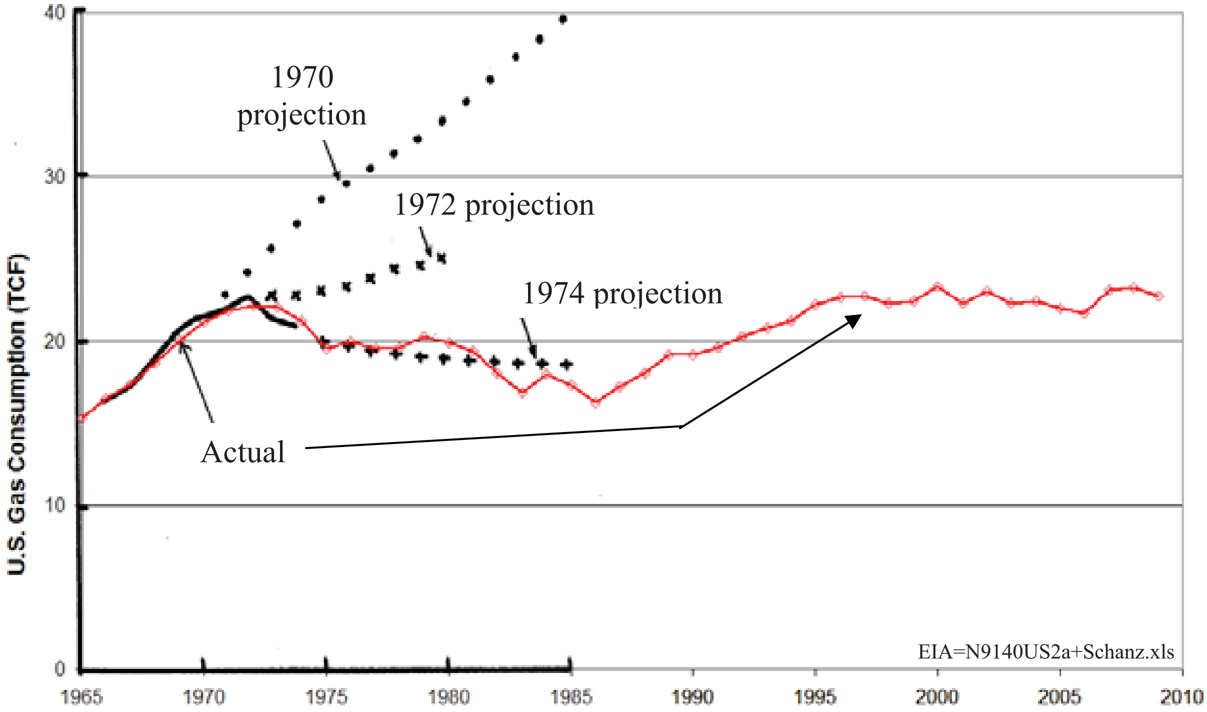
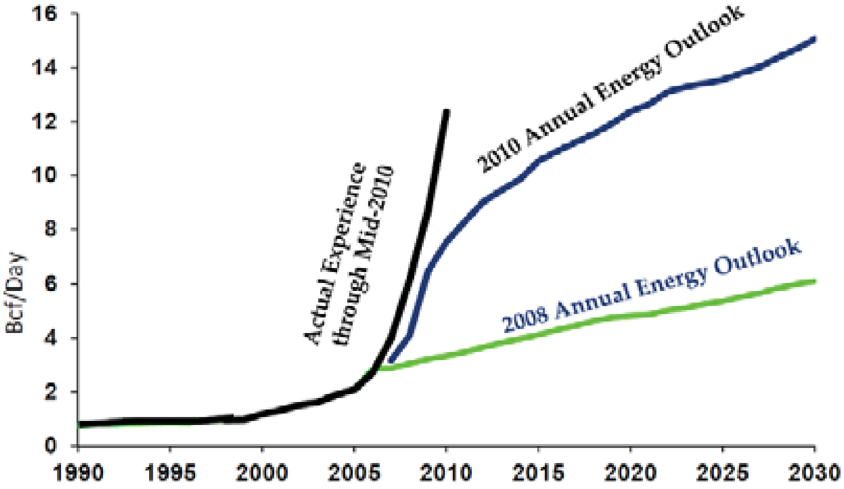


Figure 13. Map illustrating population-count mechanism for crushed-stone facilities.
Also showing Potter County and relevant surrounding counties; Bell County and surrounding counties; Harris County count with no NSSGA facility does not include surrounding counties.



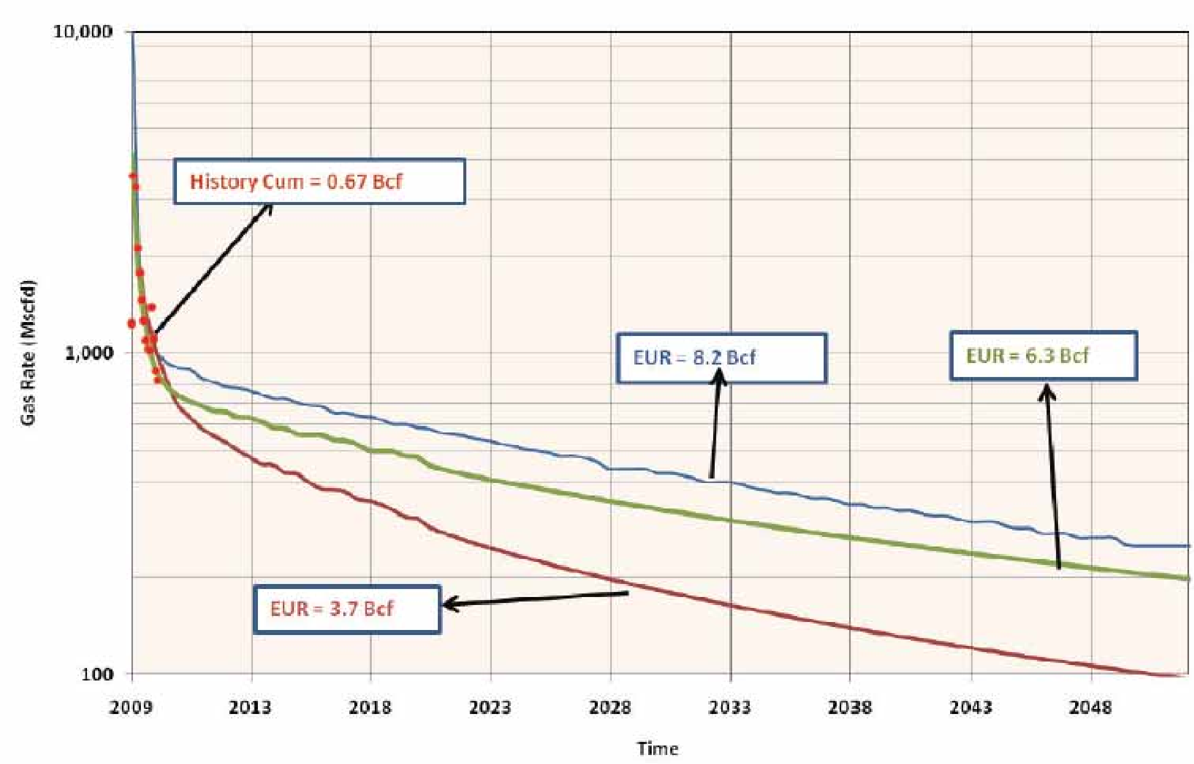
Source: Schanz (1977) and EIA website (gas consumption)
Note: figure superimposes plot from Schanz (1977) showing actual data until 1974 and projections done in 1970, 1972, and 1974 and actual data (red line) until 2009 downloaded from EIA website.

Figure 14. Making long-term projections is an art—part 1



Source: presentation by R. Smead, Navigant
http://www.naseo.org/events/winterfuels/2010/Rick%20Smead%20Presentation.pdf

Figure 15. Making long-term projections is an art— part 2



Source: modified from Vassilellis et al. (2010, Fig. 4)

Figure 16. Multiple EUR projections extrapolated from limited early data for an Eagle Ford well

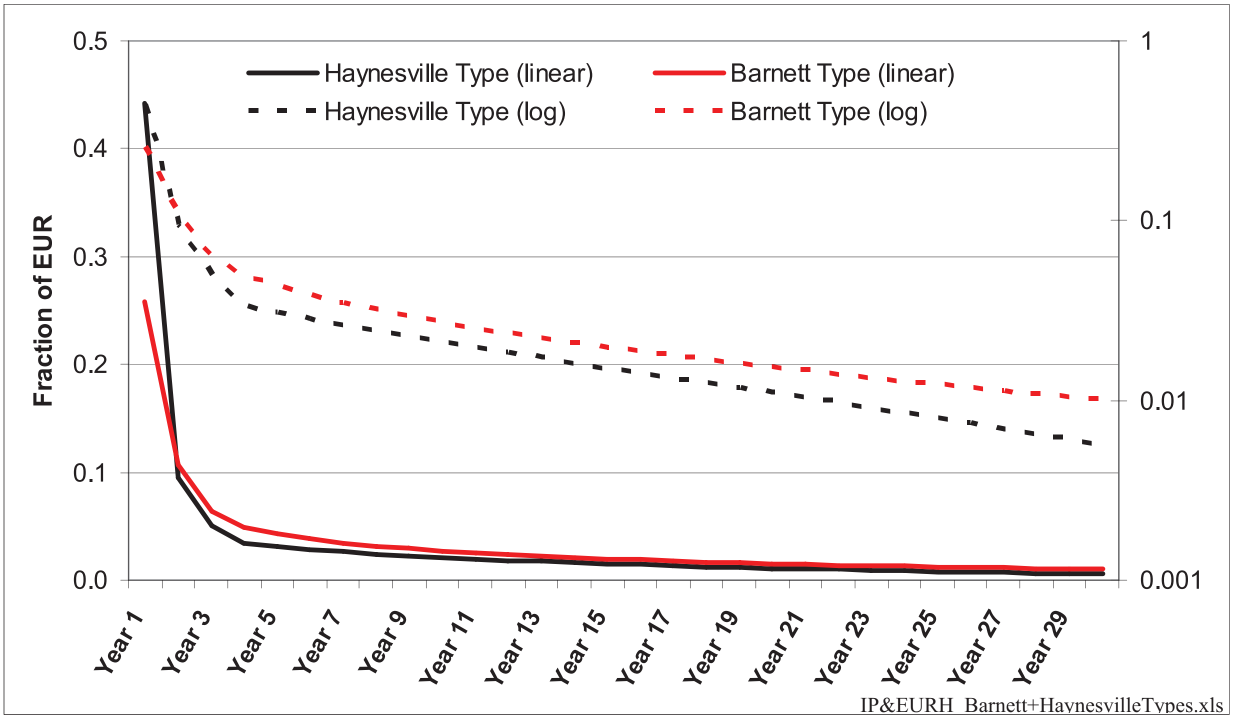
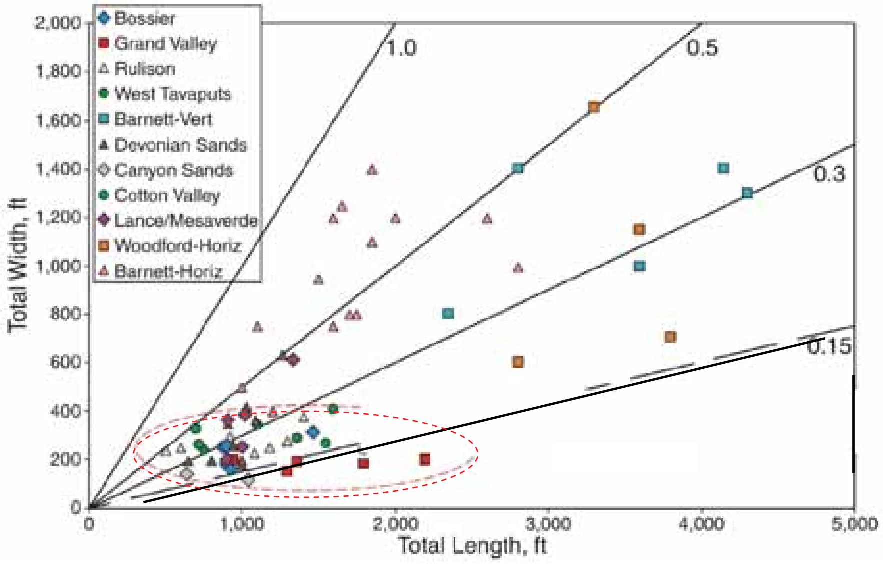
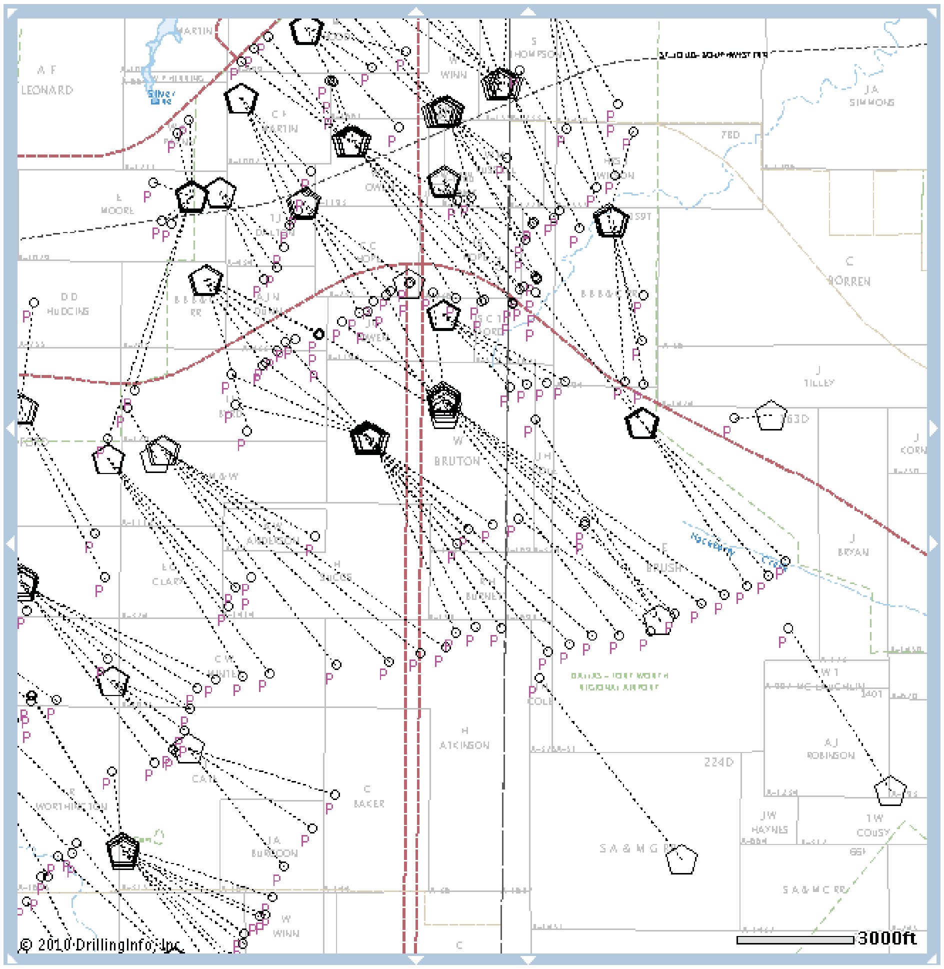


Figure 17. Decline curves assumed in this study (production-based approach)



Source: Chong et al. (2010) modified from Cipolla et al. (2008)

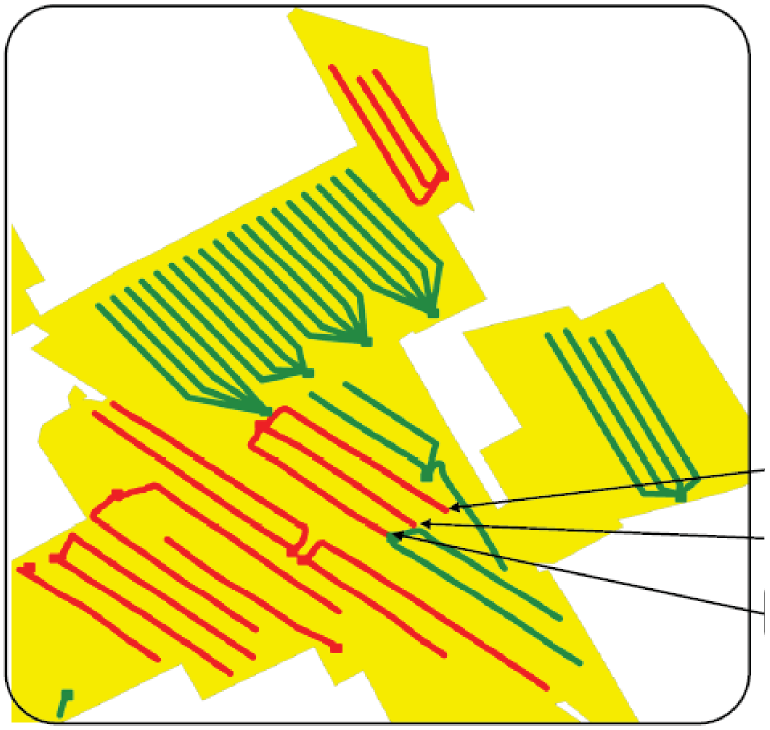
Figure 18. Lateral length vs. estimated impacted width.



Note: map displays an average drainage area of ~80 acres / well (laterals not pads) where laterals are dense.

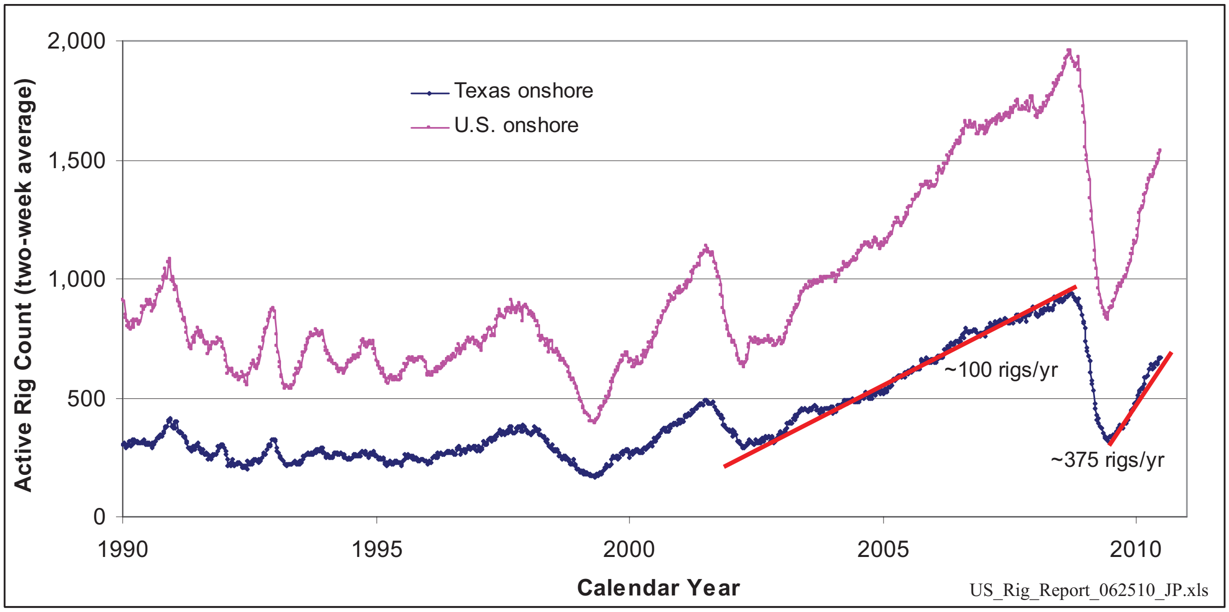
Source Courtesy of DrillingInfo

Figure 19. Example of Barnett Shale density of laterals (Dallas-Tarrant county line)



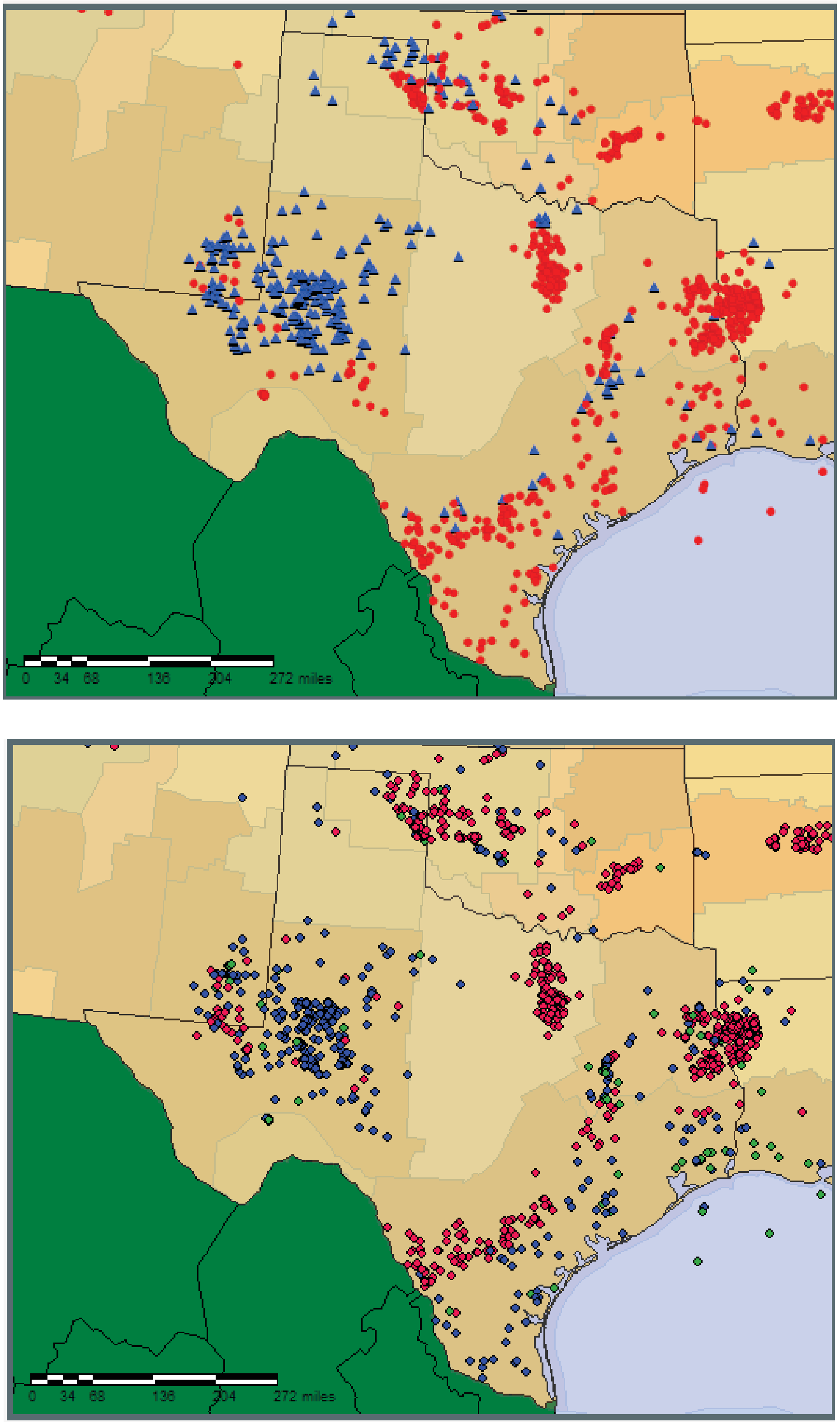
Source: Courtesy EOG Resources— Presentation to analysts, January 2008
Note: 16 completed wells (red trace) and 27 to be completed (planned in 2008)

Figure 20. Example of Barnett Shale density of laterals (Johnson County)



Source: Baker-Hughes website

Figure 21. Active rig count in the U.S. and Texas from 1990 to current



(a)

(b)

Source: Baker-Hughes website

Figure 22. Rig count as of June 25, 2010. (a) Red and blue dots denote gas and oil rigs, respectively; (b) red, blue, and green diamonds denote horizontal, vertical, and directional rigs.

4 Current Water Use

We chose the year 2008 as representative of *current use* for two reasons: (1) this work started in 2009, and not all the 2009 data were yet available, and (2) 2009 is not a representative year because of the economic slowdown; 2008 is the last year with water use more representative of what might occur in the future and is thus more appropriate as a starting point for projections.

4.1 Shales and Tight Sands

The literature on gas shales and related water use is abundant (for example, Arthur et al., 2009; U.S. DOE, 2009) and will not be reprised herein. Several reports also detail current practices in well-pad construction, drilling, completion, and well stimulation for fraced wells. (Veil, 2007; U.S. DOE, 2009; Veil, 2010).

4.1.1 Location and Extent

Section 4.1 provides an overview of the different shale and tight-sand plays in Texas. Present in all corners of the state (Figure 23, Figure 24), they include the Barnett Shale, Haynesville and Bossier Shales, Eagle Ford Shale, Barnett Shale in West Texas, and Woodford Shale, as well as liquid-rich plays such as the Granite Wash in the Anadarko Basin and the Wolfberry in the Permian Basin, the Bossier, Travis Peak and Cotton Valley Tight Sands in East Texas, and multiple formations in South Texas. U.S. DOE published a primer (U.S. DOE, 2009) summarizing the state of knowledge on fracing of gas shales and other tight formations. Good general background can also be found in PGC (2009, p. 179–192). They exist in all major basins of the state (Figure 26).

In terms of approximate numbers, as given by the scoping analysis of the 2005–2009 period, number of frac jobs was >2,500, >4,500, >6,200, >6,600, and >3,700, respectively, from 2005 through 2009, for a total of >23,500 frac jobs (2009 might be incomplete, data downloaded in April 2010). The ">" is used because a nonnegligible fraction of frac jobs is described as such but with no corresponding water-use amount in the IHS database, although it does show proppant use or long laterals, etc. These "zero" water-use wells are assigned water-use amounts as described in the methodology section. In this 5-year period, ~100 formations were fraced (Table 6), but the bulk of the frac jobs are limited to a few formations (Figure 25). In 2005, the Barnett Shale had the larger number of frac jobs (~42%), followed by the Cotton Valley of East Texas (~23%; ~27% if Travis Peak is added), Granite Wash (Anadarko Basin) at ~13%, and Wolfberry in the Permian Basin at 7%. In 2006, the order had not changed: Barnett (~57%), Cotton Valley and some Travis Peak (16%), Granite Wash (~10%), and Wolfberry (~6%). In 2007, the Barnett Shale was still dominant (~62%), but followed by Granite Wash (14%), Cotton Valley and Travis Peak (15%), and then Wolfberry (5%). In 2008, the Barnett Shale still led (~40%), but Wolfberry collected ~15%, followed by Cotton Valley and Travis Peak (~11%) and Granite Wash (~7%). In addition, there is a clear increase in geographic coverage because other plays in the Permian Basin (Grayburg, Canyon, Caballos, Clear Fork), Anadarko Basin (Cleveland), and South Texas (Vicksburg, Olmos) are starting to be fraced. The year 2009 saw an overall decrease in the number of frac jobs, but they are still led by the Barnett Shale (~41%) and Wolfberry (19%). Other previously strong plays, such as Granite Wash (6%) and Cotton Valley (~6%), lose rank as newer fraced plays such as in the Pennsylvanian and Permian of the Permian Basin keep growing in terms of the number of frac jobs. Many plays all around the state go beyond the testing stage as tens of frac jobs are performed on 10+ additional formations. Note that this ranking is done in terms of number of frac jobs, which may or may not be the same as ranking for water use.

To address the last comment and as a final check on the trends in this fast-evolving field, we performed an analysis of all wells completed in 2010 to date (early November 2010). Among a total of 10,268 completed wells, 7650 (~75%) received a treatment making use of water, including ~3850 wells (~37% of total) using >0.1 Mgal of water (Table 7 and Table 8). The minimum amount of water used is over 6 billion gallons or ~18.5 thousand AF, almost ⅔ of it in the Fort Worth Basin Barnett Shale.

4.1.2 Gas (and Oil) Shales

This report does not comprehensively document the different formations described in this section, but rather focuses on water use and mostly provides information needed to access it and make projections. Water use is different in each play and is impacted by local geological factors. There are three very active "shale gas" (oil is also produced) plays as of end of 2010 in Texas: Barnett, Haynesville/Bossier, and Eagle Ford shales. To them can be added the Pearsall Shale, Barnett and Woodford Shales in the Permian Basin, and perhaps the Bend Shale in the Palo Duro Basin in the Texas Panhandle. A map by EIA (Figure 23a) does display them all but with inaccurate footprints.

4.1.2.1 Barnett Shale

The Barnett Shale (Figure 28) is the formation where the current technology was pioneered, and it has been producing gas since the early 1990s. Productive Barnett Shale is found at depths between 6,500 and 8,500 ft in North-Central Texas, with a net thickness ranging from 100 to 600 ft. Pollastro et al. (2007) and Galusky (2009) provided an update to information presented in Nicot and Potter (2007), whereas Martineau (2007) summarized the history of the play. The Mitchell Energy / C. W. Slay #1, a vertical well, went into production in June 1982, has produced over 1.7 Bcf of gas, and is still producing after 28+ years. It is given credit as the first Barnett Shale producer (PBSN, Nov 1, 2010). As slick-water-frac and horizontal-drilling technologies were being perfected, the balance of wells initially favoring vertical wells is now disproportionally in favor of horizontal wells (Figure 27), with >2500 horizontal wells and only 100+ vertical wells completed in 2008. Figure 29 illustrates the transition and its impact on water use. There is a clear jump in the average water use in 1998 for both horizontal and vertical wells to ~1.5 million gallons/well. The amount of water used then stays more or less constant through time for vertical wells but with a much larger variance, whereas it keeps increasing for horizontal wells until it reaches a current average of 3–4 million gal/well. Progress in the technology is also visible on the histograms of the frac water volume, with a clear bimodal distribution (Figure 30a). The most recent vertical fracs (Figure 30c) display a well-behaved normal distribution centered on ~1.3 million gal/well. A histogram of horizontal well-water use, depicted in Figure 31a, also shows a well-behaved distribution, but with a broad mode and a very large range (from <1 million to >8 million gal/well). However, when reported to the total lateral length (Figure 31b), water intensity seems normally distributed, with a mean/mode of ~1000 gal/ft. Proppant amount distribution is biased toward lower values, with a long tail toward high proppant amount (Figure 32a and Figure 33a). The observation remains true in a plot of proppant loading (Figure 32b and Figure 33b).

Core counties consist of Denton, Johnson, Tarrant, and Wise Counties. Production has been relatively stable in the past 2 years at ~5 million Mcf/d (PBSN, Nov 1, 2010) although the so-called “combo” play in Montague and Clay Counties in the oil window has seen a recent increase in activity. Other counties (Stephens, Shackelford) south of the core area and in the oil window also seem to stir some interest. Other counties producing from the Barnett are Archer, Bosque, Comanche, Cooke, Coryell , Dallas, Eastland , Ellis, Erath, Hamilton, Hill, Hood, Jack , Palo Pinto, Parker, and Somervell Counties. In 2008, water use in the Barnett Shale was ~25 thousand AF (Table 9). Table 9 also presents completion water use at the county level, with Johnson County displaying the highest water use at ~8.5 thousand AF, followed by Tarrant County at 5.1 thousand AF, and Denton, Wise, and Parker Counties at 2.8, 2.1., and 1.8 thousand AF, respectively.

4.1.2.2 Haynesville and Bossier Shales

The productive interval of the Haynesville Shale of Jurassic age is >10,000 ft deep. It is an organic-rich, argillaceous, silty, calcareous mudstone that was deposited in a restricted, intrashelf basin in relatively shallow water (for example, Spain and Anderson, 2010). The current core area (Texas section) includes Harrison, Panola, Shelby, and San Augustine Counties, but the play also covers Angelina, Gregg, Marion, Nacogdoches, Rusk, and Sabine Counties (Figure 34). Typical thickness of the Haynesville Shale ranges between 300 and 400 ft in western Louisiana and 200 and 300 ft in Texas, at burial depths between 11,000 and 14,000 ft. Further west, the shale transitions to the so-called Haynesville carbonates, which are known for their excellent production from carbonate shoals and pinnacle reefs in the East Texas Salt Basin (Hammes, 2009; Hammes et al., 2009). The Haynesville Shale is overpressured, increasing the amount of gas per unit rock relative to a normally pressured shale.

The first year with significant fracing water use was 2008 (Figure 35), before which date any frac was mostly exploratory in nature. The few vertical wells stimulated in the early years of 2000 (Figure 36) probably targeted carbonate facies. Currently the bulk of wells are horizontal, with a wide range of water use from <1 million to >10 million gal/well (Figure 37a). Water intensity (Figure 37b) is not as clearly defined as it was in the Barnett Shale because of the much smaller sample size, but it stays in the same 1000 to 1200 gal/ft range (we used 1100 gal/ft). Proppant loading is higher on average than that in the Barnett Shale (Figure 38). As of October 2010, the IHS database contained ~100 wells of which ~50 of which have water-use information. After we corrected for obvious typos by assessing water-use intensity (gal/ft) and proppant loading (lb/gal), the total reported water use to date is ~260 million gal. Assigning reasonable water-use values to wells with missing data (through knowledge of proppant amount and/or lateral length), total water use to date (2008 to ~mid-2010) is ~0.5 billion gal or 1.5 thousand AF, 7% of which (0.1 thousand AF) was used in 2008, 50% (0.75 thousand AF) in 2009, and 43% (0.65 thousand AF) during the first ~8 months of 2010.

Groundwater–surface water split is unclear in Texas. However, Louisiana parishes bordering the Texas state line, where gas production started, are also part of the Haynesville core. Initially frac jobs relied heavily on the local groundwater resources of the Carrizo-Wilcox aquifer (Hanson, 2009) but, thanks to a grass-root effort, the bulk of the water use has shifted to surface water (Gary Hanson, LSU Shreveport, personal communication, 2010).

The Bossier Shale directly overlies the Haynesville Shale and represents distal parts of the overlying Cotton Valley siliciclastic wedge. The upper Bossier Shale, dominated by siliciclastics, is not as overpressured, is less organic rich, and contains less TOC than the Haynesville Shale (Hammes, 2009; Hammes and Carr, 2009). The RRC webpage describing the Haynesville combines Haynesville and Bossier, owing to a terminology issue.

4.1.2.3 Eagle Ford Shale

The Eagle Ford Formation of Late Cretaceous age covers a large section of South Texas all the way to East Texas, where it meets the deltaic deposits of the Woodbine Formation of equivalent age, as depicted in the schematic cross section of Figure 39. It lies below the Austin Chalk and is probably the source of its hydrocarbon accumulation. Located at a depth of 4,000–11,000 ft, the play is slightly overpressured (pressure gradient of 0.43 to 0.65 psi/ft; Vassilellis et al., 2010), making it more attractive because of the higher initial production rates. Most current interest is focused on the South Texas section of the Eagle Ford (Figure 40 and Figure 41). The discovery well was drilled by Petrohawk in 2008 in La Salle County (PBSN, Sept 20, 2010). The formation produces natural gas, condensate, and oil. Earlier wells were vertical, located in Central Texas (Brazos, Burleson Counties), and looking for oil. The Central Texas play is somewhat disconnected from the South Texas play (from the Mexican border to Gonzales and DeWitt Counties) by the San Marcos Arch, a constant higher-elevation structural feature (Figure 39). The Eagle Ford Shale contains oil updip, gas downdip, and gas and condensates in between. The "shale" is carbonate rich, up to 70% calcite (Cusack et al., 2010, p. 171), much higher than that of the Barnett Shale, which makes it more prone to fracing. The play is still too young to determine the location of the core area, if it exists, but most of the fracing has taken place in Dimmit, LaSalle, and Webb Counties.

As of October 2010, the IHS database contained ~270 wells, 174 of which have water-use information (Figure 42), almost all of them horizontal (Figure 43). The average frac water amount is higher than either the Barnett or Haynesville (Figure 44a), ranging from ~1 to >13 million gal/well. A histogram of water intensity shows that this shale is not as well behaved as the two previous shales (Figure 44b). We used an average of 1250 gal/ft. Total proppant amount being correlated to total water use is higher than in the Barnett and Haynesville (Figure 45a), but the proppant loading lies in between (Figure 45b). After correcting for obvious typos by assessing water-use intensity (gal/ft) and proppant loading (lb/gal), we found the total reported water use to date to be ~977 million gal. Assigning reasonable water-use values to wells with missing data (through knowledge of proppant amount and/or lateral length), we found total water use to date (~mid-2008 to ~mid-2010) to be 1.43 billion gal, or 4.4 thousand AF, 3% of which was used in 2008 (0.13 thousand AF), 37% (1.6 thousand AF) in 2009, and 60% (2.6 thousand AF) during the first ~8 months of 2010.

4.1.2.4 Woodford, Pearsall, Bend, and Barnett-PB Shales

The extent of the Woodford Formation of Devonian age is shown in Figure 46. It covers most of the Permian Basin and a small area of what would become the Central Basin Platform. It can be as thick as 600 ft in Loving and Winkler Counties but radially decreases to <100 ft outward to subcrop boundaries. In the Delaware Basin depth can reach 15,000 ft, whereas shale is ~7,000 to 9,000 ft deep in the Midland Basin. The main current target in the Anadarko Basin in Oklahoma is also shown, where the formation is called the Caney Shale. The Woodford Shale is stratigraphically equivalent to several Devonian black shales in North America, including the Antrim Shale in the Michigan Basin and the Bakken Formation in the Williston Basin (Comer, 1991, p. 6). Overall, maturity of the Woodford in the Permian Basin seems low and unpromising.

The Permian Basin Barnett seems more clay rich and not as organic rich as in the Fort Worth Basin. Figure 47 displays occurrences of the Barnett Shale in the Permian Basin. Its well-known occurrence in the Fort Worth Basin is also displayed. Kinley et al. (2008) provided a description of its most promising occurrences in the Delaware Basin. Thickness of Mississippian-age sediments in the Permian Basin is larger and can be >2000 ft in what would become the Delaware Basin and has a maximum of 700 ft in the Midland Basin.

The Pearsall Shale (Loucks, 2002; Hackley et al., 2009a) is overpressured (Wang and Gale, 2009, p.785–786; Vassilellis et al., 2010) with a pressure gradient of 0.80 to 0.89 psi/ft and is located at depths between 7,000 and 12,000 ft. Water use has been small, given the limited number of wells drilled so far.

Figure 48 displays the surge in drilling starting in 2006 and subsiding in 2009 in those 3 West Texas plays (13 in the Woodford, 12 in the Pearsall, and 22 in the Barnett-PB), with a mix of vertical and horizontal wells (Figure 49). Overall frac water use per well remains small (Figure 50) at <2 million gal per well, probably because the plays have not seen much activity in the past 2 years. Woodford, Pearsall, and Barnett-PB shales total 11.3, 44.2, and 37.8 million gal, respectively, that is, 0.035, 0.14, and 0.12 thousand AF, respectively.

The Bend Shale in the Palo Duro Basin does not seem to live up to earlier expectations, although older BEG and other reports (Dutton, 1980; Dutton et al., 1982; Brister et al., 2002; Jarvie, 2009) have credited the basin with some oil and gas generation potential. There is a scarcity of information on this shale that was described early on as a good prospect. The Palo Duro's Bend Shale tests as thermally mature and reaches gross thicknesses between 500 and 1,000 ft at depths from 7,000 to 10,500 feet (Wagman, 2006). No further work is done in this study on the Bend Shale in the Palo Duro Basin.

4.1.2.5 Conclusions on Gas Shales

Completion water-use shale-gas wells was dominated (99.0%) by the Barnett Shale in 2008 at ~25.5 thousand AF used (Figure 51 and Figure 52), whereas, as detailed in the next section, all tight formations across the state amount to ~10.4 thousand AF (Table 10). In 2008, Johnson County in the Barnett Shale footprint achieved the highest water use at 8.5 thousand AF. Note that this water-use amount includes some recycling, but, as will be described in the Future Water Use section, it is likely to be at the very most 10% and more likely just a few percent. Also note that some of the water used directly originates from stormwater collection systems and is thus not considered surface water or groundwater. However, the fraction of this source among the total water used cannot be determined easily because undoubtedly many surface ponds are filled with landowner-supplied groundwater.

Table 6. List of formations currently being fraced heavily or with the potential of being fraced heavily in the future

Name	**Basin/Subbasin**	**IHS Word Search**
Gas Shales:		
Barnett	Fort Worth	Barnett, Ellenburger, Forestburg, Marble Falls, Viola
Barnett PB	Permian	Barnett
Haynesville	East Texas	Haynesville
Eagleford	GC Rio Grande	Eagleford
Pearsall	Maverick	Pearsall
Woodford-PB	Permian	Woodford
Woodford-AB	Anadarko	Woodford
Tight Gas		
Anadarko Basin		
Atoka-AB	Anadarko	Atoka, Bend, Morrow, Granite Wash, Pennsylvanian
Cleveland	Anadarko	Cleveland, Marmaton, Cherokee, Kansas, Caldwell
East Texas Basin		
James	East Texas	James
Pettet	East Texas	Pettet, Pettit, Sligo
Travis Peak	East Texas	Travis Peak, Hosston
Cotton Valley	East Texas	Cotton Valley, Austin Chalk, Taylor, Gilmer, Schuler, Buckner
Bossier	East Texas	Bossier
Smackover	East Texas	Smackover
Fort Worth Basin		
Atoka-FWB	Fort Worth	Atoka, Bend, Morrow, Granite Wash, Pennsylvanian
Permian Basin		
San Andres	Midland+CBP	San Andres, Grayburg (Glorieta, Abo, Wichita)
Spraberry	Midland	Spraberry, Dean
Clear Fork	CBP	Clear Fork
Bone Spring	Delaware	Bone Spring
Wolfcamp	Midland	Wolfcamp
Cisco	Permian	Cisco, Canyon, Strawn, Pennsylvanian
Canyon	Permian	Cisco, Canyon, Strawn, Pennsylvanian
Strawn	Permian	Cisco, Canyon, Strawn, Pennsylvanian
Atoka-PB	Permian	Atoka, Bend, Morrow, Granite Wash
Devonian	Permian	Devonian, Thirtyone, Devonian Cherts, “Silurian”
Canyon Sands	Val Verde	Canyon, Canyon Sands
Caballos	Marathon	Caballos, Tesnus
Gulf Coast Basin		
Vicksburg	Gulf Coast	Vicksburg, Frio, Hackberry
Wilcox	Gulf Coast	Wilcox, Indio, Tucker, Lobo, Sabine Town
Olmos	Gulf Coast	Olmos, San Miguel, Navarro, Escondido

Table 7. Well statistics and water use for 2010

Category	Water Use (% of Total)	Number of Wells (% of Total)	Vertical Wells (% of Wells for Category)
Not fraced	0.0%	25.6%	
Stimulated	1.7%	34.6%	
Anadarko Basin	3.0%	2.2%	28.1%
East Texas Basin	7.8%	5.0%	44.8%
Fort Worth Basin	57.3%	13.6%	2.0%
Gulf Coast	12.3%	4.8%	33.4%
Permian Basin	17.9%	14.1%	94.1%

Table 8. Major active formations in 2010 completed well count

Category	Play/Formation	Count
Anadarko Basin	Granite Wash and others	124
	Cleveland	50
	Marmaton	18
	Others	18
	Total	**210**
Permian Basin	Delaware Group	32
	Spraberry/Dean/Wolfcamp	863
	Clear Fork	232
	Canyon Sands	48
	Caballos/Tesnus	19
	Others	168
	Total	**1362**
East Texas Basin	Cotton Valley Group	200
	Travis Peak	47
	Haynesville/Bossier Shales	115
	Cotton Valley Sands	26
	Others	99
	Total	**487**
Gulf Coast Basin	Eagle Ford	193
	Olmos	68
	Vicksburg	39
	Wilcox/Lobo	64
	Frio	20
	Others	80
	Total	**464**
Fort Worth Basin	Barnett Shale	1295
	Others	23
	Total	**1318**
Stimulated only (<0.1 Mgal)	Permian Basin	2460
	East Texas	315
	Gulf Coast	169
	Fort Worth	132
	Others	733
	Total	**3809**
Not Stimulated	Frio	482
	Wilcox	185
	Austin Chalk	140
	Others	1811**
	Total	**2712**

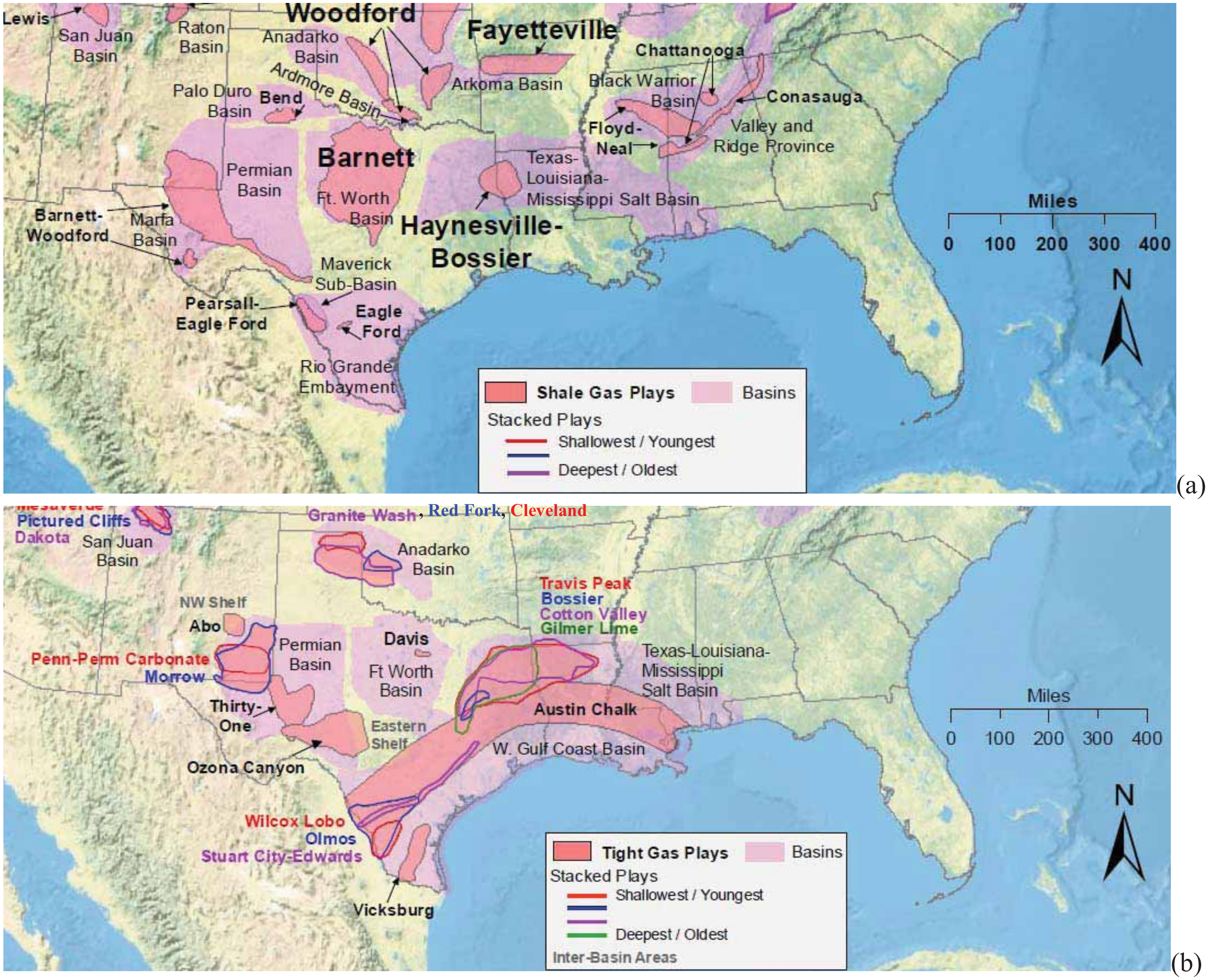
Table 9. County-level shale-gas-completion water use in the Barnett Shale (2008)

County	Water Use (thousand AF)	County	Water Use (thousand AF)
Archer	0.003	Jack	0.085
Brazos	0.008	Johnson	8.459
Burleson	0.034	La Salle	0.010
Clay	0.020	Maverick	0.007
Cooke	0.229	Montague	0.571
Culberson	0.045	Palo Pinto	0.206
Dallas	0.076	Panola	0.036
Denton	2.752	Parker	1.768
Dimmit	0.044	Reeves	0.048
Eastland	0.012	Rusk	0.011
Ellis	0.096	Somervell	0.171
Erath	0.295	Tarrant	5.147
Harrison	0.058	Webb	0.007
Hill	1.137	Wise	2.217
Hood	2.154	**Total**	**25.70**

Table 10. Summary of fracing water use

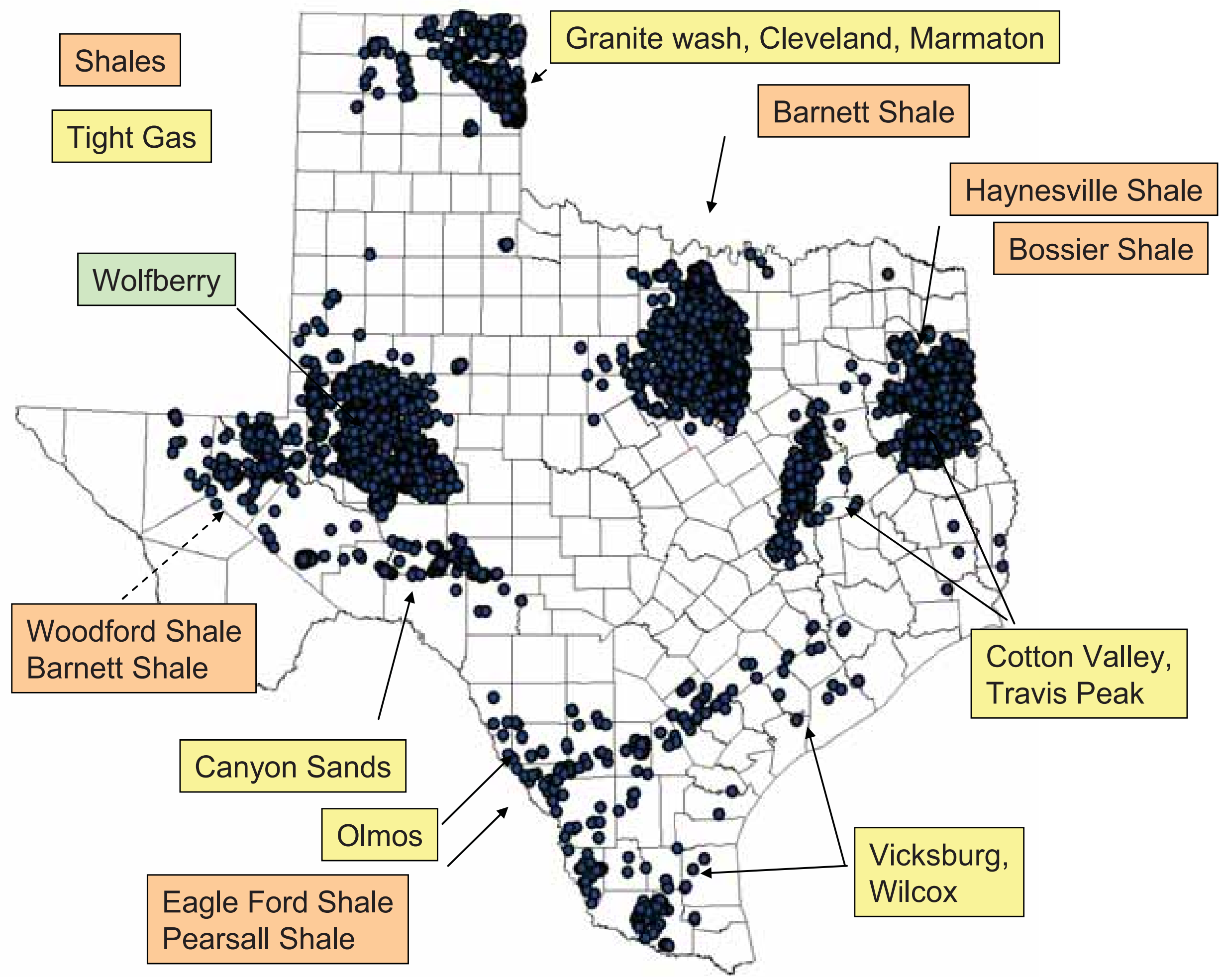
Play	Water Use (thousand AF)
Barnett Shale	25.45
Haynesville Shale	0.11
Eagle Ford Shale	0.07
Woodford/Barnett PB/Pearsall Shale	0.09
Anadarko Tight Formation	2.22
East Texas Tight Formation	4.26
Permian Basin Tight Formation	3.09
Gulf Coast Tight Formation	0.6
Caballos/Tesnus Tight Formation	0.17
Sum Shale (filtered at >0.001 Mgal)	25.71
Sum Tight Fm. (filtered at >0.001 Mgal)	10.33
Sum All (filtered at >0.001 Mgal)	36.04

MiningWaterUse2008_2.xls



Source: EIA website, updated Spring 2010

Figure 23. EIA spatial definition of shale-gas and tight-gas plays



Source: IHS database

Figure 24. Map showing locations of all frac jobs 2005–2009, and main (mostly) gas plays

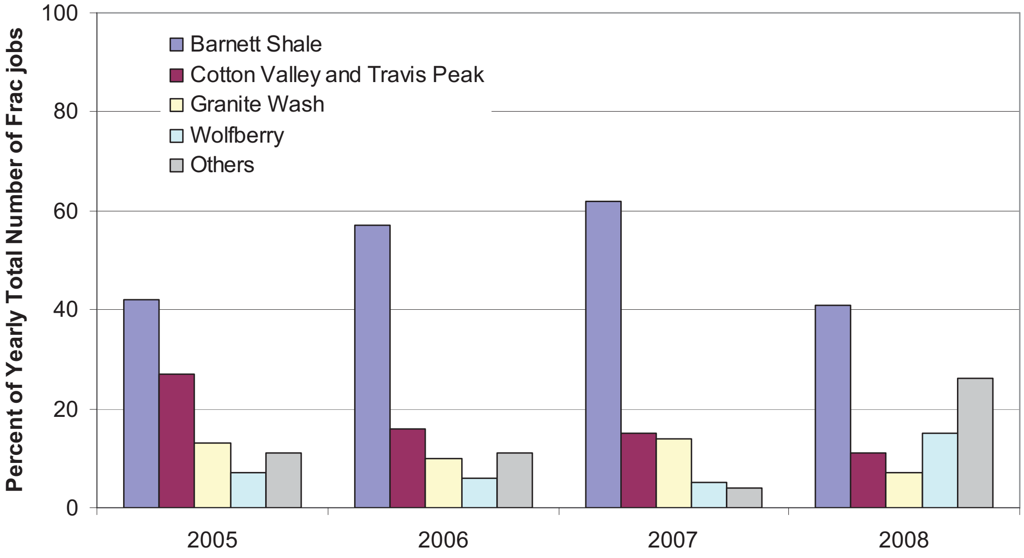
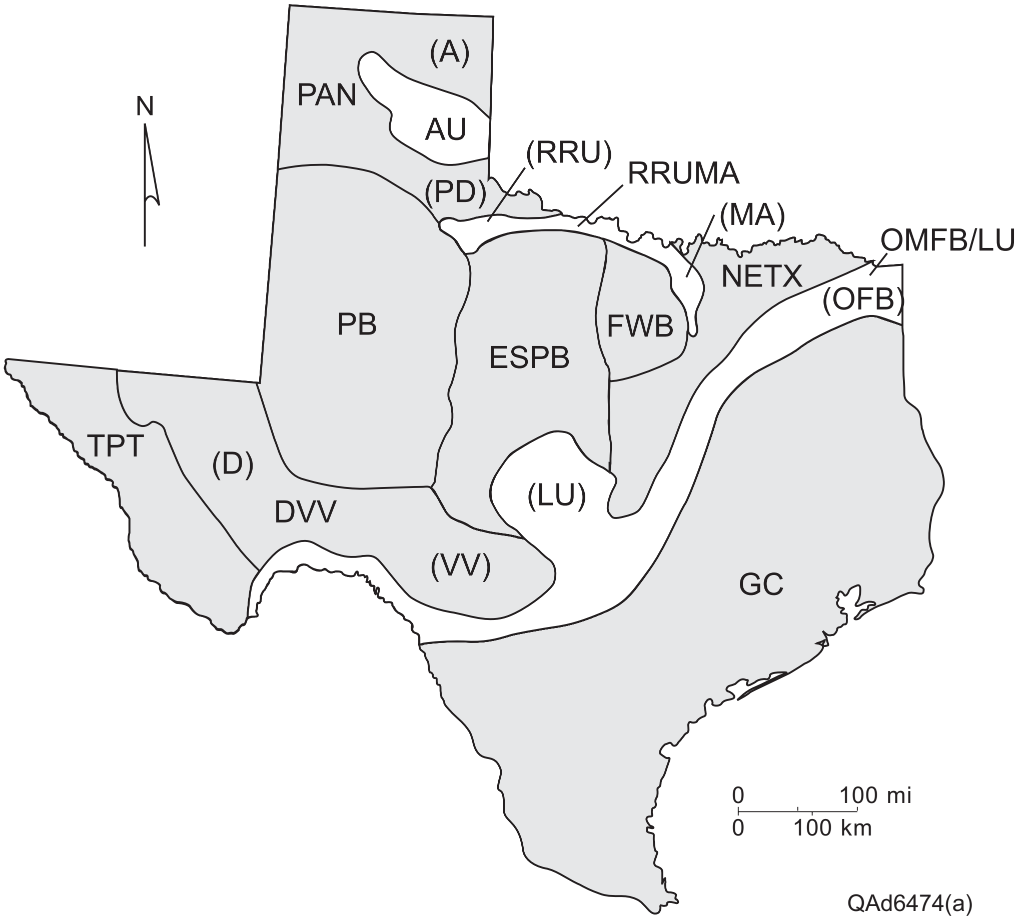


Figure 25. Percentage of frac jobs (not water use) in major plays in 2005-2008



Source: Ambrose et al. (2010)
Note: Regions are: AU Amarillo Uplift, DVV Delaware (D) and Val Verde (VV) Basins, ESPB Eastern Shelf of the Permian Basin, FWB Fort Worth Basin, GC Gulf Coast, LU Llano Uplift, NETX Northeast Texas, OFB Ouachita Foldbelt, OMFB/LU Ouachita and Marathon Foldbelts and Llano Uplift, PAN Texas Panhandle, PB Permian Basin, PD Palo Duro Basin, RRUMA Red River Uplift (RRU)-Muenster Arch (MA), TPT Trans-Pecos Texas

Figure 26. Major geologic regions (basins and uplifts) in Texas

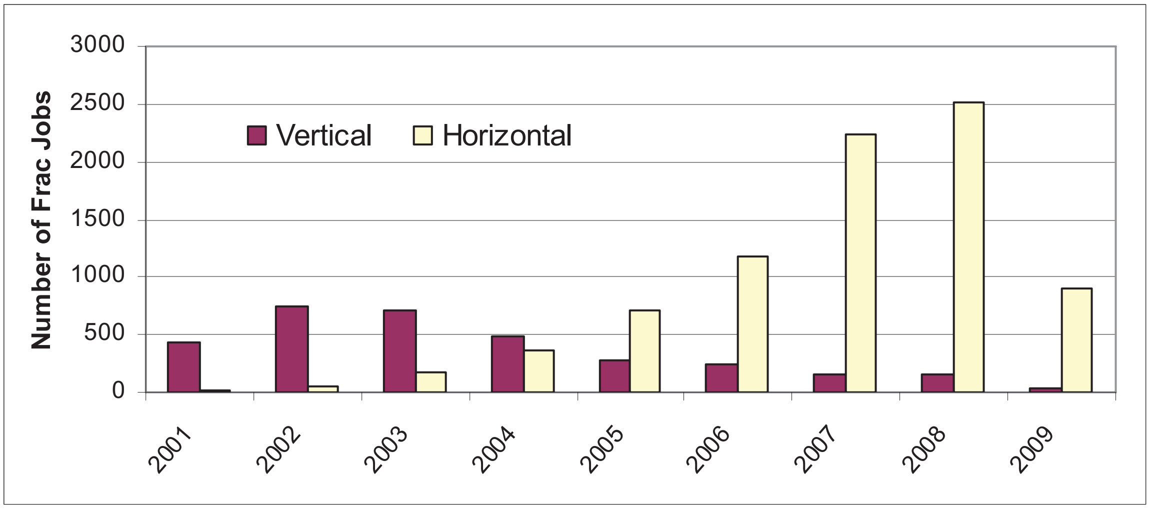
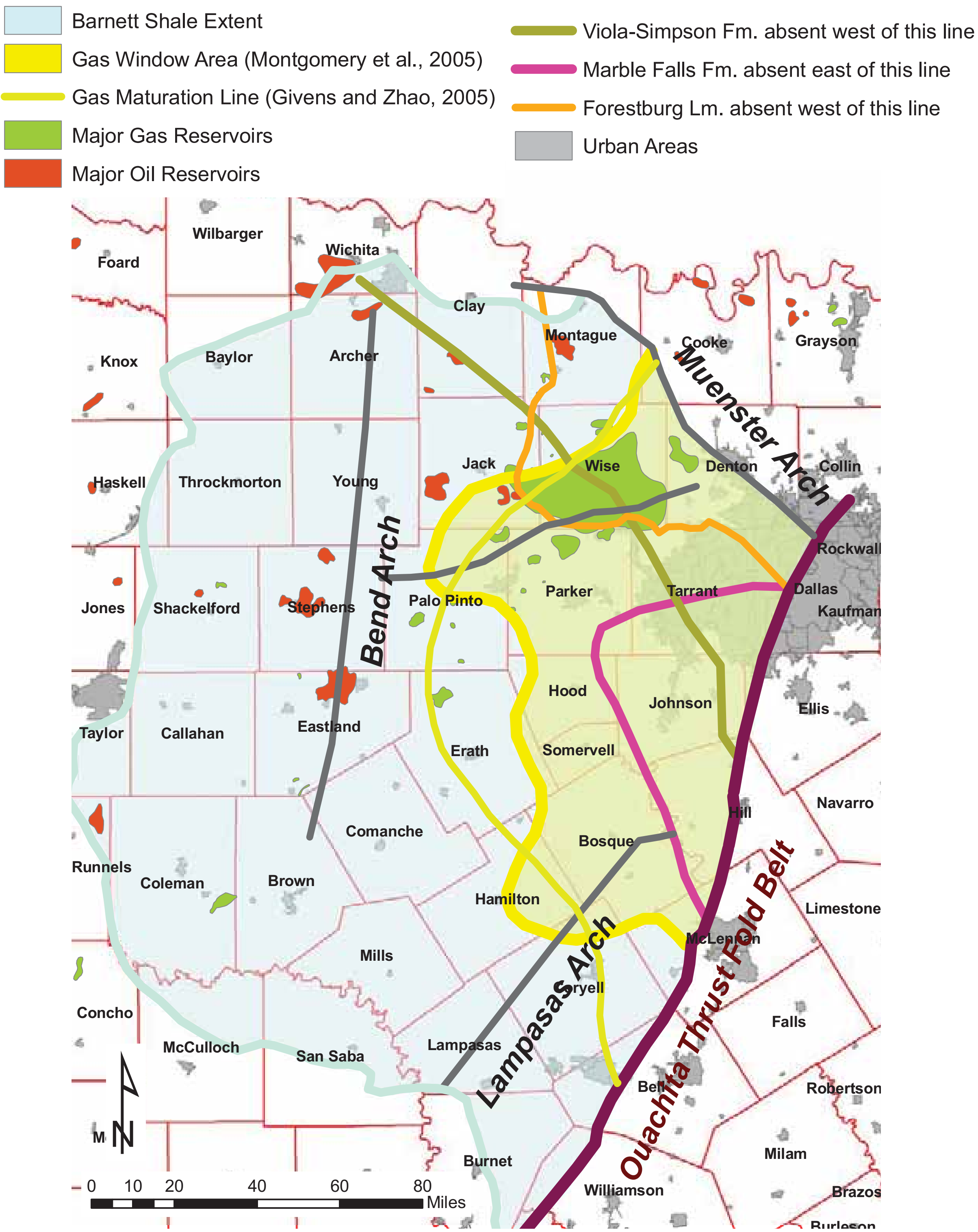
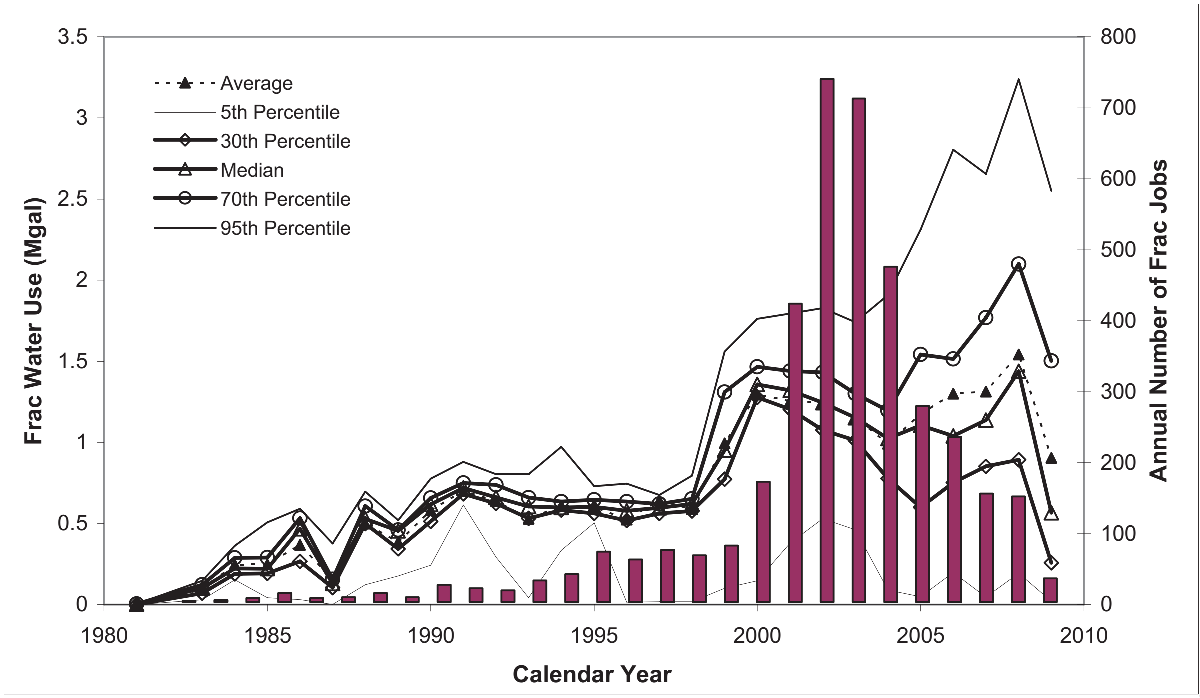


Figure 27. Barnett Shale—vertical vs. horizontal and directional wells through time

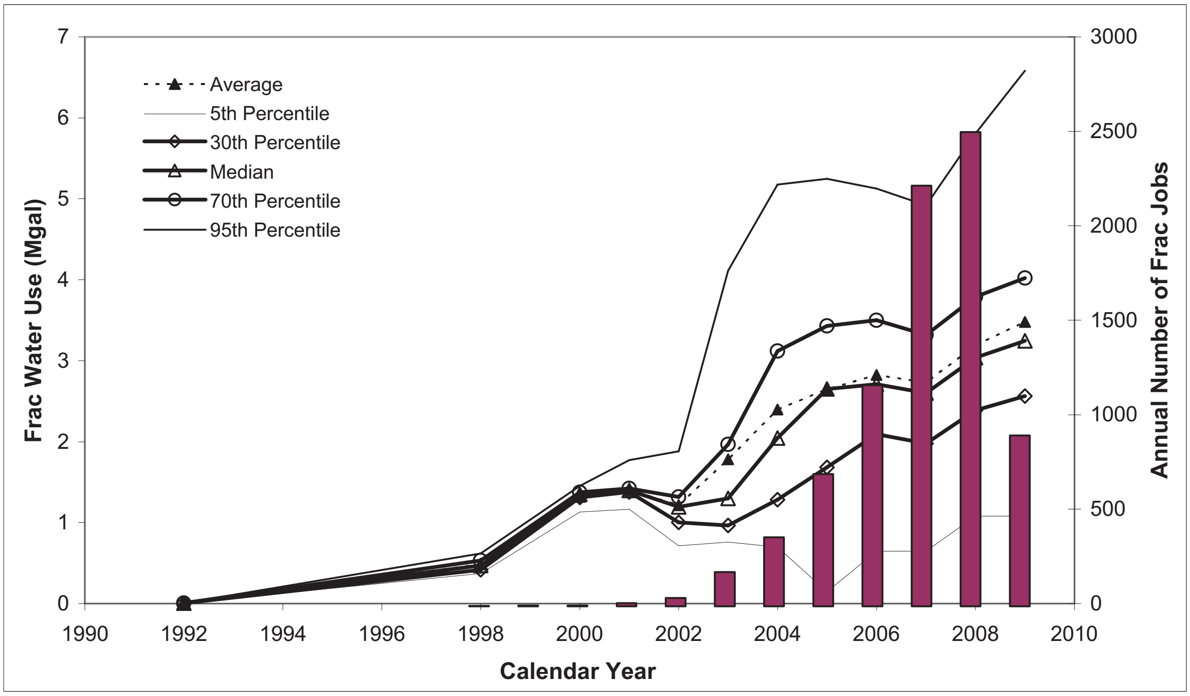


Source: Nicot and Potter (2007)
Note: Forestburg limit modified from Zhao et al. (2007); all others modified from Montgomery et al. (2005); major oil and gas reservoirs from Galloway et al. (1983) and Kosters et al. (1989). The Major Gas and Oil Reservoirs refer to non-Barnett production.

Figure 28. Barnett Shale footprint



(a)



(b)

Figure 29. Barnett Shale – Annual number of frac jobs superimposed to annual average, median, and other percentiles of individual well frac water use for (a) vertical wells, and (b) horizontal wells.

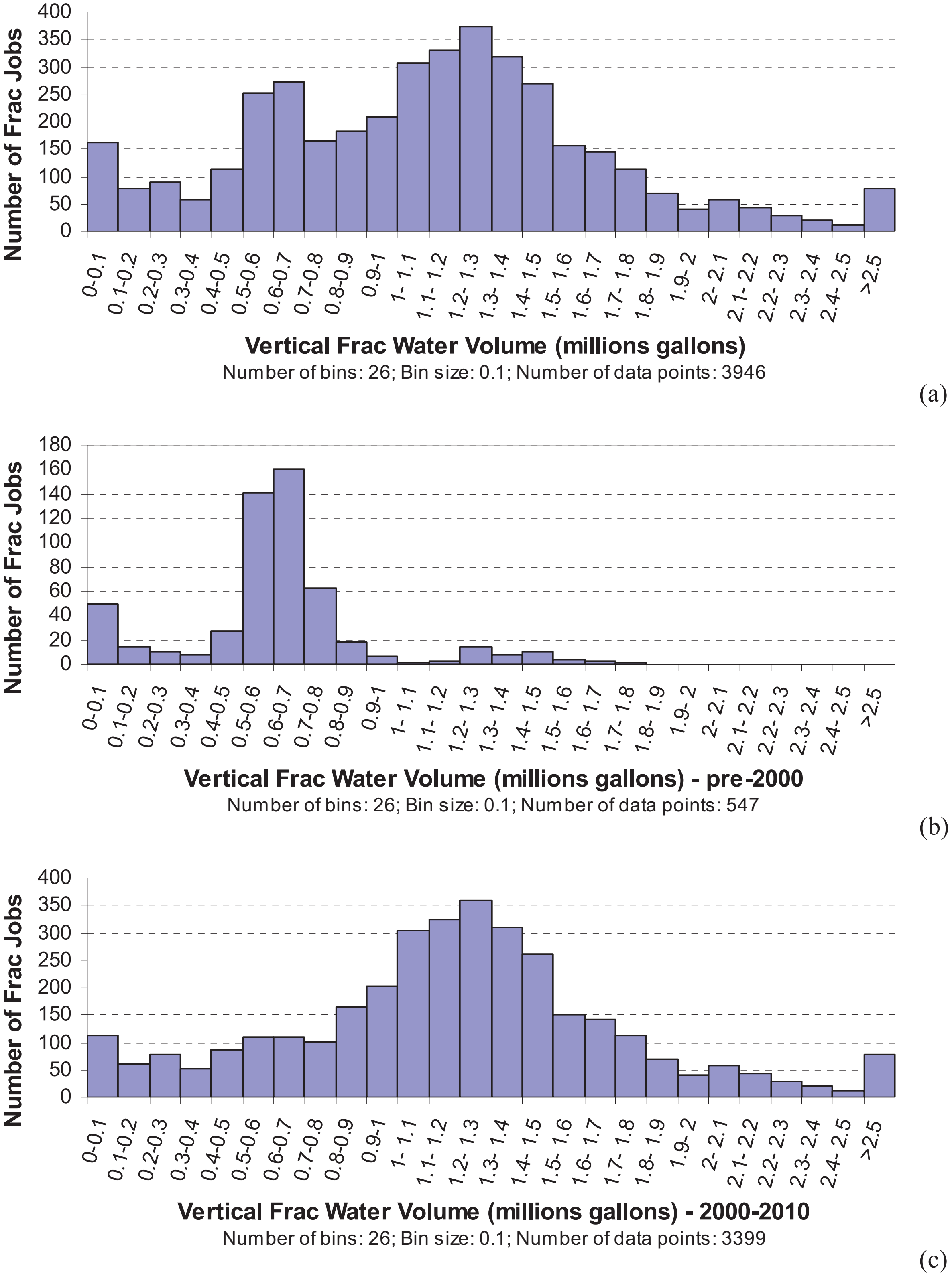


Figure 30. Barnett Shale— Histograms of frac water volume for vertical wells for (a) all wells, (b) pre-2000 wells, and (c) 2000–2010 wells

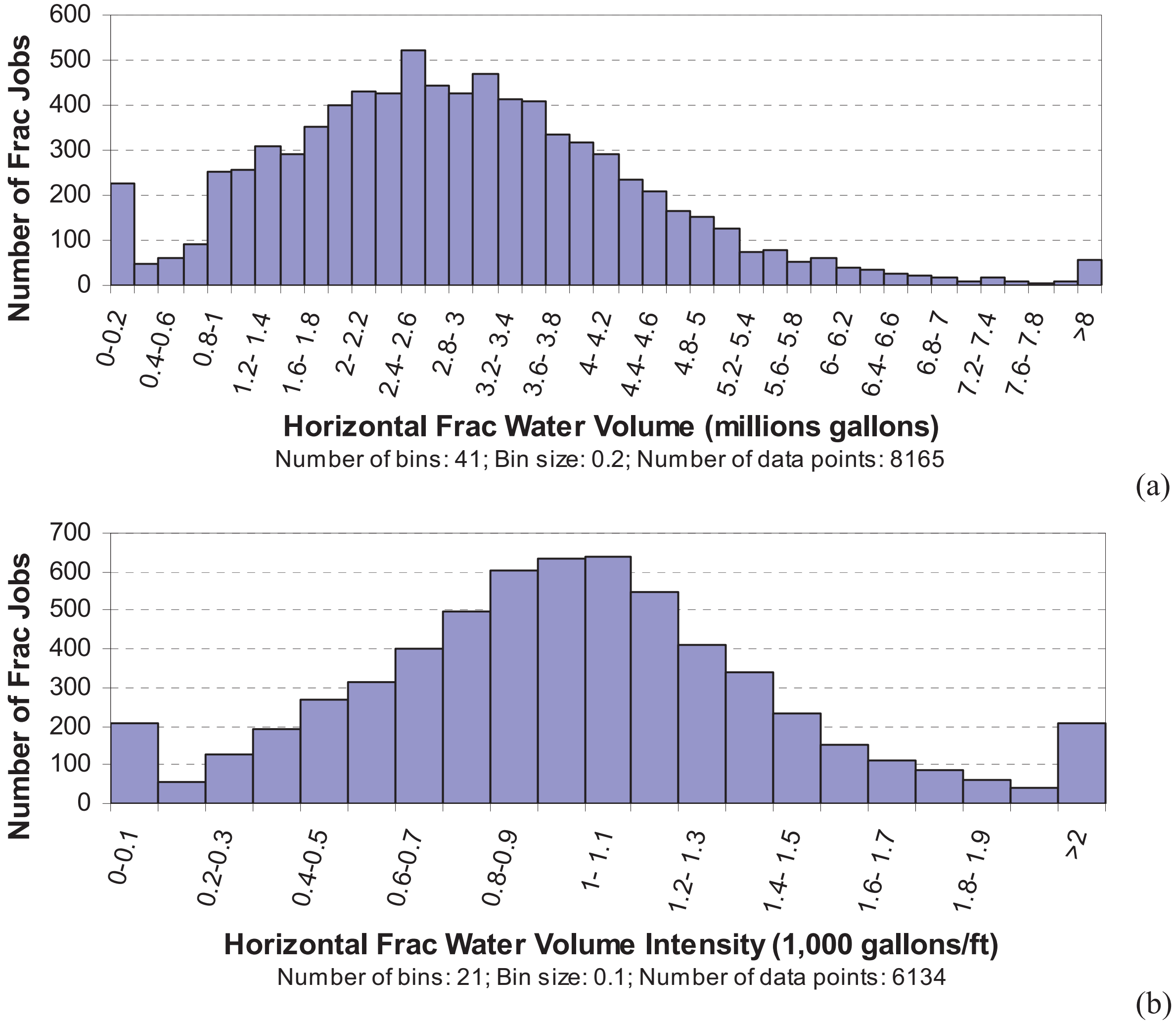
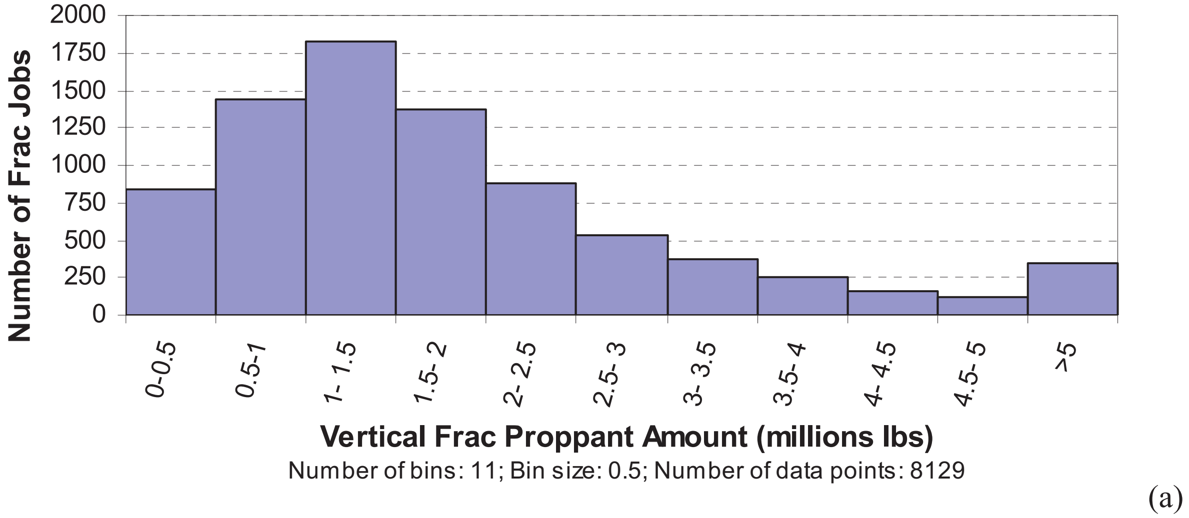
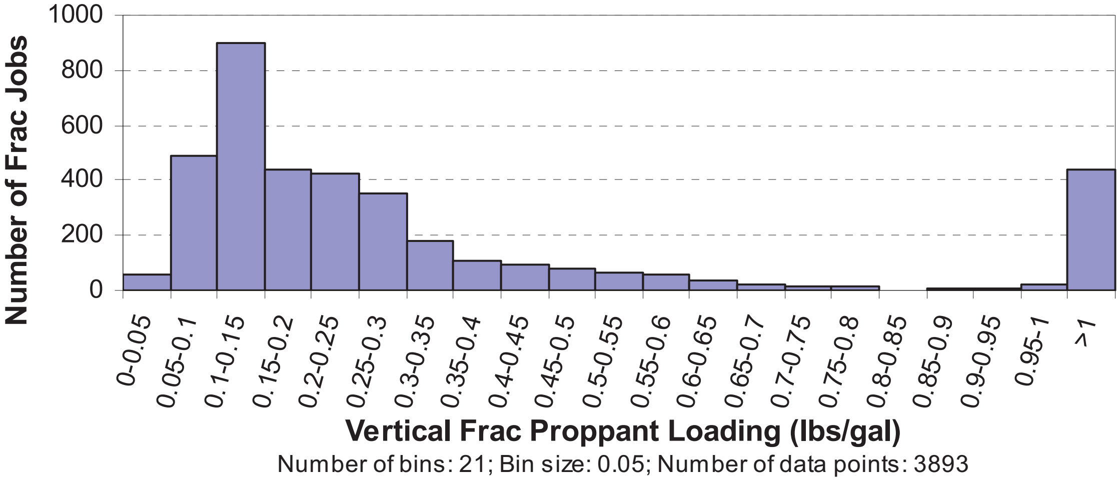


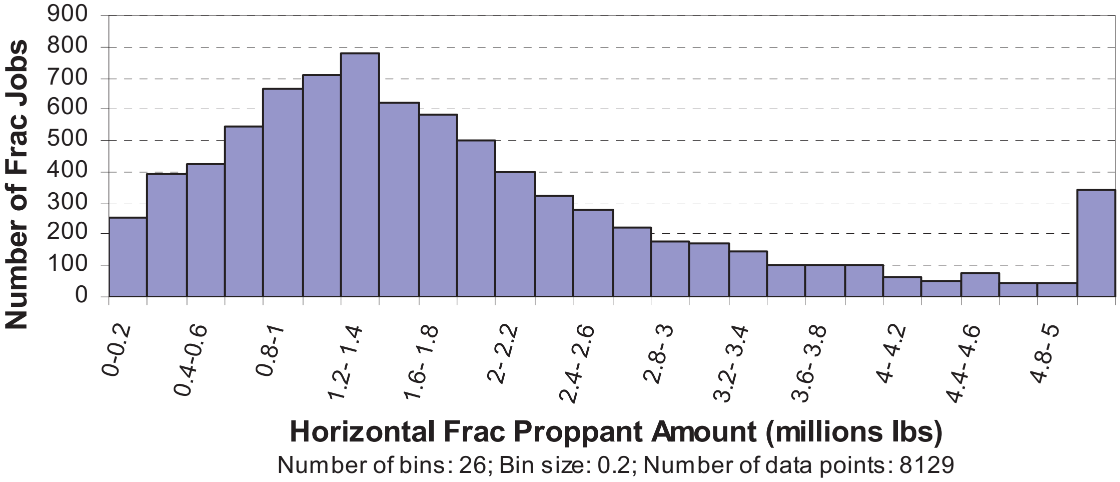
Figure 31. Barnett Shale—frac water use: (a) total volume, (b) intensity in 1,000 gal/ft



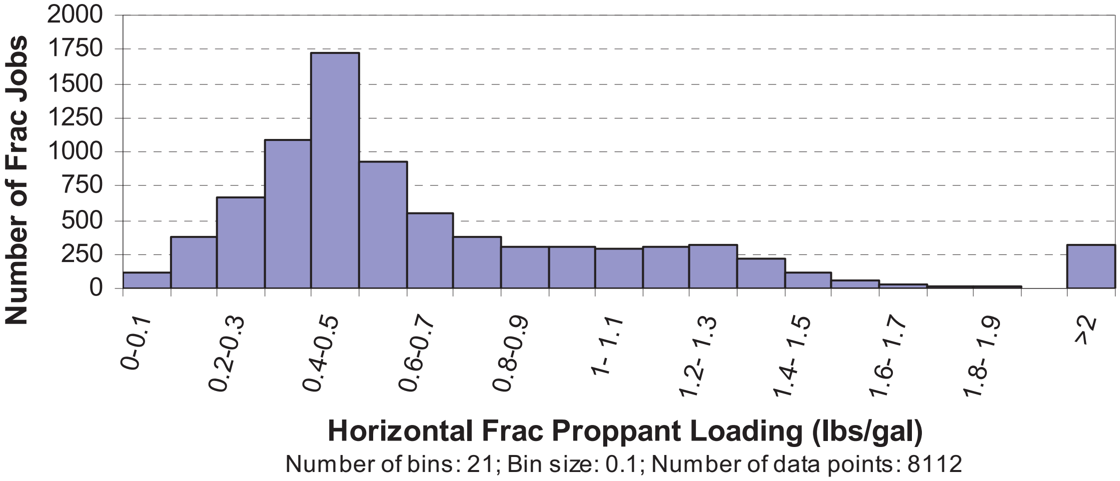


(b)

Figure 32. Barnett Shale—vertical well: (a) total proppant amount and (b) proppant loading

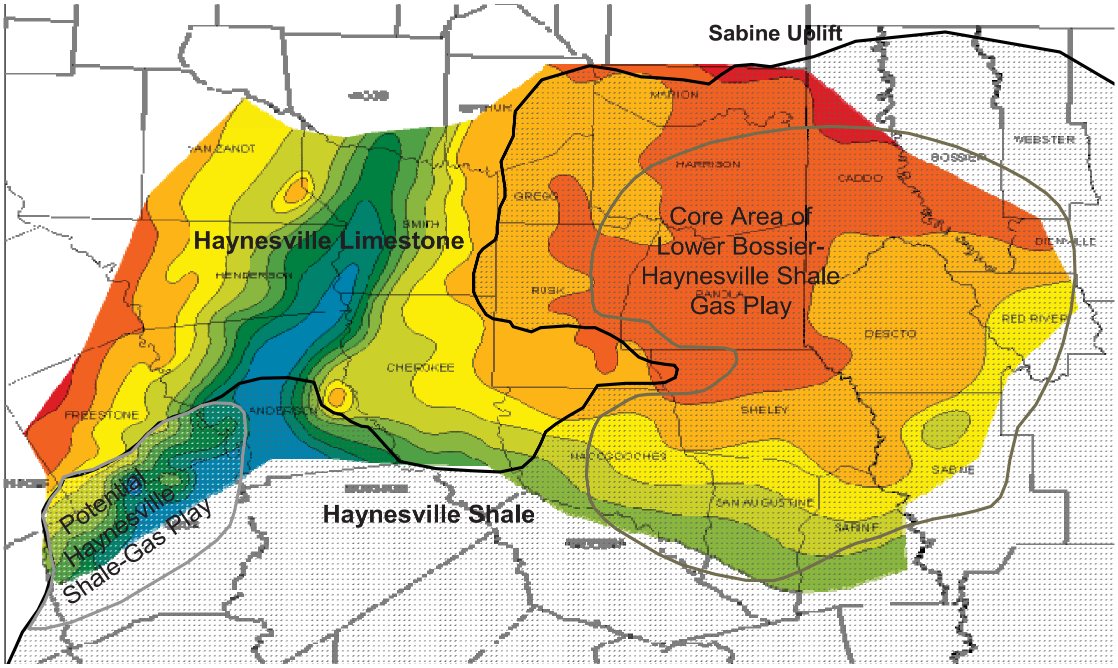


(a)



(b)

Figure 33. Barnett Shale—Horizontal well: (a) total proppant amount and (b) proppant loading



Source: courtesy Dr. Wang, BEG

Figure 34. Haynesville Shale footprint

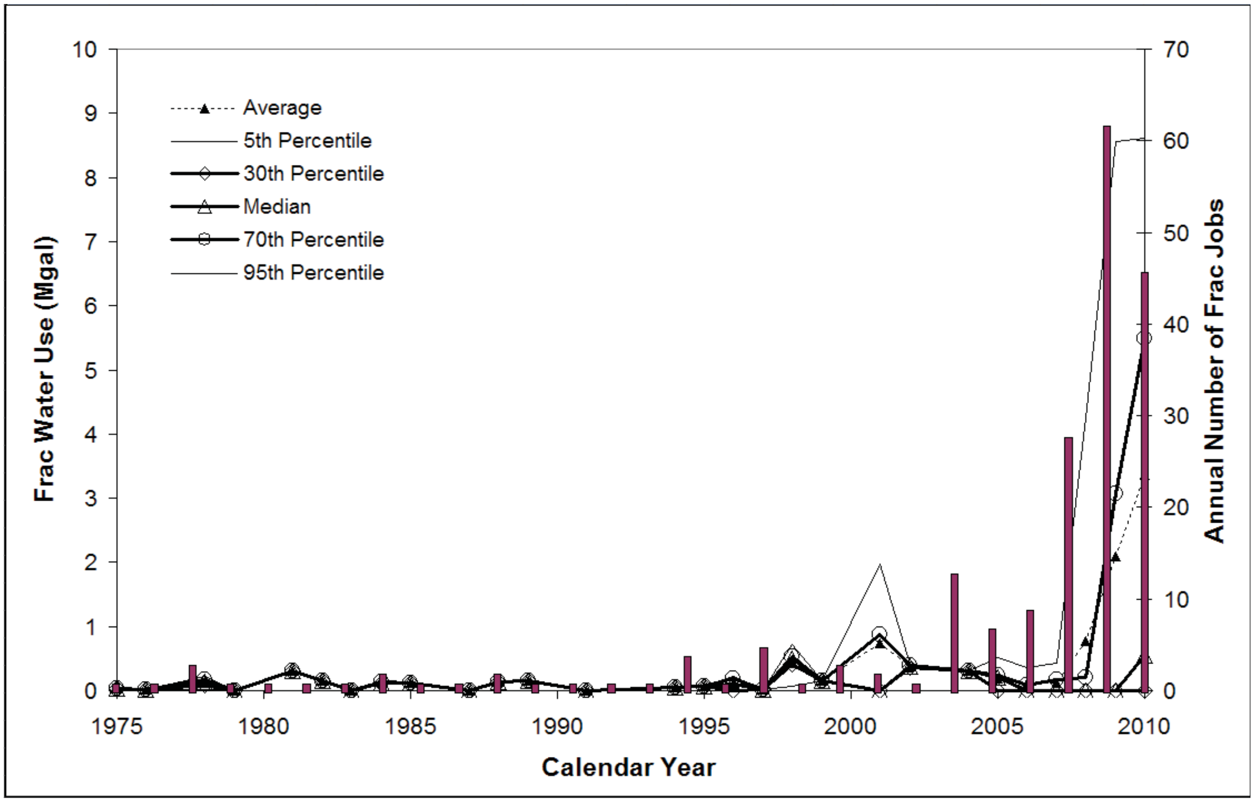


Figure 35. Haynesville Shale—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use

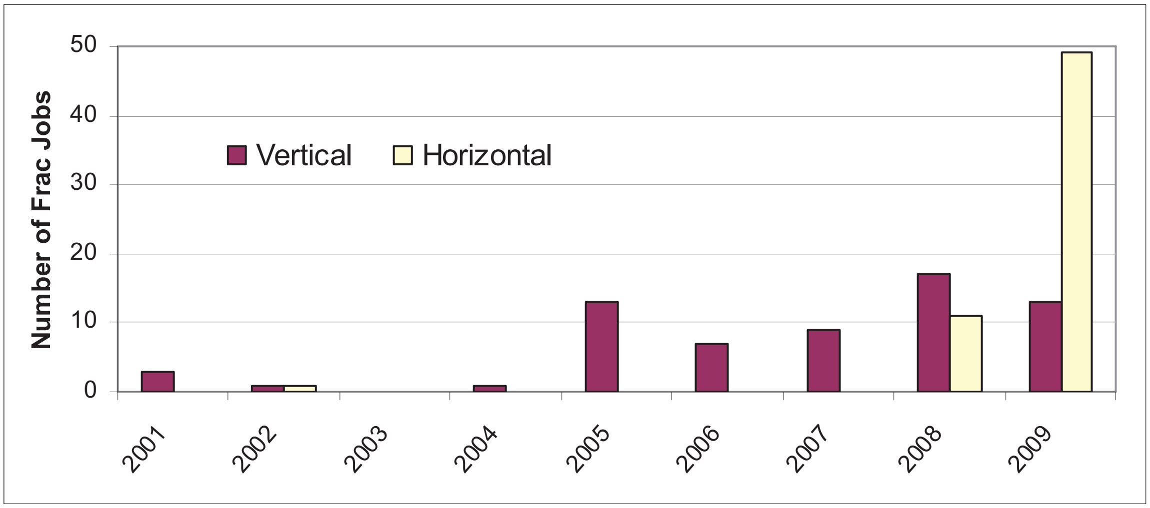


Figure 36. Haynesville Shale—vertical vs. horizontal and directional wells through time

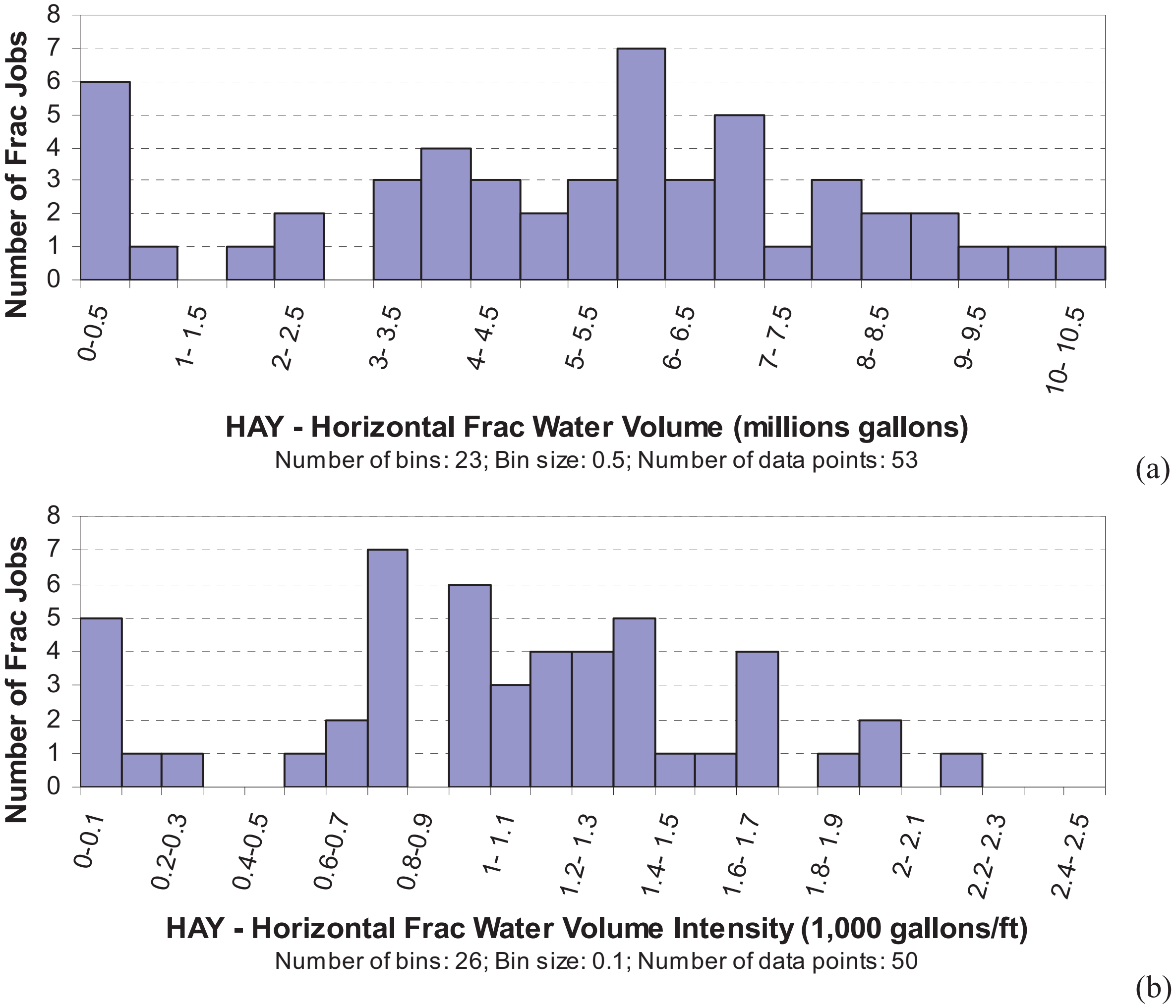


Figure 37. Haynesville—horizontal well frac water use: (a) total volume; (b) intensity in 1,000 gal/ft (2008 and beyond)

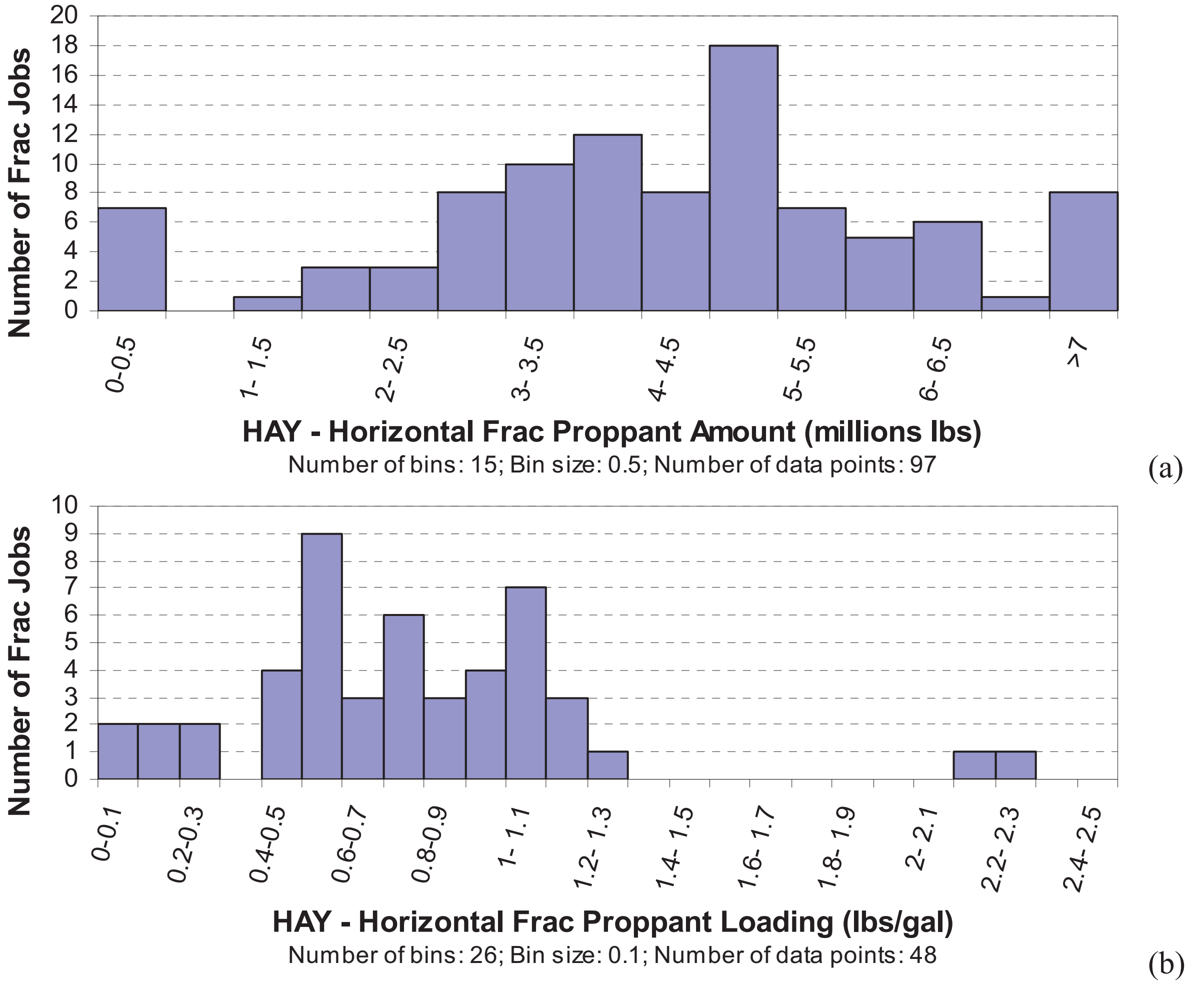
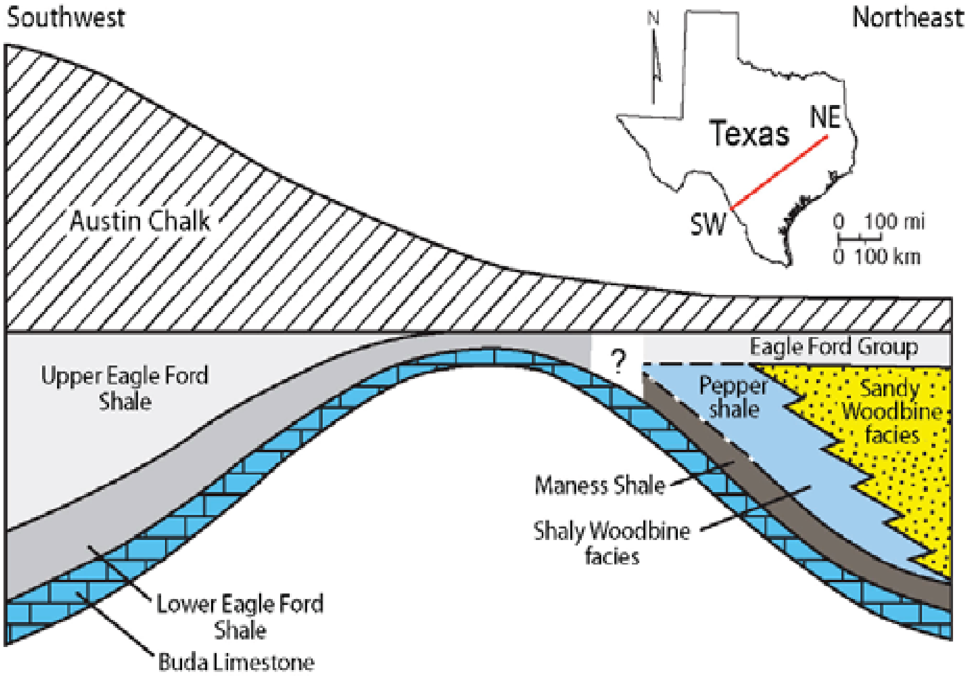
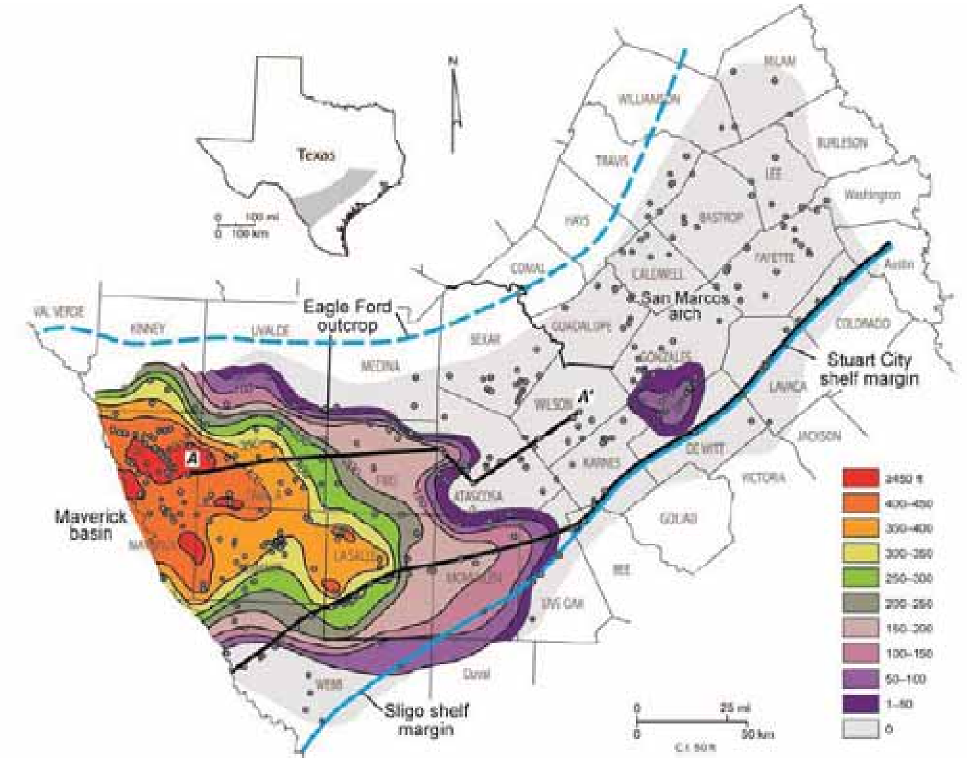


Figure 38. Haynesville—horizontal well: (a) total proppant amount and (b) proppant loading (2008 and beyond)



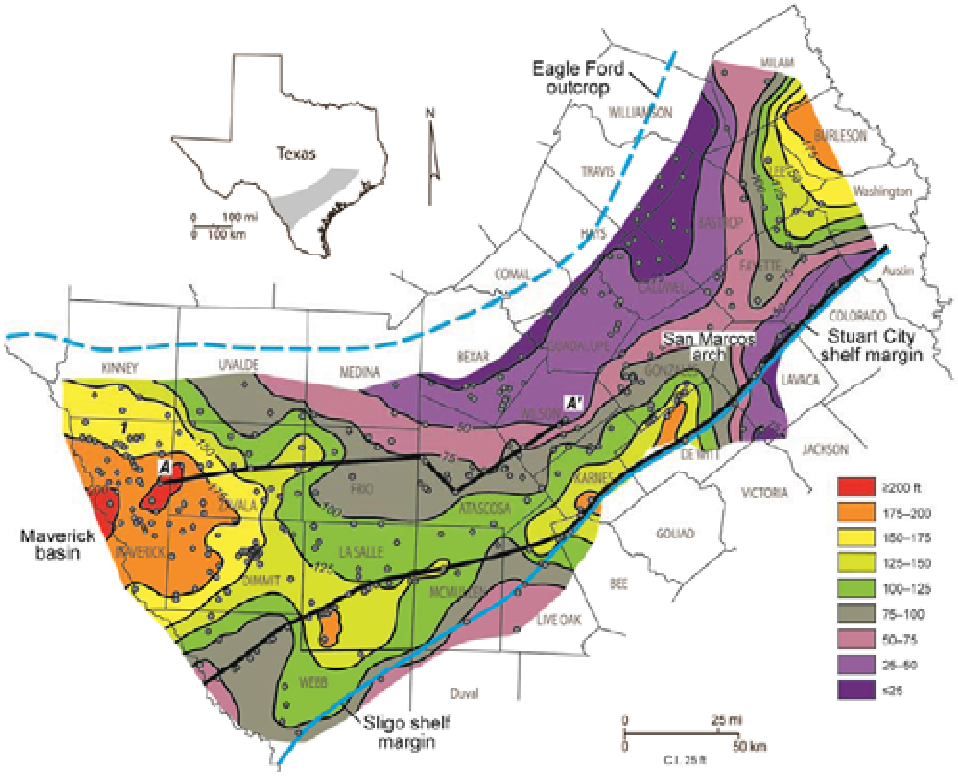
Source: Hentz and Ruppel (2010, Fig. 9)
Note: cross section hangs on top of Eagle Ford; top of Eagle Ford shallower in East Texas Basin than in Maverick Basin to the southwest

Figure 39. SW-NE schematic strike cross section illustrating regional lithostratigraphic relationships across the Eagle Ford play area



Source: Hentz and Ruppel (2010, Fig. 7)

Figure 40. Isopach map of upper Eagle Ford Shale



Source: Hentz and Ruppel (2010, Fig. 6)

Figure 41. Isopach map of lower Eagle Ford Shale

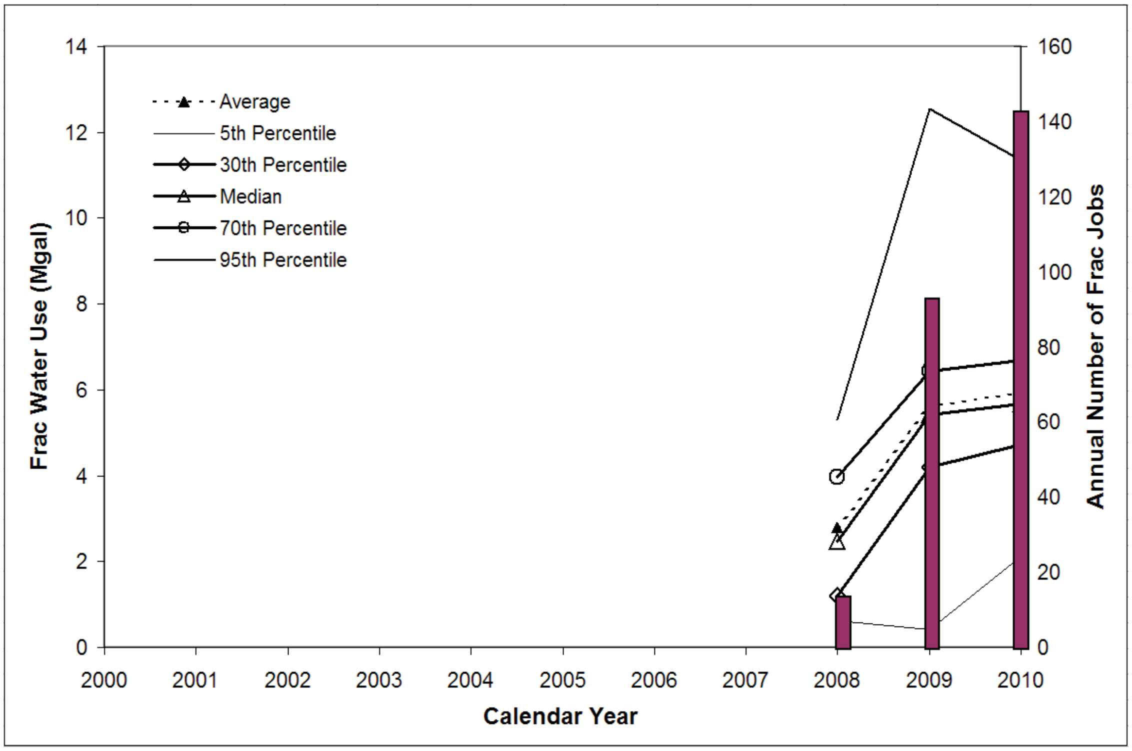


Figure 42. Eagle Ford Shale—Annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use

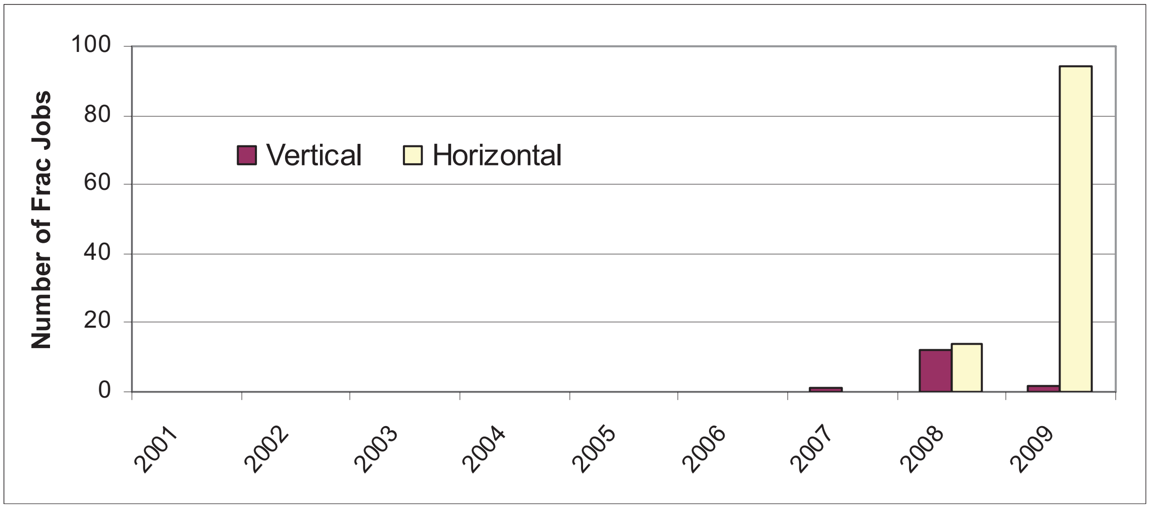


Figure 43. Eagle Ford Shale—vertical vs. horizontal and directional wells through time

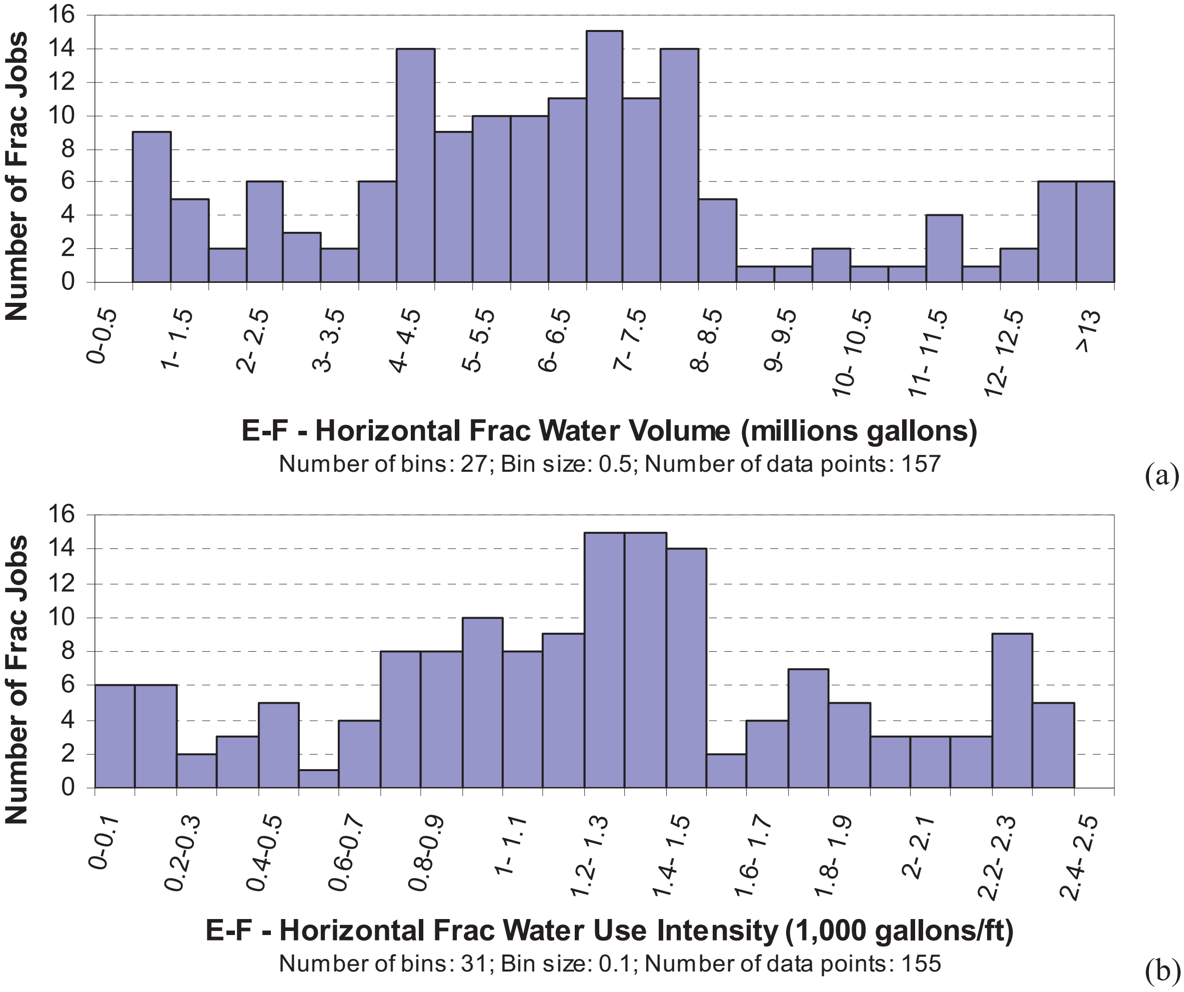


Figure 44. Eagle Ford—horizontal well frac water use: (a) total volume; (b) intensity in 1,000 gal/ft (2008 and beyond)

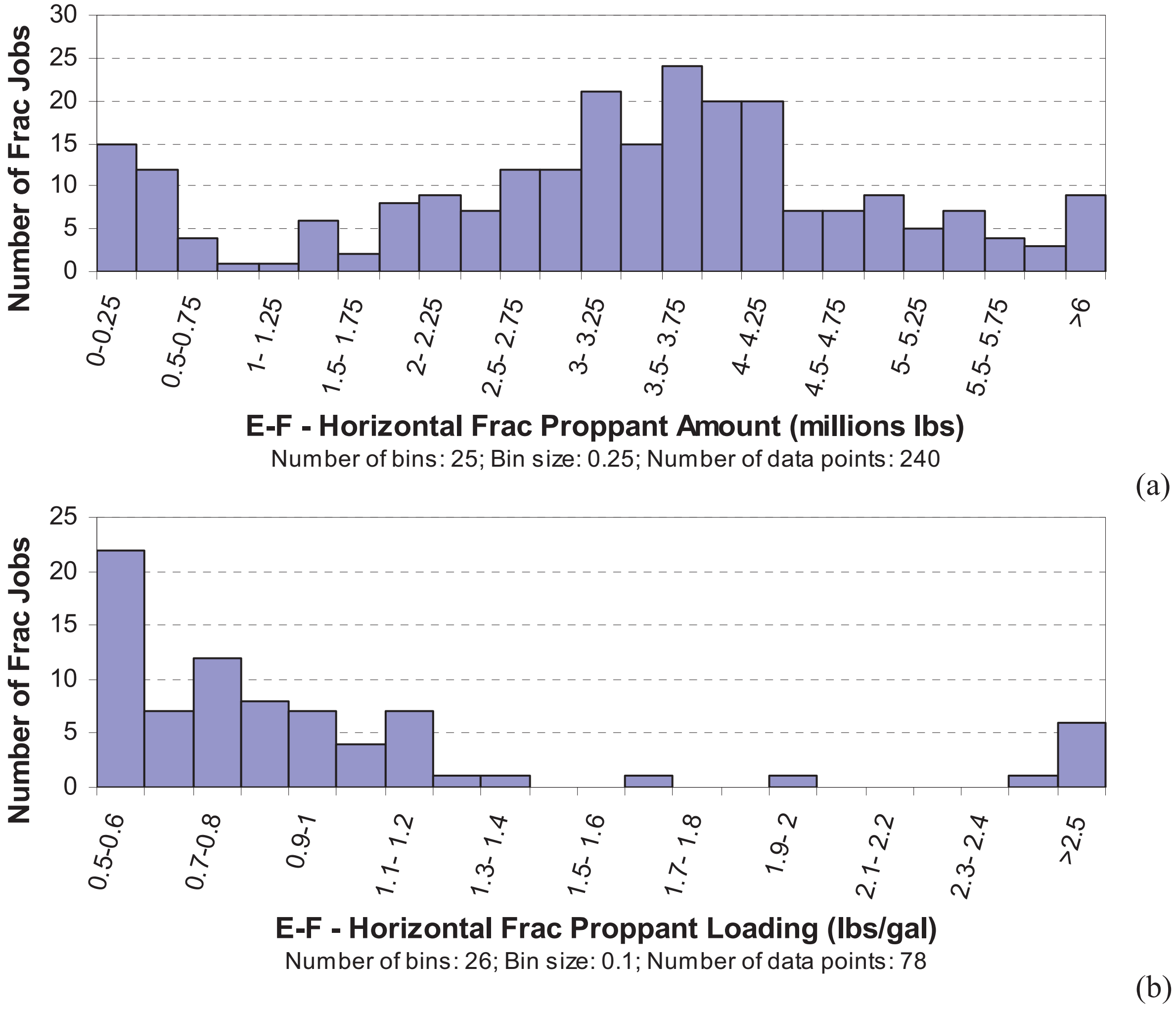
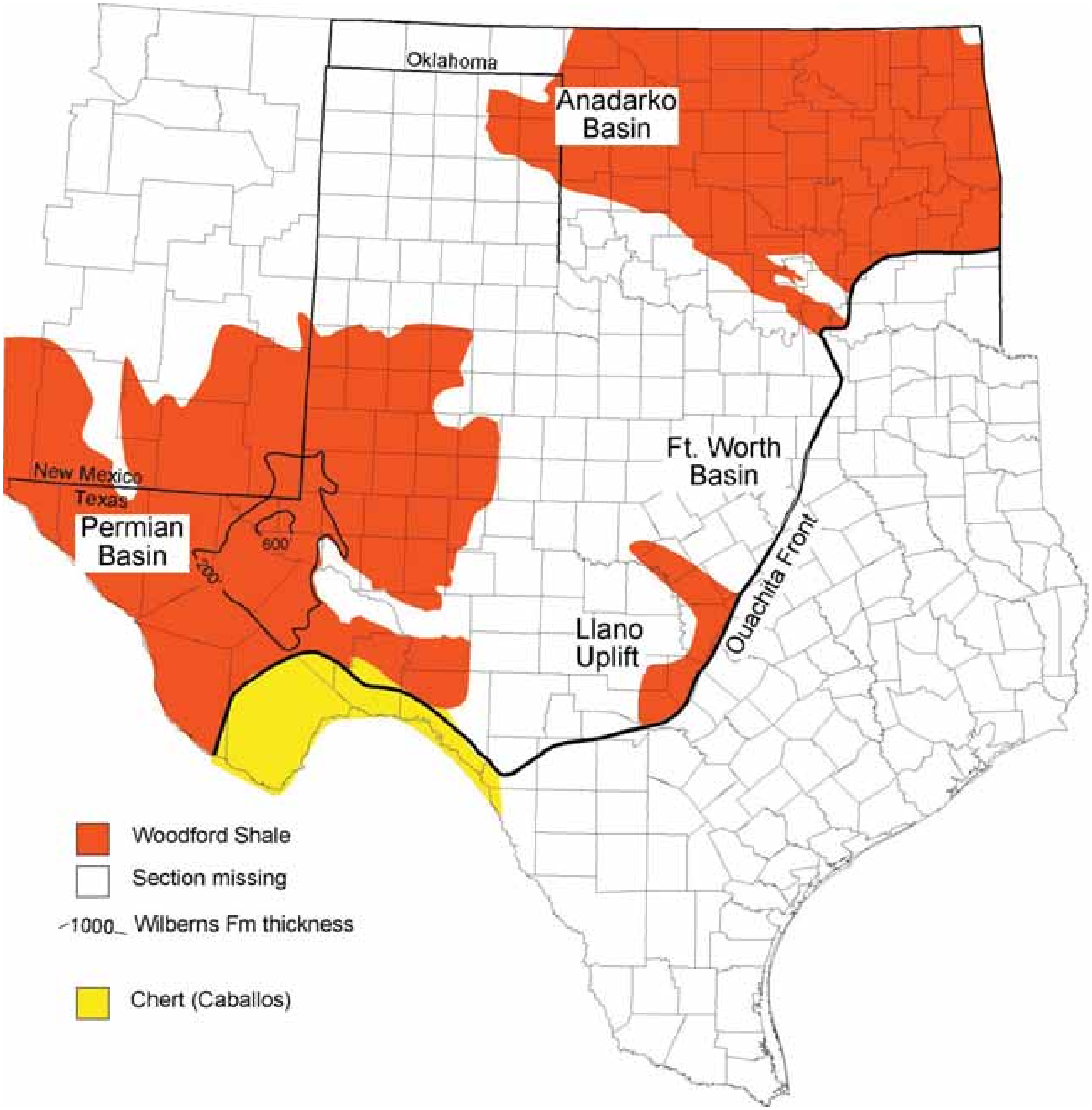
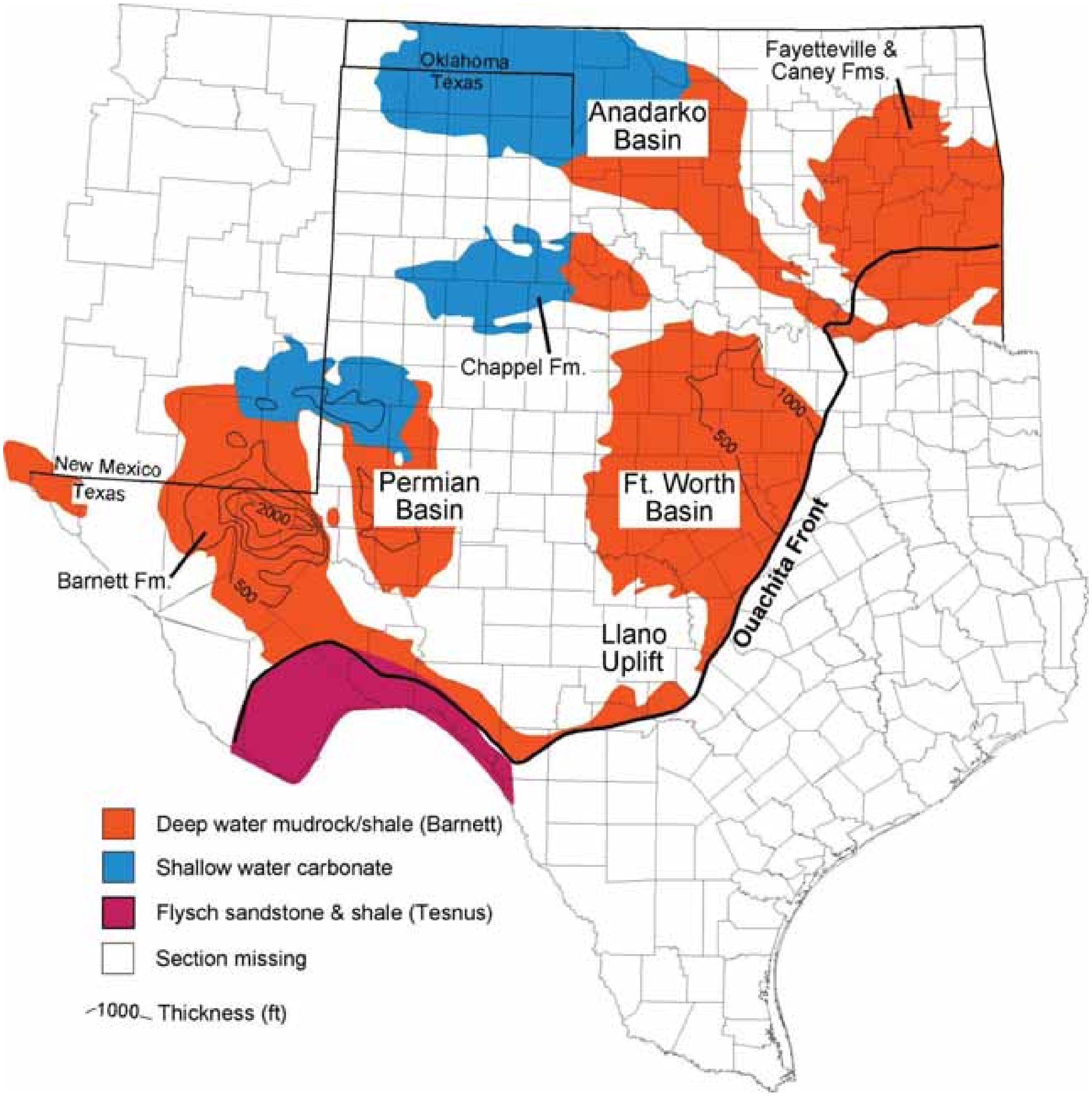


Figure 45. Eagle Ford—horizontal well: (a) total proppant amount and (b) proppant loading (2008 and beyond)



Source: Craig et al. (1979) modified by Stephen Ruppel and mudrock group (BEG)
Note: plot also displays thickness of the Wilberns Formation of Cambrian age

Figure 46. Woodford (Upper Devonian) occurrences in Texas



Source: Craig et al. (1979) modified by Stephen Ruppel and mudrock group (BEG)

Figure 47. Mississippian (including Barnett) facies distribution

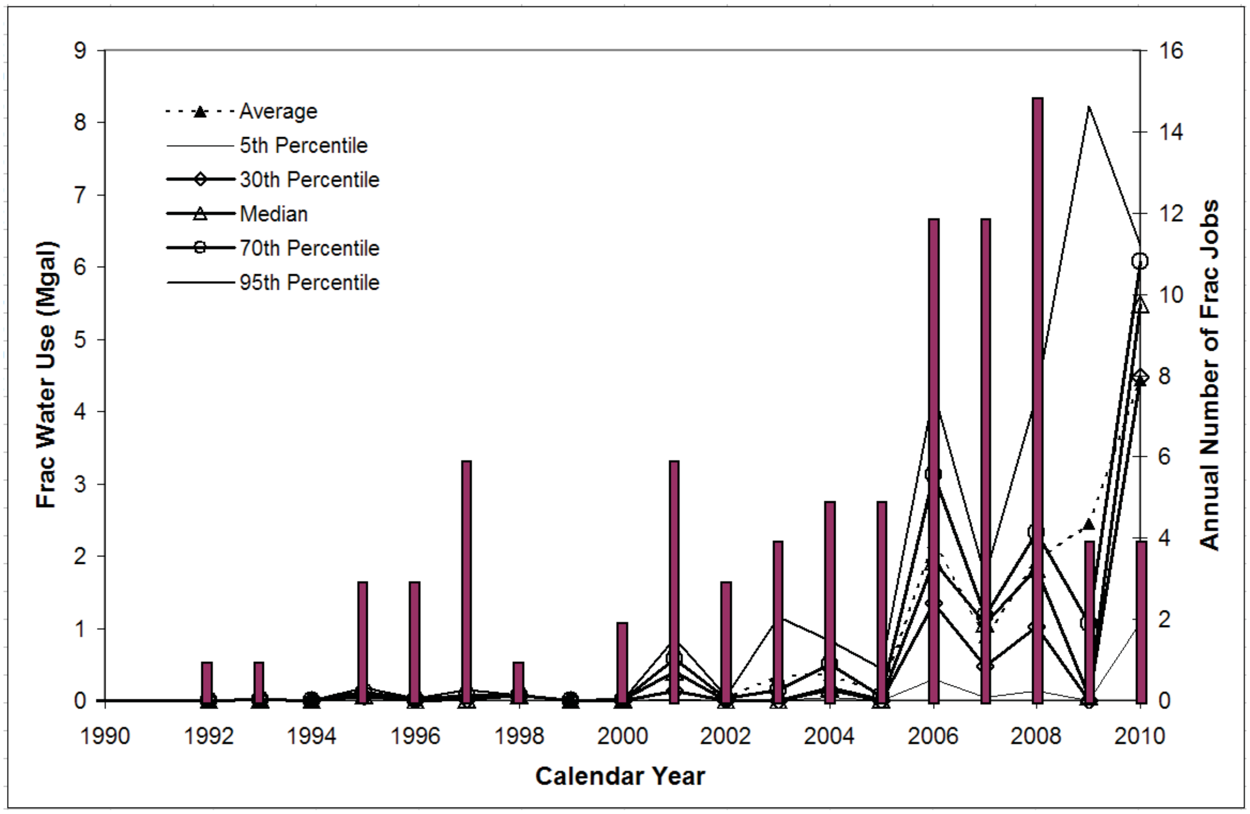


Figure 48. Woodford-Pearsall-Barnett PB—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use

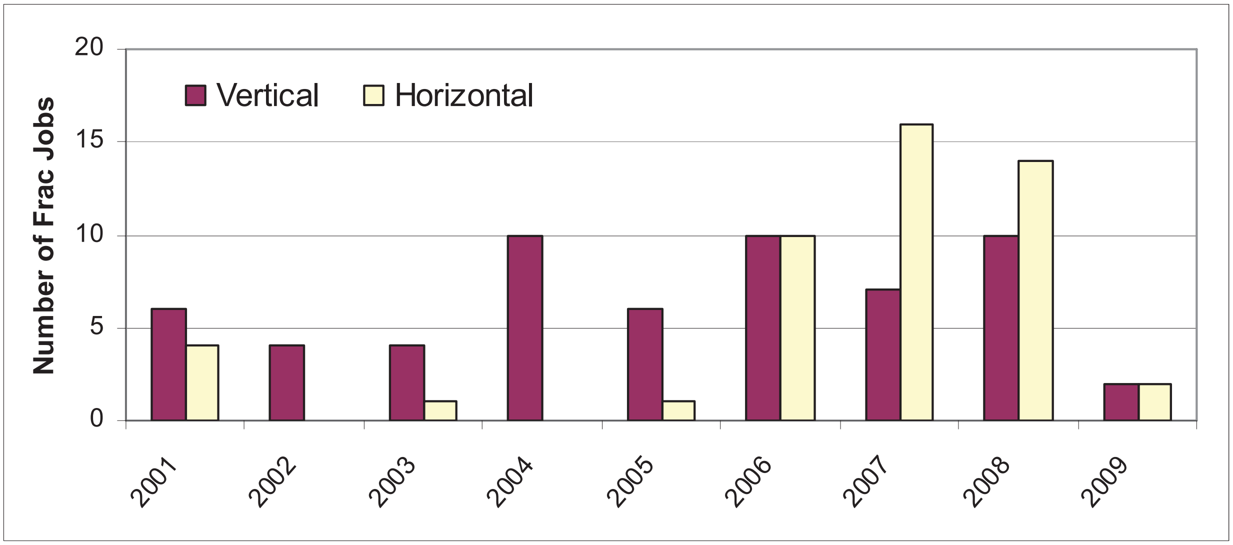


Figure 49. Woodford-Pearsall-Barnett PB—vertical vs. horizontal and directional wells through time

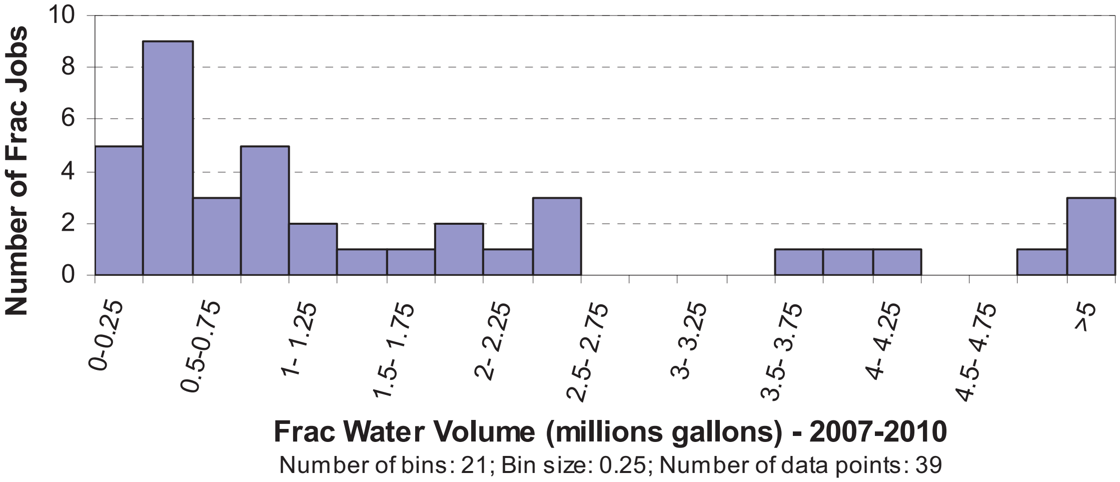
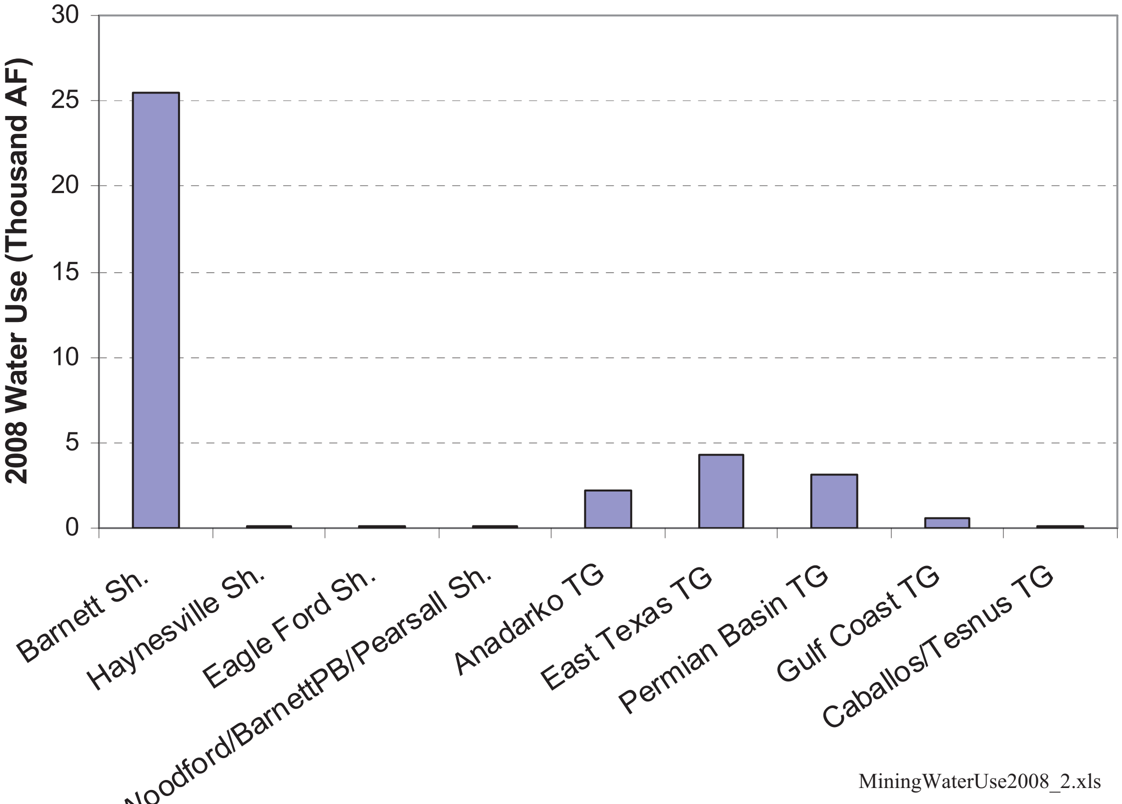


Figure 50. Woodford-Pearsall-Barnett PB horizontal and vertical well frac water use



MiningWaterUse2008_2.xls

Figure 51. Water use for well completion in gas shales and tight formations (2008)

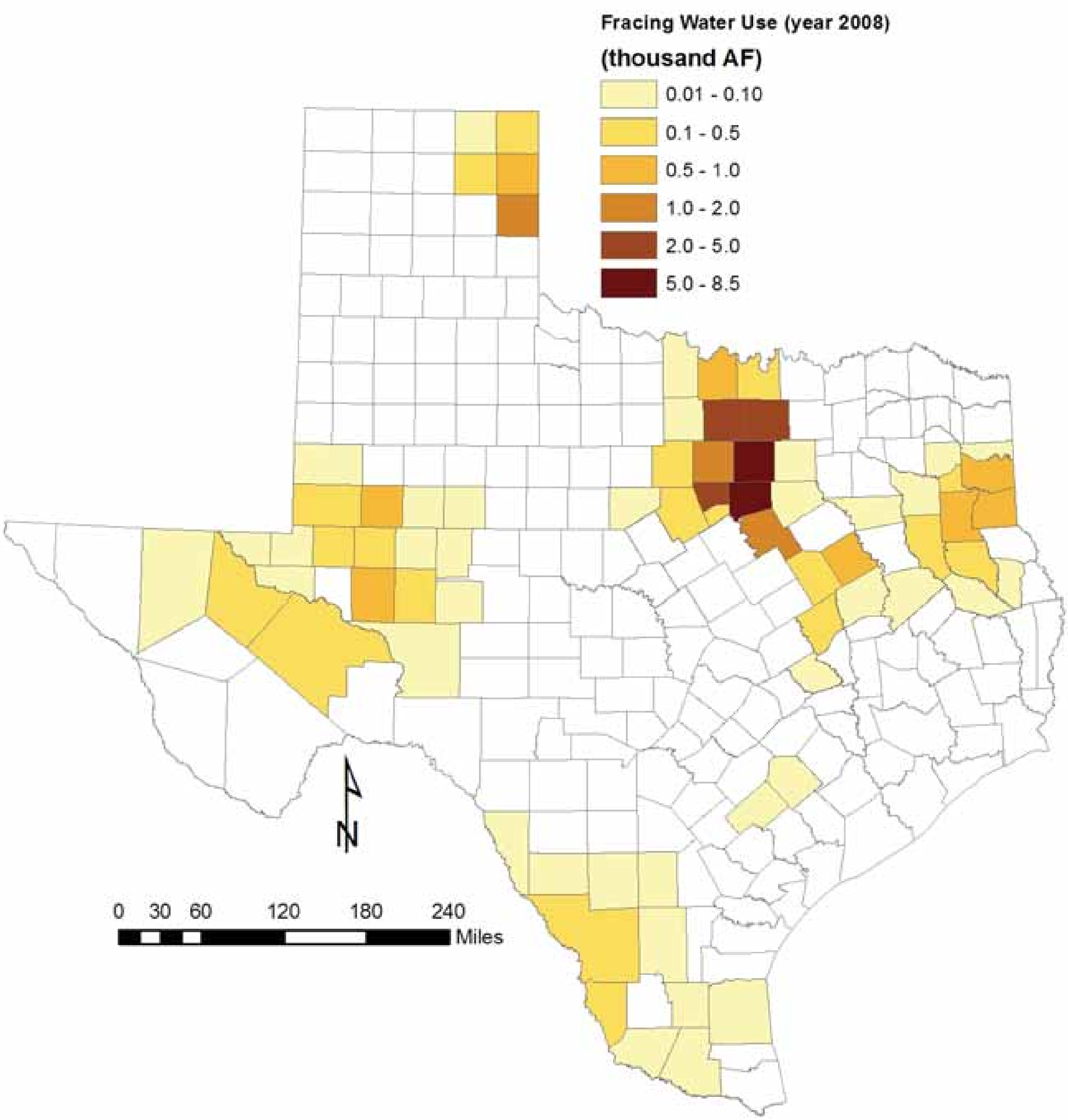


Figure 52. County-level fracing water use (2008)

4.1.3 Tight Reservoirs

Tight-sand plays are more numerous than shale-gas plays and have a longer history, going back to the 1950s and early days of the frac technology. In each basin, many formations have been fraced one time or another, and in this report they are grouped by rock type and geological affinity. BEG published many reports in the 1980s and 1990s in collaboration with GRI (Gas Research Institute, now GTI) related to tight-gas hydrocarbon accumulations. Extended summaries were presented by Finley (1984) and then Dutton et al. (1993), who considered the following Texas tight gas plays: Travis Peak (Hosston) Formation and Cotton Valley Sandstone in East Texas, Cleveland Formation and Cherokee Group in the Anadarko Basin in the Texas Panhandle, Olmos Formation in the Maverick Basin of South Texas, and the so-called Davis sandstone in the Fort Worth Basin (informal unit of the Atoka Group) (Figure 53). They were chosen because they were major gas producers at the time. Dutton et al. (1993) added the Vicksburg Formation and Wilcox Group along the Gulf Coast, the Granite Wash to the Anadarko Basin, the Morrow Formation in the Permian Basin, and the Canyon Sands in the Val Verde Basin. An observation made about many of these tight reservoirs is that low permeability is diagenetic and is caused by pore occlusion rather than depositional due to a clay matrix. In opposition to the gas shales previously discussed, tight sands are conventional in that they form reservoirs and local accumulations (Dutton et al., 1993, p. 5). A map by EIA (Figure 23b) cites them all, but with inaccurate footprints.

4.1.3.1 Anadarko Basin

Sediments of the Anadarko Basin occur mostly in Oklahoma, but its western section is located in the northern Texas Panhandle, including Gray, Hansford, Hemphill, Hutchinson, Lipscomb, Ochiltree, Oldham, Roberts, Sherman, and Wheeler Counties. The Anadarko Basin contains a thick (>18,000 ft) accumulation of siliciclastics and carbonate sediments resulting from the deposition of large volumes of arkosic sediments eroded from the Amarillo Uplift (Ambrose et al., 2010). These sediments are overlain and interfingered by carbonate and sandy deposits of the Marmaton Group and Cleveland Formation (Hentz and Ambrose, 2010). Most of the historical tight gas occurs within the thick undifferentiated interval of the so-called Granite Wash of Pennsylvanian and Permian age. Formations of similar age, such as the Caldwell, Cherokee, Cleveland, and Marmaton, contain tight-gas reservoirs as well as oil.

The basin has seen several cycles of activity since the 1950s, as evidenced by its fracing history (Figure 54b). However, the wells were vertical and the fracing water volumes were small (<0.1 Mgal/well) (Figure 54a). Since 2008, the frac water volume has increased to an average of **0.4 Mgal/well** (Figure 54a) but with a very long tail (Figure 55a). More recently, deviated vertical (directional) and horizontal have been developed in the basin (multimodal histogram of Figure 54b). Average water intensity is ~450 gal/ft (Figure 54c) with a broad mode. Both horizontal and vertical wells have been growing (Figure 56). The formation described as the Granite Wash has been fraced the most often, followed by the Cleveland Formation (Figure 57). In 2008, **2.22 thousand AF** of water was used for fracing purposes.

4.1.3.2 East Texas Basin

The East Texas Basin, sometimes incorporated into the Gulf Coast Basin in high-level regional studies, is a clearly individualized feature in northeast Texas with thick sediments of mostly Cretaceous age. It consists of a deep trough aligned in Anderson and Smith Counties (East Texas Salt Basin) and two flanks with formations of similar age but not necessarily of similar lithology on each side (Table 11). The eastern flank abuts the Sabine Uplift over the Texas-Louisiana state line. The Travis Peak (also called Hosston) Formation (Early Cretaceous) and the Cotton Valley Sandstone (Late Jurassic) have been historical targets and producers in the tight-gas category, most of the activity being confined east of the trough, although many opportunities also exist farther west. The Cotton Valley Sandstone (Figure 58) has a spatial distribution similar to that of the Haynesville Shale. It consists of multiple generally low-permeability sand layers interspersed with shaly material. So that the reservoir could drain efficiently, well spacing has been reduced to 20 acres in many places (Baihly et al., 2007). Cotton Valley is the formation currently being fraced the most, followed by the Travis Peak Formation (Figure 60), although several other formations are also being stimulated, such as the Bossier and the Pettet Formations.

Most of the wells are vertical, although the proportion of horizontal wells is growing (Figure 59). Fracing took off in the 1990s, as it did in other tight formations, with a sharp increase in average water use in recent years (Figure 61)— **0.9 Mgal** and **3 Mgal/well** for vertical and horizontal wells, respectively (Figure 62). In 2008, the East Texas Basin used a total of **4.26 thousand AF** of water for fracing purposes.

4.1.3.3 Fort Worth Basin

The Fort Worth Basin hosts the Barnett Shale and is home to the areally extensive and highly productive Pennsylvanian fan-delta sandstone and conglomerate play (Kosters et al., 1989) (likely sources from the Barnett). Formations include Atoka and Bend Conglomerate (Thompson, 1982). This area has not been traditionally an area with significant tight-gas accumulations. Dutton et al. (1993) mentioned an interval called the Davis Sandstone, but it does not seem to be of significance, given the few wells possibly fraced recently in this interval (Table 8). In addition, any completion would be dwarfed by the Barnett Shale.

4.1.3.4 Permian Basin

The Permian Basin contains a thick accumulation of sediments from Cambrian to Permian age on a Precambrian basement. Despite its long hydrocarbon production history (>30 Bbbl, or about half the state's overall oil production) as compiled according to play by Dutton et al. (2005a,b), the basin still contains important reserves because <30% of the OOIP has been produced (Dutton et al, 2005a, p. 343). Most of the Permian Basin is in the oil window, although significant amounts of gas may exist deeper. Major operators have been content to focus on the abundant oil resources (Figure 63). The classical division of the Permian Basin into the Delaware Basin, Central Basin Platform, and Midland Basin, from west to east (to which the Eastern Shelf can be added), holds only for Permian and Pennsylvanian times (Table 12, Figure 64). At earlier periods, the Permian Basin area was not individualized in basins but presented a more complex but more regionally uniform geometry, with sediments deposited before the expression of the Delaware and Midland Basins. This geological history allows for grouping of the many series described in the IHS database into logical larger groups. However, techniques used by the operators respond more to the nature of the rock than to its age.

The Delaware Basin is in general deeper than the Midland Basin (on the other side of the Central Basin Platform) for a formation of the same age. For example, Bone Spring, Clear Fork, and Spraberry are formations of equivalent age (Figure 65). Similarly the Delaware Mountain Group in the Delaware Basin is equivalent to the San Andres-Grayburg on the Central Basin Platform and in the Midland Basin. Carbonates dominate the platform sediments, but clastics and calcareous mudrocks are more prevalent in the basins.

In Texas, the Delaware Basin includes Culberson, Reeves, and Loving Counties, as well as parts of Jeff Davis, Pecos, Ward, and Winkler Counties. The Central Platform extends from Gaines to Pecos Counties, and the Midland Basin from Terry and Lynn Counties to the north to Crockett County to the south. The Eastern Shelf parallels the Midland Basin to the east, all the way to the Bend Arch and the Fort Worth Basin and Llano Uplift.

The Delaware Basin also contains formations of interest, such as the Bone Spring Formation (also called the Avalon Shale or Leonard Shale in New Mexico) (Figure 66). It is present in Loving, Reeves, and Ward Counties, although maturity drops off quickly. The Bone Spring has seen a surge in interest but is still relatively unexplored. The Delaware Mountain Group, stratigraphically above the Bone Spring Formation, but similar in terms of lithology and broad depositional environments, has many reservoirs from shallow depth (2,500 ft) to much deeper levels (>8,000 ft). Recovery is low, <30% after secondary and possibly tertiary production (Dutton et al., 2005a, p. 312–314). The top of the gas window in the Delaware Basin is estimated to be at ~10,000 ft.

The important development of the so-called Wolfberry play in the Midland Basin corresponds to operators fracing similar rocks of stacked Spraberry, Dean, and then Wolfcamp (Figure 67), and possibly Strawn basinal deposits involving up to 12 stages in vertical wells at a depth of >7,000 ft. Spraberry/Dean reservoirs have historically had a fairly low recovery (10% of OOIP, Dutton et al., 2005a, p. 205). Most of the fracing has focused on the margins of the basin along the Central Platform and the Eastern Shelf. There has been a considerable interest in the Wolfberry play in the past few years, as illustrated by the number of recent wells (Figure 24).

Canyon Sands in the Val Verde Basin, a southeastern extension of the Permian Basin south of the Ozona Arch (Crockett County), were deposited in deep environments (Dutton et al, 1993, p. 122). The Canyon Sands, initially thought equivalent to the Canyon Formation in the Permian Basin, are actually mostly of Permian age (Hamlin et al., 1995, p. 4-5), although the name remains. For convenience, we also added the Devonian Caballos and Mississippian Tesnus Formations south of the Ouachita Front (Figure 46 and Figure 47) to the Permian Basin category.

Overall the Permian Basin has seen 50,000+ frac jobs in the past 50 years (Figure 68), including 18,300+ with water use >0.1 Mgal (Figure 69), and ~2,900 frac jobs with water use >0.5 Mgal, mostly in the past few years. The plots show a clear upward trend in all percentiles since 2000, with average water use approaching **1 Mgal/well** (Figure 70) with a broad distribution (once <0.1Mgal jobs are removed) (Figure 71). This is a relatively modest amount per current standards, but most of the wells are vertical (Figure 72). Many formations are being fraced, but the Spraberry/Dean in the Midland Basin, the Clear Fork in the Central Platform, and the Wolfcamp underlying both form the bulk of the frac jobs (Figure 73 and Figure 74). Devonian formations are also the subject of interest. We treated the Caballos and Tesnus Formations separately because they are located farther south, but their statistics are similar to those of other formations of West Texas, with a sharp increase in recent years (Figure 75) and an average water use at ~0.35 Mgal/well (Figure 75 and Figure 76).

In 2008, the Permian Basin (Texas section) used a total of **3.25 thousand AF** of water for fracing purposes (including 0.17 for the Caballos/Tesnus).

4.1.3.5 Maverick Basin and Gulf Coast

The Texas southern Gulf Coast province is well known for its gas-prone hydrocarbon accumulations and includes the Frio Formation, a prolific conventional gas producer, as well as the Wilcox deltaic (Table 13; Figure 147 in Appendix C). Tight-gas formations such as Vicksburg and Wilcox Lobo tend to occur deeper (Dutton et al., 1993). The Maverick Basin, included in the Gulf Coast area for the purpose of this study, contains the Olmos Formation, another important tight-gas formation. Overall, Gulf Coast tight formations have not seen the increase in average frac water volume as seen in all other basins, despite a sharp increase in the number of frac jobs (Figure 78). The reason may be due to the lack of horizontal wells (Figure 73). Recently active plays include the Vicksburg, the Wilcox, and the Olmos Formations, which have been traditionally fraced (Figure 79). The amount of water used is low (**<0.2 Mgal/well** for the most part) (Figure 80), but the proppant amount is relatively high (Figure 81), leading to a high proppant loading (Figure 82). These plays have most likely not been swept by the new fracing technologies, but we assume that they will in the future (we assume a water use of **0.5 Mgal/well** or projections), as operators revisit older plays through refracing and infill wells.

In 2008, the Gulf Coast Basin used a total of **0.60 thousand AF** of water for fracing purposes.

4.1.3.6 Conclusions on Tight Formations

Water use for tight formation completion is less than half of that for gas shales, at 10.4 thousand AF (Table 10 and Figure 51). Table 14 lists all counties with a total use >0.001 AF in 2008. Average water use across the 84 counties (Figure 52) is~120 AF, and Wheeler County, in the Panhandle, has the highest water use at 1.07 thousand AF.

Table 11. Simplified stratigraphic column of the East Texas Basin showing commonly fraced intervals, as well as potential targets (in bold)

System	Age	Formation / Group		
			Salt Basin	
Cretaceous		**Austin Chalk***		
		Glen Rose/Fredericksburg/ Washita/Eagle Ford		
		Pearsall / Rodessa / James		
		Sligo / **Pettet***		
		Hosston/**Travis Peak***		Hosston/**Travis Peak***
		Cotton Valley*		**Cotton Valley***
Jurassic		**Bossier Sands***		**Bossier Shale***
		Haynesville Limestone		**Haynesville Shale***
		Smackover/Buckner		

Table 12. Simplified stratigraphic column of the Permian Basin showing commonly fraced intervals, as well as potential targets (in bold)

System	**Age**	**Formation / Group**		
		Delaware Basin	**Central Platform**	**Midland Basin**
Permian	Ochoan	Salado/Rustler/Dewey Lake and Dockum		
	Guadalupian	**Delaware Mountain Group* (Brushy, Cherry, & Bell Canyon)**	Queen/Seven Rivers/**Yates***/Tansill San Andres Grayburg	
	Leonardian	**Bone Spring***	Clear Fork	**Spraberry*/Dean***
	Wolfcampian	Wolfcamp Basin	Wolfcamp Platform	**Wolfcamp Basin***
Pennsylvanian		Morrow/Atoka/Strawn/Canyon/Cisco		
Mississippian		**Barnett***	N/A	Platform Carbonates **Barnett***
Devonian		**Devonian*/Woodford***		
Silurian		**Siluro-Devonian***		
Ordovician		Simpson Group/Ellenburger		
Cambrian		Wilberns		

Table 13. Simplified stratigraphic column of South Texas Gulf Coast showing commonly fraced intervals, as well as potential targets (in bold)

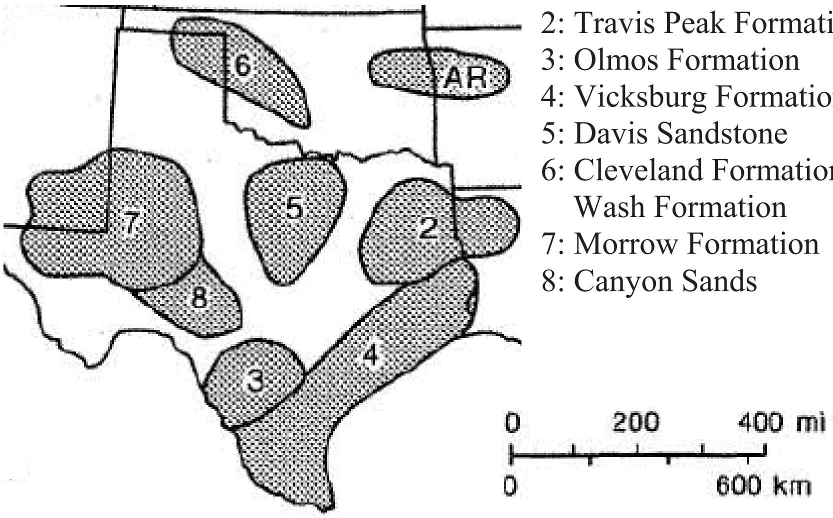
System	**Age**	**Formation / Group**
Oligocene		**Vicksburg*/Frio***
Eocene / Paleocene		**Wilcox-Lobo***/Carrizo/Queen City/Sparta/Yegua/Jackson
Paleocene (Early)		Midway
Cretaceous		**San Miguel*/Olmos*/Escondido***
		Austin Chalk*
		Eagle Ford*
		Glen Rose/Edwards/Stuart City/Georgetown/Del Rio/Buda/
		Pearsall*
		Hosston/Sligo
Jurassic		Cotton Valley

Table 14. County-level tight-formation-completion water use (2008)

County	**Water Use (thousand AF)**	**County**	**Water Use (thousand AF)**	**County**	**Water Use (thousand AF)**
Andrews	0.132	Harrison	0.815	Ochiltree	0.071
Angelina	0.090	Hemphill	0.721	Panola	0.908
Bee	0.006	Henderson	0.028	Pecos	0.183
Borden	0.003	Hidalgo	0.074	Reagan	0.308
Brazoria	0.003	Houston	0.013	Real	0.002
Brooks	0.015	Howard	0.047	Reeves	0.057
Calhoun	0.003	Irion	0.062	Roberts	0.216

County	Water Use (thousand AF)	County	Water Use (thousand AF)	County	Water Use (thousand AF)
Cherokee	0.120	Jackson	0.004	Robertson	0.208
Colorado	0.002	Jim Hogg	0.002	Rusk	0.540
Crane	0.003	Kenedy	0.027	San Augustine	0.088
Crockett	0.026	La Salle	0.017	San Patricio	0.002
Culberson	0.012	Lavaca	0.018	Smith	0.052
Dawson	0.007	Leon	0.055	Starr	0.068
DeWitt	0.013	Limestone	0.264	Sterling	0.022
Dimmit	0.004	Lipscomb	0.141	Terrell	0.008
Duval	0.020	Live Oak	0.003	Terry	0.004
Ector	0.183	Loving	0.030	Upshur	0.030
Edwards	0.002	McMullen	0.044	Upton	0.999
Fort Bend	0.003	Marion	0.029	Val Verde	0.001
Freestone	0.501	Martin	0.560	Van Zandt	0.002
Frio	0.004	Matagorda	0.008	Ward	0.067
Gaines	0.018	Maverick	0.015	Webb	0.112
Glasscock	0.096	Midland	0.371	Wharton	0.006
Goliad	0.009	Mitchell	0.027	Wheeler	1.071
Gregg	0.128	Nacogdoches	0.384	Willacy	0.005
Hale	0.002	Navarro	0.004	Winkler	0.014
Hansford	0.003	Newton	0.001	Yoakum	0.005
Hardin	0.001	Nueces	0.008	Zapata	0.107

MiningWaterUse2008_2.xls



Source: modified from Dutton et al. (1993, Fig. 1)

Figure 53. Location of basins in Texas containing low-permeability sandstone with historical frac jobs

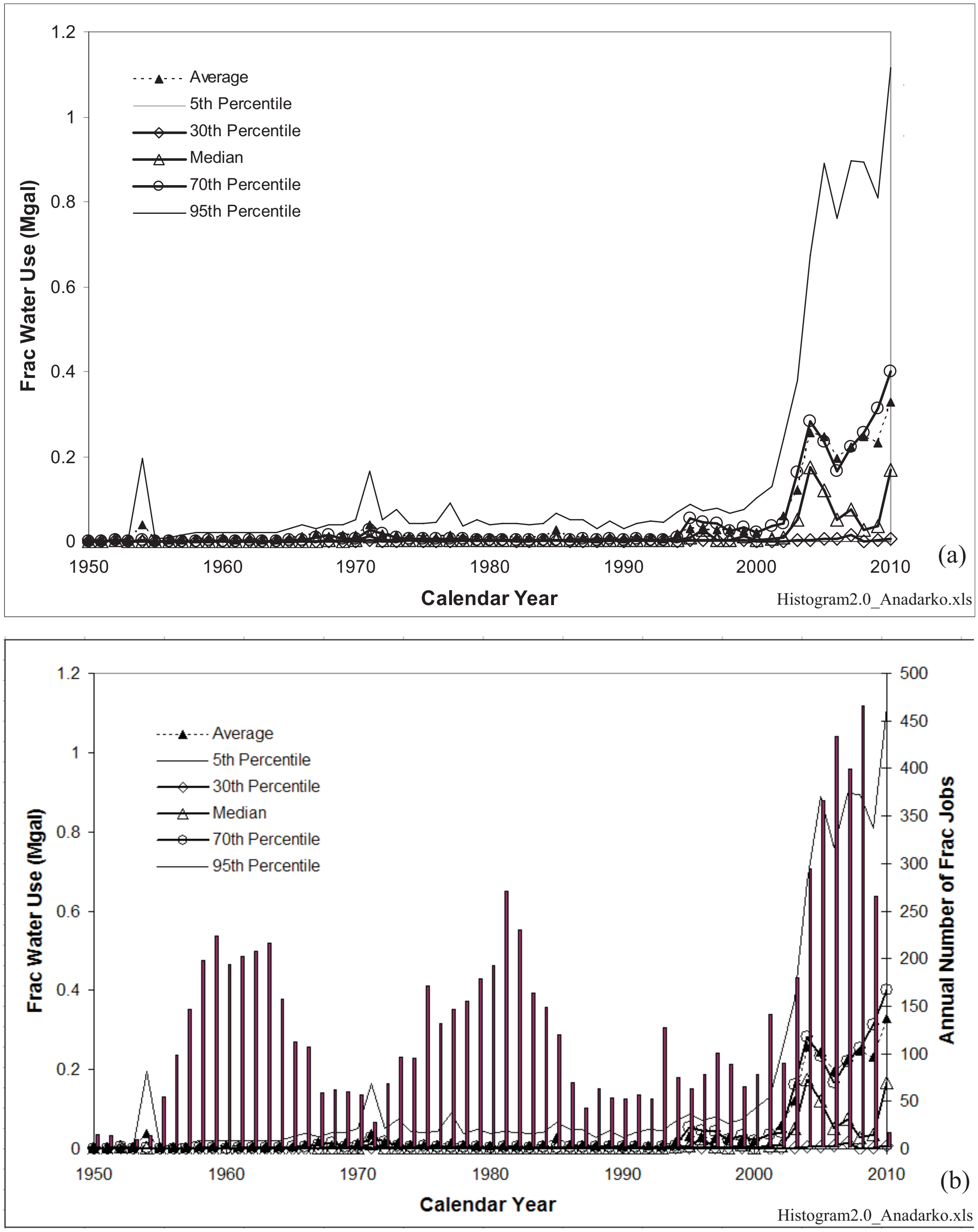
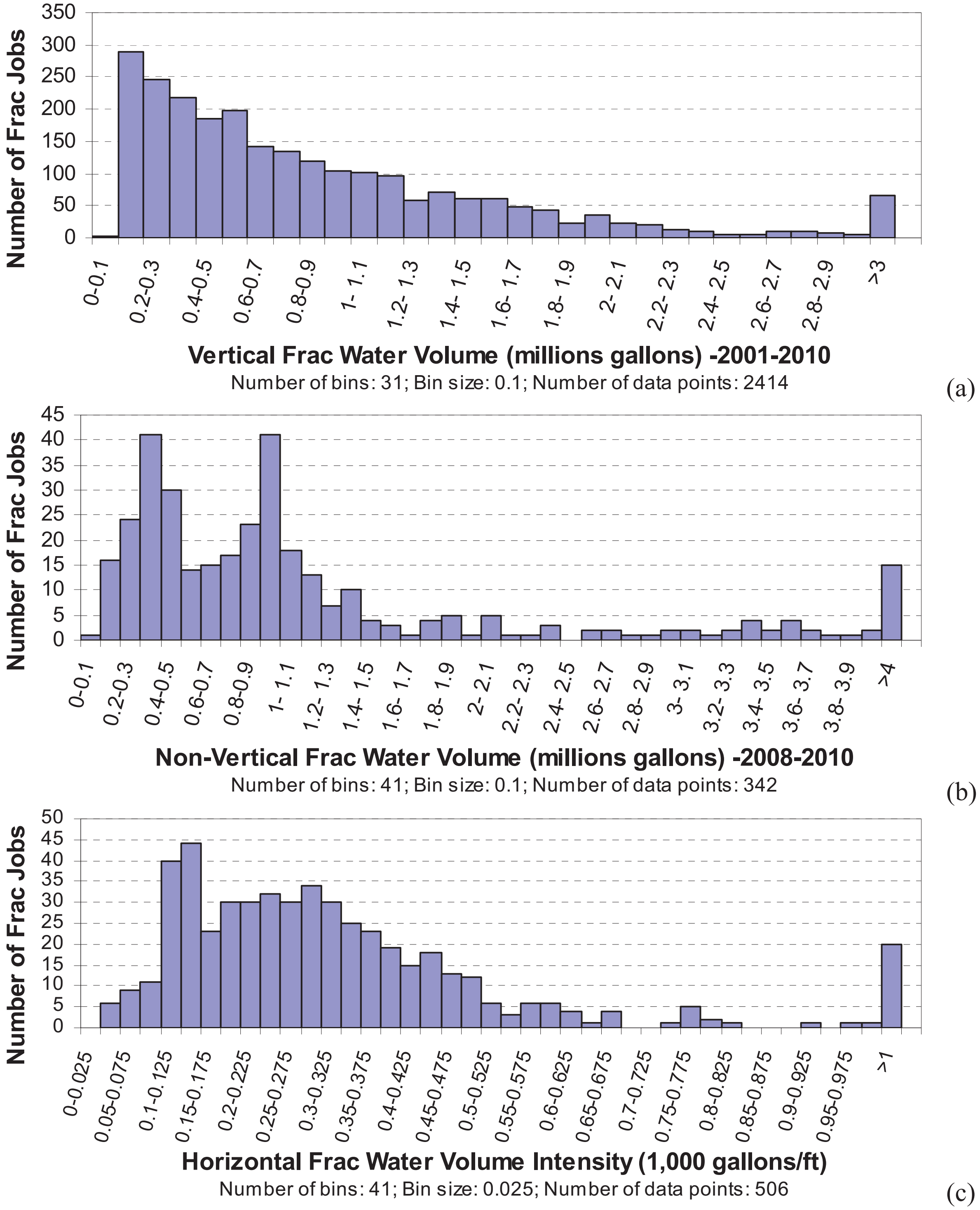


Figure 54. Anadarko Basin—annual number of frac jobs (b) superimposed on annual average, median, and other percentiles of individual well frac water use (a)



Note: (c) uses only those "H" wells for which lateral length can be computed—histograms include only those frac jobs using >0.1 Mgal.

Figure 55. Anadarko Basin—frac water use in vertical wells (a), nonvertical wells (b), and water-use intensity in selected horizontal wells (c)

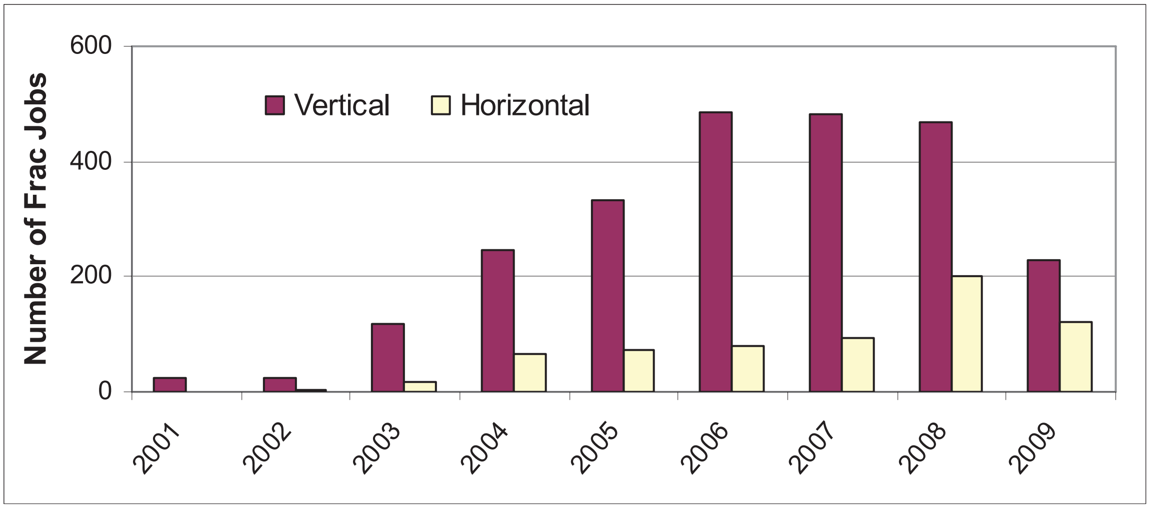


Figure 56. Anadarko Basin—vertical vs. horizontal and directional wells through time

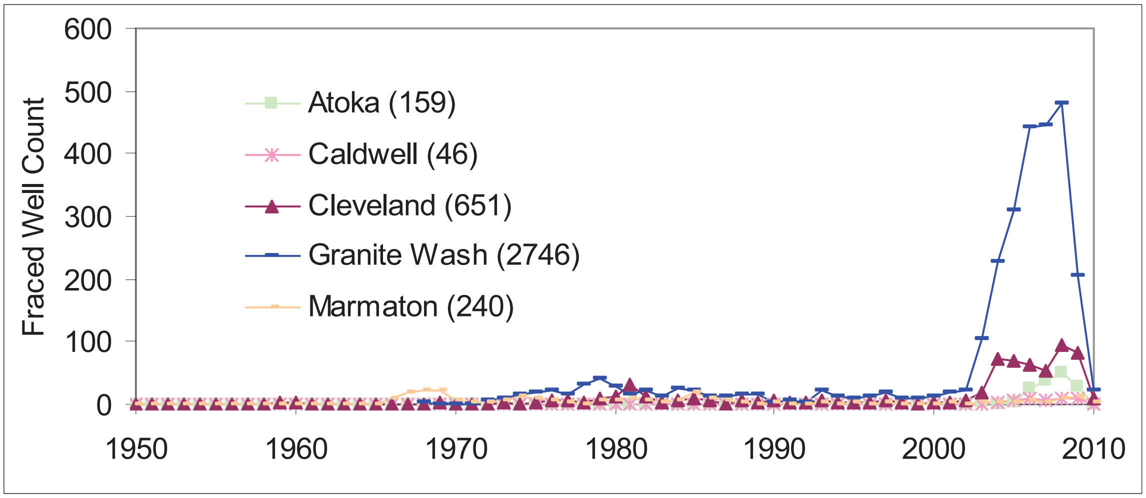
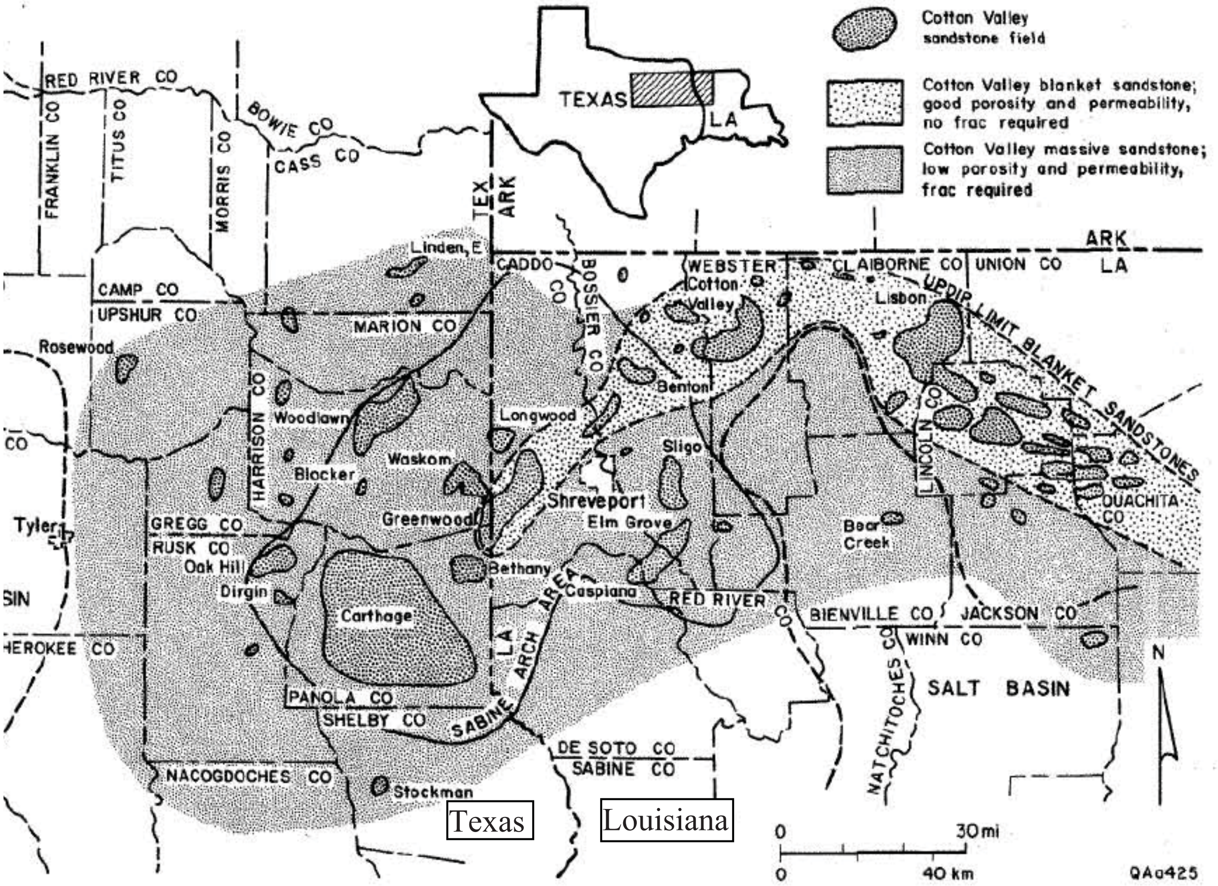


Figure 57. Anadarko Basin—fraced well count per formation



Source: Dutton et al. (1993, Fig. 24)

Figure 58. Distribution of Cotton Valley reservoir trends in East Texas

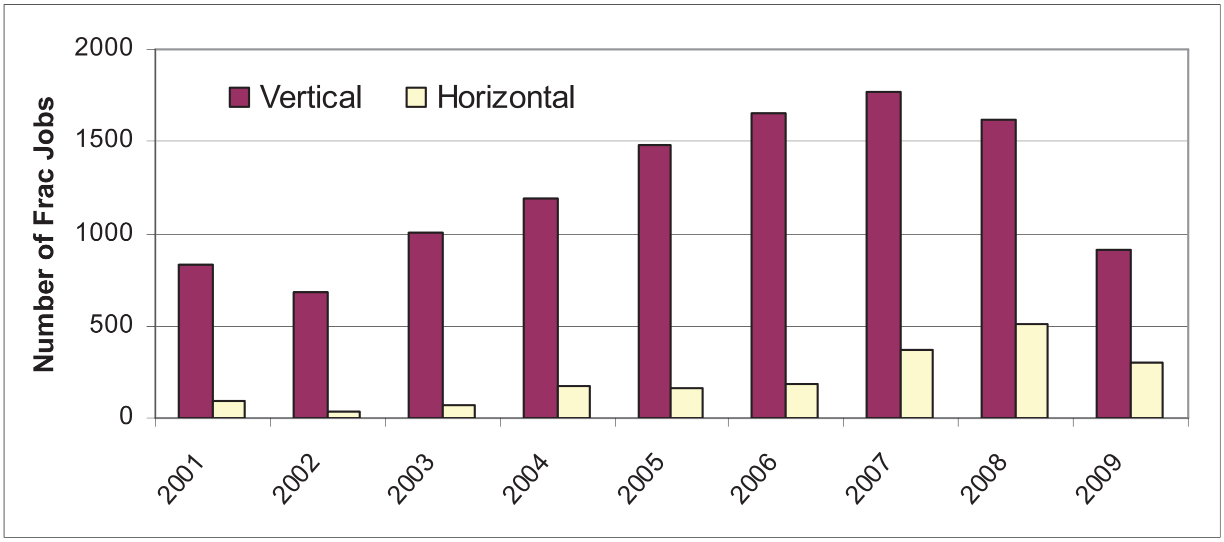


Figure 59. East Texas Basin—vertical vs. horizontal wells through time

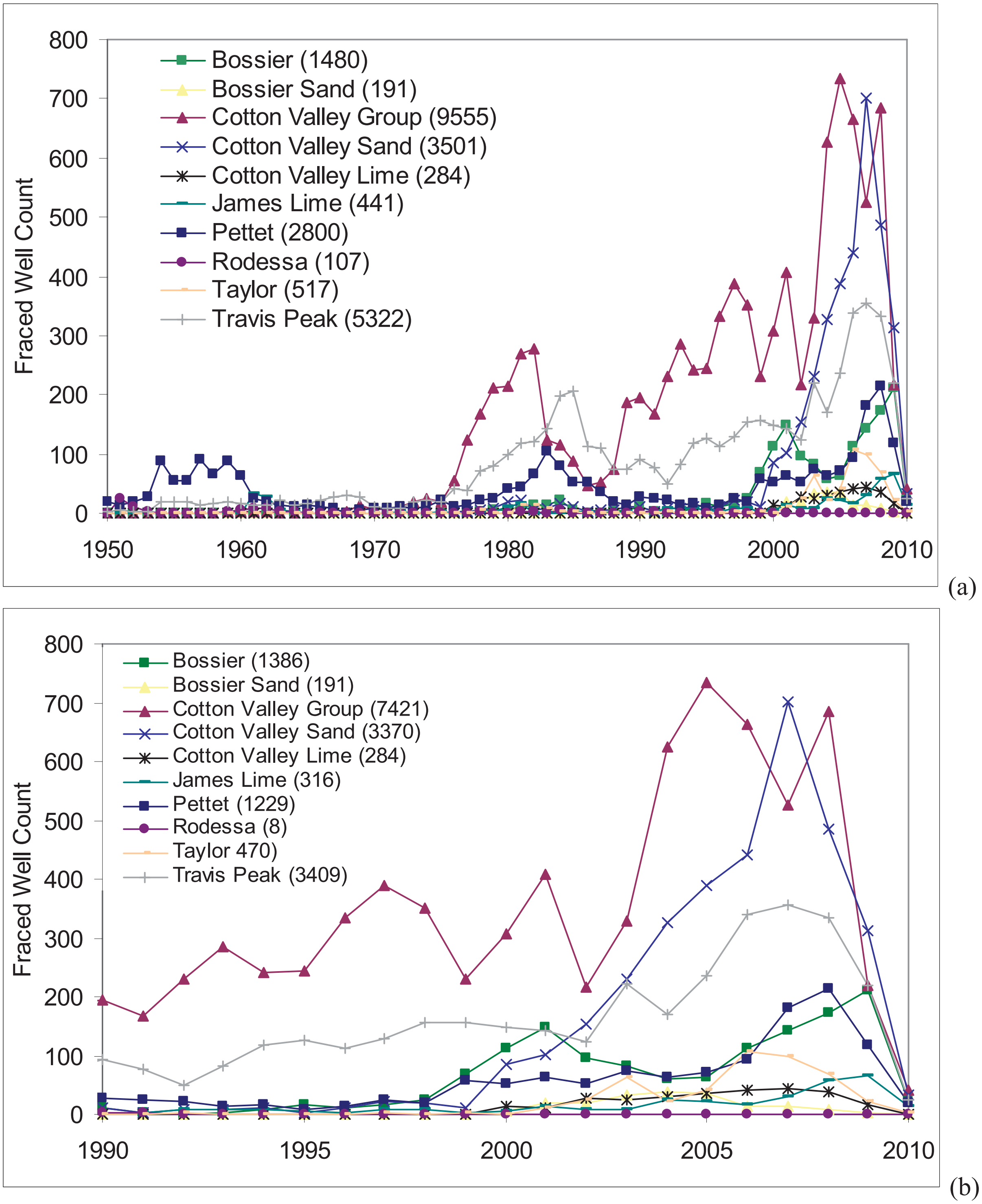


Figure 60. East Texas Basin—Fraced well count per formation from 1950 (a) and 1990 (b)

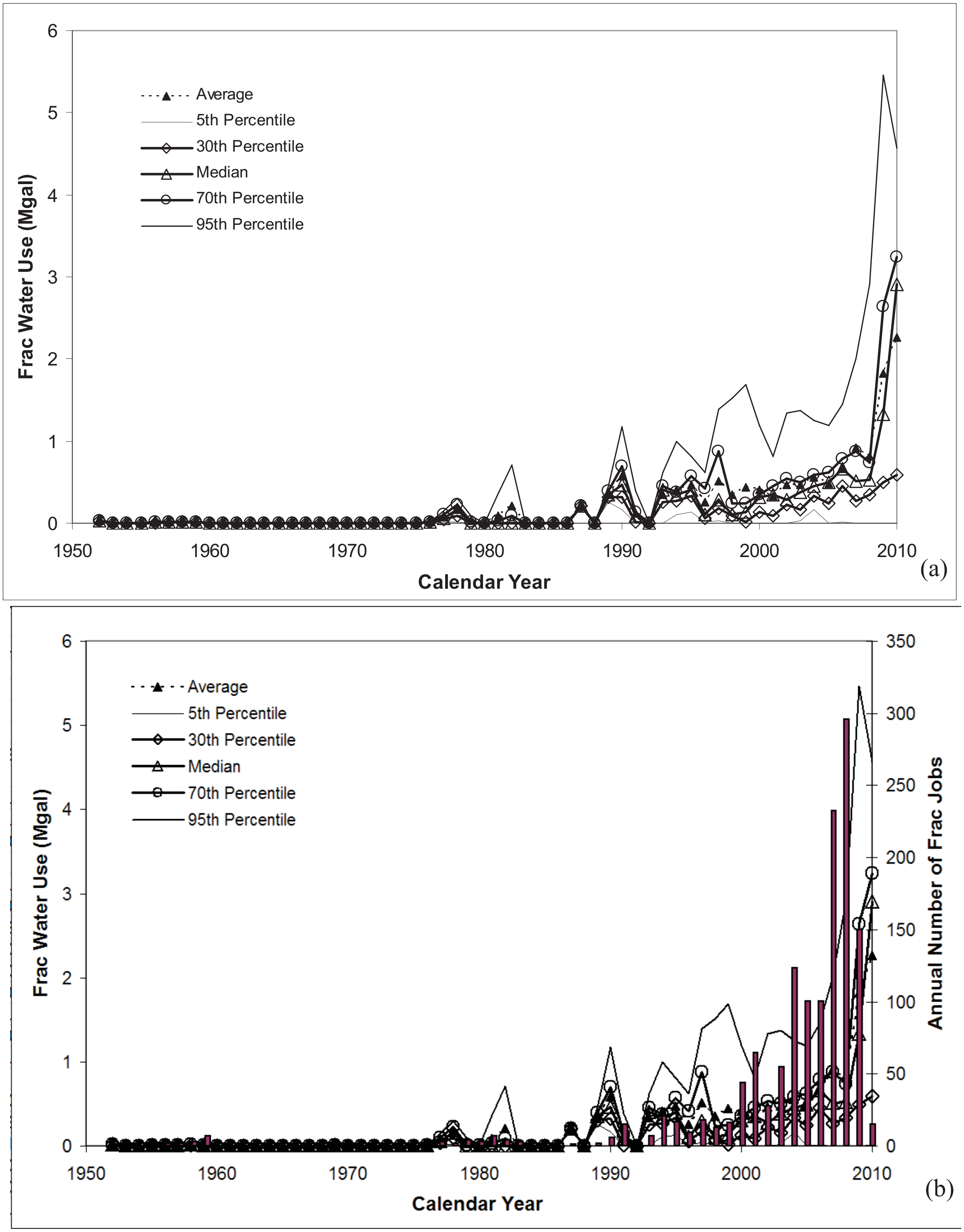
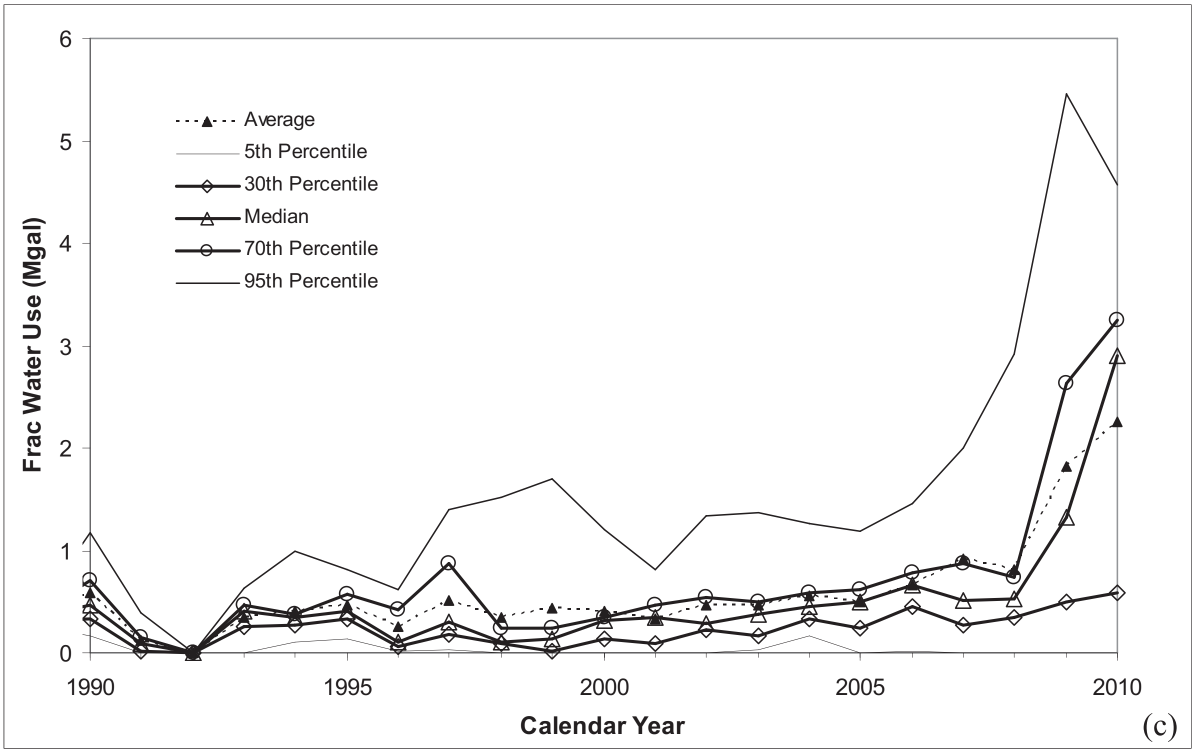


Figure 61. East Texas Basin—annual number of frac jobs (b and d) superimposed on annual average, median, and other percentiles of individual well frac water use (a and c) for 1950–~2008 (a and b) and 1990–~2008 (c and d) periods



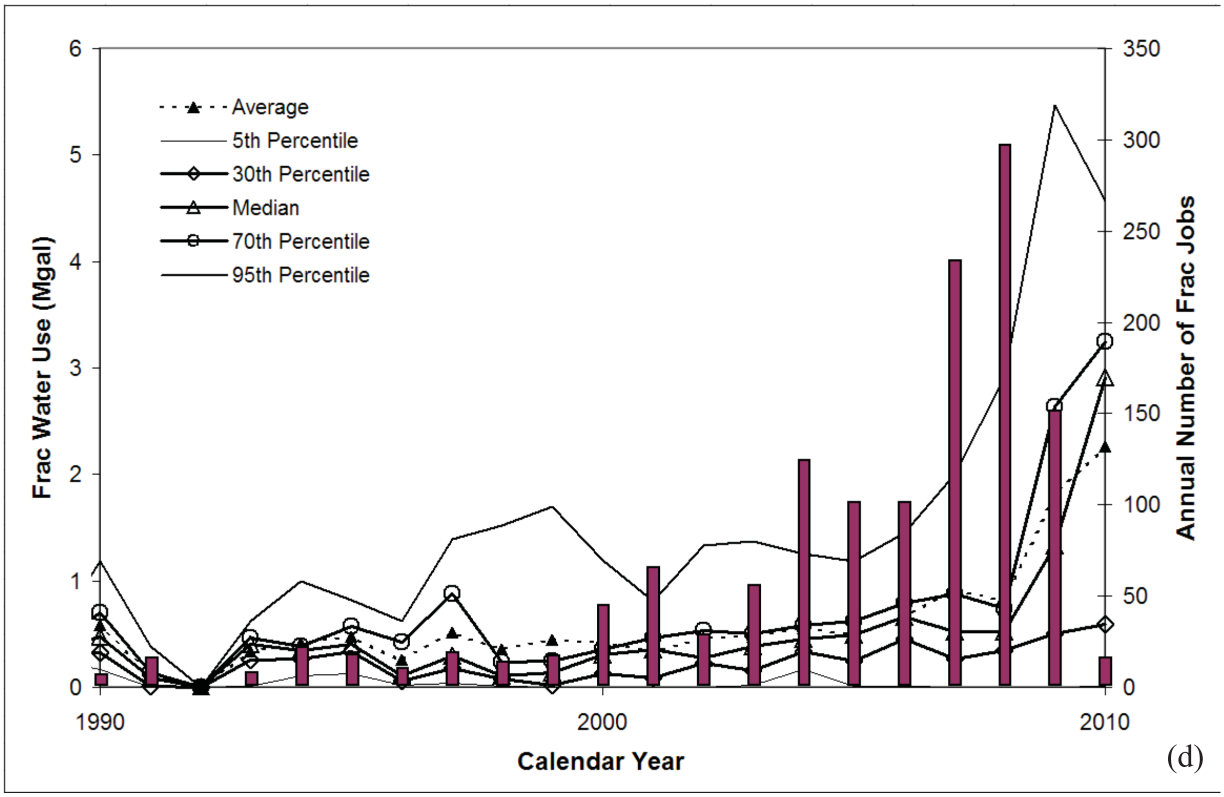
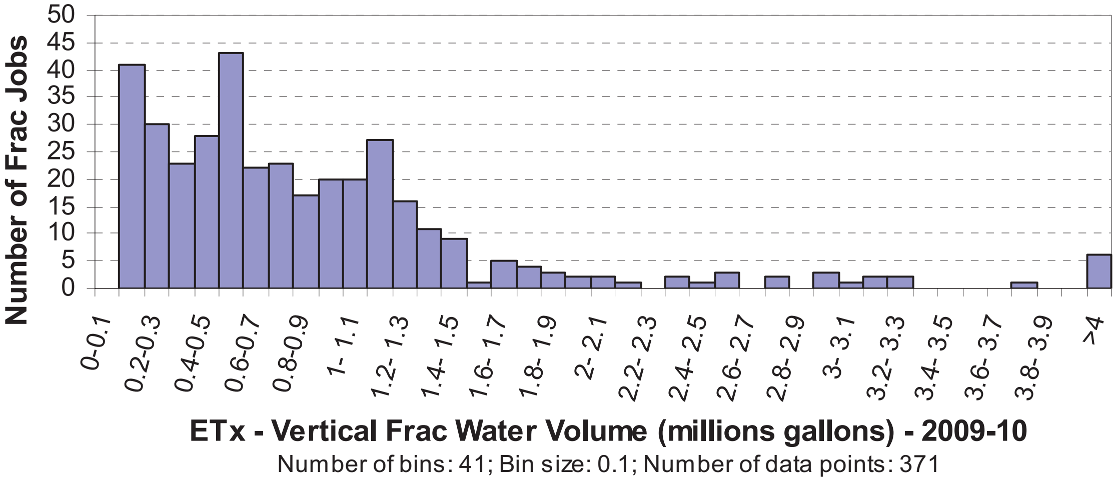
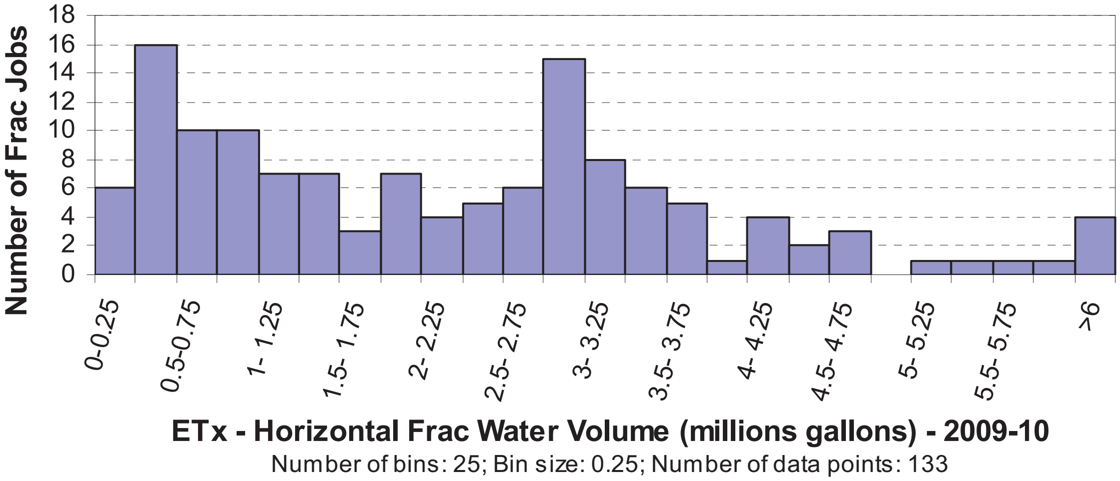


Figure 61. East Texas Basin—annual number of frac jobs (b and d) superimposed on annual average, median, and other percentiles of individual well frac water use (a and c) for 1950–~2008 (a and b) and 1990–~2008 (c and d) periods (continued).



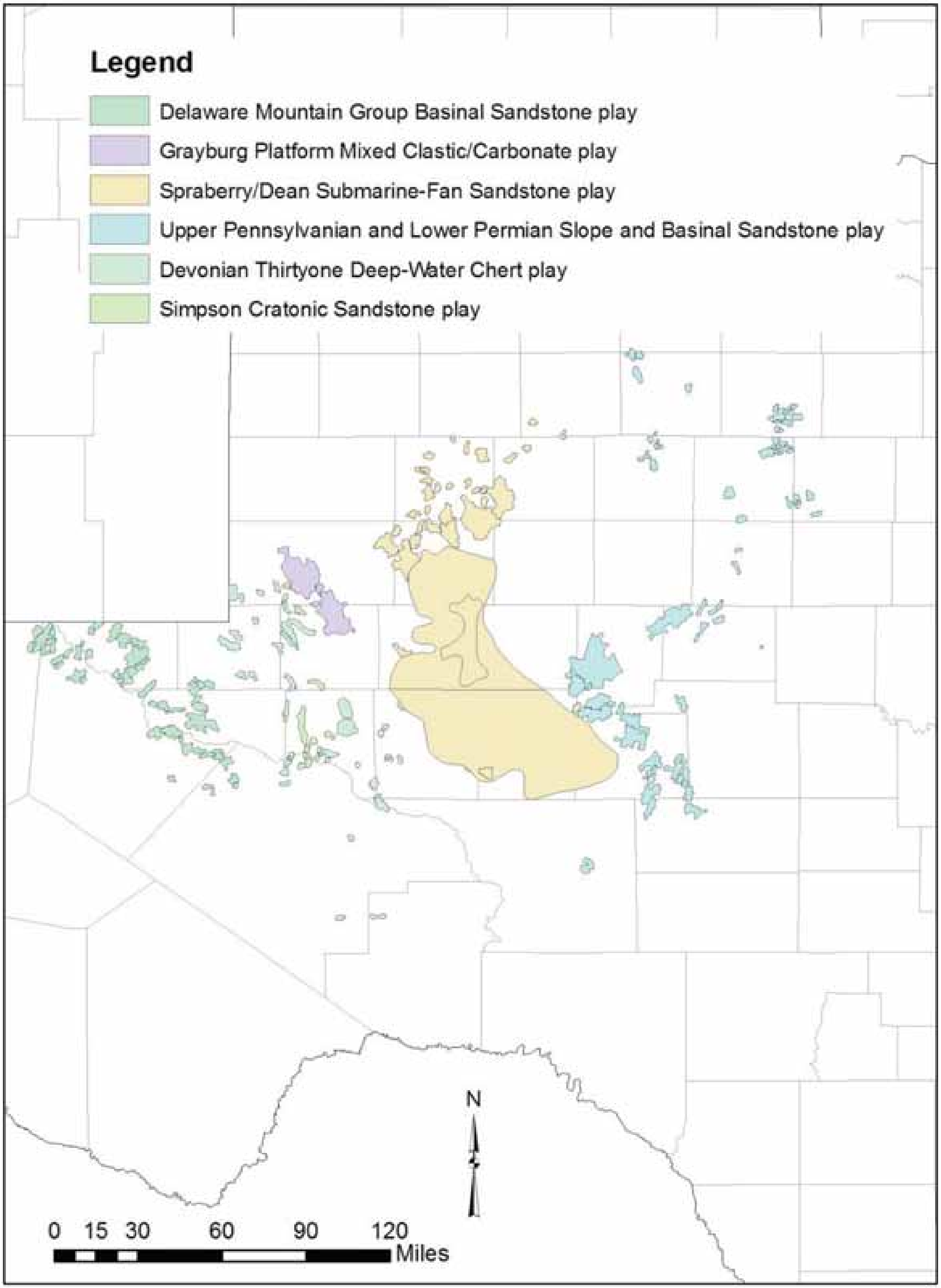
(a)



(b)

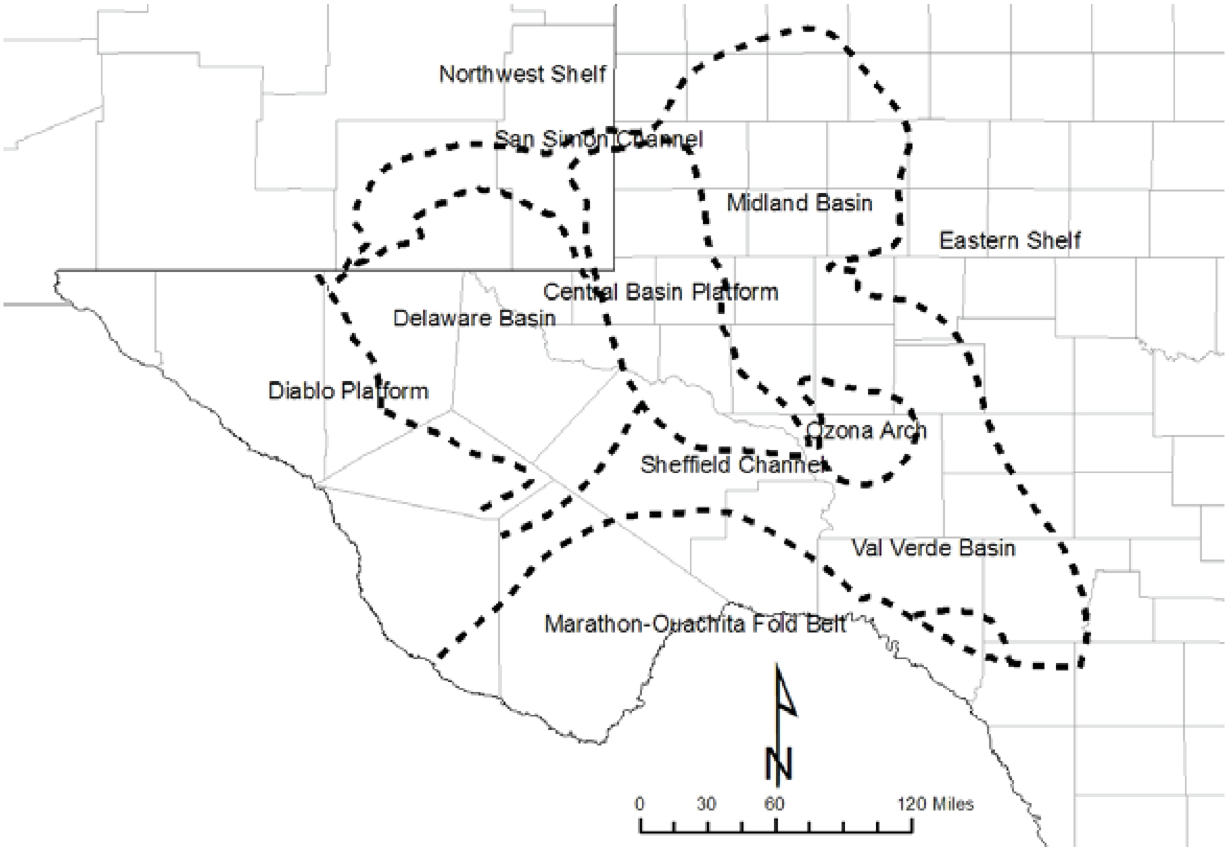
Note: Histograms include only those documented frac jobs using >0.1 Mgal

Figure 62. East Texas Basin—frac water use in vertical wells (a) and horizontal wells (b)



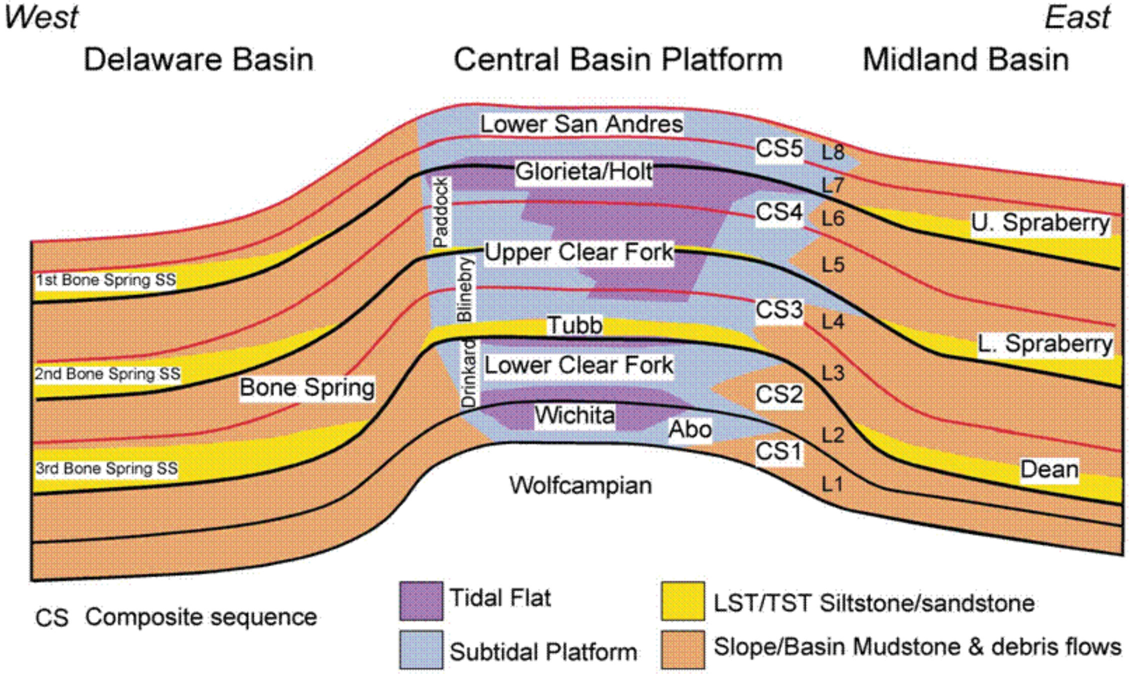
Source: Dutton et al. (2005a—GIS files)

Figure 63. Main clastic plays in the Permian Basin



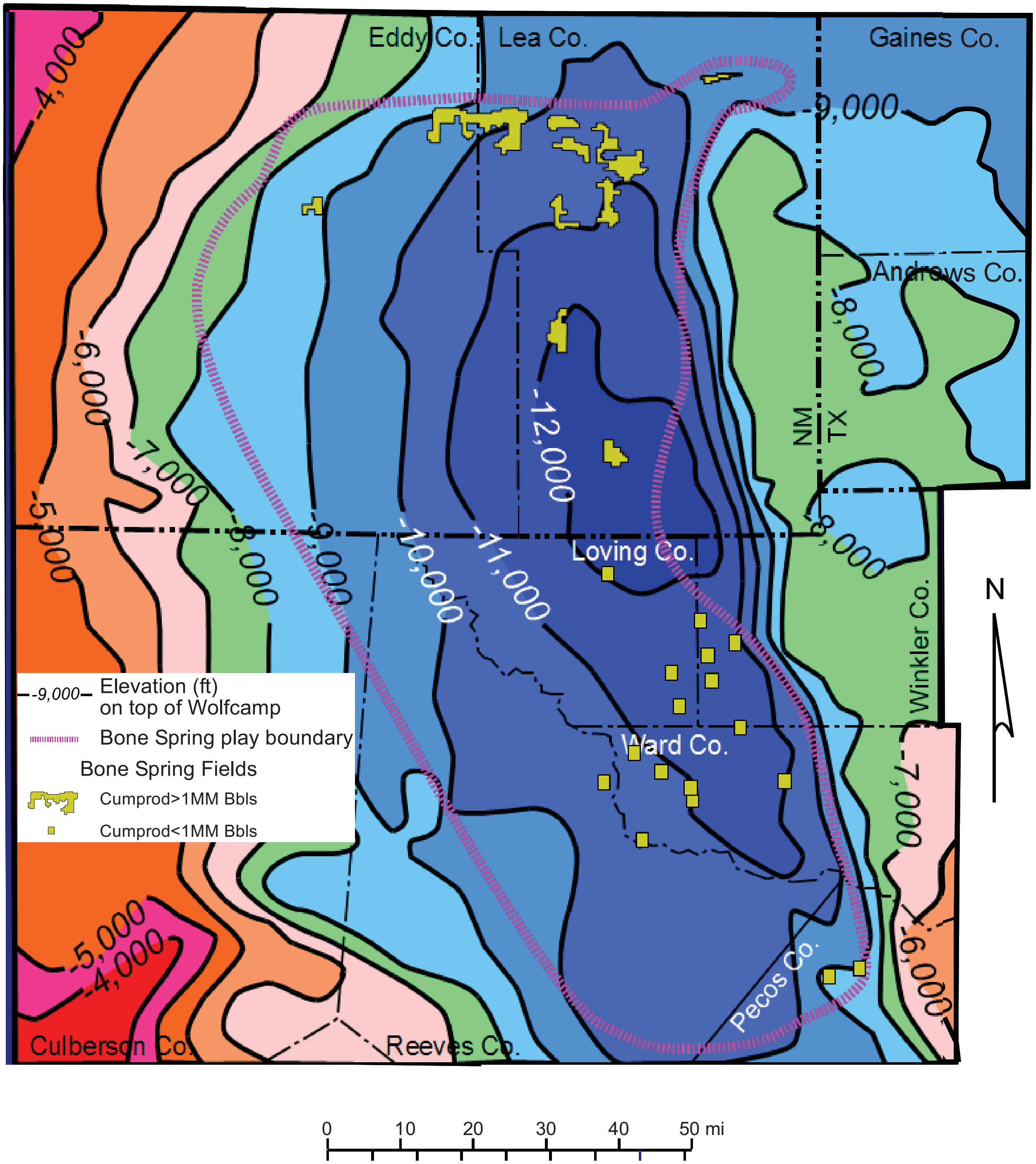
Source: from GIS coverage of companion CD of Dutton et al. (2005a)

Figure 64. Permian Basin geologic features



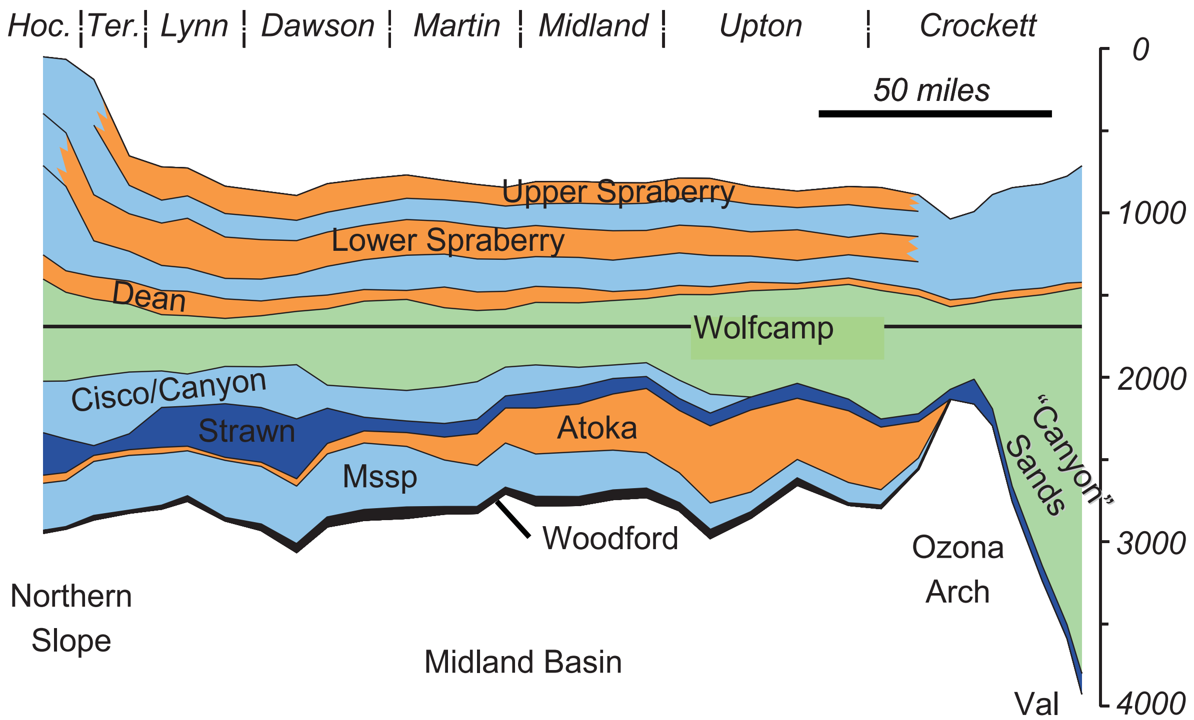
Source: Courtesy of Stephen Ruppel and Mudrock group at BEG

Figure 65. Regional sequence stratigraphy of the Leonardian (Permian)



Source: Seay Nance and the Mudrock Group at BEG

Figure 66. Bone Spring footprint and elevation of top of Wolfcamp



Source: Scott Hamlin and the Mudrock Group at BEG; vertical scale in feet

Figure 67. North-south Midland Basin cross section of Permian (Leonard and Wolfcamp), Pennsylvanian, Mississippian, and Devonian

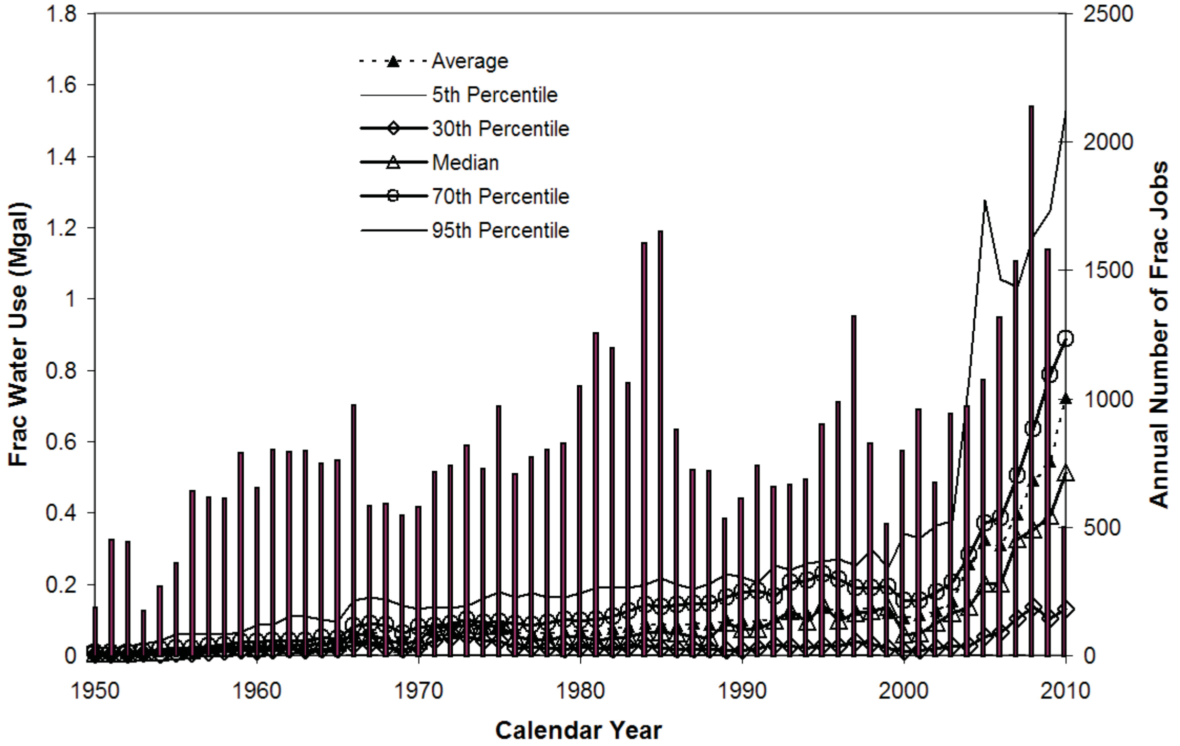


Figure 68. Permian Basin—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use (all 50,000+ wells).

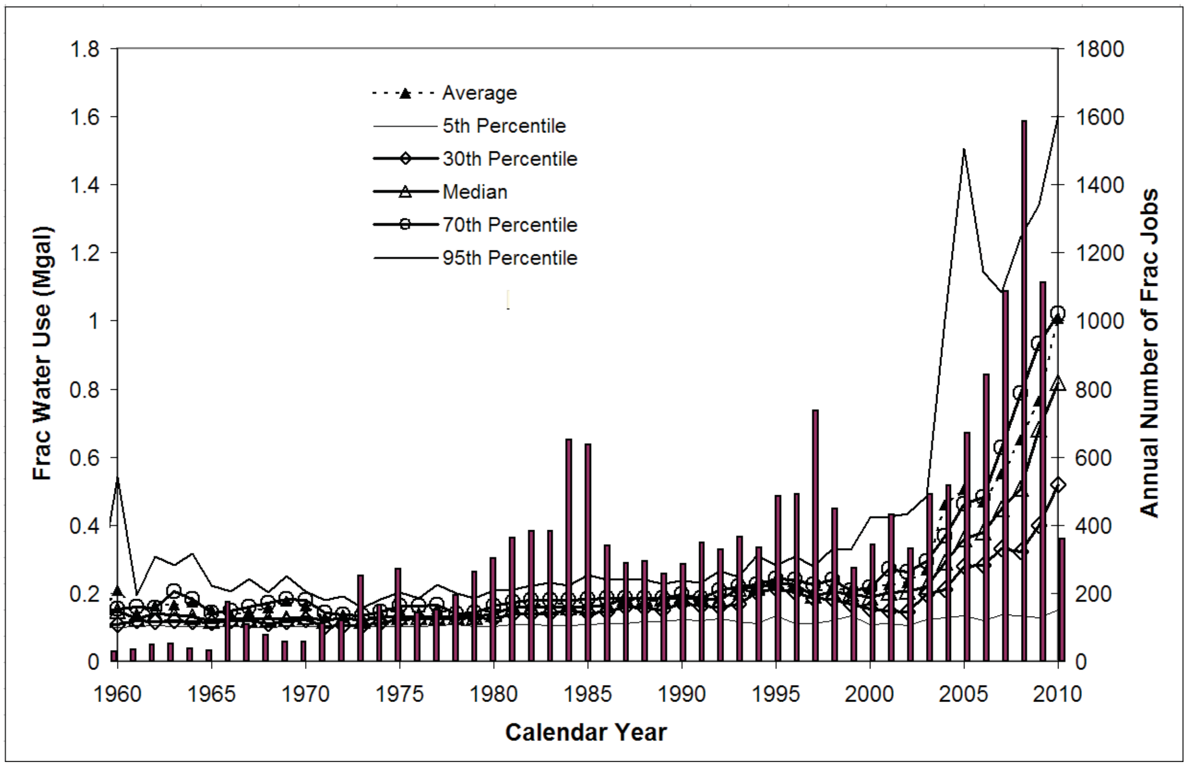


Figure 69. Permian Basin—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use (water use > 0.1 Mgal)

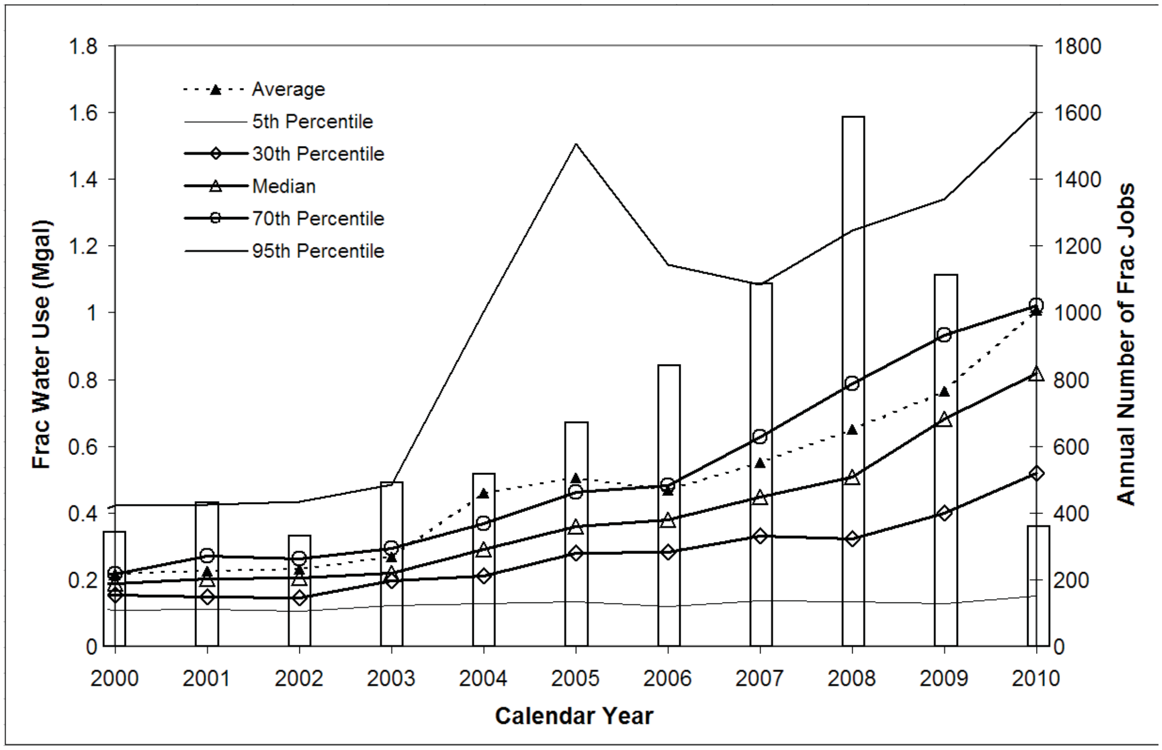


Figure 70. Permian Basin—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use (water use >0.1 Mgal since 2000)

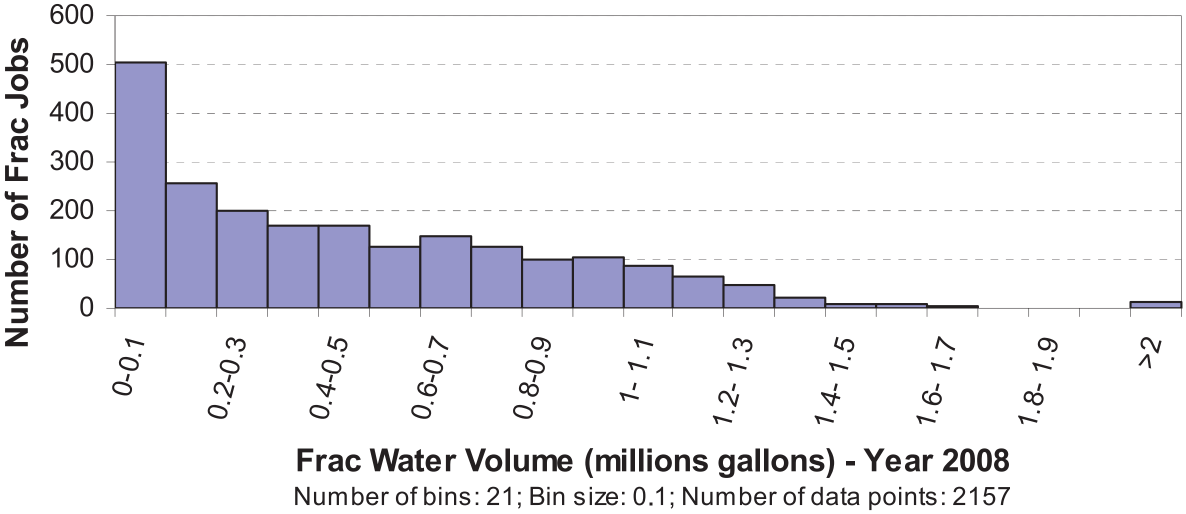


Figure 71. Permian Basin—frac water use in vertical wells

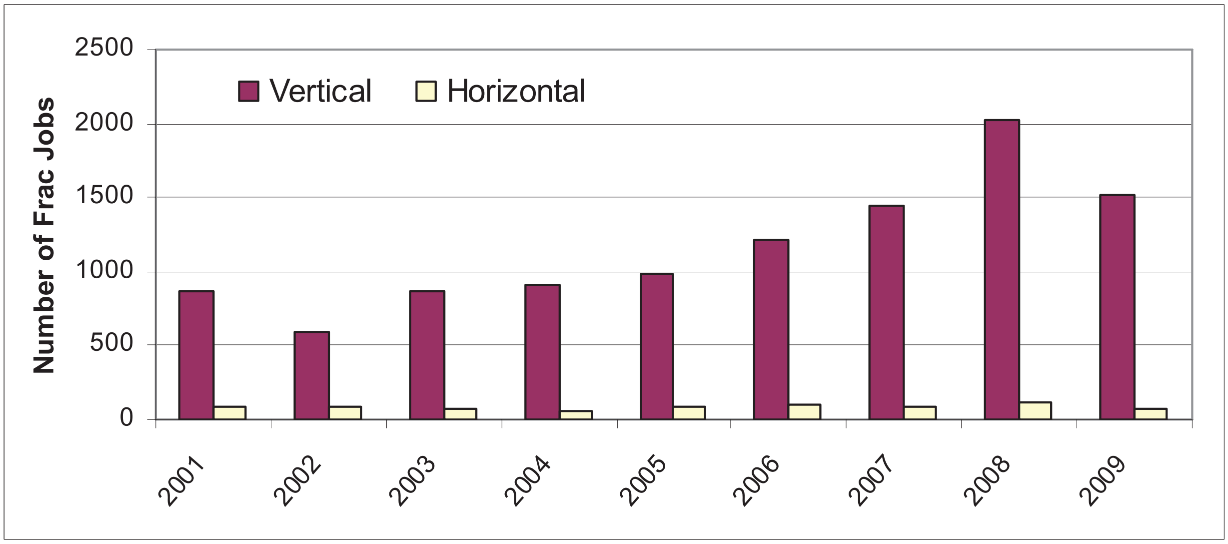
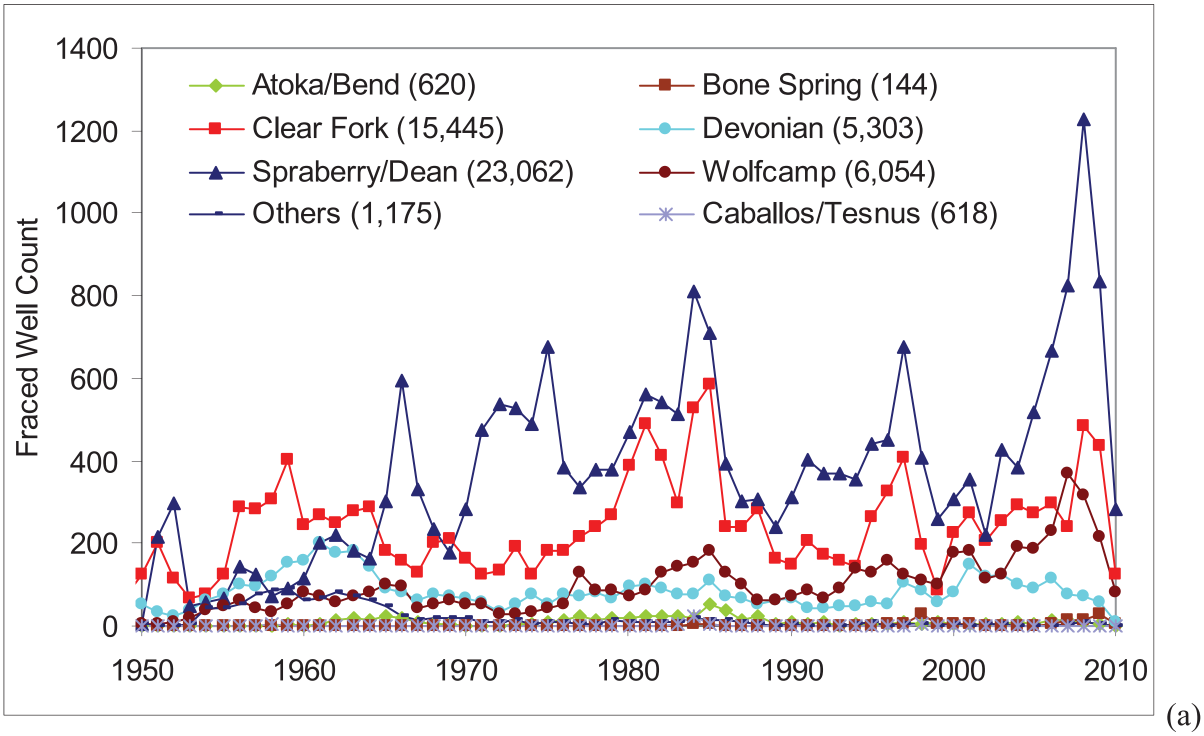


Figure 72. Permian Basin—vertical vs. horizontal wells through time



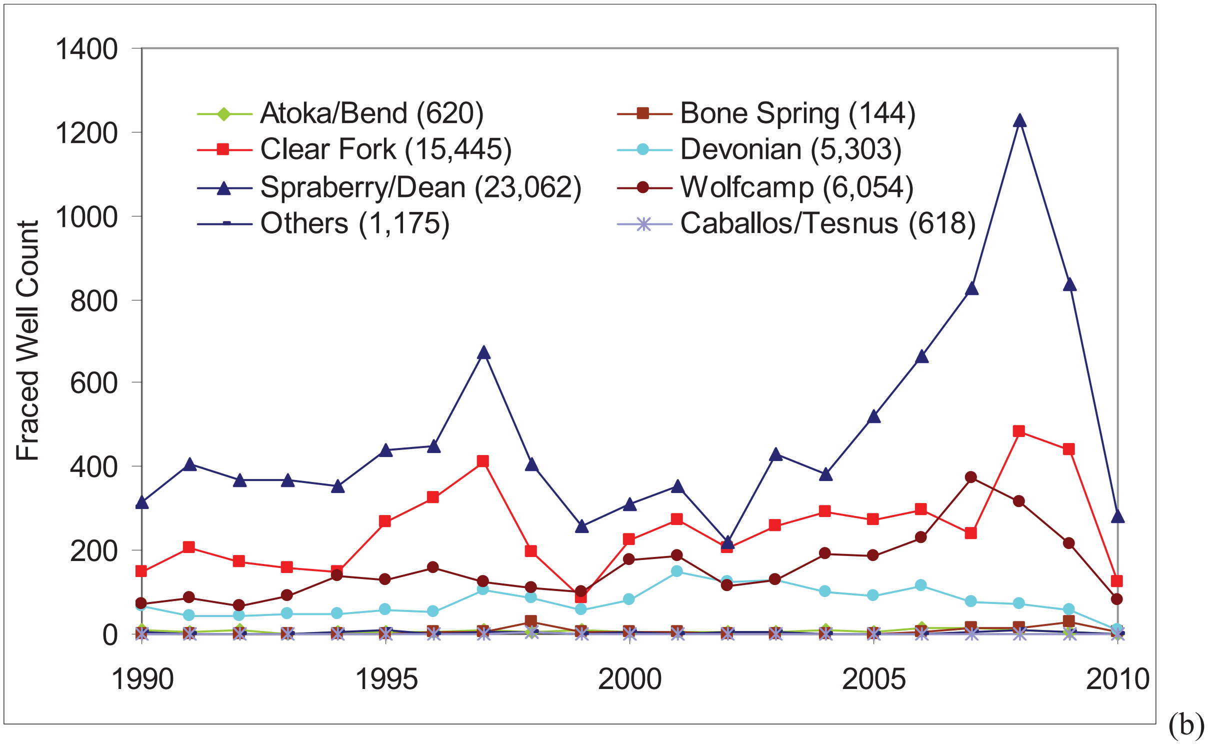
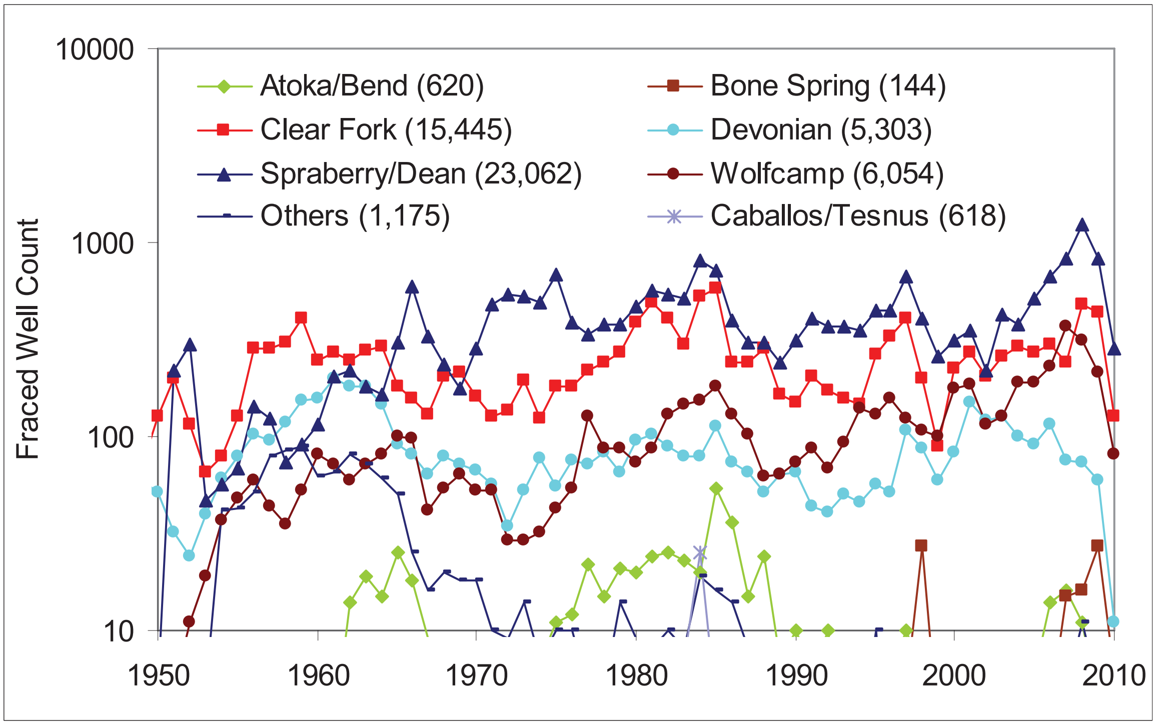
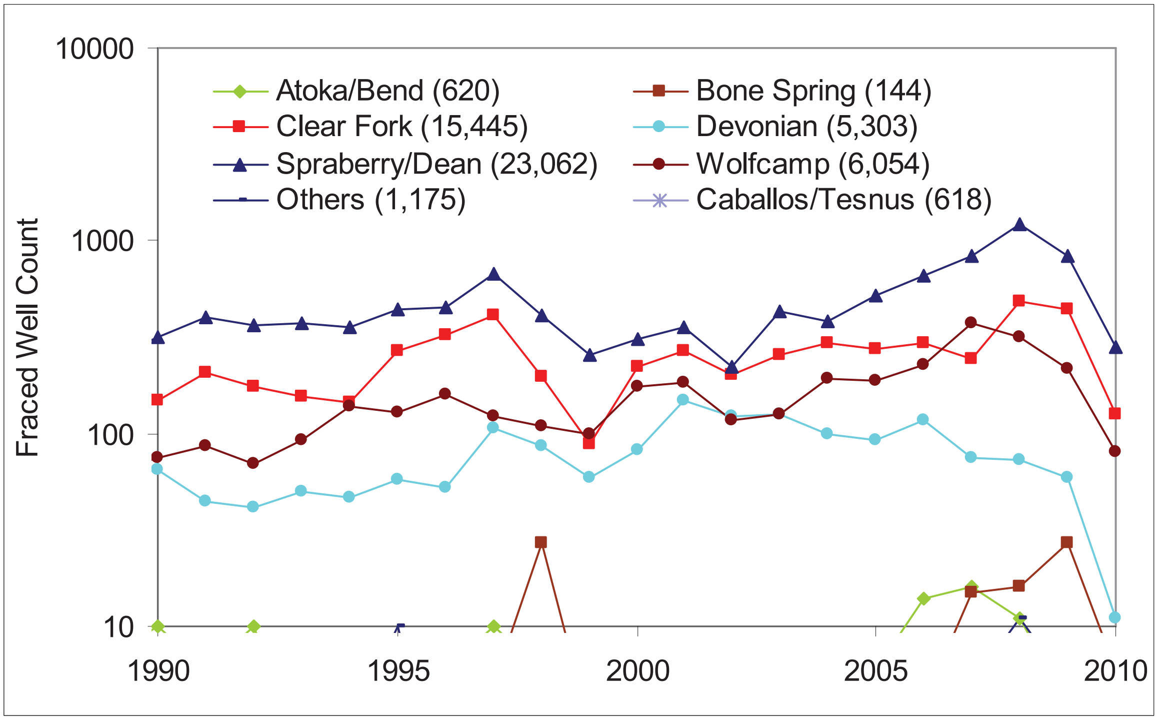


Figure 73. Permian Basin—fraced well count per formation from 1950 (a) and from 1990 (b) (linear scale—including Caballos/Tesnus)



(a)



(b)

Figure 74. Permian Basin—fraced well count per formation from 1950 (a) and 1990 (b) (log scale—including Caballos/Tesnus)

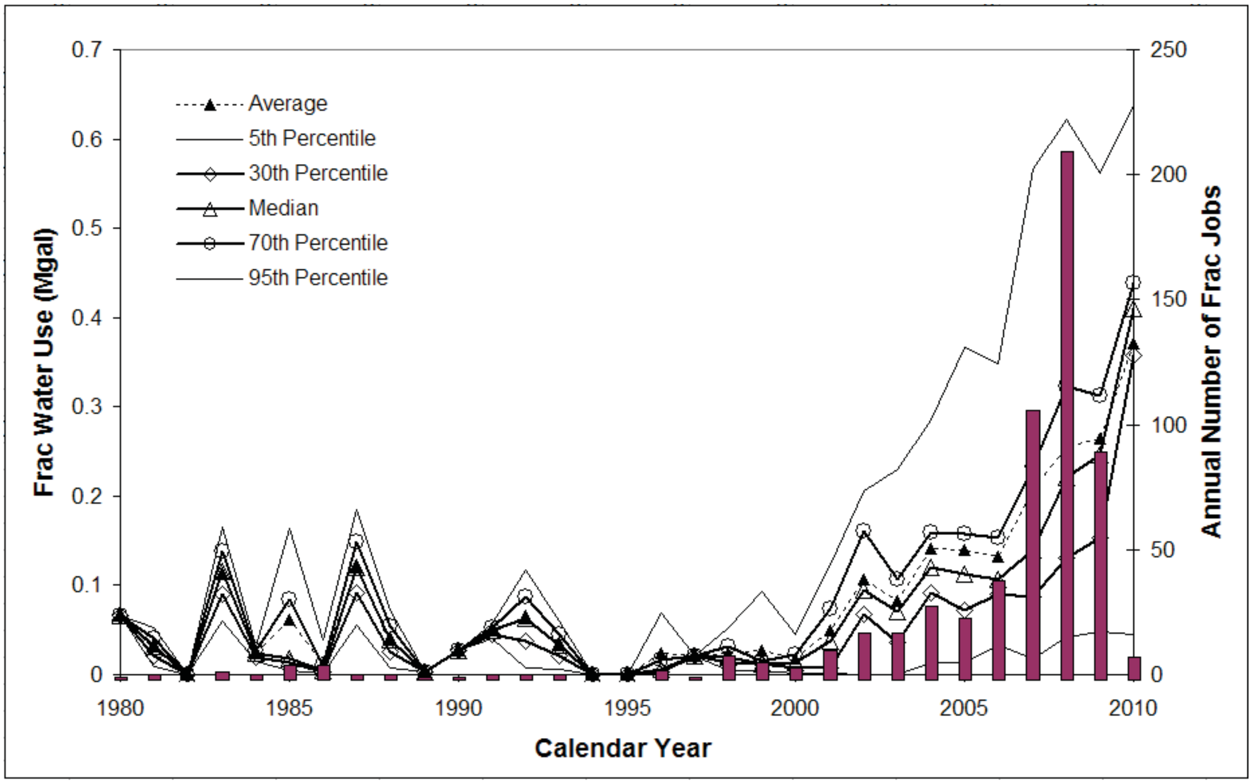


Figure 75. Caballos-Tesnus—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use

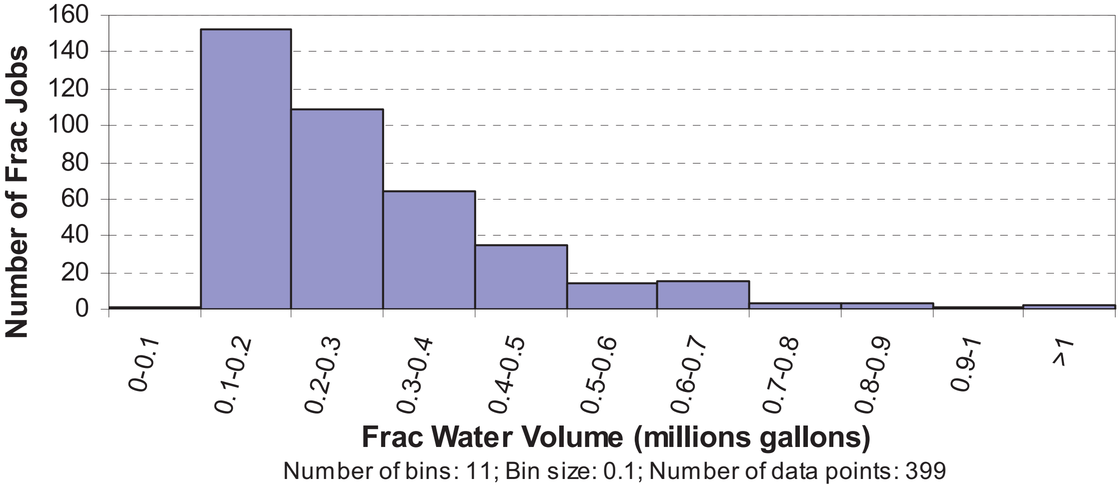


Figure 76. Caballos-Tesnus—frac water volume

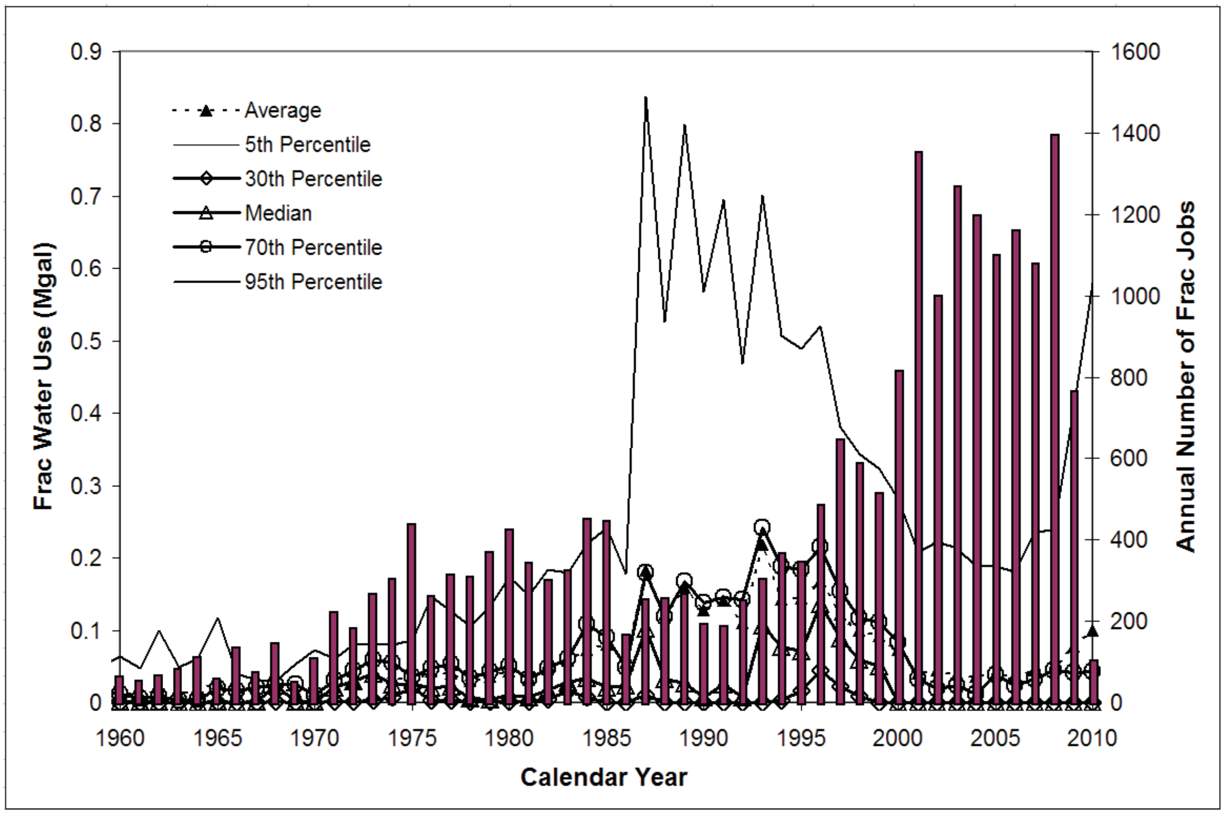


Figure 77. Gulf Coast Basin—annual number of frac jobs superimposed on annual average, median, and other percentiles of individual well frac water use

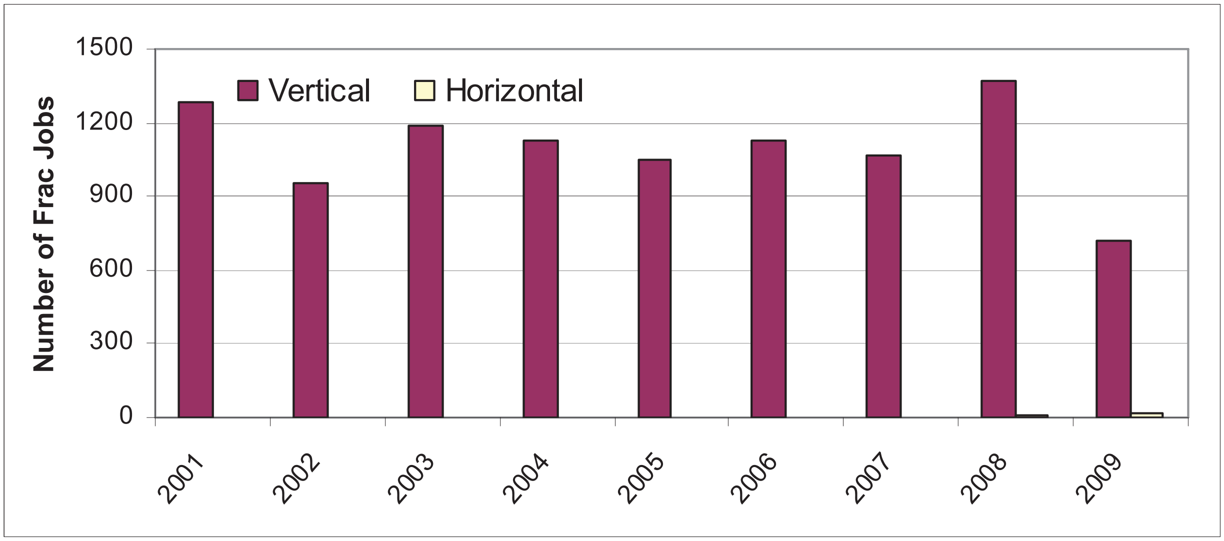
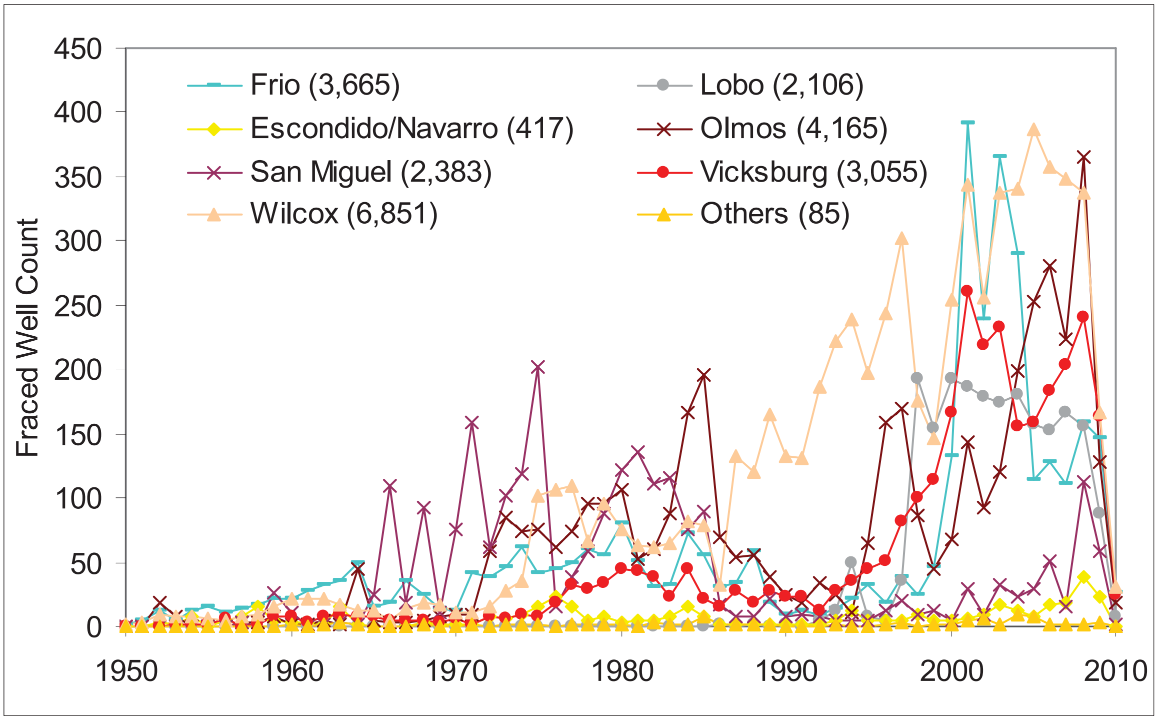
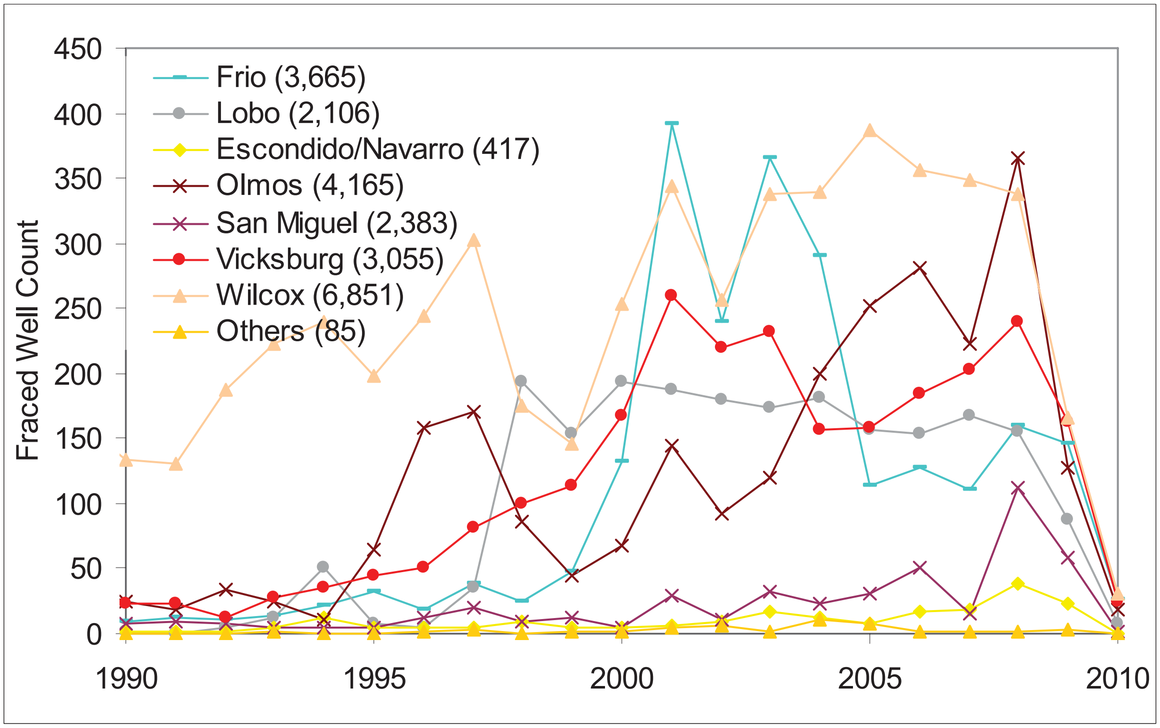


Figure 78. Gulf Coast Basin—vertical vs. horizontal wells through time

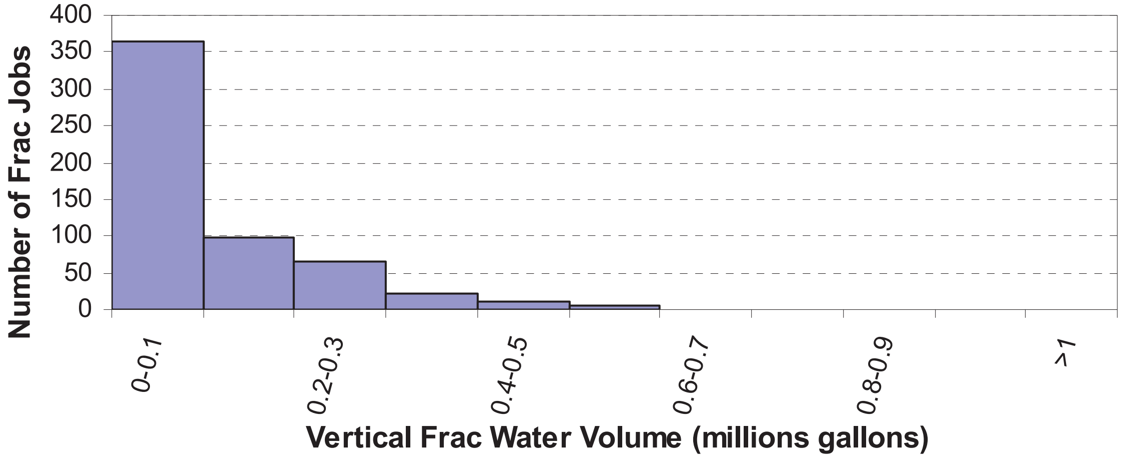


(a)



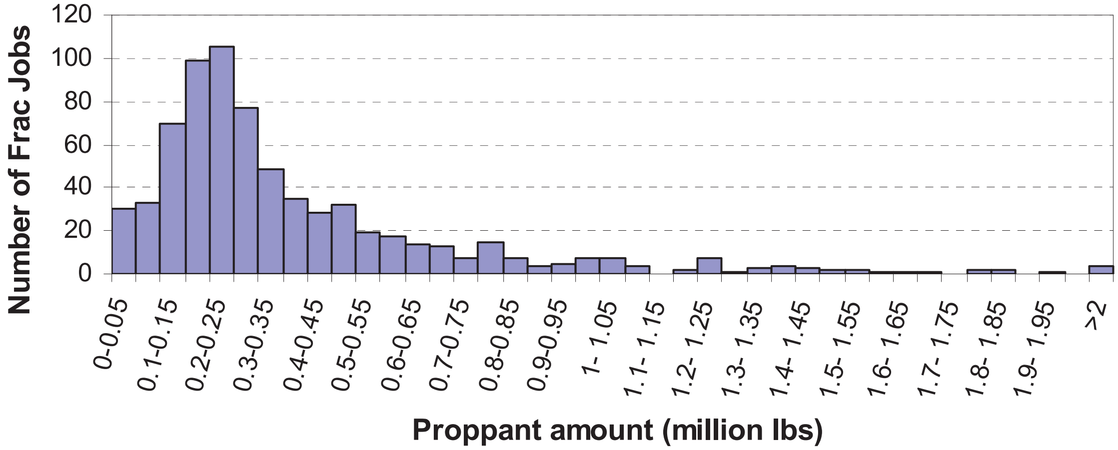
(b)

Figure 79. Gulf Coast Basin—fraced well count per formation from 1950 (a) and 1990 (b)



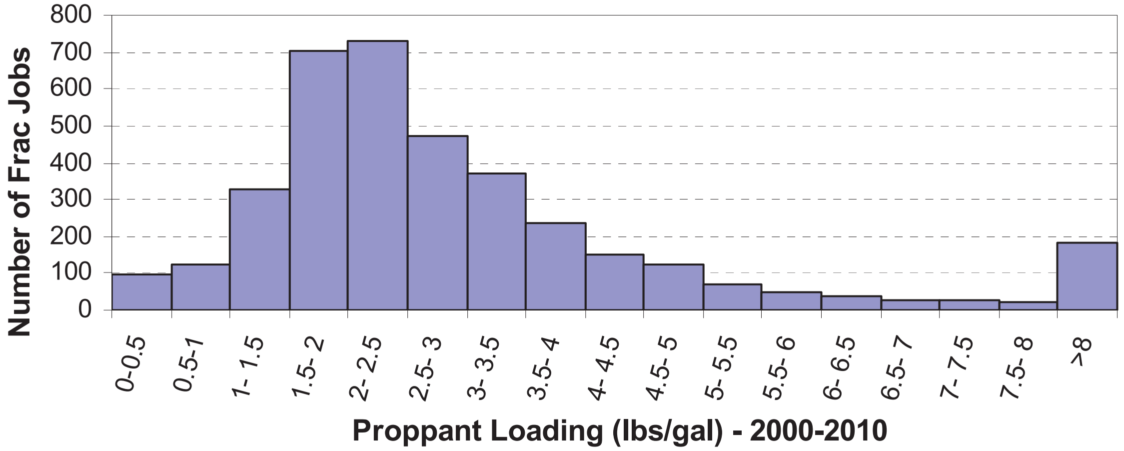
Number of bins: 11; Bin size: 0.1; Number of data points: 567

Figure 80. Gulf Coast—frac water volume (2008)



Number of bins: 41; Bin size: 0.05; Number of data points: 713

Figure 81. Gulf Coast—proppant volume (2008)



Number of bins: 17; Bin size: 0.5; Number of data points: 3738

Figure 82. Gulf Coast—proppant loading (all years)

4.2 Oil and Gas Drilling and Waterflooding

Besides stimulation, the oil and gas upstream industry makes use of fresh water during waterflooding operations and the drilling of wells. The amounts used are uncertain because they are not clearly documented in regulatory forms. In Texas, there is no requirement to document exactly the type of fluids injected in UIC Class II wells (such as those wells used for waterflooding); only the overall total volume and the types of fluids (by "checking a box" in the mandatory H10 form) need be documented, without specifying their share. A cursory calculation also shows that the amount of water used to develop drilling muds for the 10 to 20,000 wells drilled each year in the state could significantly contribute to total fresh water use in the mining category. U.S. DOE (2009, p. 64) put forward a figure of 400,000 and 1,000,000 gal to drill a well in the Barnett and Haynesville Shales, respectively. Volumes undoubtedly vary substantially between wells, and those horizontal wells with long laterals represent the high end of the range. Still, these values are significant and could have a large impact on overall mining water use if all the water is fresh and if the rate per well is sustained at the state level.

4.2.1 Waterflooding

4.2.1.1 Information available before this study

A look at historical reports suggests that the amount of fresh water used in the oil and gas industry has been decreasing during the past few decades. Guyton (1965, p. 40) estimated that in Texas (mostly Permian Basin) and southeast New Mexico, the industry used approximately 50 to 70 thousand AF/yr of fresh water in the early 1960s for the extraction process. In the middle of the 20th century, the RRC used to publish biennial reports on secondary and tertiary recovery, including water use. The latest of such reports seems to have been published in 1982 (RRC, 1982). Fresh-water use was reported at ~80 thousand AF in 1980 and 1981 (Table 15). The latest comprehensive survey of fresh-water use in the oil and gas industry dates back to the 1990s (De Leon, 1996), and fresh water use was estimated at ~30 thousand AF. The survey concerned mostly pressure maintenance, waterflooding, and other EOR techniques, but not drilling. We summarize next the content of the letter report. In 1996, the RRC sent a survey request of fresh and brackish water usage in EOR projects in 1995 to oil and gas operators. The survey was initiated in November 1996 using a special makeup water-survey form (Form H-17). A total of 1,543 forms were mailed, with a return rate of ~84%. Whether the results were scaled to account for unresponsive operators is unclear, but they probably were not. The forms documented the injection of 251,716,698 bbl (32.444 thousand AF) of fresh water during calendar year 1995. Definition of fresh water is more lax than for the rest of this document because it includes all water with a TDS <3,000 mg/L. The volume of fresh water actually injected was only 7.6% of the total fresh water volume permitted for injection in 1995 (3.3 Bbbl). The volume of fresh water actually injected represents 3.3% of the total combined volume of all liquids (7.63 Bbbl) injected ca. 1995. The forms also documented the injection of 78,180,043 bbl (10.077 thousand AF) of brackish water during the same period. Brackish water in this RRC survey is defined as having a TDS between 3,000 and 10,000 mg/L. Brackish-water use represents about (24%) of the combined non-saline water. The top five counties (Gaines, Stephens, Hockley, Yoakum, and Andrews) represent 76% of the total fresh-water consumption, and adding five more (Cochran, Lubbock, Dawson, Garza, and Leon) represents 88% of the total (Table 16 and Figure 83). De Leon (1996) did not document the breakdown of brackish-water use by district or county. All of the top 10 counties belong to the Permian Basin except the last one (Leon County). A total of 55 counties were reported by operators to receive fresh-water injection. Many others in the list are also located in West Texas (Figure 83); RRC districts 8A+8 (~Permian Basin) correspond to 69.4% of total fresh-water injection, and adding district 7B (>99% in Stephens County) increases the share to 92.0%. Adding district 7C instead of district 7B results in 69.7% of total fresh-water injection; a combination of districts 7C, 8, and 8A corresponds to a common definition of the Permian Basin using RRC districts. The large amount of water reported to have been used in 1995 in Stephens County is anomalous, both in terms of its location and of its high county-level water-use coefficient (that is, water amount used in the county divided by county production) (Figure 84) and is investigated later because it makes up >20% of the total fresh water used in 1995 in Texas oil fields. Recomputing the water-use coefficients by including production only from those fields being flooded (list provided in De Leon, 1996) still shows a high coefficient but within the tail of the distribution (Figure 85). Most of the fields are in the 2- to 7-bbl range of water/bbl of oil, although Stephens County regular fields display a water-use coefficient three times higher. Something like this could have happened if a large EOR operation had started around that time, but a look at the production of these combined fields does not show an uptick in production in 1995 (at ~3.7 million barrels) or shortly thereafter, but, instead, a slow decrease until 2002, at which time production stabilized at ~2 million bbl/yr. However, publications by Weiss (1992) and Weiss and Baldwin (1985) suggest that major EOR operations were ongoing at the time in Stephens County.

Approximately ¾ of the fresh water used in 1995 is groundwater, most of it from the Ogallala aquifer (~85% or ~60% of total injected fresh water). However, note that 1995 received less than average precipitation (NOAA historical climatological data and records for Midland) and that groundwater use in that year might have been anomalously high. Another important note concerns double-counting: in 1995 >40% of the fresh water was purchased. Anecdotal evidence suggests that water purchase is still current practice. There is no issue if the water was purchased from wholesalers, but if it was purchased from municipalities, then it may already have been counted toward municipal use.

Total water use of fresh and brackish water in the oil and gas industry amounted to 330 million barrels (42.5 thousand AF) in 1995. RCC (http://www.rrc.state.tx.us/barnettshale/wateruse.php) projected that it would have decreased to 316, 276, 254, and 212 million barrels (40.7, 35.6, 32.7, and 27.3 thousand AF) in 1998, 1999, 2000, and 2001, respectively. Note that these figures were extrapolated before shale-gas growth but may include reporting from tight-gas water use, particularly in East Texas. The basis for these figures is not explained in the RRC documents.

4.2.1.2 Extrapolations from the RRC 1995 Survey

Early studies suggest that most waterfloods take place in West Texas (RRC Districts 8, 8A, and 7C; see Figure 9 for location). In addition, most of the oil produced in the state comes from the Permian Basin (Figure 86 and Figure 87). Only oil reservoirs are typically waterflooded. A look at the number of wells permitted to inject fresh water (Table 17) confirms that Districts 8 and 8A are the center of this practice. This section focuses on these districts. Given the current lack of specific reporting of fresh- and saline-water volumes, our approach is to relate known volumes of oil produced in 1995 with known waterflood water volumes. The 1995 RRC survey is the most recent comprehensive survey to be completed on waterflood water use and was used as a basis for estimating current water use. The RRC survey was combined with another survey performed for this study (Galusky, 2010).

One way to compute future water use is to tie oil production and water use, which can be done at the county level and which is the elemental unit of this study (Figure 84), or at the finer field level (Figure 85). The first step is to analyze 1995 production data vs. RRC survey fresh/brackish-water use (De Leon, 1996). Production numbers were extracted from the RRC online query engine for the calendar year 1995. At the coarsest state level, Texas produced 1134 million barrels in 1995, resulting in an average water use of 0.22 bbl/bbl. If one considers only those counties that reported fresh-water use, the average climbs to 0.79 bbl/bbl for oil production of 319 million barrels. Average water use can be low in some counties (<1 bbl/bbl) because many fields may not undergo secondary or tertiary recovery, but in those counties regularly performing waterfloods, a reasonable average is between 1 and 2.5 bbl/bbl. Field scale seems the most appropriate scale for understanding water use, but even then figures depend on the stage of the waterflood and on the fraction of those production wells not yet impacted by the flood. However, given the relatively large number of fields considered (~100), we expect the data to be representative of waterflood water use in 1995. The "Stephen County Regular" oil field has an anomalously high water use, accounting for ~20+% of total 1995 fresh-water use. Overall fresh-water consumption obtained by summing up all field oil production and water use and taking the ratio is 2.28 bbl/bbl, which is equivalent to making the average per field weighted by the field production. Taking the average, giving the same weight to all fields, results in a value of 5.67 bbl of fresh water/bbl of oil. Somewhat arbitrarily dismissing outlier fields with an average >15 or <1 bbl/bbl results in an average of 4.5 bbl of makeup fresh water/bbl of oil.

A piece of information more readily available than fresh-water injection is total injected fluid volume (made available in RRC records as disposal in producing formations, disposal in nonproducing formations, and waterfloods and other secondary and tertiary recovery processes). Thus, in order to make fresh-water-use projections, we need an estimate of the share of fresh water relative to all water being injected for waterflood secondary-recovery processes. Unfortunately, the RRC website does not currently include injection volumes for 1995, the reference year for fresh-water injection, and we were not able to access the information. It does, however, contain injection volume at the district level for 1998 through 2002 (Table 18, Table 19, and Figure 88). The website (http://www.rrc.state.tx.us/data/wells/statewidewells.php) breaks down water as injected into disposal wells (either in the producing formation or not) or for recovery. Here we are only interested in water used for waterflooding and other recovery processes that represents ~58% of total injection in this year range. Although variable across the years, a representative number is 3.5 million barrels, ~75% of which is injected in districts 08 and 8A in the Permian Basin, and ~90% if districts 7B and 09 are also included. In these four districts, making up almost of the water used for secondary and tertiary recovery, most of the water is used for secondary recovery (>75%) and not disposed of (Figure 89). Percentage of fresh water in the total volume of water used in waterflood varies (Table 20). Contrasting reported waterflood volume (all water types) during the 1998–2002 period to reported fresh water used in 1995 suggests that, at least 10 to 15 years ago, at most 4% of waterflood water was fresh (later we will add correction factors). District 7C is anomalously high at ~14%; a likely reason is that there is less produced water available near the waterflooded field and the proximity of Possum Kingdom Lake in Stephens and neighboring counties. District 8A, with more than half of the state volume of waterflood fresh water, shows a percentage close to 10% fresh-water use, and close to 13% if brackish water is added.

Closer to 2008, after a lack of data for a few years (2003–2006), the RRC website provides data from 2007 through an interactive query site compiled from H10 forms (http://webapps.rrc.state.tx.us/H10/h10PublicMain.do). However, unlike the 1998–2002 period, there is no breakdown in water type. A plot of injection volumes collecting 1998–2002 and

2007–2008 data sets (Figure 91) shows no major change in the injection volume pattern. A simple extrapolation, assuming that waterflood/total injection and fresh-water waterflood ratios have not changed in the past 15 years and using total injection figures from 2007 and 2008, results in total waterflood water use of ~28 thousand AF (Table 21), most of it in district 8A. This value must be considered only preliminary because, as described in the next section, adding correction factors more than halves this initial water-use estimate.

4.2.1.3 Current Waterflooding Water Use

In this section, we integrate results from the Permian Basin operator survey (Galusky, 2010). The survey provided information (1) on added operator reliance on brackish water as opposed to fresh water, (2) on switching from disposal into nonproducing formations to useful injection into producing intervals, and (3) increased dependence on secondary and tertiary recovery, as illustrated in Figure 92, with a stable water-injection level combined with decreasing oil production. The 1995 RRC survey (De Leon, 1996) reports a fresh-water–brackish-water split of ~75%– 25%. New confidential, anecdotal information obtained through the informal survey of Permian Basin producers suggests that the 2010 fresh– brackish water split now favored brackish water –20% fresh water and 80% brackish water. In other words, the fraction of fresh water in the usable (fresh+brackish) water category went down from 75% to 20% in 15 years. In addition, although the information was gathered from Permian Basin operators, we assumed it valid across the state (error, if any, is small at the state level because most fresh water for waterflooding purposes is injected into the Permian Basin). We also assumed that, overall, increased reliance on waterfloods and other recovery processes is balanced by the increased useful use of saline water.

Note that in the following developments we discuss projections to 2060, as well as current fresh-water use. Both are calibrated in the same calculation with the help of the 1995 RRC survey. The estimation (more accurate than the preliminary estimate of the previous section) of historical and forecast water use for oil-field-pressure maintenance in EOR (waterfloods and CO_2 floods) production entailed the following steps:

a- Historical (1995–2010) annual oil production from EOR was estimated on the basis of published data and company surveys and anecdotal information (for waterflood oil production) (Figure 93).

b- Applying and generalizing basic reservoir engineering principles, we estimated that at least 1.3 bbl of water is required for EOR pressure maintenance for every barrel of oil produced.

c- The fresh-water fraction of EOR makeup water in 1995 was estimated to be ~75% of the total. The fresh-water fraction of EOR makeup water in 2010 was estimated to be 20% of the total and was taken from the returned company surveys. We assumed that there has been a linear decline in the fraction of fresh water used in EOR between these periods and that this decline will continue until it reaches a value of 5% by 2023, at which point we forecast that it will hold this percentage through 2060.

d- We estimated the fraction of oil production from EOR in 1995 to be approximately 61% of total oil production and assumed that this fraction increased linearly to a value of 66% in 1997, as estimated by RRC. We then held this rate of annual increase through the last year of the forecast period of 2060. Anecdotal evidence (for example, Henkhaus, 2007) suggests that about ⅔of the oil is produced through EOR processes.

e- Total annual oil production was forecasted by extrapolating 1995– 2010 production through 2060 using a simple exponential decline curve.

f- Makeup water use was then estimated by multiplying the total annual oil production times the fraction of oil production from EOR, times the makeup water factor (1.3 bbl water/bbl oil as described earlier), times the respective water fractions (fresh versus saline/brackish). Makeup water use was calculated in this way for both the historical period of record (1995–2010) and forecasted through the year 2060. This calculation was done on the basis of aggregate regional oil production and on a county-level basis, according to their respective historical and forecast total annual oil production values.

A simple scaling was then applied to those counties outside of districts 8, 8A, and 7C according to their fresh-water use in 1995 and total injection volume in the 2002–2005 period. The state-level estimated 2008 water use for **nonprimary recovery processes is ~13 and 25.5 thousand AF for fresh and brackish water**, respectively (Figure 94 and Table 22). As expected, the spatial distribution of waterflood water use is heavily weighted toward the Permian Basin (Figure 96). We are reasonably confident in the total of 38.5 thousand AF, but less in the distribution between fresh and brackish categories.

4.2.2 Drilling

The number of holes drilled per year in the past 50 years has varied from 30,000+ to <10,000, whereas the number of oil and gas wells completed during the same period has varied from 5,000+ to <25,000 (Figure 95). The holes-drilled category includes, in addition to completed wells, dry holes, service wells, and the like. The past decade has seen a steady increase in the number of wells drilled per year in Texas, which was interrupted only by the recent economic slowdown. A significant fraction is related to recent shale-gas production (gas-well curve crossing over the oil-well curve in Figure 95), but the recent interest in unconventional oil is also visible; many other wells were drilled in conventional reservoirs.

Well drilling requires a fluid carrier to remove the cuttings and dissipate heat created at the drill bit. The fluid also keeps formation-water pressure in check. Broadly, three types of fluids are used: (1) air and air mixtures, (2) water-based muds, and (3) oil-based muds. By far the most common method involves water-based muds. Clean water is needed to optimize the mud performance. Air drilling is traditionally used in the thick unsaturated zone with no source of water nearby or low-permeability formations with sufficient strength, but it is becoming more popular (U.S. DOE, 2009, p. 55), as in the Marcellus Shale in Pennsylvania, in which many wells are drilled in the formation with little added water. For similar subsurface conditions, drilling practices differ from region to region, and we did not attempt a comprehensive study of drilling practices. Oil-based mud is typically used at greater depths or when sensitive clays, for example, could be a problem. As a general rule, a water-supply well (typically the most convenient way of obtaining water) is drilled next to the drilling site, although the amount of water used is not always metered. The amount of water required is what is needed to fill up the well bore, as well as the mud pit (must be large enough to allow time for the fine rock cutting to settle), if neither a closed loop is used nor auxiliary equipment. An additional factor is that for many wells, the mud system has to be changed, at least partly, in the course of the drilling. An approximate rule of thumb would be to multiply the borehole volume by some coefficient. Anecdotal evidence suggests that this multiplier could range from 3 to 6 or higher. Additional water is used to wash equipment to prepare the cement slurry for these wells to be completed. A proper cement set up also requires clean water. Overall, the water used is typically fresh or slightly brackish; produced water is typically not used because it is dirty and the operator would need to treat it at a cost before using it.

Several approaches were followed to collect data on drilling-water use: (1) survey of operators in the Permian Basin (Galusky, 2010), (2) borehole-volume approach with information downloaded from the IHS database, and (3) other, less structured evidence gathered from the literature and through informal discussion with site engineers.

The last category includes documentation published by Chesapeake (2009) of 400,000 gal/well in the Barnett Shale, 600,000 gal/well in the Haynesville Shale, and 125,000 gal/well in the Eagle Ford Shale (Marcellus consumes only 100,000 gal/well). A Chesapeake Barnett well is drilled all the way using water-based mud. The Haynesville is typically much deeper than the Barnett, and the horizontal section is drilled using oil-based mud, whereas most of a Chesapeake Marcellus well is drilled using oil-based muds except for the air-drilling USDW section (M. E. Mantell, personal communication, 2010). No data were collected on the drilling approach in the Eagle Ford Shale. Computing average well-bore volume from the IHS database for the Chesapeake Barnett and Haynesville wells (17.3 and 36 thousand gallons, respectively) provides a multiplier on the order of 15. Barnett Shale survey results from Galusky (2007, p. 7 and Table 1) indicate that, in 2006, about 10% of total water use was dedicated to drilling, that is, 150,000 to 300,000 gal/well. The split between groundwater and surface water is likely to be similar to that of completion (about equal) for those fraced wells. However, the split is unknown for nonfraced wells, although likely to favor groundwater because laying pipes from surface-water bodies would be prohibitively expensive to obtain the relatively small amount of water needed for drilling. More anecdotal evidence from the Middle Pecos GCD suggests that water use for well drilling was in the range of 200,000 to 300,000 gal/well in 2009. A significant fraction of major and minor aquifers in Pecos County are brackish, however, so average fresh water is probably about half of this figure. A rule of thumb applicable at least in the Permian Basin suggests 0.3 to 1 bbl/ft, that is, between 75,000 and 250,000 gal/well for a 6,000-ft-deep well. In Texas, many wells are drilled to the 5,000- to 7,000-ft depth range because many reservoirs are located around those depths (Nicot, 2009b). Another rule of thumb heard during this study was 1 barrel of water per cubic foot of hole, which translates into a multiplier of 5.6.

The borehole-volume approach consists of extracting dimension information about all wells drilled in Texas in a given year (Table 23), correcting for those wells with no casing information (20% on average) and applying a multiplier to estimate drilling-water use. The average Texas well has a volume of ~15,000 gallons. Clearly, the deeper the well, the larger the water use. However, the increase is not linear for several reasons: borehole diameter decreases with depth in a stepwise fashion, the use of several mud systems is more likely, surface installation are larger. We initially used a multiplier of five to find average drilling-water use during the past decade of ~3,000 AF, varying from 2.4 to 4.6 thousand AF/yr. However, in light of survey returns (see later section) and increased interest in generally deeper gas shales, a multiplier of 10 seemed more realistic, resulting in an initial preliminary estimate for average drilling-water use of 6 thousand AF/yr in the past decade across the state.

The third approach consisted of accessing the information through an operator survey in the Permian Basin (Galusky, 2010) in districts 8, 8A, and 7C, which consistently represent one-third of the wells drilled in Texas (Table 24). A reasonable value used for the computation was ~130,000 gal/well (0.41 AF/well) of fresh water combined with ~500,000 gal/well (1.59

AF/well) of brackish and saline water. This computation resulted in total water use for the three districts of ~2,300 AF in 2008 (~6,300 wells spudded according to IHS database) and ~2,200 AF in 2010, amounts not predicted to grow unless shale-gas production takes hold in a strong way in West Texas.

Although not negligible at the state level, drilling water use is distributed across all oil- and gas-producing counties in the state. In 2008, about ~20,000 wells had been spudded in Texas (IHS database and RRC website). Barnett Shale Tarrant and Johnson Counties had the most wells spudded, 825 and 890, respectively. Assuming an average 0.4 million gal water use per well (conservative because vertical wells are also included in the count) results in drilling-water use of 1,000 AF in each county. Next are Permian Basin counties (Andrews, Upton, Ector, Pecos, Webb, Martin, and Midland, in decreasing order of number of wells), with 550 to ~250 wells spudded per county in 2008, resulting in 0.23 to 0.1 thousand AF per county. A final figure of 130,000 gal/well for 20,000 wells was eventually retained, leading to a **drilling-fresh-water use of 8.0 thousand AF**. Note that reuse is likely occurring in the drilling field as flowback water from fracing operations can be used for drilling additional wells. There is no data on how widespread the practice is.

Table 15. Historical water use in secondary and tertiary recovery (million barrels)

	Saltwater		Brackish Water		Fresh Water		BW	FW
	(million bbl)							
District	**1980**	**1981**	**1980**	**1981**	**1980**	**1981**	**1995**	**1995**
1	13.0	12.4	13.3	17.3	4.5	3.4		1.4
2	31.6	20.6	0.0	0.0	0.0	0.0		0.0
3	71.6	59.9	0.0	0.0	0.1	0.0		0.0
4	84.8	79.6	0.1	0.0	0.0	0.0		0.0
5	14.3	9.3	0.0	0.0	1.1	1.0		4.2
6	57.8	57.5	2.4	2.4	23.8	24.6		8.5
6E	0.5	1.6	5.1	6.2	1.0	1.0		0.8
7B	131.6	133.5	1.7	1.4	46.0	41.5		57.0
7C	53.2	52.1	8.3	6.7	5.8	4.7		1.0
8	603.8	617.2	462.7	440.4	73.5	81.2		19.3
8A	791.3	855.1	42.1	41.0	453.3	413.3		155.3
9	277.8	292.3	3.3	3.3	12.4	12.1		1.1
10	19.6	20.5	0.0	0.0	15.9	14.5		3.1
Total	**2150.9**	**2211.6**	**539.1**	**518.7**	**637.5**	**597.3**	**78.2**	**251.7**

Source: RRC (1982) and De Leon (1996)

Historical Injection 2=fromRRC1982Report.xls

Table 16. Fresh-water use in EOR operations (1995 RRC survey)

County	Fresh-Water Use (bbl)	County	Fresh-Water Use (bbl)	County	Fresh-Water Use (bbl)
Gaines	59,347,090	Frio	1,076,890	Williamson	95,238
Stephens	56,208,617	Irion	963,590	Bastrop	88,625
Hockley	42,684,399	Scurry	896,000	Ward	73,000
Yoakum	19,466,366	Gregg	818,571	Bowie	70,262
Andrews	12,520,625	Marion	640,379	Cass	54,750
Cochran	8,857,214	Franklin	628,405	Stonewall	44,147
Lubbock	8,146,162	Nolan	557,791	Panola	42,323
Dawson	5,517,713	Young	534,265	Hardin	40,783
Garza	4,448,645	Winkler	365,000	Atascosa	22,850
Leon	4,203,810	Howard	220,462	Jack	15,602
Ector	3,574,347	Martin	214,778	Archer	4,305
Anderson	3,145,589	Dickens	196,060	Coleman	3,000
Gray	3,145,143	Clay	194,280	Callahan	1,800
Hale	2,421,237	Rusk	163,173	Tom Green	375
Terry	2,139,628	Eastland	158,393	Wilson	45
Smith	1,933,184	Zavala	143,054		
Wood	1,658,113	Cooke	134,394	**Total (bbl)**	**251,716,698**
Pecos	1,257,715	Camp	120,745	**Total (AF)**	**32,444**
Lynn	1,149,368	Knox	117,233		
Mitchell	1,090,170	Wichita	100,995		

Source: De Leon (1996)

FreshWater+OilProduction_RCC1995.xls

Table 17. Number of permitted fresh-water injection wells as of January 2010

District	Injection into Nonproducing Intervals	Injection into Production Formation	Secondary Recovery	Total
01	5	18	380	403
02	1	1	0	2
03	0	1	3	4
04	3	0	5	8
05	1	0	68	69
06	3	42	244	289
6E	0	8	40	48
7B	1	39	628	668
7C	0	5	87	92
08	1	81	3,961	4,043
8A	5	368	9,075	9,448
09	2	12	112	126
10	2	30	199	231
Total	24	605	14,802	15,431

Source: Fernando De Leon (RRC, January 2010) custom data pull

Table 18. District-level total water injection volume vs. waterflood volumes (1998)

1998—All volumes in bbl						
District	**Disposal in nonprod. zone**	**Disposal in prod. zone**	**Waterflood**	**Other**	**Total**	**Water-flood/ Total**
1	221,676,839	36,224,868	21,626,651	0	279,528,358	7.7%
2	121,625,598	29,673,891	58,255,145	0	209,554,634	27.8%
3	378,303,159	77,043,184	38,606,639	1,653,895	495,606,877	7.8%
4	77,713,906	19,949,912	29,217,354	0	126,881,172	23.0%
5	24,783,981	29,833,615	15,594,964	0	70,212,560	22.2%
6	122,873,017	73,922,979	53,064,690	0	249,860,686	21.2%
6E	0	356,784,106	26,290,016	0	383,074,122	6.9%
7B	25,100,019	28,512,343	321,250,271	0	374,862,633	**85.7%**
7C	45,307,377	73,054,222	79,496,652	0	197,858,251	40.2%
8	139,510,861	208,640,430	1,203,840,221	341,660	1,552,333,172	**77.6%**
8A	68,752,368	115,105,922	1,211,495,952	0	1,395,354,242	**86.8%**
9	24,556,396	36,674,585	198,195,141	15,370	259,441,492	76.4%
10	25,714,081	24,599,525	20,115,688	0	70,429,294	28.6%
Totals:	**1,275,917,602**	**1,110,019,582**	**3,277,049,384**	**2,010,925**	**5,664,997,493**	**57.8%**

Source: RRC website

Iniection Volume 2002 RRC +1998-2001.xls

http://www.rrc.state.tx.us/data/wells/statewidewells.php

Note: includes all water types (fresh to saline, produced and others)

Table 19. District-level total water-injection volume vs. waterflood volumes (2002)

Year 2002—All volumes in bbl						
District	**Disposal in nonprod. zone**	**Disposal in prod. zone**	**Waterflood**	**Other**	**Total**	**Waterflood / Total**
1	209,482,615	29,795,963	12,464,957	0	251,743,535	5.0%
2	112,608,696	20,504,067	56,234,669	0	189,347,432	29.7%
3	323,989,781	71,070,254	23,308,202	292,511	418,660,748	5.6%
4	84,577,088	13,963,848	21,024,812	0	119,565,748	17.6%
5	36,118,853	28,867,538	15,452,586	0	80,438,977	19.2%
6	149,292,665	86,293,340	41,801,873	0	277,387,878	15.1%
6E	158,881	348,180,269	31,694,999	0	380,034,149	8.3%
7B	24,602,044	26,477,559	252,445,261	1,528	303,526,392	**83.2%**
7C	40,711,999	63,911,860	88,144,873	0	192,768,732	45.7%
8	152,802,343	194,498,880	1,163,394,951	159,900	1,510,856,074	**77.0%**
8A	65,416,720	114,281,934	1,258,302,110	0	1,438,000,764	**87.5%**
9	26,395,288	30,699,374	156,616,151	27,386	213,738,199	73.3%
10	16,073,237	19,443,141	16,880,842	0	52,397,220	32.2%
Totals:	**1,242,230,210**	**1,047,988,027**	**3,137,766,286**	**481,325**	**5,428,465,848**	**57.8%**

Source: RRC website InjectionVolume_2002_RRC_+1998-2001.xls

http://www.rrc.state.tx.us/data/wells/statewidewells.php

Note: includes all water types (fresh to saline, produced and others)

Table 20. Estimated district-level fraction of fresh-water in waterflood water volumes

District	**Waterflood water use average (all types) 1998–2002 (million bbl)**	**1995 fresh-water use (million bbl)**	**Fresh / Total**	**Fresh + Brack / Total***
01	267.0	1.43	0.53%	0.70%
02				
03	496.5	0.04	0.01%	0.01%
04				
05	81.6	4.20	5.15%	6.75%
06	288.4	8.46	2.93%	3.84%
6E	420.7	0.82	0.19%	0.00%
7B	393.8	56.97	14.47%	18.95%
7C	223.6	0.96	**0.43%**	**0.56%**
08	1,689.3	19.32	**1.14%**	**1.50%**
8A	1,578.3	155.27	**9.84%**	**12.89%**
09	252.1	1.10	0.44%	0.57%
10	69.6	3.15	4.52%	5.92%
Totals	**5,760.8**	**251.72**	**4.37%**	**5.59%**

InjectionVolume_2002_RRC_+1998-2001.xls

*Obtained by multiplying by the same coefficient of 1.31 for all districts to account for brackish-water use

Table 21. Initial guess for extrapolated district-level fresh-water use for waterfloods

District	1998–2002 Average Fraction of Waterflood vs. Total Injection	1995 Fresh-Water Use Fraction vs. Total Waterflood	Average 2007–2008 Total Injection (million bbl)	Extrapolated Fresh-Water Use (thousand AF)
01	6.1%	0.53%	485.0	**0.02**
02	28.5%	0%	[213.7]	
03	6.3%	0.01%	469.0	**0.00**
04	20.3%	0%	[137.0]	
05	19.8%	5.15%	197.0	**0.26**
06	11.7%	2.93%	756.6	**0.15**
7B	84.8%	14.47%	388.0	**6.13**
7C	42.9%	0.43%	287.5	**0.07**
08	77.2%	1.14%	1,652.7	**1.88**
8A	87.5%	9.84%	1,716.3	**19.03**
09	74.0%	0.44%	263.9	**0.11**
10	31.5%	4.52%	105.7	**0.19**
Total	58.2%	4.37%	6321.62	**27.85**

InjectionVolume 2002 RRC +1998-2001 1.xls

Table 22. County-level estimate of fresh-water use for waterfloods

County	Fresh 2008	Fresh 2010	Brack 2008	Brack 2010	County	Fresh 2008	Fresh 2010	Brack. 2008	Brack. 2010
State Total	**12.95**	**7.87**	**25.52**	**29.91**					
Anderson	0.013	0.008	0.026	0.031	Lipscomb	0.005	0.003	0.009	0.011
Andrews	0.552	0.384	1.243	1.457	Loving	0.038	0.074	0.240	0.282
Archer	0.005	0.003	0.009	0.010	Lubbock	0.359	1.307	4.239	4.968
Atascosa	0.001	0.001	0.002	0.002	Lynn	0.051	0.207	0.670	0.785
Baylor	0.000	0.000	0.001	0.001	Marion	0.001	0.001	0.002	0.002
Borden	0.123	0.000	0.000	0.000	Martin	0.009	0.084	0.273	0.320
Brown	0.008	0.005	0.016	0.018	Maverick	0.001	0.001	0.003	0.003
Callahan	0.029	0.018	0.057	0.067	McCulloch	0.010	0.009	0.029	0.034
Camp	0.004	0.003	0.009	0.010	McMullen	0.001	0.000	0.001	0.001
Carson	0.001	0.000	0.001	0.001	Menard	0.002	0.250	0.809	0.948
Clay	0.002	0.001	0.004	0.004	Midland	0.328	0.035	0.114	0.134
Cochran	0.390	0.005	0.017	0.020	Mitchell	0.048	0.003	0.009	0.011
Coke	0.034	0.109	0.355	0.416	Montague	0.006	0.004	0.012	0.014
Coleman	0.035	0.021	0.068	0.080	Moore	0.001	0.001	0.003	0.003
Comanche	0.001	0.000	0.001	0.001	Motley	0.004	0.027	0.089	0.104
Concho	0.027	0.108	0.351	0.412	Navarro	0.004	0.002	0.007	0.008
Cooke	0.007	0.004	0.014	0.016	Nolan	0.074	0.045	0.146	0.171
Cottle	0.002	0.007	0.022	0.026	Ochiltree	0.006	0.004	0.012	0.015
Crane	0.399	0.027	0.086	0.101	Oldham	0.005	0.003	0.010	0.012

County	Fresh 2008	Fresh 2010	Brack 2008	Brack 2010	County	Fresh 2008	Fresh 2010	Brack. 2008	Brack. 2010
Crockett	0.086	0.007	0.021	0.025	Palo Pinto	0.029	0.018	0.058	0.068
Crosby	0.020	0.228	0.739	0.866	Pecos	0.055	0.066	0.212	0.249
Culberson	0.007	0.033	0.108	0.127	Potter	0.001	0.000	0.001	0.002
Dawson	0.243	0.039	0.125	0.146	Reagan	0.152	0.024	0.077	0.090
Dickens	0.009	0.000	0.000	0.000	Red River	0.001	0.001	0.003	0.003
Dimmit	0.001	0.000	0.001	0.002	Reeves	0.027	0.019	0.061	0.071
Eastland	0.115	0.070	0.228	0.267	Runnels	0.027	0.060	0.194	0.228
Ector	0.158	0.019	0.061	0.072	Rusk	0.019	0.011	0.037	0.044
Fisher	0.150	0.091	0.295	0.345	Schleicher	0.016	0.030	0.096	0.112
Floyd	0.000	0.031	0.101	0.119	Scurry	0.039	0.000	0.000	0.000
Foard	0.001	0.001	0.002	0.002	Shackelford	0.075	0.046	0.148	0.173
Franklin	0.002	0.001	0.004	0.004	Sherman	0.003	0.002	0.006	0.007
Freestone	0.002	0.001	0.004	0.005	Smith	0.007	0.004	0.014	0.016
Gaines	2.616	0.002	0.007	0.008	Stephens	1.786	1.086	3.520	4.126
Garza	0.196	0.011	0.036	0.042	Sterling	0.045	0.007	0.023	0.027
Glasscock	0.156	0.085	0.276	0.324	Stonewall	0.218	0.132	0.430	0.503
Gray	0.024	0.014	0.047	0.055	Sutton	0.001	0.001	0.005	0.005
Grayson	0.002	0.001	0.004	0.004	Taylor	0.025	0.015	0.049	0.057
Hale	0.107	0.271	0.880	1.031	Terrell	0.004	0.106	0.343	0.401
Hansford	0.002	0.001	0.003	0.004	Terry	0.094	0.019	0.061	0.072
Hartley	0.003	0.002	0.005	0.006	Throckmorton	0.069	0.042	0.137	0.160
Haskell	0.031	0.019	0.061	0.072	Titus	0.003	0.002	0.005	0.006
Hockley	1.881	0.001	0.004	0.005	Tom Green	0.032	0.011	0.036	0.042
Hopkins	0.015	0.009	0.029	0.034	Upshur	0.012	0.007	0.024	0.028
Howard	0.010	0.014	0.046	0.053	Upton	0.315	0.000	0.001	0.002
Hutchinson	0.006	0.004	0.013	0.015	Van Zandt	0.019	0.012	0.038	0.044
Irion	0.042	0.169	0.548	0.642	Ward	0.003	0.003	0.010	0.012
Jack	0.001	0.001	0.002	0.002	Wheeler	0.001	0.000	0.001	0.002
Jones	0.041	0.025	0.080	0.094	Wichita	0.020	0.012	0.040	0.047
Kent	0.297	0.006	0.019	0.023	Wilbarger	0.003	0.002	0.005	0.006
King	0.121	1.818	5.893	6.907	Wilson	0.001	0.000	0.001	0.001
Knox	0.001	0.001	0.002	0.003	Winkler	0.016	0.022	0.071	0.083
Lamb	0.013	0.136	0.442	0.518	Wood	0.006	0.004	0.012	0.014
Leon	0.019	0.011	0.037	0.043	Yoakum	0.858	0.219	0.709	0.832
Limestone	0.001	0.001	0.002	0.003	Young	0.003	0.002	0.005	0.006

InjectionVolume_2002_RRC_+1998-2001_1.xls

Table 23. Estimated and calculated oil and gas well drilling water use

	No. of Wells w/ Casing Data	Average Borehole Volume (gal/well)	Total BH Volume (Mgal)	Total BH Volume (Th. AF)	Total No. of Wells	Corrected Total BH Volume (Th. AF)	Multiplier	Water Use (Th. AF /yr)
2009	9,019	16,093	145.1	0.445	11,542	0.570	10	**5.70**
2008	16,311	15,585	254.2	0.780	19,121	0.915	10	**9.15**
2007	14,513	15,168	220.1	0.676	16,930	0.788	10	**7.88**
2006	13,273	14,890	197.6	0.607	15,832	0.723	10	**7.23**
2005	11,535	15,744	181.6	0.557	13,929	0.673	10	**6.73**
2004	9,964	15,851	157.9	0.485	12,488	0.607	10	**6.07**
2003	9,067	15,709	142.4	0.437	11,539	0.556	10	**5.56**
2002	7,013	16,203	113.6	0.349	9,146	0.455	10	**4.55**
2001	8,676	15,628	135.6	0.416	11,504	0.552	10	**5.52**
2000	7,412	14,897	110.4	0.339	10,411	0.476	10	**4.76**

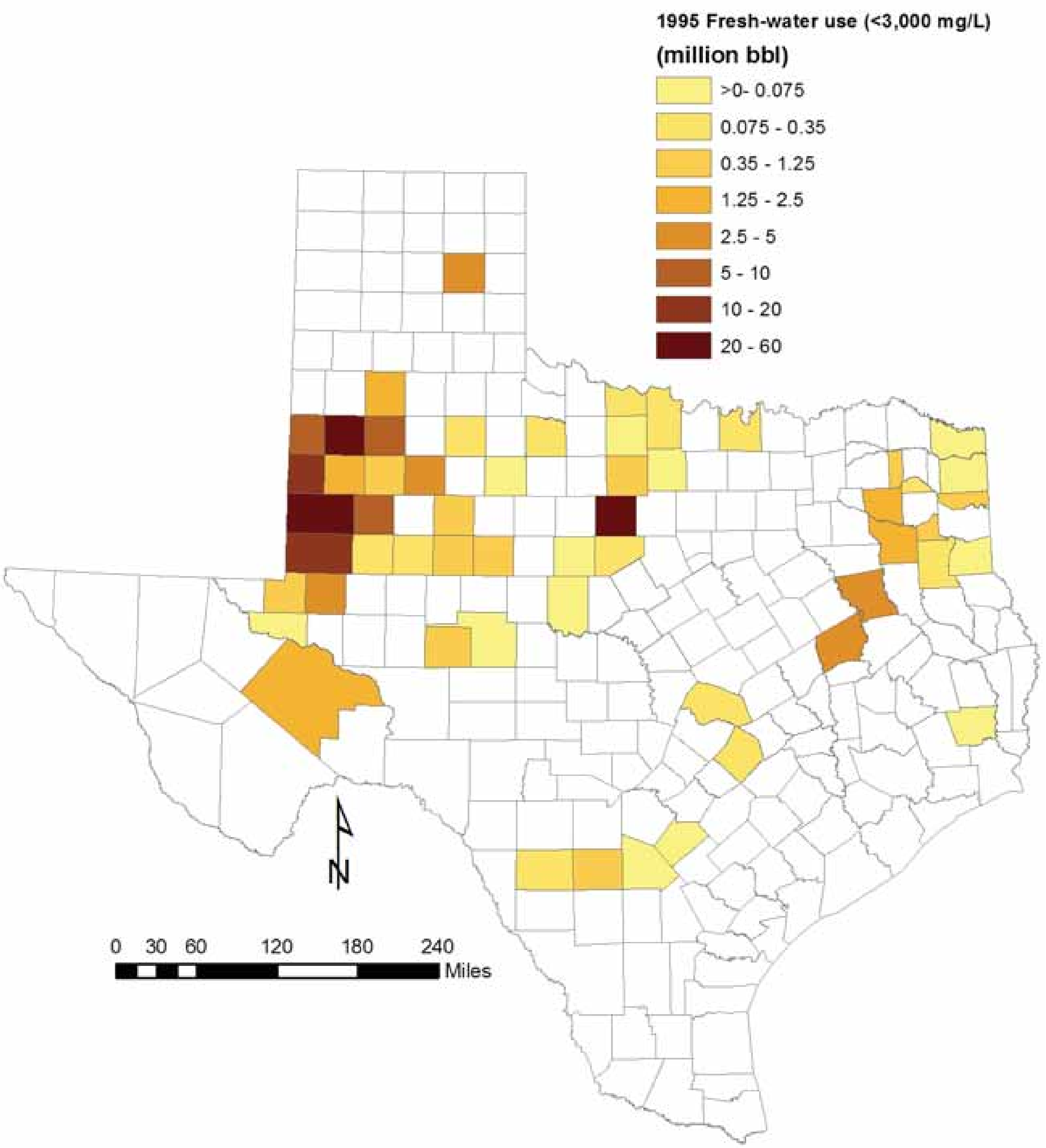
Source: IHS database

Results 2000-2009 1.xls.xls

Table 24. New drill per district

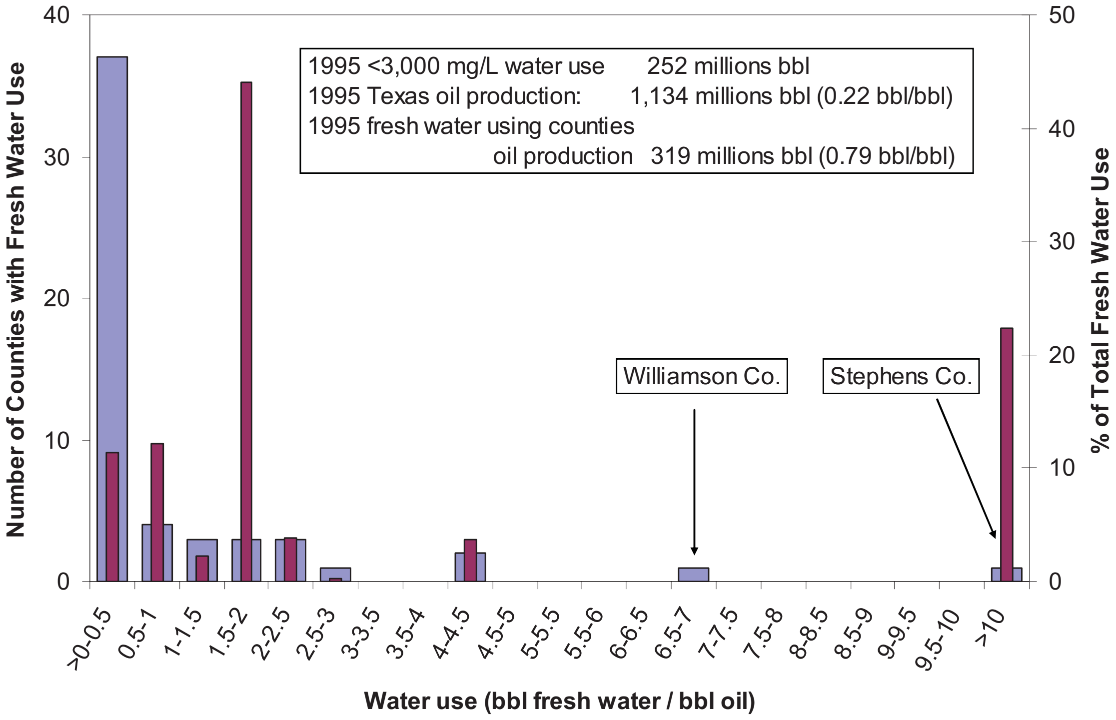
District	01	02	03	04	05	06	7B	7C	08	8A	09	10	Total
2006	369	510	451	1,354	555	1612	409	1,539	1,557	778	1,614	1,003	12,188
2007	354	398	422	982	621	1,968	327	1,565	1,789	698	2,214	952	12,291
2008	428	447	496	1,162	678	1,884	689	2,033	2,368	532	3,492	1,046	15,255

Source: RRC website



Source: 1995 RRC survey

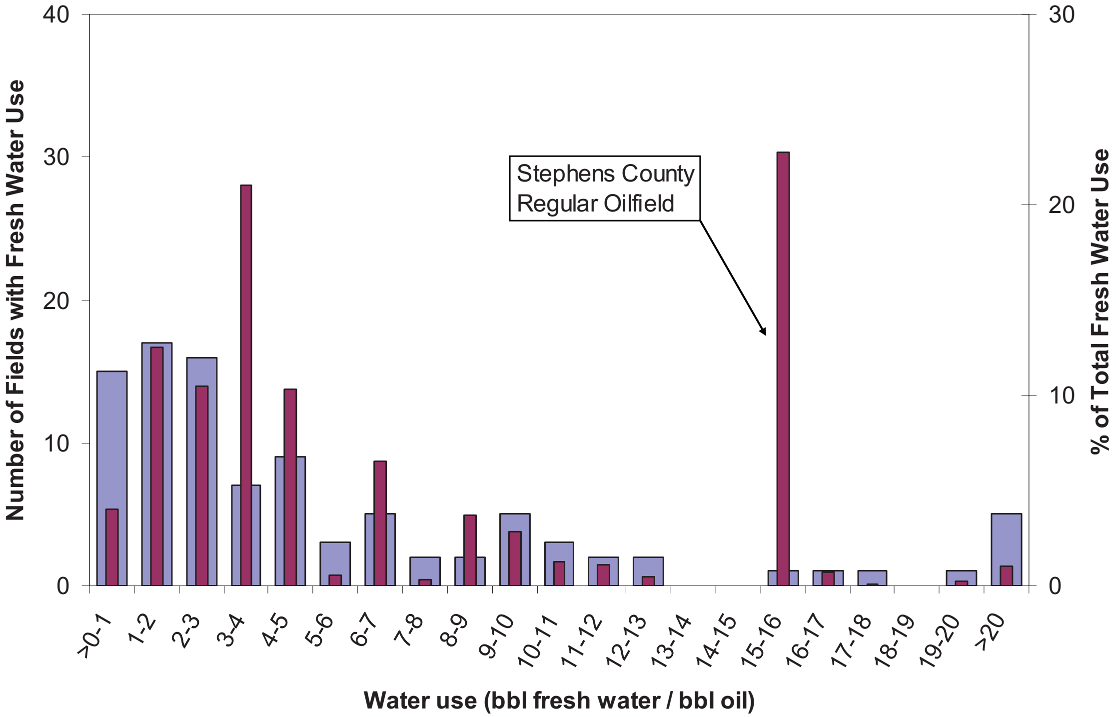
Figure 83. Map of counties using fresh water in EOR operations according to the 1995 RRC data (1 million bbl = 129 AF)



FreshWater+Oil Production RCC1995.xls

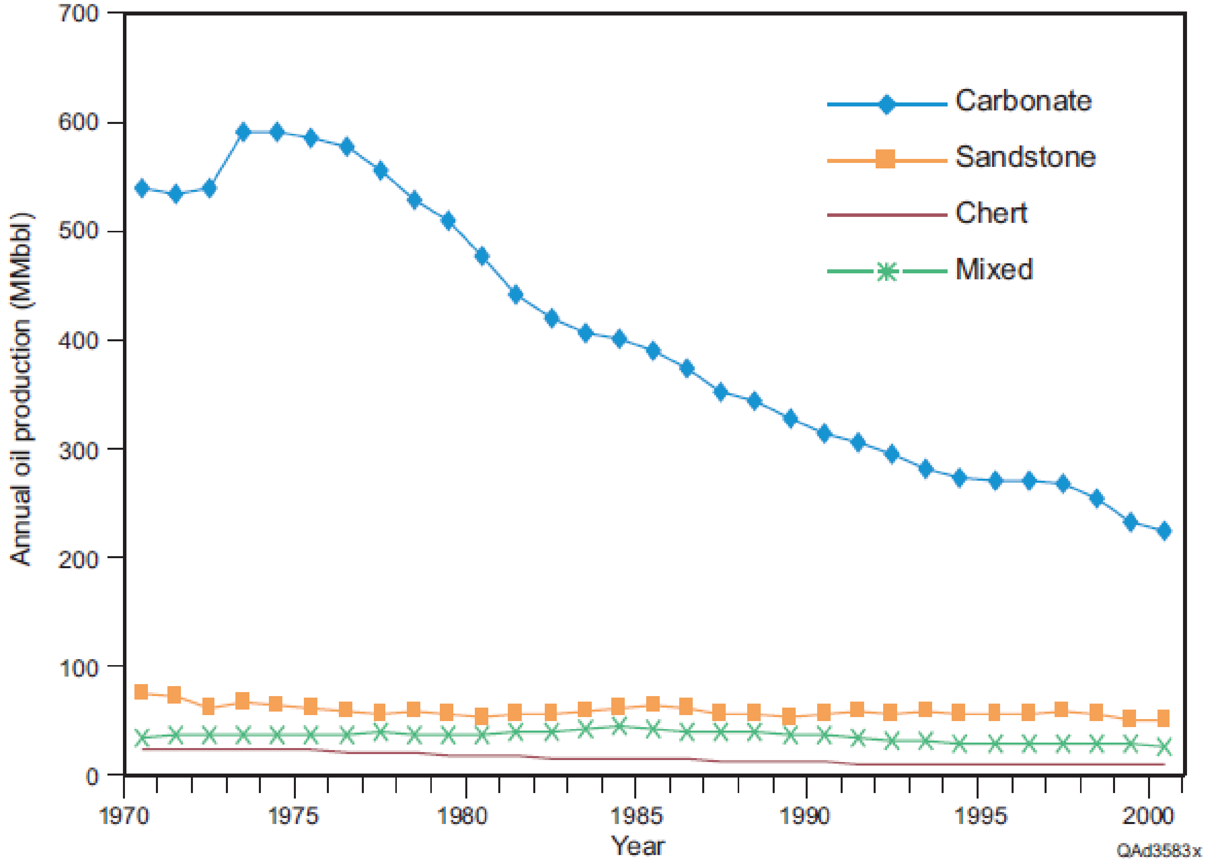
Note: obtained by dividing fresh-water use as reported by RRC by county production regardless of the actual number of fields being waterflooded

Figure 84. Histogram (year 1995) of county-level waterflood water-use coefficient (wide columns) and fraction of total fresh-water use for each bin



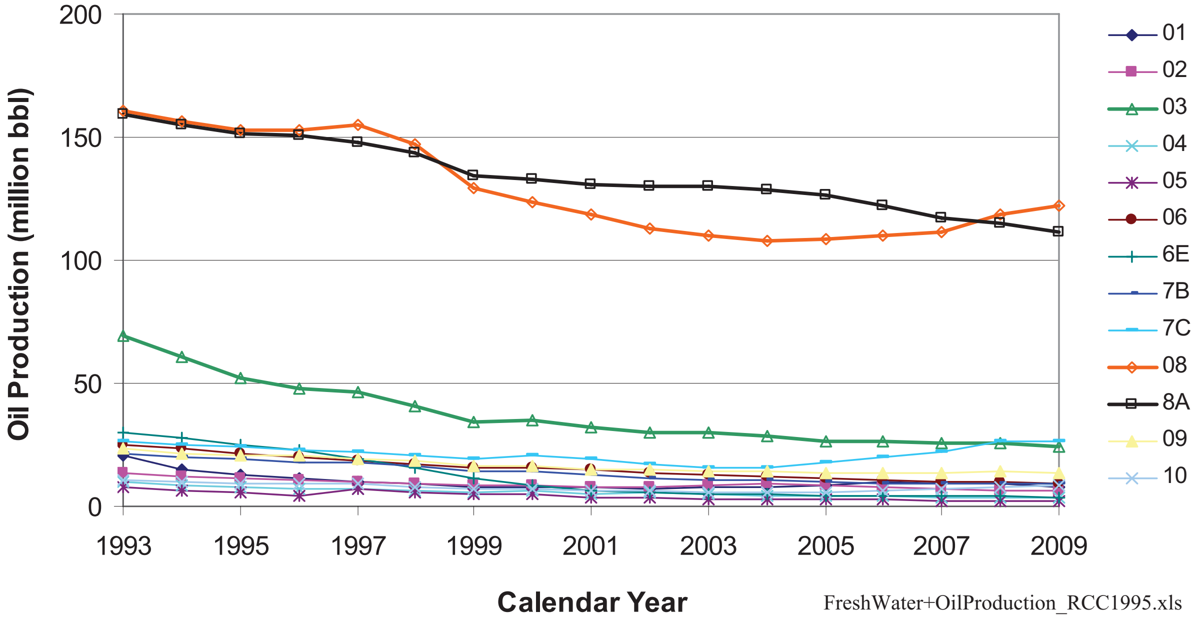
FreshWater+OilProduction RCC1995.xls

Figure 85. Histogram (year 1995) of water-use coefficient in waterflooded oil fields (wide columns) and fraction of total fresh-water use for each bin



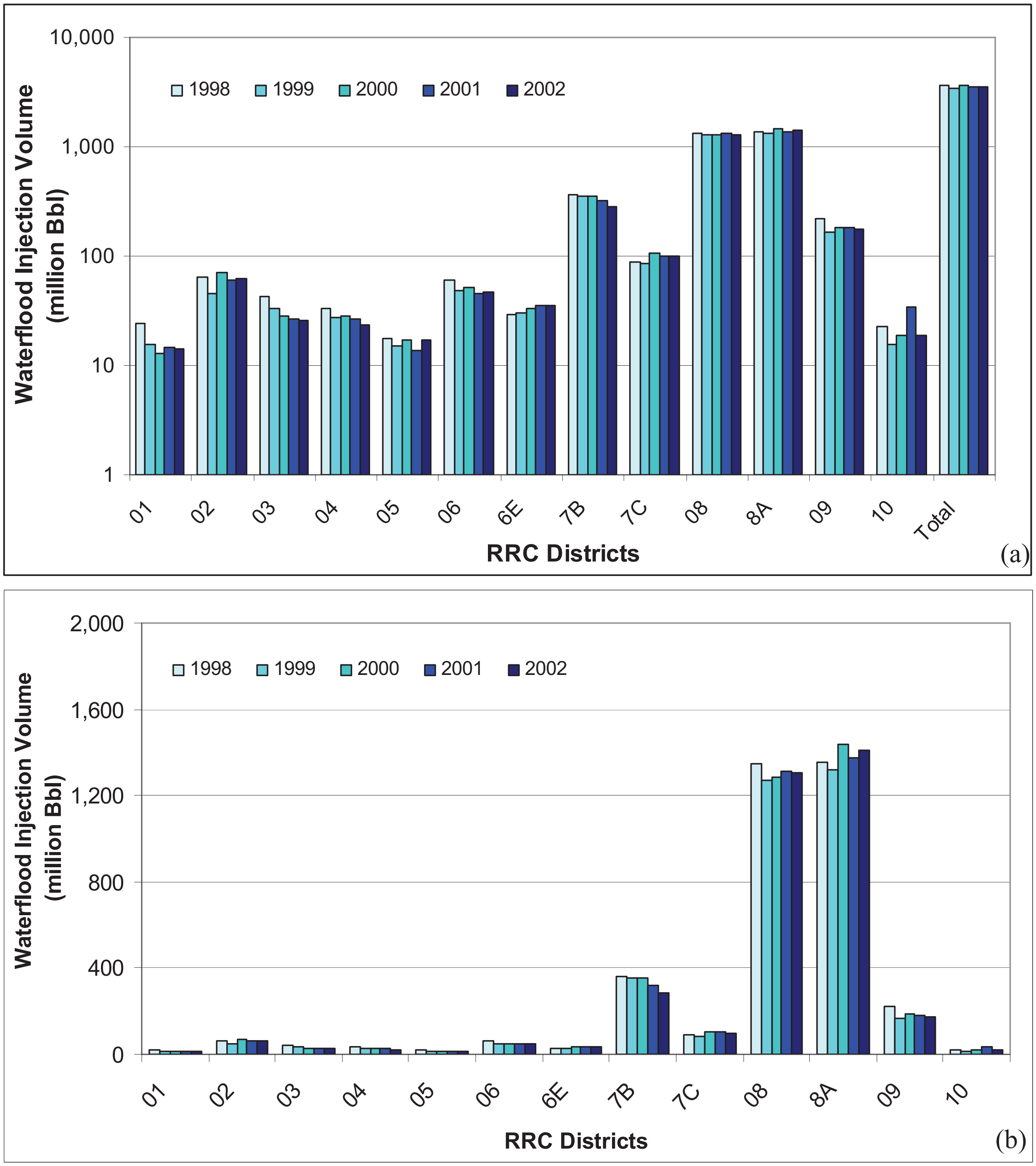
Source : Dutton et al. (2005a, Fig. 130)

Figure 86. Production histories of significant-sized oil reservoirs in the Permian Basin by lithology



Source: RRC online system http://webapps.rrc.state.tx.us/PDQ/generalReportAction.do

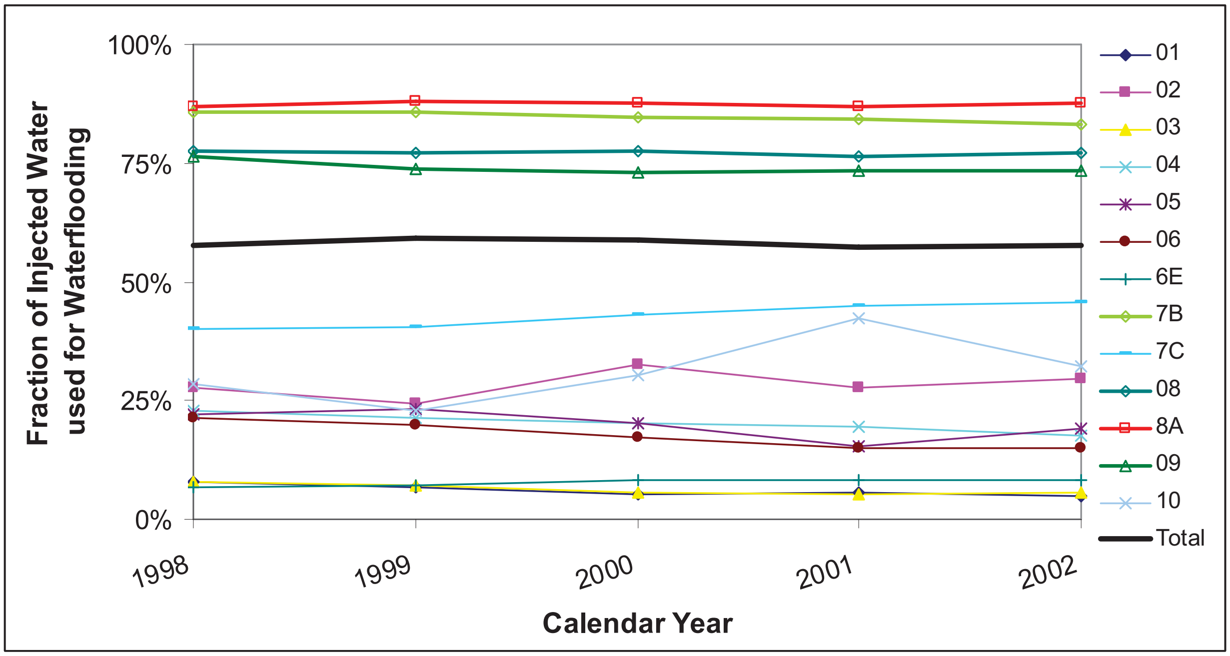
Figure 87. Annual oil production per district (1993–2009)



InjectionVolume 2002 RRC +1998-2001.xls

Source: RRC website http://www.rrc.state.tx.us/data/wells/statewidewells.php
Note: figures were corrected by the statewide correction factor for incomplete data (typically 10% more than reported)

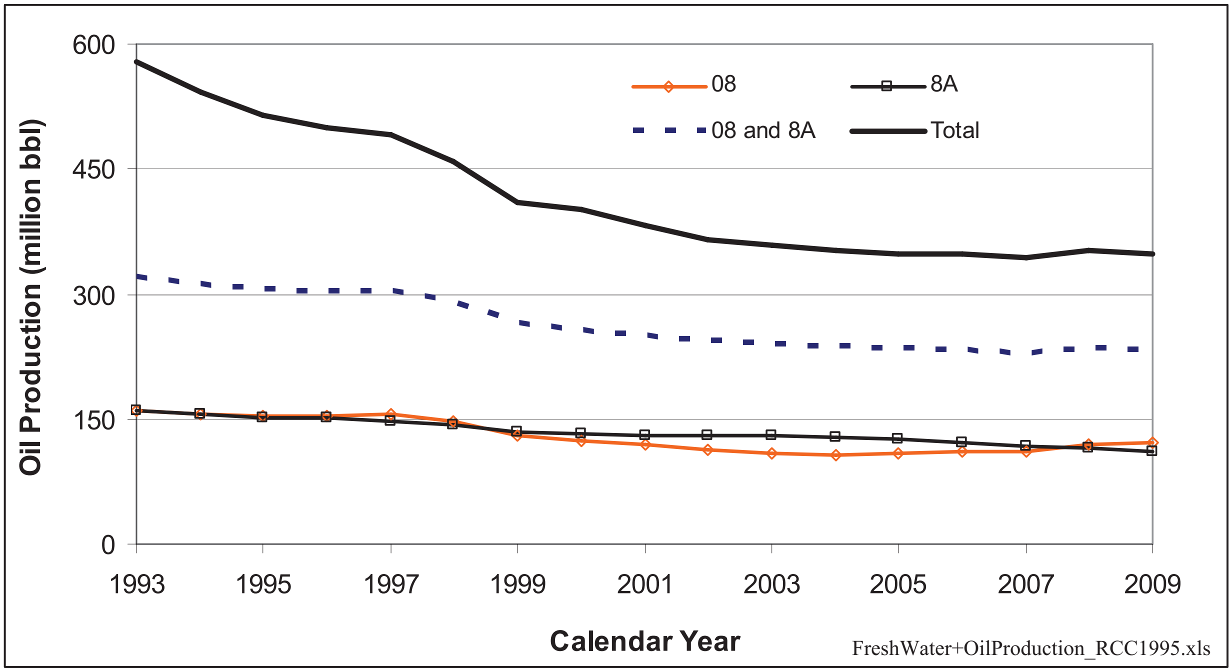
Figure 88. RRC district-level annual waterflood-dedicated injection volume in Texas (1998–2002): (a) log scale, (b) linear scale



Source: RRC website
http://www.rrc.state.tx.us/data/wells/statewidewells.php

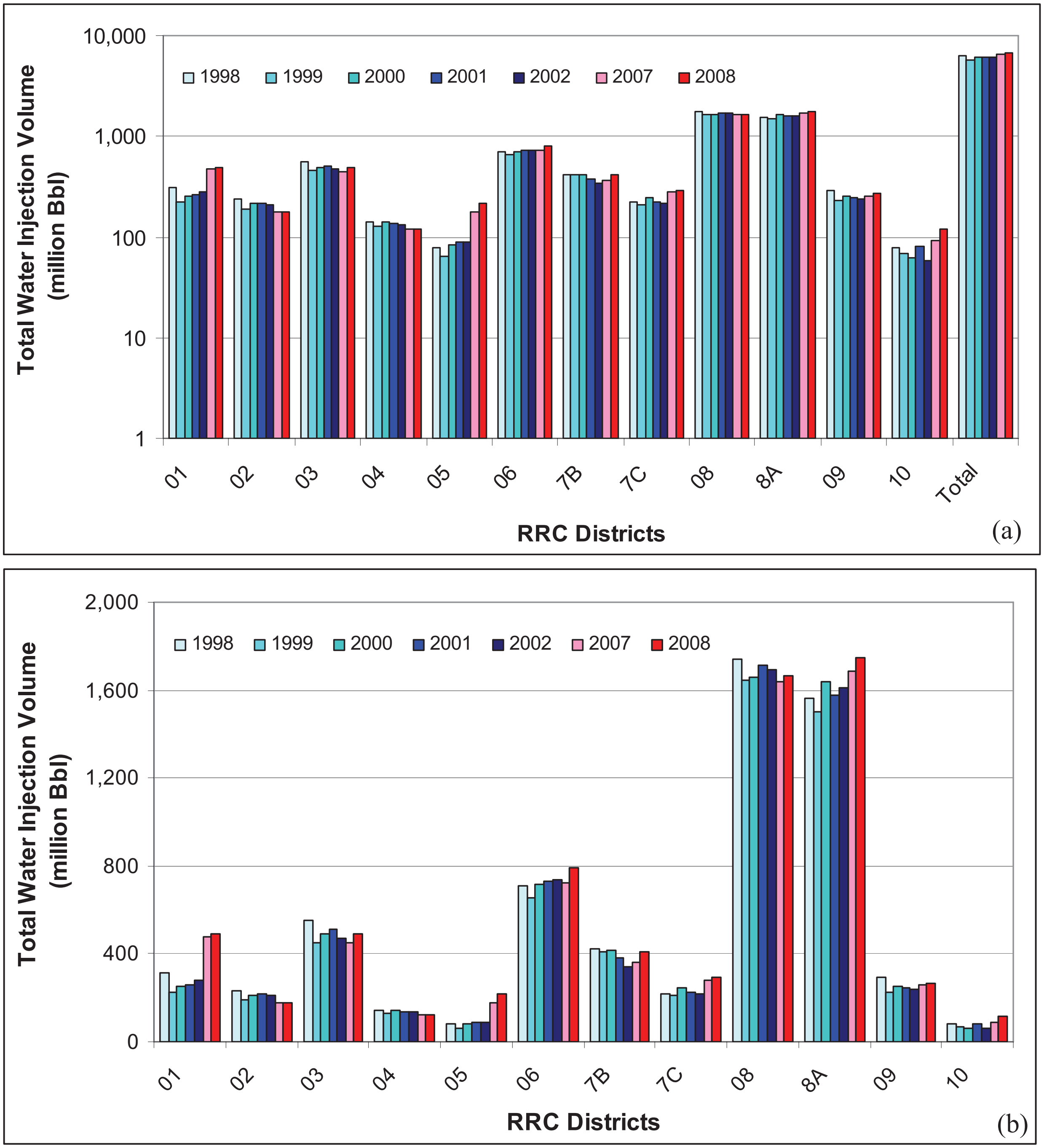
InjectionVolume_2002_RRC_+1998-2001.xls

Figure 89. RRC district-level fraction of injected water (of all types) used for waterflooding



Source: RRC online system http://webapps.rrc.state.tx.us/PDQ/generalReportAction.do

Figure 90. Oil production in districts 8 and 8A



InjectionVolume_2002_RRC_+1998-2001.xls

Source: RRC website http://www.rrc.state.tx.us/data/wells/statewidewells.php for years 1998 to 2002 and http://webapps.rrc.state.tx.us/H10/h10PublicMain.do for years 2007 and 2008

Note: districts 6 and 6E are now combined

Figure 91. RRC district annual total water (of all types) injection volume (1998–2002 and 2007–2008): (a) log scale, (b) linear scale

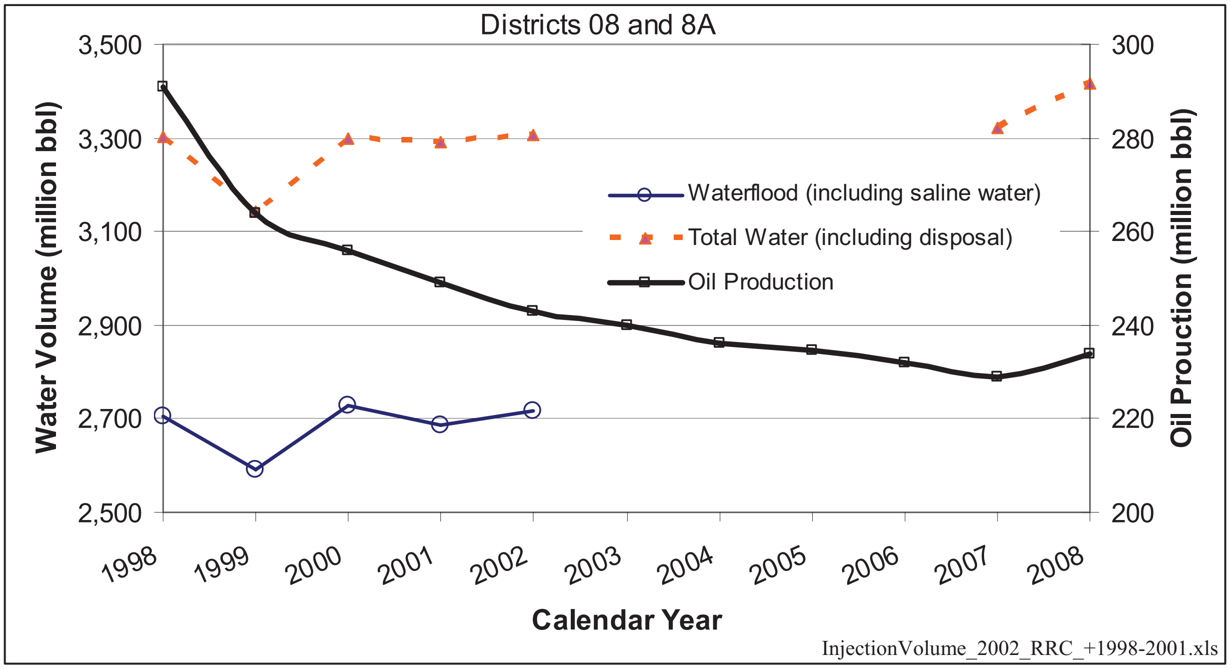
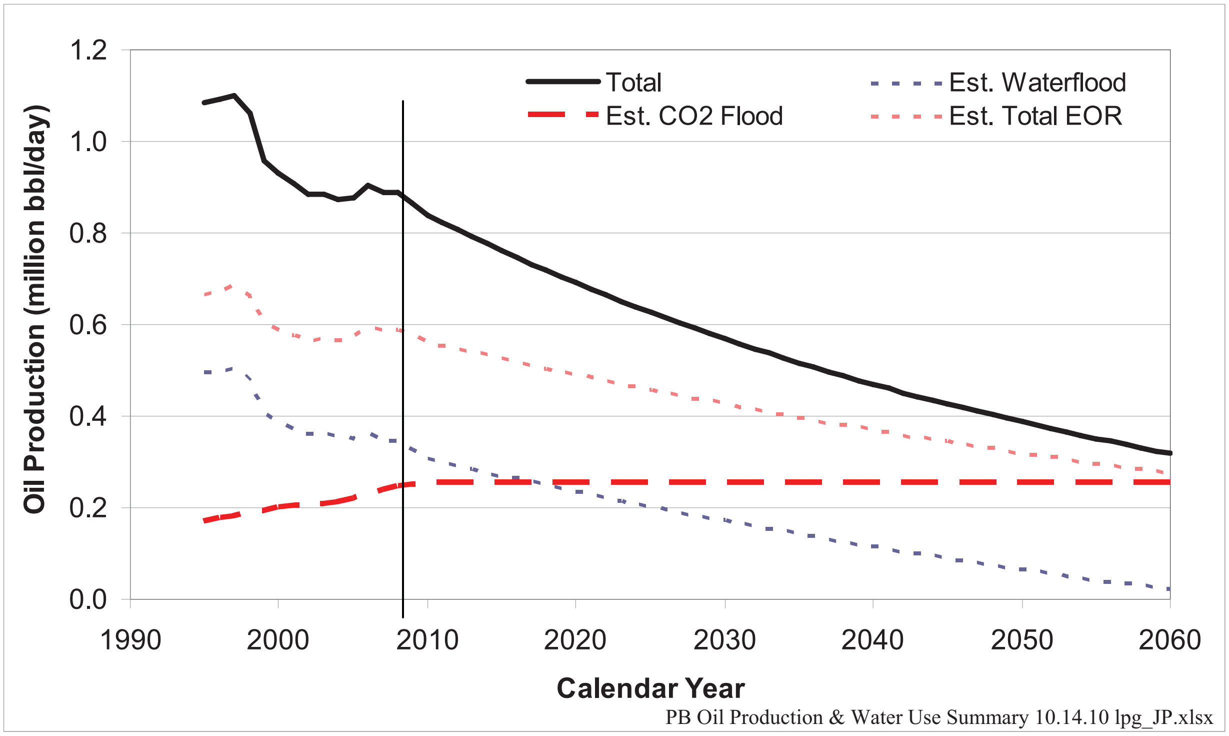
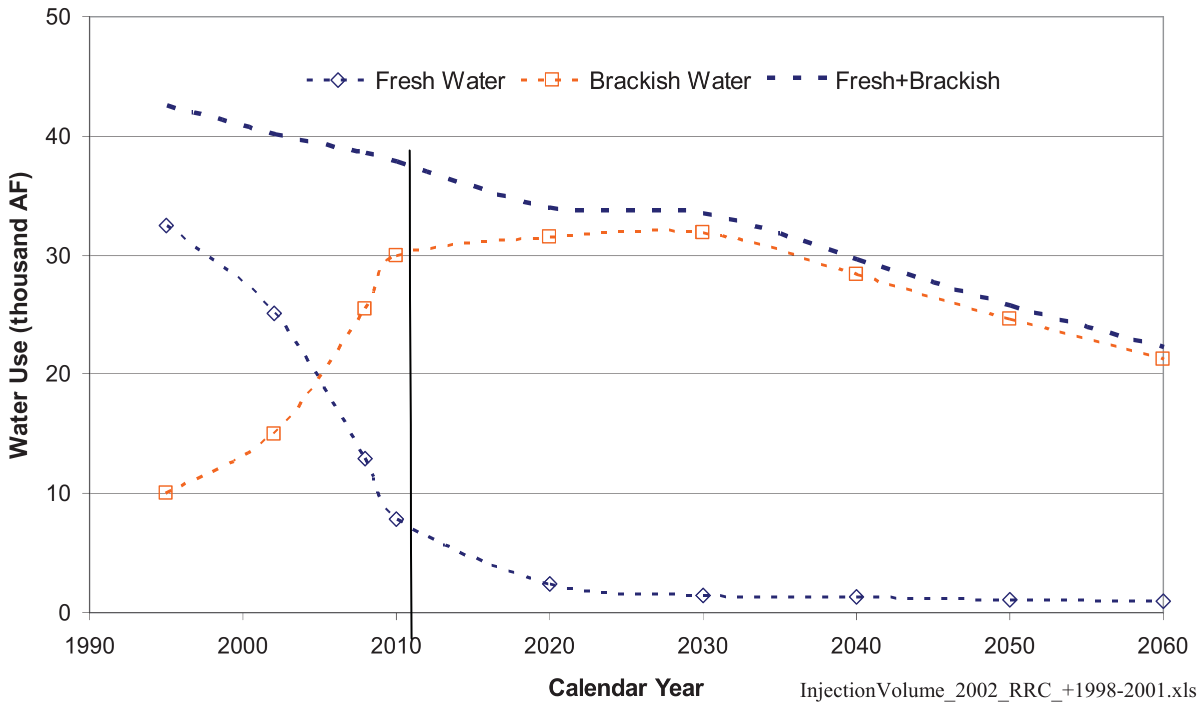


Figure 92. Comparison of oil production and water injection in RRC districts 08 and 8A (1998–2008)



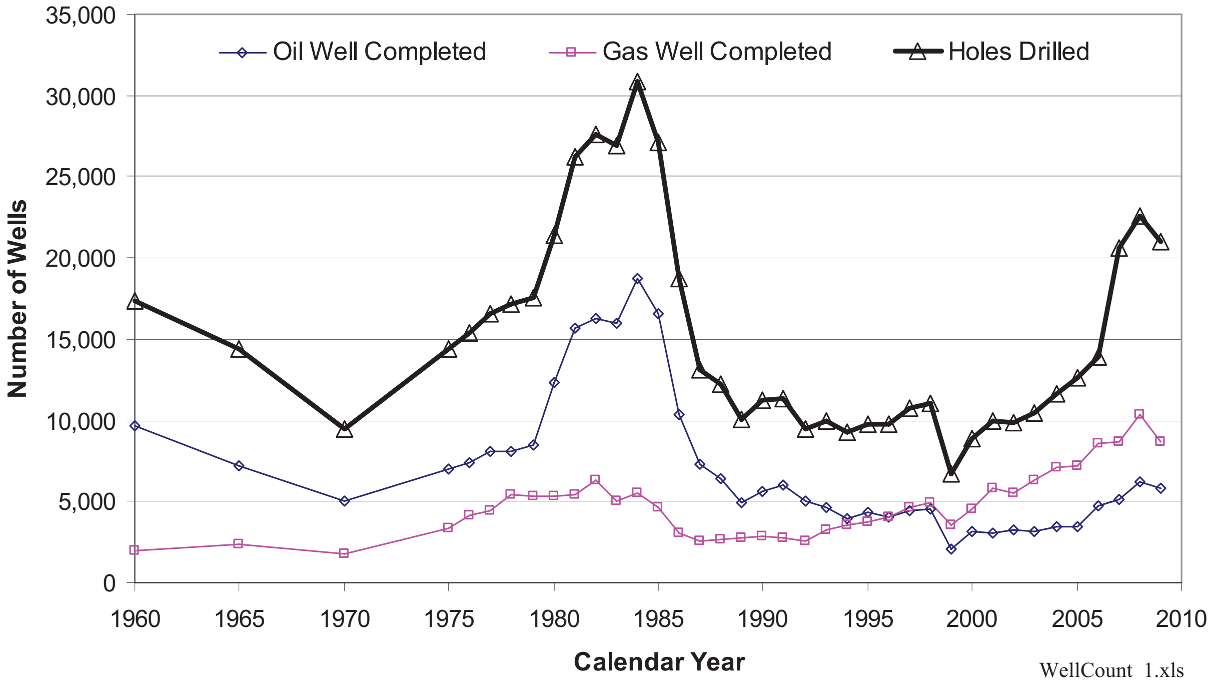
Note: data only for historical total production

Figure 93. Historical and forecast for oil production in districts 8, 8A, and 7C



Note: Only data points are from 1995 RRC survey

Figure 94. Estimated current and projected fresh- and brackish-water use for pressure maintenance and secondary and tertiary recovery operations



Source: RRC website http://www.rrc.state.tx.us/data/drilling/txdrillingstat.pdf
Note: completions include mostly new drills but also re-entered and recompleted wells (10-15% of total)

Figure 95. Number of holes drilled and of oil and gas wells completed in Texas between 1960 and 2009

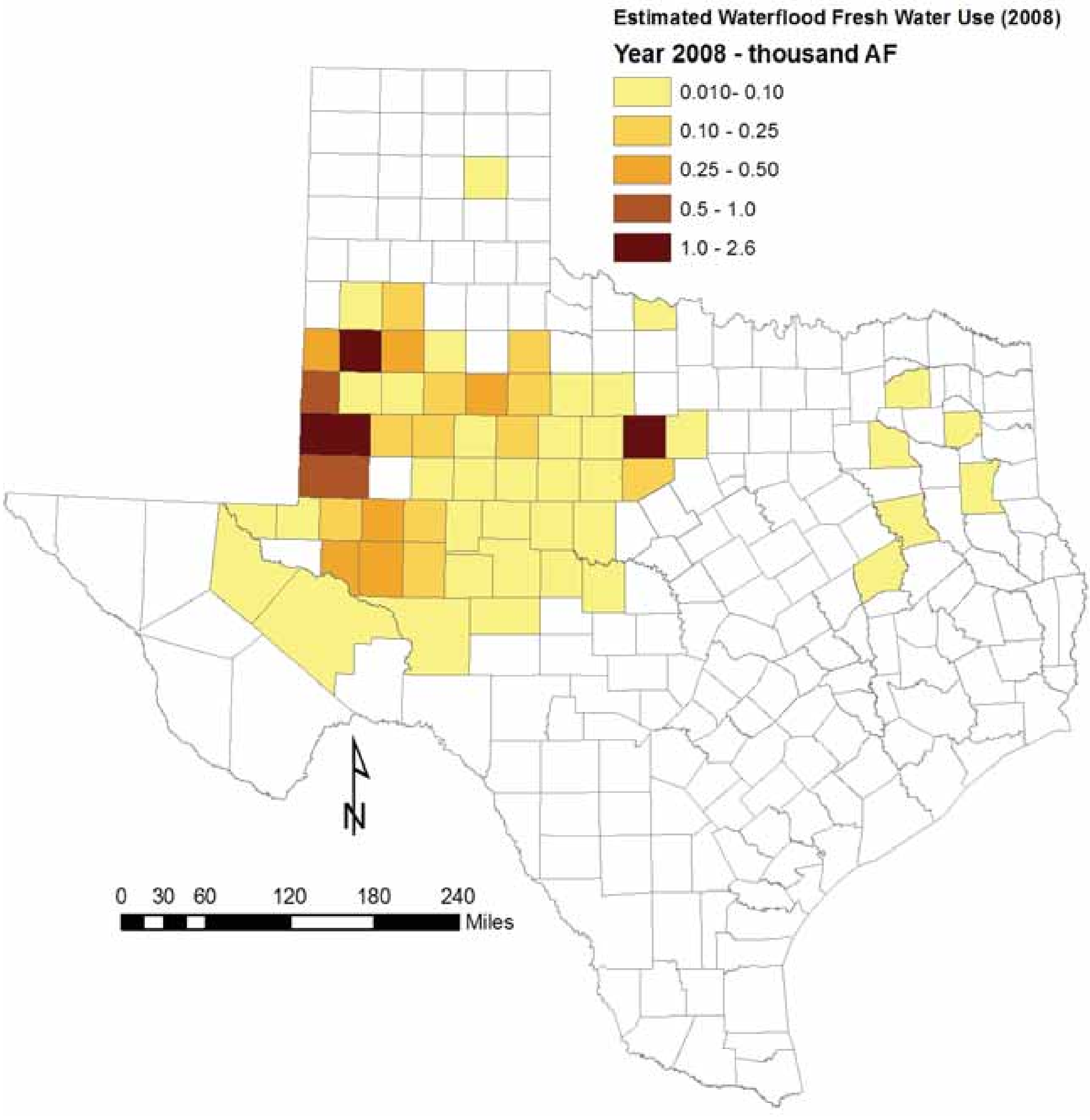


Figure 96. Estimated fresh-water use for waterfloods (2008)

4.3 Coal and Lignite

Total coal production for 2009 was >1 billion short tons for the country, 35+ million short tons of which the state of Texas produced (Table 1). Currently Texas has 11 active coal mines or groups of mines, with 2 mines (Kosse and Twin Oak mines) coming fully online in the next few years (Figure 97).Total production has been decreasing for 2 decades (Figure 98 with more details in Figure 100). All mines are above ground, mining lignite grade resources to a depth of 250 ft. All coal operations in Texas are currently mine-mouth, meaning the coal is used to power a power plant or other facility close to the mine. All mines with significant production in the past decades are still in operation, except for Sandow transitioning to the adjoining Three Oaks, both operated by ALCOA, Inc., (Williams, 2004) and the two Gibbons Creek locations (operated by the Texas Municipal Power Agency, TMPA–Bryan College Station), idle since 1996. The survey went only to current operators. From north to south, mines with recent activity as listed on the RRC website are given in Table 25.

In general, coal-mining processes require water during operations for activities such as dust suppression, waste disposal, reclamation and revegetation, coal washing, transportation, and drilling. In Texas, coal mining does not require drilling, coal washing, or transportation by slurry pipeline, and water use is limited to dust suppression and equipment washing. However, there is a need for dewatering and depressurization for most mines (Table 26). The water pumped is either discharged into a lake or stream or first discharged into a retention or sedimentation pond and then routed to a lake or stream. Therefore, once the water has been initially pumped from the ground to allow initial mining to occur, the water becomes available for use as surface water. Many mines also contract additional water from water-supply wells and water rights in order to supply fresh water to office operations (Table 27). Additionally, water for mining activities such as dust suppression and hauling activities may come either from these separate water-supply wells or from the retention ponds. Tracking where the water is routed, from where and what it is used, and the exact amount of consumption prove to be a difficult task. Whereas agencies track water pumped for operations and discharged into local surface waters, no central agencies tracks the entire operation when it comes to mining. The TWDB sends a survey to operators for groundwater pumped from water-supply wells, whereas the RRC tracks water pumped for depressurization and dewatering. Additionally, mining operators must report water-quality information on discharged water to lakes and streams to TCEQ. In order to further delineate the data, a questionnaire (Appendix D) was sent to mining operators regarding their water usage via TMRA.

In 2009, 37.1 million short tons of lignite was produced in the state, requiring production of 25.7 thousand AF of water and resulting in an average raw water use of 227.5 gal/st. However, including only consumption (and not dewatering), the same coal production required only 2.6 thousand AF or 22.8 gal/st. For comparison purposes, Chan et al. (2006) reported that, in 2003, given national coal-production statistics, a rough estimate of overall water required for coal extraction (mining and washing) ranged roughly from 86 to 235 million gal/day for an overall coal production of 1,071.7 million short tons, including 86.4 million short tons of lignite (EIA) (30 to 80 gal/st). These nationwide numbers represent a mix of uses, coal washing for Appalachian and interior coals, depressurization for lignite, and slurry pipelines.

The Sandow mine used to contribute a large fraction of total coal-mining water use (Figure 99), more than half of the ~40,000 AF/yr of produced groundwater until 2008. The current overall amount is <20,000 AF/yr. Currently no mine comes close to the threshold of 10 thousand AF/yr. However, surface water is also used in some mines, according to data we collected for the years 2009–2010. Overall, we assumed that the amount and distribution of the water used in 2009–2010 are very similar to those used in 2008 (year chosen as representative) in the coal industry.

Luminant mines in East Texas (Monticello Thermo, Monticello Winfield, Oak Hill, Martin Lake, and Big Brown) have a total water use of between 1 and 2.5 thousand AF/yr, which is mostly due to overburden dewatering, do not need to be depressurized (or very little), and have to pump supplementary (variable across mines) amounts of water to satisfy their operational needs. All of the water is fresh and is used mostly for dust suppression. An additional mine in the same Sabine Uplift area (South Hallsville in Harrison County operated by Sabine Mining Company) shows a larger water volume being processed at 5.8 thousand AF/yr, but that includes no groundwater pumping for overburden dewatering or for depressurization. The operating technique here appears to allow for overburden seepage to collect in the pit and mix with surface water.

Central Texas mines (including Jewett, Calvert/Twin Oak, Sandow/Three Oaks) are characterized by some depressurization pumping. Levels of depressurization and dewatering vary considerably across mines. Mines located in the Calvert Bluff Formation above the prolific Simsboro aquifer of Central Texas (between the Colorado and Trinity Rivers) are forced to produce large amounts of water to depressurize and avoid heaving of the mine floor (for example, Harden and Jaffre, 2004). The Sandow mine in Milam County used to pump large amounts of water from the Simsboro, in excess of 20 thousand AF/yr.

Gibbons Creek and San Miguel mines tap the Jackson Group lignite, not the Wilcox. The San Miguel mine does produce groundwater, but it is saline and is reinjected into the subsurface. For the purpose of this study, the San Miguel mine has zero water use. Two new mines will be developed in the future: Twin Oaks, next to the current Calvert mine in Robertson County and Kosse Strip in Limestone County. They will be discussed in the Future Use section.

Table 28 summarizes our findings: a total of 25.6 thousand AF is pumped, only 2.6 thousand AF of which is consumed. Most is groundwater (18.4 thousand AF), 1.1 thousand AF of which is consumed.

Table 25. Lignite and coal-mining operations in Texas

Name	County	Current Operator	Cumul. Prod. 1976–2007 (million st)[A]	Water-Use Range (thousand AF/yr)	Status
Monticello Thermo	Hopkins	Luminant	35.4	~0.9	Active in 2009
Monticello Winfield	Titus	Luminant	268.1	0.6–1.0	Active in 2009
Darco	*Harrison*	*Norit Americas Inc.*	*6.8*		*Not in operation* *2001 last prod.*
Hallsville	Harrison	Sabine Mining Company	80.4	~5.8	Active in 2009
Oak Hill	Rusk	Luminant	101.2	1.2–1.7	Active in 2009
Martin Lake	Panola	Luminant	265.9	~1.0	Active in 2009
Big Brown	Freestone	Luminant	160.7	~2.5	Active in 2009
Jewett	Freestone/Leon	Tx Westmoreland Coal Company (NRG)	167.7	~2.0	Active in 2009
Calvert	Robertson	Walnut Creek Company	32.6	7.2	Active in 2009
Sandow	*Milam*	*ALCOA Inc.*	151.0	>25 *1990–2008 average*	*Not in operation* *2005 last prod.*
Three Oaks	Bastrop/Lee	ALCOA Inc.	13.7	4.0-5.0	Active in 2009
Gibbons Creek	*Grimes*	*TMPA*	*43.0*		*Not in operation* *1996 last prod.*
Powell Bend		*LCRA*	*1.6*		*No longer permitted* *1993 last prod.*
San Miguel	Atascosa/McMullen	San Miguel Electric Cooperative	80.2	0.2 saline	No fresh or brackish water use
Little Bull Creek		*Amistad Fuel Company*	*0.43*		*No longer permitted* *1987 last prod.*
Eagle Pass	*Maverick*	*Dos Republicas Resources Co., Inc.*	*0*		*Not (ever?) in operation.*
Palafos, Rachal, Trevino	*Webb*	*Farco Mining, Inc.*	*7.2*		*Not in operation* *2004 last prod.*
Thurber		*Thurber Coal Company*	*0.46*		*No longer permitted* *1983 last prod.*

Note: mine locations not in operation are in italics in smaller print

[A]: RRC website file tx_coal.xls

Table 26. Water fate for current lignite operations in Texas

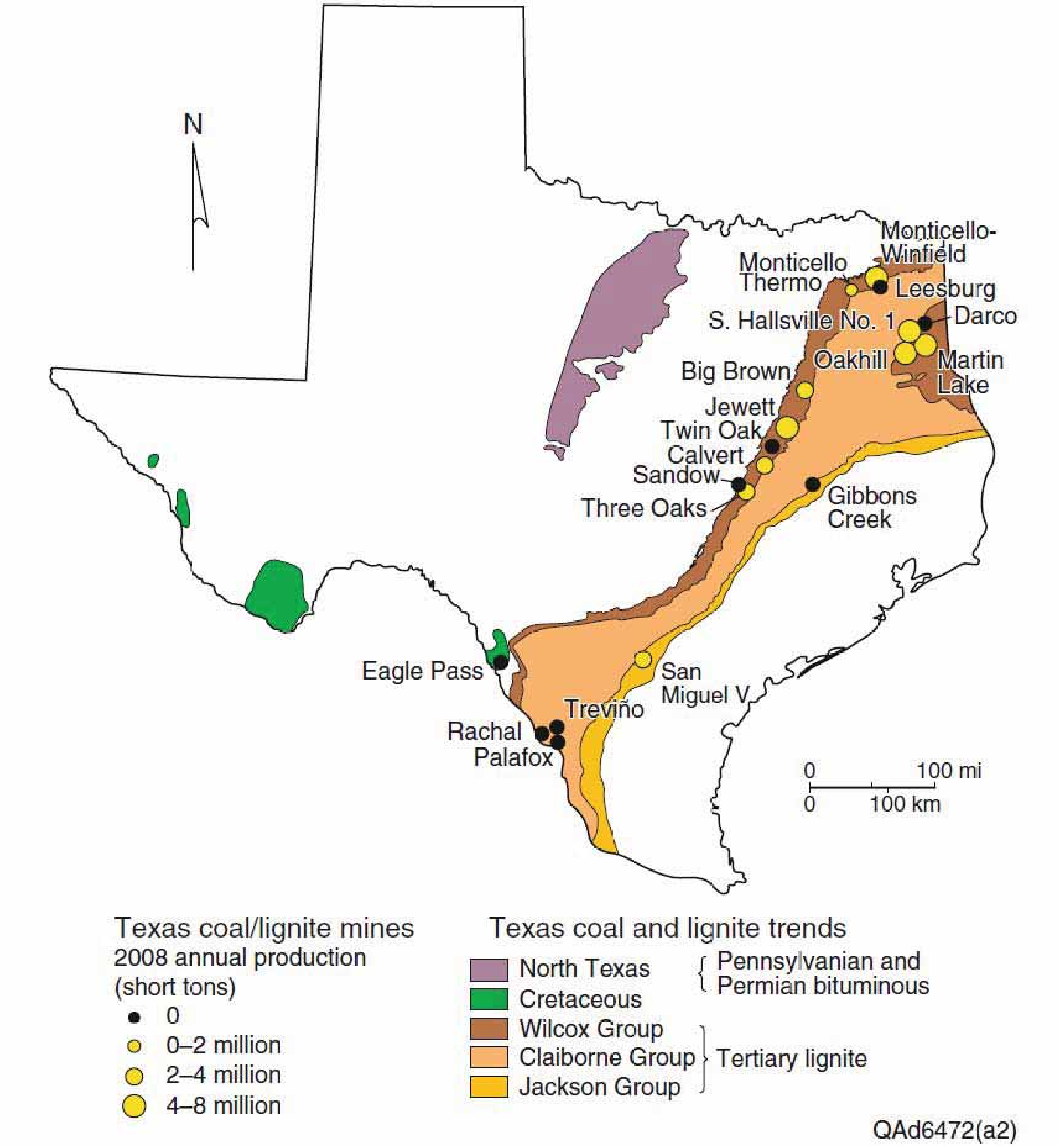
Name	County	Dewatering	Depress.	Other	Use
Monticello Thermo	Hopkins	77.7% overburden	0%	22.3% water supply	95% dust suppression 5% washing
Monticello Winfield	Titus	0%	0%	100% water supply	95% dust suppression 5% washing
Hallsville	Harrison	99.9% pit	0%	0.1% water supply	
Oak Hill	Rusk	54% overburden	0%	46% water supply	95% dust suppression 5% washing
Martin Lake	Panola	12.9% overburden	0%	87.1% water supply	95% dust suppression 5% washing
Big Brown	Freestone	92.5% overburden	3%	4.5% water supply	95% dust suppression 5% washing
Jewett	Freestone/ Leon	98% but mostly overburden dewatering		2% water supply	
Calvert	Robertson	2% overbrd. 2% pit	95%	1% water supply	Mine operations + discharge
Sandow	*Milam*		*100%*		
Three Oaks	Bastrop/ Lee		99%	1% water supply	
San Miguel	Atascosa/ McMullen	2% pit	98%	unknown	Discharge to Class V injection wells

Table 27. Water source for current lignite operations in Texas

Name	County	Fresh	Brackish	GW	SW
Monticello Thermo	Hopkins	100%	0%	80%	20% (water rights)
Monticello Winfield	Titus	100%	0%	50%	50%
Hallsville	Harrison	100%	0%		100% pit dewatering but also seepage (GW)
Oak Hill	Rusk	100%	0%	58.5%	41.5% (water rights)
Martin Lake	Panola	100%	0%	100%	0%
Big Brown	Freestone	100%	0%	100%	0%
Jewett	Freestone/ Leon	95%	5%	Unknown	Assumed all GW
Calvert	Robertson	100%	0%	100%	
Sandow	*Milam*	*100%*	*0%*		
Three Oaks	Bastrop/ Lee	100%	0%	100%	0%
San Miguel	Atascosa/ McMullen	0%	0%	100% saline	0%

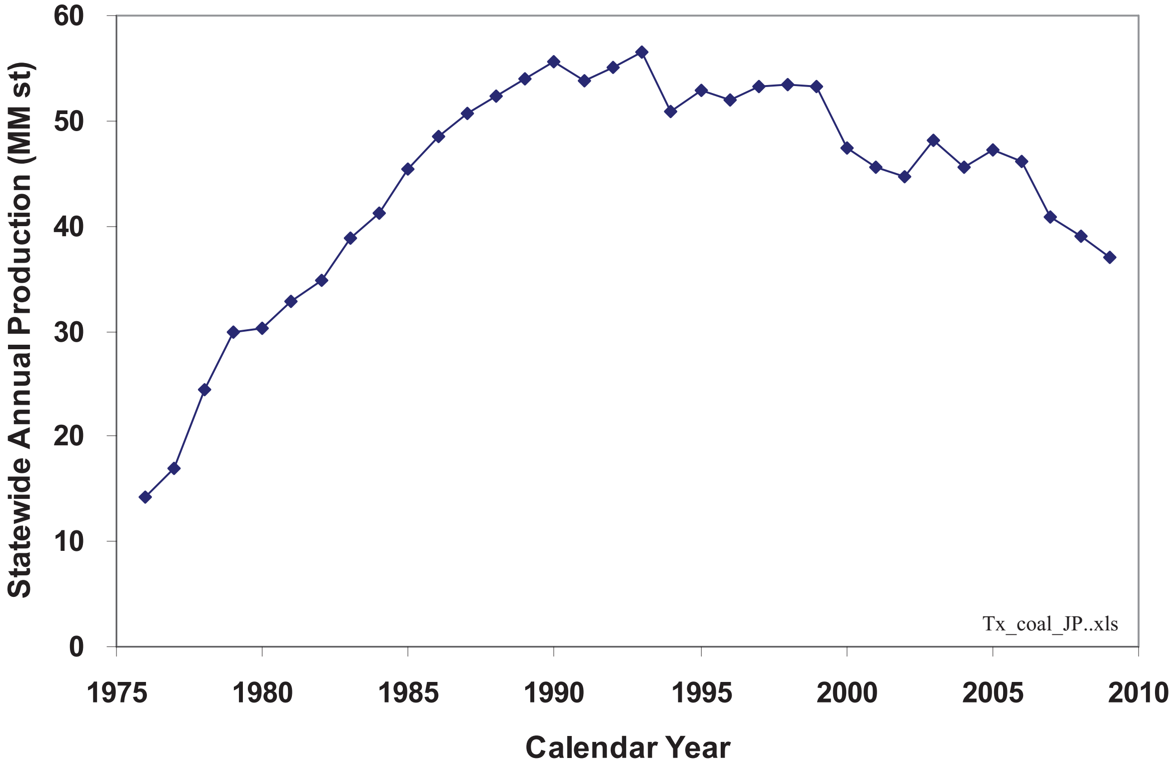
Table 28. Estimated lignite mine water use per county in AF/yr (2010)

Contributing Mine	**County**	**Total Pumpage**	**Total Consumption**	**Pumpage Groundwater**	**Consumption Groundwater**	**Pumpage Surface Water**	**Consumption Surface Water**	**Pumpage Fresh Water**	**Consumption Fresh Water**
San Miguel	Atascosa	0	0	0	0	0	0	0	0
1/2 Three Oaks	Bastrop	2,089	21	2,089	21	0	0	2,089	21
Big Brown, 1/3 Jewett	Freestone	3,129	124	3,129	124	0	0	3,095	124
South Hallsville	Harrison	5,800	6	6	6	5,794	0	5,800	6
Monticello Thermo	Hopkins	920	205	735	21	185	185	920	205
1/2 Three Oaks	Lee	2,089	21	2,089	21	0	0	2,089	21
1/3 Jewett	Leon	667	13	667	13	0	0	633	13
1/3 Jewett, Kosse Strip	Limestone	694	41	694	41	0	0	661	41
Martin Lake	Panola	982	855	554	428	428	428	982	855
Calvert, Twin Oak	Robertson	7,436	74	7,436	74	0	0	7,436	74
Oak Hill	Rusk	1,265	582	741	58	524	524	1,265	582
Monticello Winfield	Titus	619	619	310	310	310	310	619	619
TOTAL		**25,689**	**2,562**	**18,449**	**1,116**	**7,240**	**1,446**	**25,589**	**2,562**



Source: Ambrose et al. (2010)

Figure 97. Distribution of Texas lignite and bituminous coal deposits, coal mines currently permitted by the RRC with 2008 annual production in short tons



Source: RRC website file tx_coal.xls

Figure 98. Statewide coal/lignite annual production (1975–2009)

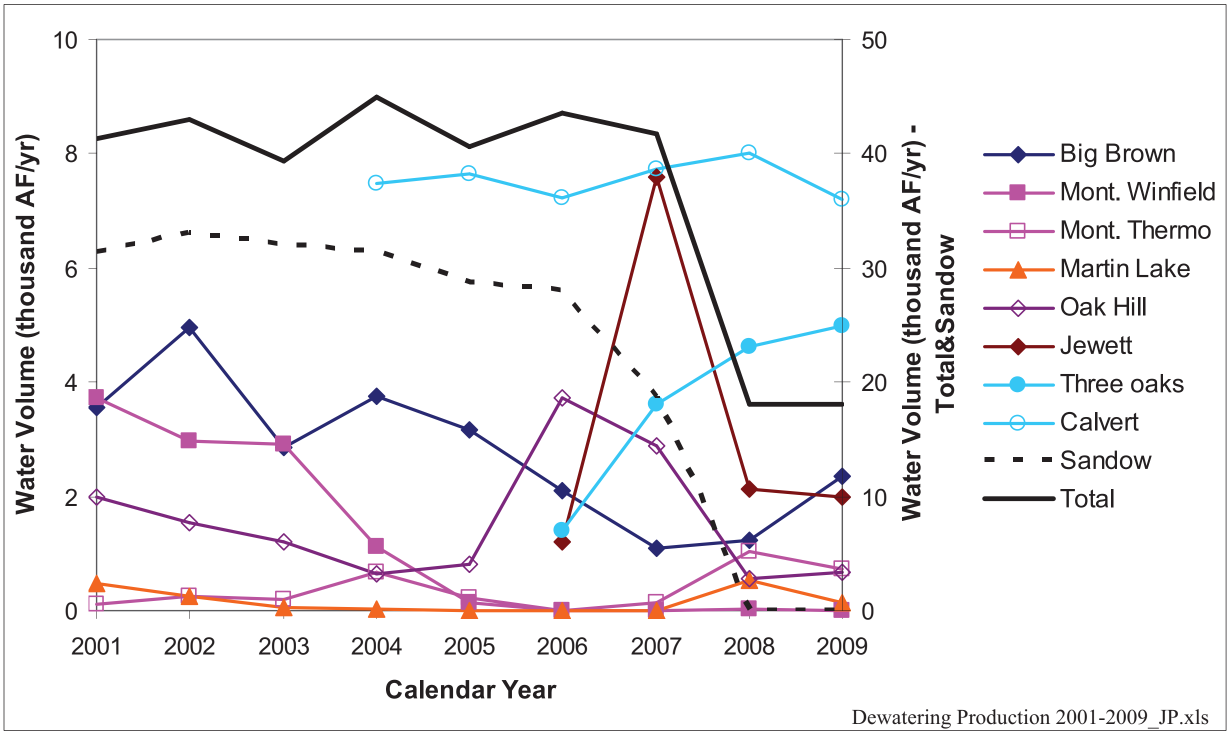
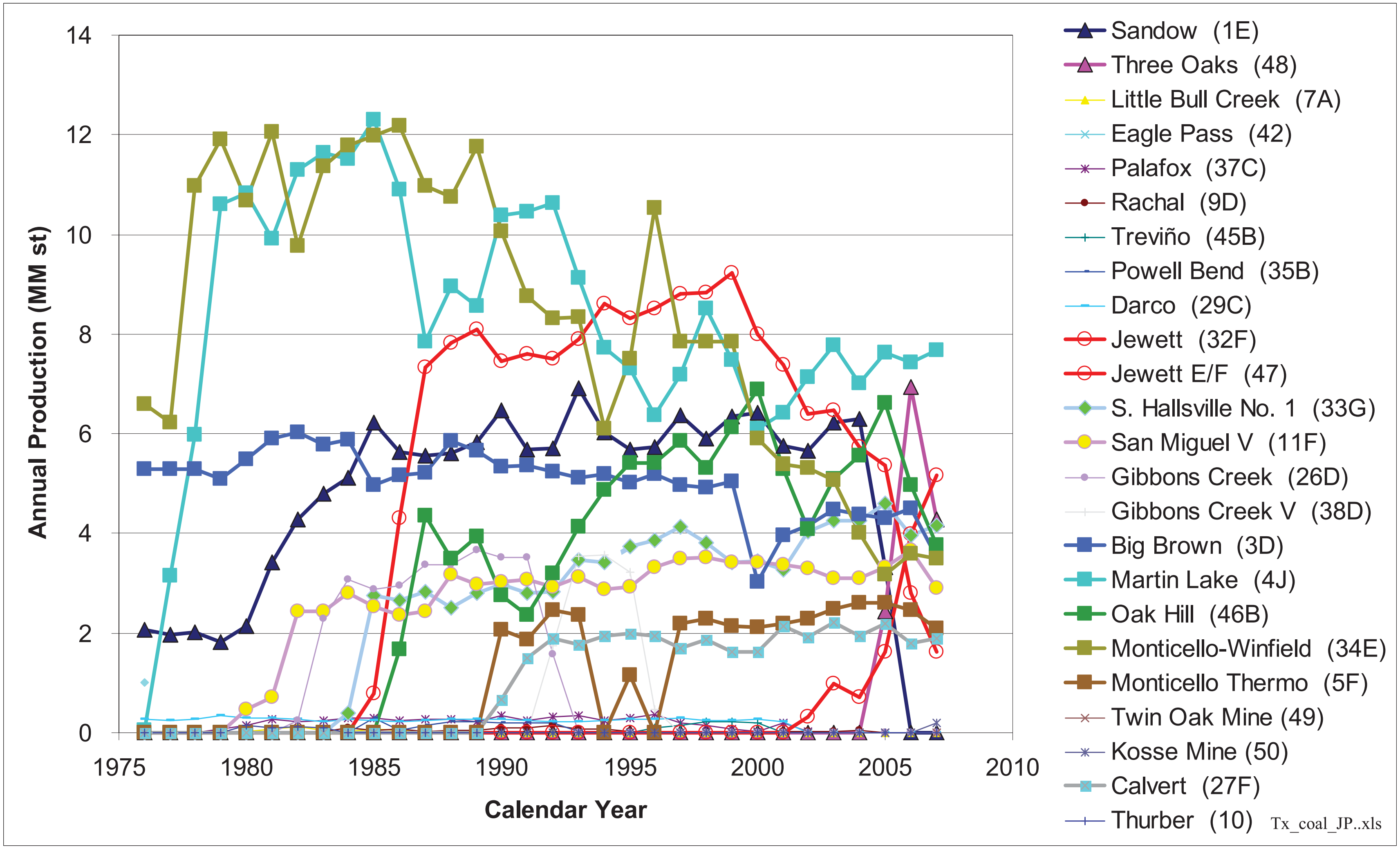


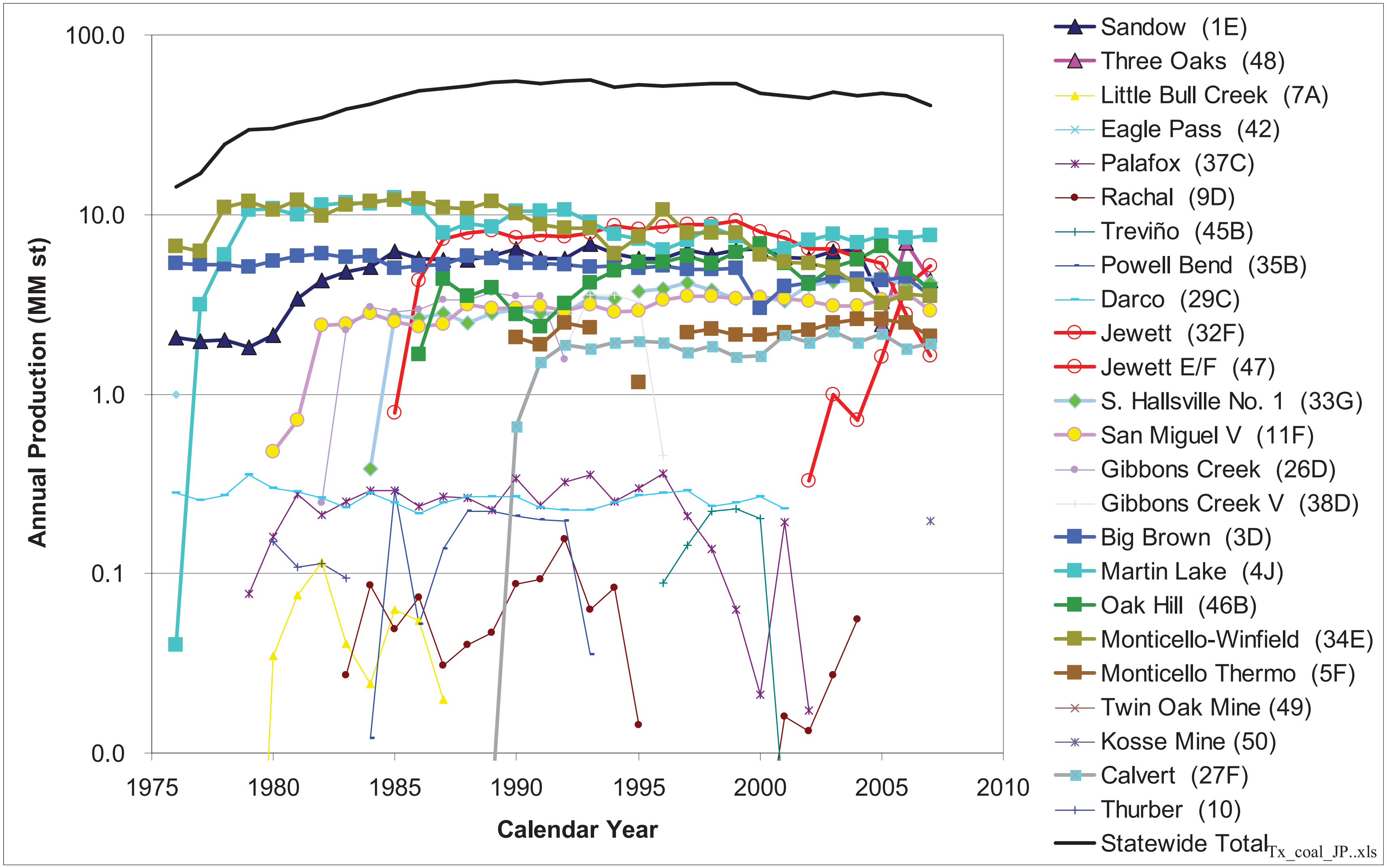
Figure 99. Lignite mine groundwater production 2001–2009



(a) linear scale

Note: permit numbers in brackets

Figure 100. Production of Texas coal mines (1976–2007)



(b) log scale

Source: RRC website file tx_coal.xls

Figure 100. Production of Texas coal mines (1976–2007) (continued)

4.4 Aggregates

This section summarizes work presented in Walden and Baier (2010) that addresses nonfuel industrial mineral mining, including aggregates, stone, clays, metals, and nonmetallic minerals. Most of the information focuses on crushed stone and construction sand and gravel, which make up the largest portion of the industrial mineral mining industry in Texas and constitute one of the greatest water users. As detailed in the methodology section (Section 3.3.3), the current TWDB data set is used as a basis and is compared with the newer BEG survey. In Section 4.4, we describe our efforts to bring in additional information, particularly confirmation of water-use coefficients.

4.4.1 General Aggregate Distribution

Aggregates fall into two major categories: crushed stone and sand and gravel, as well as a miscellaneous third category. Having a low value on a mass basis, aggregates tend to concentrate around urban areas because transportation costs can be prohibitive unless they possess an intrinsically higher value such as industrial sand (used in hydraulic fracturing) or igneous crushed stones (Figure 101). Aggregate products can be economically trucked up to 50 miles and can be shipped by rail up to 200–250 miles.

Carbonates (limestone and dolomites) for crushed rock exist in large quantities across most of the state but typically come from selected formations such as the Edwards Limestone (Garner, 1994), especially along the Balcones Fault Zone (west of San Antonio to south of Dallas). Overall, crushed stone consists mostly of limestones but also sandstones, as well as granitic rocks in the Llano area and volcanic rocks (“trap rock”) in the Uvalde area. Carbonates, and more generally crushed stones, have several purposes, including concrete making, ballast, base material under foundations, roads, and railroads, but also manufacture of cement and lime. Sand and gravel facilities are located mainly along streams and rivers and in the Gulf Coastal Plains and tend to be smaller and sometimes intermittent.

Some facilities are located below the water table and need to pump seeping groundwater (as well as stormwater) from the exploitation pit. It is difficult to estimate the amount of groundwater (which should be counted toward withdrawal) relative to the amount of stormwater (which should not be counted as either groundwater or surface-water withdrawal) without undertaking a study of the local hydrologic system, unless a water-source breakdown is provided by the operator.

4.4.2 Description of Mining Processes

4.4.2.1 Crushed Limestone Mining

Hard-rock limestone is mined by blasting large sections of the quarry wall and extracting the shot rock with excavators, loaders, or other mechanical equipment. Large dump trucks transport the material to rock crushers, where it is reduced to a size that can be moved by conveyor belts to other parts of the operation. No water is used during extraction except for roadway watering and dust suppression, as needed. Initial rock crushing and separation are also performed dry except for dust suppression. Road-base products, which contain higher proportions of clay and pit fines, are produced in this dry section of the plant. Harder rock is passed sequentially through a series of crushers, shakers, and screens with a multistage washing system to produce a variety of product sizes. Amount of water used depends on how dirty the rock is and the number of products to be generated. Different sized products are separated and stockpiled for delivery to customers. Products can be mixed in various proportions to satisfy specific customer specifications. The wash water removes very fine particles and impurities from the larger aggregate products. These small particles are further separated from the wash water using cyclones, rotating screws, weirs, and fine screens to produce manufactured sand. Figure 102 represents a simple flow diagram of a typical crushed-stone mining process.

The remaining water is captured and typically routed to large settling ponds to allow super-fine particles of silt and clay to settle out of suspension before being pumped back to supply ponds to be recycled for reuse in the process. Smaller operations or quarries with limited available space may use closed filtration or similar equipment to further clean and recycle wash water. Discharge of water is rare and generally only occurs during seasonal, heavy rainfall events that overwhelm the retention ponds. As a result of the active water recycling and reuse efforts in place at most crushed-stone quarries, only ~20 to 30 percent of the water used in the operation is actually consumed and must be replaced. Water loss generally results in four ways: (1) retention of water in the moisture content of final product shipped to customers; (2) application of water on roadways, conveyor belts, and transfer points to suppress dust; (3) spillage and absorption of water from washing process equipment and pipes; and (4) evaporation from ponds and open equipment.

Rainwater, spillage, and drainage from stockpiles are collected and routed to settling ponds or other equipment to reduce the amount of makeup water required. Surface ponds that are below the local water table may also have significant groundwater seepage into the ponds. In some areas of the state, this seepage is often enough that active pumping from groundwater or surface-water sources is not required or may only be necessary during summer months or periods of extreme drought. Brackish or saline water cannot be used for aggregate mining because the salt will adversely impact the quality of the concrete, asphalt, and other products manufactured from the materials.

4.4.2.2 Sand and Gravel Mining

In open-pit sand and gravel mining, material is removed using excavators, front-end loaders, draglines, or shovels and transported by trucks for processing. Deposits are frequently located near streams or waterways and are mined moist. No water is required for extraction and, in some cases, water must be pumped away from the mining site to allow access by machinery, although some facilities with deposits below the water table use dredges. Dewatering of groundwater seeping into the mining site is often used as wash water but may also need to be supplemented by groundwater and surface-water sources.

In most dredge-type sand and gravel mining, materials are pumped from the bottom of a body of water and piped to the processing plant in a high volume of water. The sand and gravel are separated, and the bulk of the water is returned to the original location. This return water is critical to maintaining an adequate volume of water at the mine site to allow continued pumping. Some dredge mines use bucket dredges to load material onto barges or other means of transport to processing locations.

Sand and gravel are processed through a series of shakers, screens, and washers to size, separate, and clean different products. Larger rocks may be crushed or removed for other uses. Rotating screens with water sprays are used initially to treat wet materials before log washers or rotary scrubbers remove clays and organic materials. Screening is used to separate product by size. Products are dewatered with screw conveyors, cyclones, or other separators and then transported to stockpiles. Wash water is routed to stormwater retention ponds, where particles are allowed to settle out. It is then recycled as process water or applied on plant roadways for dust suppression, as needed. Because sand and gravel are typically wet, little if any water is required on conveyors or other equipment for dust suppression. The moisture content of sand and gravel can be ~5% to 6%, resulting in proportional loss of water.

4.4.3 External Data Sets

Several databases (MSHA, USCB) list aggregate facilities and related commodities but do not include information on their production (Table 2, Table 3). A trade association (NSSGA) in association with USGS also reports names and locations of aggregate facilities but, similar to USCB and MSHA, does not provide commodity production or water use. As described next, we investigated with little success the possibility that TCEQ own information about water use. TCEQ regulates surface-water rights. We also conducted a survey of GCDs to access information on groundwater use.

4.4.3.1 TCEQ Central Registry

TCEQ is responsible for the regulation and permitting of all sources of air and water pollution and has adopted rules that specify the control technologies and emissions limits that must be met by industries, including mining operations, in Texas. The TCEQ has established a Central Registry of all regulated entities, which contains information about the companies and specific locations of industrial sites. Each regulated site is issued a Registration Number or RN Number, which allows the agency and the public to readily access this information and links to other program records related to permitting, compliance, inspections, enforcement, and other actions taken by the TCEQ. The Central Registry database was queried to extract information on all active facilities with major, two-digit SIC Codes of 10, regarding metal mining, and 14, regarding mining and quarrying of nonmetallic minerals, except fuels. The numbers and types of facilities identified by this search were far larger than identified by MSHA and NCCGA and are shown in Table 29.

4.4.3.2 TCEQ Surface-Water Diversion

The TCEQ issues and regulates water-rights permits and withdrawals of most surface water in Texas including navigable waters, reservoirs, and major impoundments. Each water right holder must submit monthly reports indicating the amount of water diverted, amount returned, and the amount consumed. The TCEQ provided spreadsheet data on water-rights reports from entities identifying themselves as mining users for 2006–2008. The agency was unable to segregate the mineral-mining facilities from other mining interests, such as oil and gas or coal, so it was difficult to clearly differentiate the available data. Many of the companies that were clearly recognizable as mineral mining reported no surface-water diversions, or they indicated that they consumed 100 percent of the amount that they did divert. In some cases, companies did report significant return-flow quantities. However, there appeared to be some confusion on the appropriate reporting requirements because some companies reported that the sum of the amount returned and consumed exceeded the amount that was diverted throughout the year. Appendix F includes a table that provides all of the active water-rights holders in the mining industry, along with the amount of water they are authorized to withdraw in acre-feet per year. It also includes a table of the 2008 Water Rights Reporting Data.

Further evaluation of the TCEQ Water Rights data to identify and extract industrial mineral mining information and to resolve gaps and inconsistencies in the reported values may be worthwhile. However, most mineral mining operations do not depend on surface-water-rights diversions except to supplement captured stormwater and recycled water when needed.

The TCEQ does not regulate the extraction of groundwater. Local GCDs have been established to monitor and control the amount of water withdrawn from aquifers in many areas of the state. No centralized data are available for specific types of water use, and additional investigation would be required to survey GCDs to determine whether they maintain data on mining activities within their jurisdiction. Information gathered from GCDs is posted in Appendix E.

4.4.3.3 TCEQ TPDES

The TCEQ regulates wastewater from major industrial and commercial sources under the Texas Pollution Discharge Elimination System (TPDES) through permits that control the amount and quality of effluent discharged. Discharge of process water requires an individual, site-specific permit, whereas discharge of stormwater can often be authorized under the Multi-Sector General Permit (MSGP) for major industrial activities. All of the SIC code categories for mineral mining operations (major two-digit Groups 10 and 14) are subject to the MSGP. Facilities are required to monitor and report the quantity of discharges but do not need to report captured or recycled water if it does not leave their property. Because most mining operations actively recycle much of their water, they only discharge during periods of exceptionally heavy rain. Examination of individual TPDES permits and discharge-monitoring reports will be of limited value in quantifying water use or consumption.

The TCEQ regulates the emission of air pollutants to reduce or avoid the release of contaminants that could adversely affect public health or the environment. Mineral mining operations have the potential to emit particulate matter (PM) from a number of processes that require controls to be implemented. Rules and air-quality permit requirements most often direct mining operations to reduce these PM emissions by applying water sprays to crushers, conveyors, transfer points, stockpiles, and roadways to suppress dust. This application becomes a major source of water consumption because most or all of the water used for these purposes evaporates. TCEQ rules do not require sources to monitor or report the amount or frequency of water used for particulate controls. Although some facilities record some related activities, such as the number or frequency of water trucks used to spray roadways, for their own management needs, such data are not consistent and cannot be reliably used. Further evaluation of air permits or controls will have limited value in quantifying the amount of water used or consumed by the mining industry.

4.4.3.4 TCEQ SWAP Database

The federally mandated TCEQ Source Water Protection (SWAP) project database contains a wealth of information about current and past mining activities and is a good source to locate facilities. However, it does not provide information about water use.

4.4.4 BEG Survey Results

4.4.4.1 Survey of Facilities

Results of the BEG survey are summarized in Table 30 (without reference to specific facilities or their location). Total production for crushed stone from the surveyed facilities translates into ~35 million tons, or 22.5 % of state total production, and may be sufficient to imply some validity and predictive power to this aggregate category. On the other hand, sand and gravel survey results add up to only ~3.6 million tons, or 3.6% of the state total production, and thus provide more limited predictive power. Overall surveyed facilities are well distributed across the state and are located in areas where most of the population resides (Figure 103). The 26 facilities (18 crushed stone and 8 sand and gravel) show a large range in terms of production (<0.2 to >13 million tons per year), reported gross water use (a few AF/yr to >4,000 AF/yr), reported net water use (a few AF to >2,000 AF/yr), and in a category called groundwater and surface-water net water use (from 0 to >1,000 AF/yr). The last category does not consider stormwater in net water use and account only for so-called external sources (surface water or groundwater). Plotting the information (Figure 104) graphically illustrates the relationship between these types of water use.

The stormwater category is included because precipitation falling on the property is generally redirected to sumps and ponds to comply with TCEQ regulations. Often that stored stormwater alone can be sufficient to run aggregate operations. This study did not try to determine whether the drainage area and precipitation at a specific facility are consistent with the amount of stormwater reported to be used. Such a task goes beyond the scope of work, although data to perform it are readily available. Discriminating between stormwater and groundwater is difficult in a pit whose bottom might be deeper than the water table, but it is just as conceivable to think that the stored stormwater recharges the aquifer as to think the reverse.

Water-use statistics are computed with and without accounting for stormwater (Table 31): the crushed-stone water-use coefficient is either 64 gal/st (with all water sources) or 36 gal/st (without counting stormwater), and sand and gravel water-use coefficient is either 68 gal/t (all water sources) or 47 gal/st (without storm water). Excluding dry process facilities and facilities from a company that seems to have much lower water-use coefficients produces 151 and 66 gal/st for wet process and crushed stone facilities, respectively. However, we think that the fraction of dry vs. wet process facilities is representative of the state as a whole (because we obtained complete data from a large operator in the state) and that lower water-coefficient facilities should also be included in the average (because they come from several large facilities). Recall that in the methodology section we explained that averages were made on a production basis not as a simple average of each facility average.

The amount of reported recycling varies widely from none for dry-process crushed-stone facilities, which only consumes water for dust suppression and a few wet-process crushed-stone facilities, possibly because they have stormwater in excess, to almost 100% in some highly water-conscious facilities. A few wet-process crushed stone facilities also reported no recycling, possibly because they have excess storm water available or because they misinterpreted the question. Most facility recycling rates range from 65% to 90%. For the washed crushed-stone mining operations that reported recycling, rates were in the expected range of from 49% to 86%. Recycling at surveyed sand and gravel operations was reported at rates ranging from 74% to 99%.

Unexpectedly, five operations indicated that no recycling of water was conducted at the mines and that all of the gross water used was consumed. This may be due to a misunderstanding of the survey questionnaire rather than an unrealistic indication that all water is used only once at the facility and is lost to product or evaporation. A more probably interpretation is that no exceptional recycling activities have been implemented to increase water reuse. In these cases, the reported amounts should be considered net water use. This study focuses on the net water use and did not need knowledge of gross water use or recycling rate because, unlike oil and gas activities, recycling serves only one single facility. The large spread in net water use is illustrated in Figure 105, which displays histograms of water consumption. However, values cluster ~0 to

30 gal/t for dust control (roads and machinery) and show a bimodal distribution at <20 gal/t and ~50 gal/t for washing. Both distributions have very long tails. Gross-washing water use reportedly ranges from a minimum of 3.0 gpm/tph for very clean rock (rare) up to 15.0 gpm/tph for dirty rock (as sometimes seen in the Edwards Limestone), that is, 180 to 900 gal/t (Walden and Baier, 2010).

The source of consumed water (Table 32) is equally difficult to generalize because of the limited size of the analyzed sample, but it seems that on average more than half of the consumed water is groundwater. This figure, however, represents an average that matches only a few facilities (Table 30). Water for most operations come from only one of three possible sources (groundwater, surface water, or stormwater). It is thus impossible to attribute water source at a county level without specific knowledge of the water use at each facility.

4.4.4.2 Survey of GCDs

Survey results are described in detail in Appendices D and E and integrated within the body of the report. Overall, except for a few very responsive districts, most GCDs either did not respond to the survey or did not have access to the requested information. In summary, findings indicate that most groundwater conservation districts do not collect estimates of groundwater use by mining operations. The districts generally rely on information reported by the TWDB, even though they may not be able to confirm the information. Fewer than 50 percent of the districts surveyed replied with any information. Of the respondents, only 20 percent provided any quantitative volumetric estimate of use or permitted use of groundwater by mining entities. No districts reported having monitoring systems in place to measure groundwater use that was permitted for mining. Therefore, other than the reported current use data in Appendix D (Table 72), the districts were unable to provide better projections of water use by mining.

4.4.5 Historical and Current Aggregate Water Use

Table 33 summarizes some historical water-use coefficients, a parameter not easy to come by as discussed earlier. Old reports (for example, Quan, 1988, published by the Bureau of Mines) mention ~300 gal/st but variable across the years (470 to 220) (his Fig. 30) and probably across the country as well as a function of local conditions. About half is recycled water (Quan, 1988, Table 5). Crushed stone intensity of water use ranges from 60 to 150 gal/st (his Fig. 34). Quan (1988) presented data for 7 individual years between 1954 and 1984. The trend is towards reduction in water use but not in a regular fashion and actually shows an uptick in the last year (1984), amount of recirculated/recycled water increased from a small fraction in 1954 to 50% in 1984. Quan (1988, p.32) estimating future water use in 2000 for the U.S. Bureau of Mines also relied on intensity of use coefficients using them as multipliers to the projected mineral production. Norvell (2009, Table 3) calibrated USGS water-use coefficients from Quan (1988) to Texas water-use surveys done ca. 2000. He doubled water-use relative to the U.S. average and assumed 80% recycling. Mavis (2003, Table 6.1–2) provided figures in the following subcategories for the sand and gravel category: 1–6 gal/t for dust control of machinery (this is consumed), 60–180 gal/t for wet screening, ~60 gal/t for sand screw, and ~90 gal/t for gravity classifier. The last three categories are for gross water use.

Recent WUS surveys conducted by the TWDB have a small overlap with the BEG survey (Table 34) in terms of facility, with an approximate agreement in terms of net water use. TWDB results cannot be used to develop water-use coefficients because production values are not provided, but they were integrated into their specific counties, as described in the methodology section.

Overall, **~24,700 AF and ~18,300 AF (total of 43,000 AF)** was consumed across the state for aggregate production. Results for individual counties are listed in Table 35.

Table 29. TCEQ Central Registry records of mining facilities in Texas

SIC Code	Type of Mine	No. of Mines	SIC Code	Type of Mine	No. of Mines
Major Group 10: Metal Mining					
1011	Iron Ore	4	1081	Metal Mining Services	8
1044	Silver Ore	6	1094	Uranium–Radium–Vanadium Ore	52
1061	Ferroalloy Ore (except Vanadium)	4	1099	Misc. Metal Ore	18
Major Group 14: Mining and Quarrying of Nonmetallic Minerals, Except Fuels					
1411	Dimension Stone	118	1446	Industrial Sand	74
1422	Crushed and Broken Limestone	1285	1455	Kaolin and Ball Clay	14
1423	Crushed and Broken Granite	8	1459	Clay, Ceramic, and Refractory Minerals (not elsewhere classified)	
1429	Crushed and Broken Stone (not elsewhere classified)	296	1474	Potash, Soda, and Borate Minerals	8
1442	Construction Sand and Gravel	1041	1479	Chemical and Fertilizer Mineral Mining (not elsewhere classified)	60
			1481	Nonmetallic Minerals Services, Except Fuels	29
			1499	Misc. Nonmetallic Minerals, Except Fuels	100

Table 30. Water-use survey results from selected aggregate operations

Production (Mt/yr)	Gross Water Use (1000s AF/yr)	Net Water Use (1000s AF/yr)	GW &SW Net Use (1000s AF/yr)	Water Use (gal/st)	Recycle Rate (%)	Source Water		
						GW	SW	StW
Crushed stone (wet process)								
4.00	4.1	1.3	0.00	107	68%			100%
1.76	2.9	0.5	0.54	100	81%	100%		
0.80	1.1	1.1	1.10	450	0%	100%		
1.33	1.6	0.4	0.41	100	75%	100%		
0.85	1.2	0.2	0.09	65	86%		50%	50%
1.50	1.4	1.4	0.00	300	0%			100%
*0.20**	0.2	0.2	0.15	*est 250*	0%		100%	
*0.65**	0.1	0.1	0.03	*est 250*	0%	55%		45%
*0.18**	0.3	0.1	0.04	*est 250*	52%	30%		70%
*0.33**	0.3	0.3	0.00	*est 250*	0%			100%
3.50	1.1	0.3	0.33	31	70%	100%		
13.70	4.3	1.1	1.06	25	75%	100%		
0.60	1.1	0.2	0.14	92	84%	80%		20%

Production (Mt/yr)	Gross Water Use (1000s AF/yr)	Net Water Use (1000s AF/yr)	GW &SW Net Use (1000s AF/yr)	Water Use (gal/st)	Recycle Rate (%)	Source Water		
						GW	SW	StW
Crushed stone (dry process)								
0.29	0.01	0.01	0.01	9	0%	100%		
0.39	0.01	0.01	0.00	10	0%			100%
4.56	0.14	0.14	0.14	10	0%	100%		
2.28	0.07	0.07	0.00	10	0%			100%
5.00	0.02	0.02	0.02	2	0%	18%	82%	
Sand and gravel								
0.55	0.29	0.08	0.08	45	74%		100%	
0.52	0.12	0.04	0.04	26	67%		100%	
0.21	0.12	0.03	0.00	38	79%			100%
0.50	1.84	0.03	0.03	18	99%		100%	
0.50	2.00	0.35	0.35	228	83%	100%		
0.30	0.09	0.02	0.02	22	76%	100%		
0.52				0	Y			100%
0.48				0	Y			100%

*: estimated

Note: some facilities may underreport their stormwater use

Table 31. Aggregate net water use/consumption based on BEG survey results

	Number of Data Points - % of State Production	1000s AF /million tons	Gal/t
Crushed-stone water-consumption coefficient			
All water sources	17–22.5%	0.197	64
GW+SW only	17–22.5%	0.109	36
Wet process crushed large w/o low water-use coefficient facilities			
All water sources	10–~8%	0.465	151
GW+SW only	10–~8%	0.204	66
Sand and gravel water consumption coefficient			
All water sources	6–3.6%	0.209	68
GW+SW only	8–3.6%	0.143	47

Table 32. Net water-use breakdown by water source

		Groundwater	Surface water	Stormwater
Crushed Stone	Weighted by production	0.706	0.011	0.295
	Facility average	0.491	0.129	0.381
Sand and gravel	Weighted by production	0.689	0.291	0.020
	Facility average	0.250	0.375	0.250

Note: crushed stone survey represents ~22.5% of total production, whereas sand and gravel survey sample represents only 3.6% of production

Table 33. Historical water-use coefficients for aggregates (gal/st)

Withdrawal	Recycled	Total	Discharge	Consumption	Source
Sand and Gravel					
		220–470*			Quan (1988, Fig.30) 1954-1984
130	59	189	88	42	Quan (1988, Table C-5) 1984
260			52	208	Modified from Norvell (2009, p.13)
		211–336			Mavis (2003, Table 6.1-2)
Industrial Sands					
806	2891	3697	259	547	Quan (1988, Table C-5) 1984
1612			322	1290	Modified from Norvell (2009, p.13)
Crushed Stone					
		60–150			Quan (1988, Fig.34) 1954-1984
68	64	132	48	20	Quan (1988, Table C-5) 1984
136			27	109	Modified from Norvell (2009, p.13)

*including industrial sand

Table 34. Results from recent TWDB WUS

Sand and Gravel		Crushed Stone	
Year	Net Water Use (AF)	Year	Net Water Use (AF)
2007	72	2007*	1,058
2007	1,468	2007*	824
2005	3,020	2007*	1,196
2006	6	2007**	625**/0.9
2007	0	2002	625
2001	150	2007	4,822
2007	2	2007	1,787
2007	386	2007	185
2007	112	2007	341
2007	0	2007	0.6
2004	5	2007	0.3
2007	2,384		

*facility with water-use approximately confirmed by BEG survey
**consistent with BEG survey only for earlier years
Source: TWDB Office of Planning

Table 35. Estimated county-level crushed-stone and sand and gravel water use for 2008 (other counties are assumed to have zero water use)

County	CS	S&S	County	CS	S&S
Unit: 1000s AF					
Atascosa		0.350	Kaufman	2.063	0.195
Bastrop		0.063	Kerr		0.059
Bell	0.747	0.346	Lampasas	0.293	0.012
Bexar	3.108	1.028	Liberty		0.108
Borden		0.000	Limestone	0.210	
Bosque		0.013	Lubbock		0.415
Brazoria		0.565	Maverick	0.052	
Brazos		0.230	McLennan		1.025
Brown	0.000		Medina	0.287	0.063
Burnet	0.280	0.031	Montague	0.104	0.010
Callahan	0.131		Montgomery		0.028
Coke		0.003	Navarro		0.062
Colorado		1.540	Nolan	0.023	
Comal	3.634	0.099	Nueces		0.445
Cooke	0.818	0.026	Oldham	0.165	0.002
Coryell	0.275		Orange		0.136
Dallas		1.574	Parker	0.170	0.253
Denton		1.262	Potter	0.192	0.308
Duval		0.604	Reeves	0.014	0.008
Eastland	0.150		Sabine	0.053	
Ector	0.168		San Patricio	0.340	0.055
El Paso		0.581	Smith		0.106
Ellis	2.898		Somervell		0.386
Fannin		0.006	Starr		0.142
Fayette		0.082	Stonewall	0.019	
Floyd	0.169		Tarrant		1.093
Fort Bend		0.000	Taylor	0.000	
Galveston		0.282	Travis	0.135	0.718
Glasscock	0.095		Uvalde	0.055	
Grayson		0.041	Val Verde		0.031
Guadalupe		0.186	Victoria		0.000
Harris		2.494	Walker	0.454	
Henderson		0.115	Ward		0.016
Hidalgo	0.170	0.603	Washington		0.018
Hutchinson	0.127	0.023	Webb	0.226	0.005
Jack	0.238		Williamson	2.273	
Jefferson		0.131	Wise	1.422	0.229
Johnson	3.091	0.075	Young	0.035	
Jones		0.010	**TOTAL**	**24.7**	**18.3**

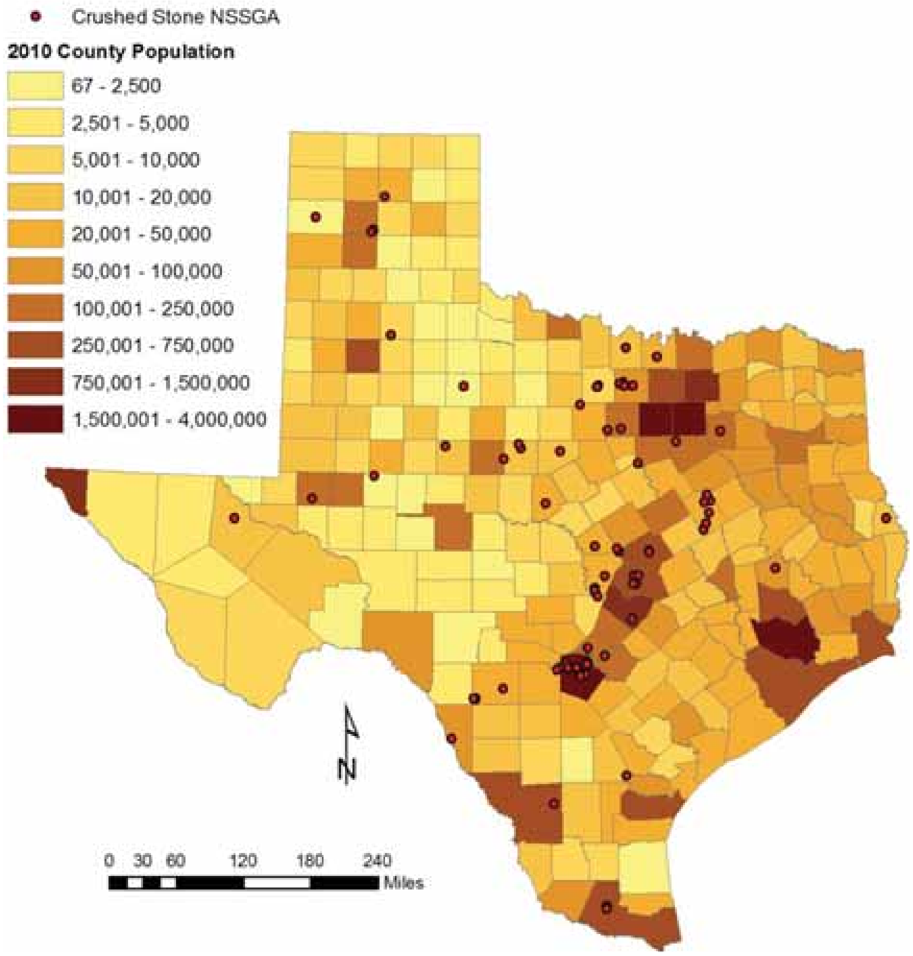


Figure 101. County population in 2010 (TWDB projection) and crushed-stone NSSGA facilities

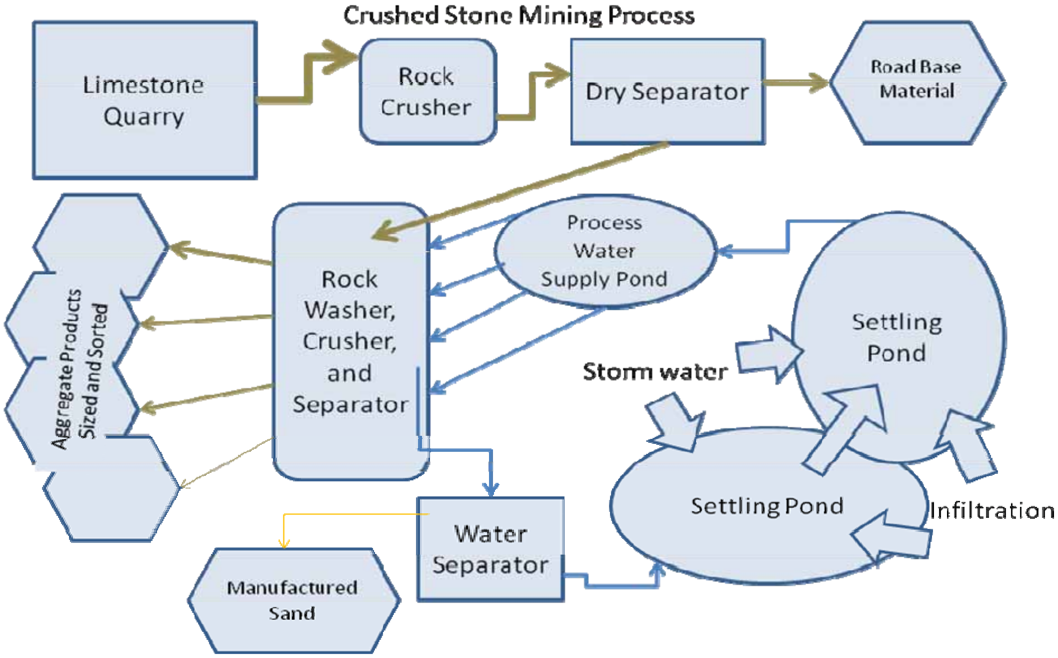
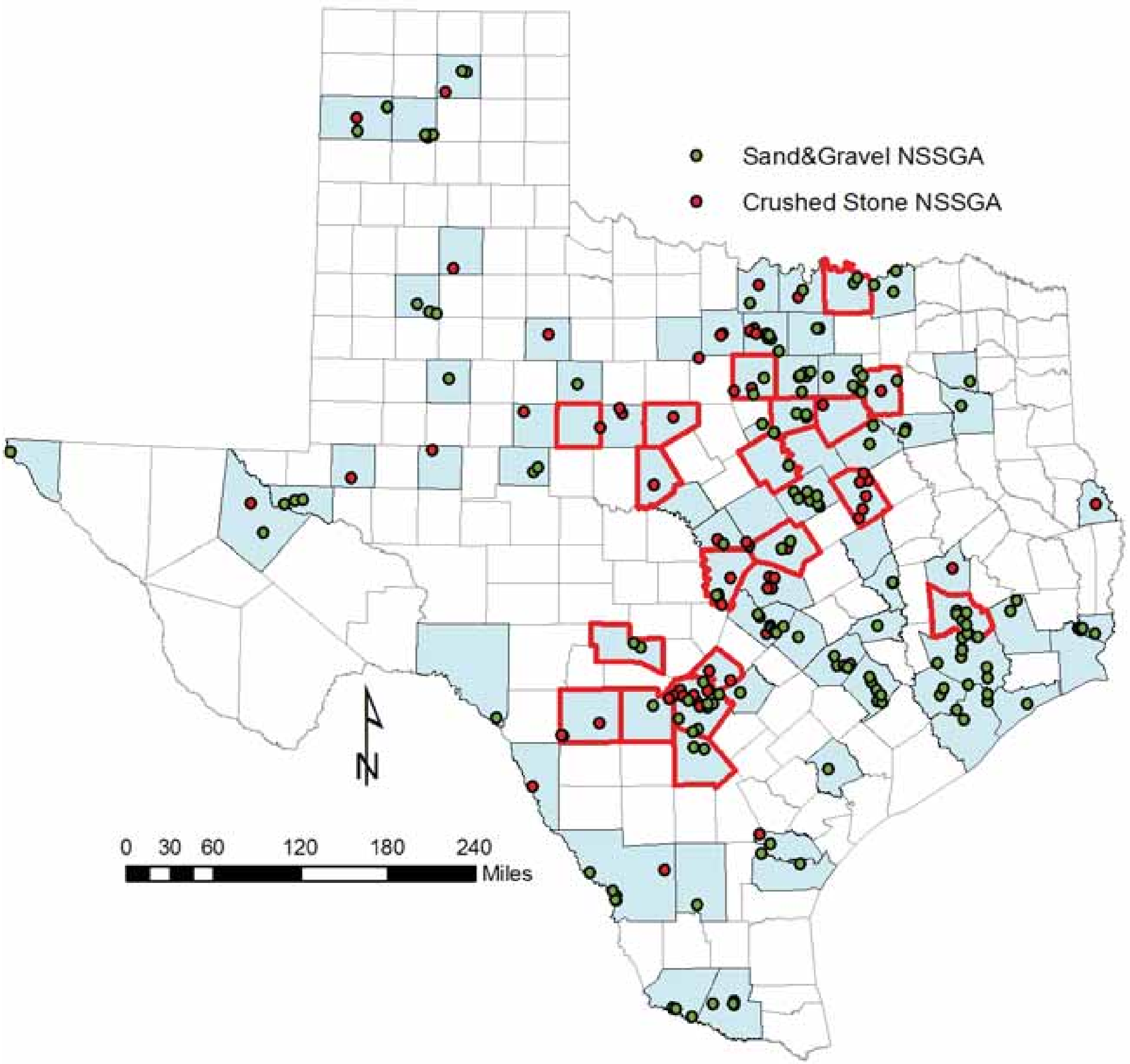
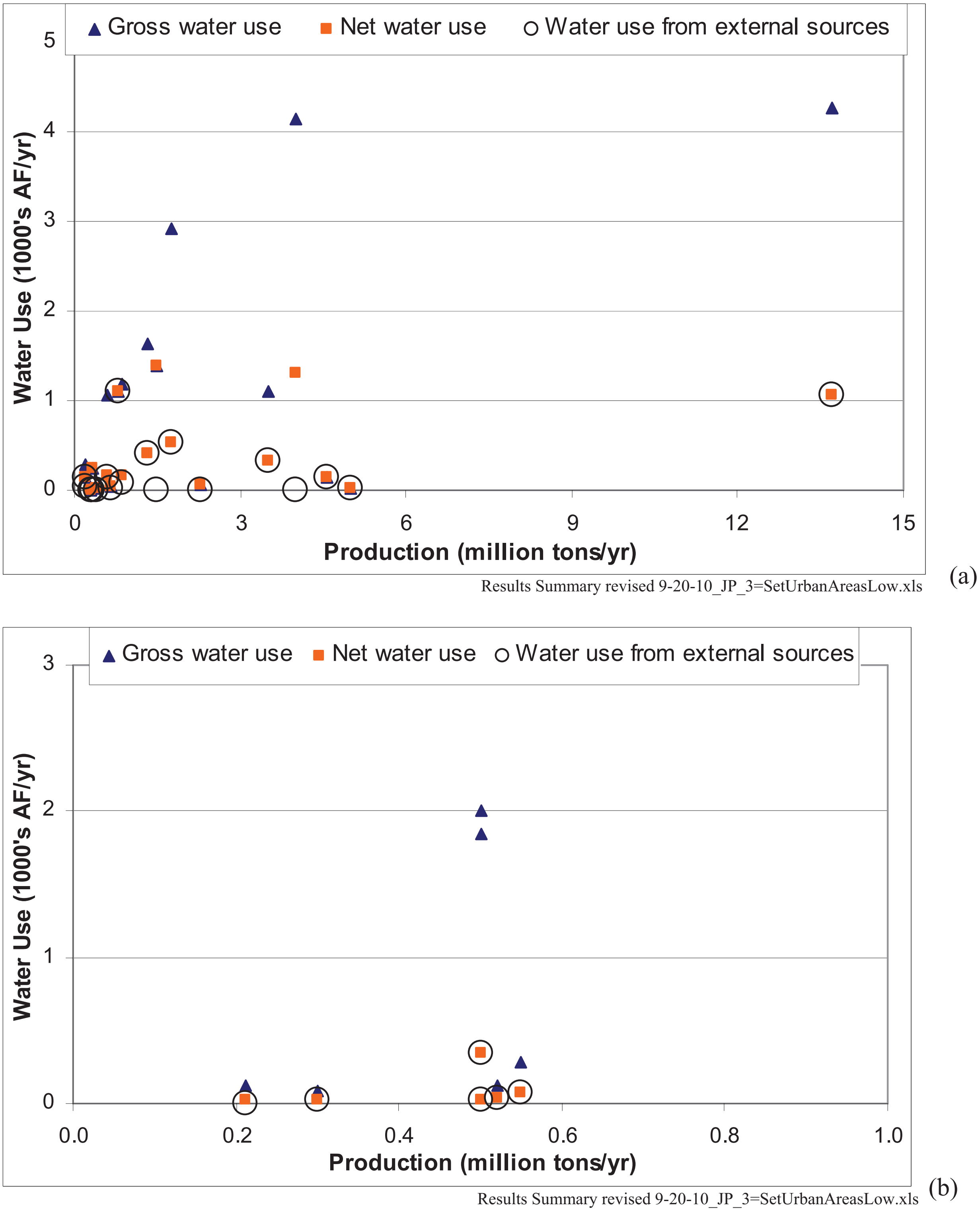


Figure 102. Flow diagram of typical crushed-stone process



Source: NSSGA/USGS database

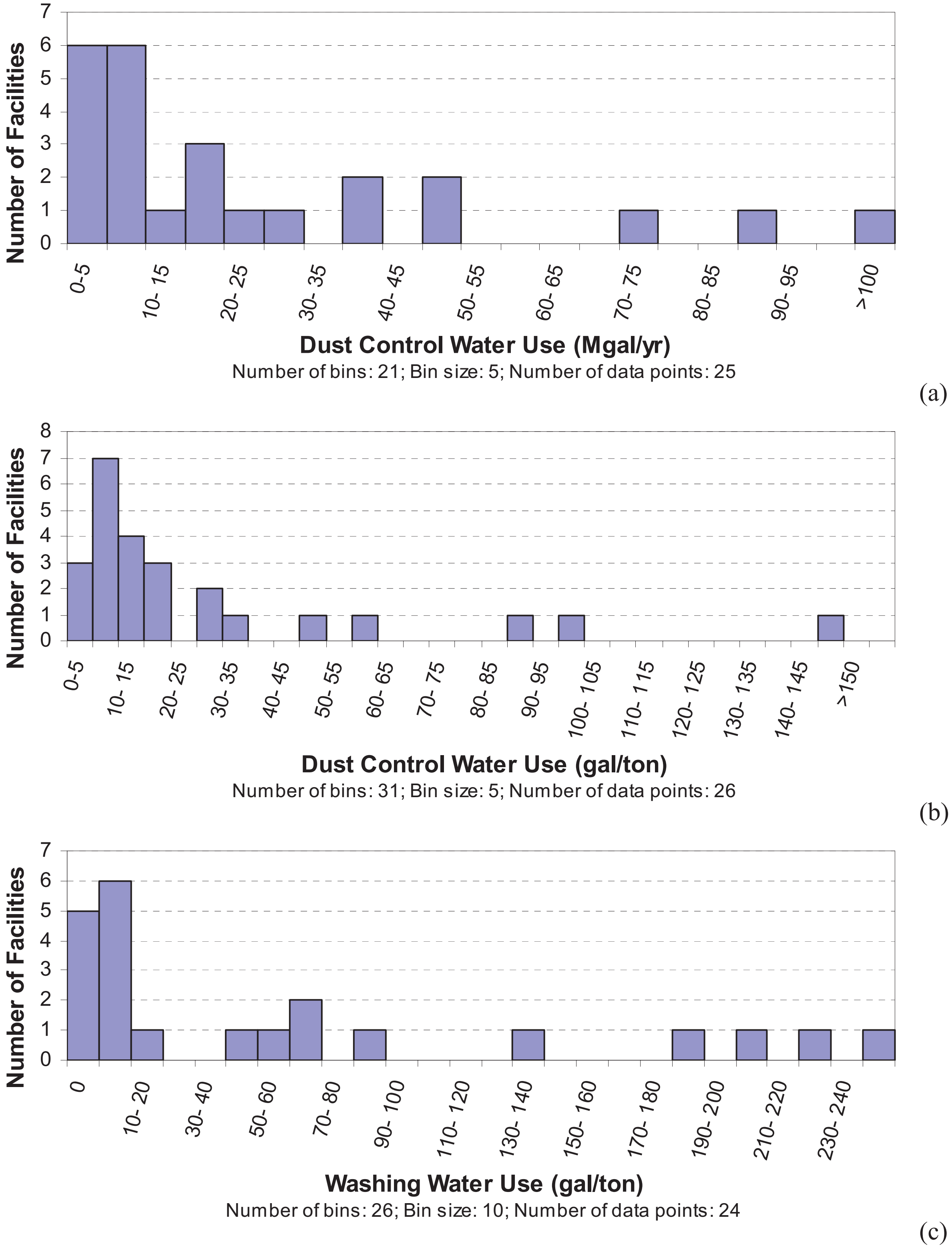
Figure 103. Counties with NSSGA-listed facilities; highlighted county lines represent those counties with information from the BEG survey



Results Summary revised 9-20-10_JP_3=SetUrbanAreasLow.xls

Results Summary revised 9-20-10_JP_3=SetUrbanAreasLow.xls

Figure 104. Water use from BEG survey for (a) crushed stone facilities; (b) sand and gravel facilities



Source: BEG survey

Figure 105. Histograms of aggregate net water use for washing and dust control: (a) per facility, (b) and (c) per unit production

4.5 Other Nonfuel Minerals

This section examines water in categories with smaller water use overall, although a few facilities may still use a significant amount of water. The dimension-stone category included many facilities, but other nonfuel facilities are too few to derive water use statistically, and they have to be analyzed individually.

Water use from the cement industry is not included in this section, not because mining of raw material is not mining, but because it is usually associated with a manufacturing SIC code (#3241). There are currently 12 cement plants, which are largely associated with the extensive Cretaceous limestones in Central Texas (Kyle and Clift, 2008). In surveys, it could be difficult to discriminate between water use in the cement plant proper and in the quarries, particularly because water use for most installations is likely to be related to dust suppression only, a small fraction of total usage overall. However, we can still infer an order of magnitude amount of water consumed in mining proper by applying values derived from crushed-rock aggregate installations. In 2009, Texas produced 11 million metric tons of cement (USGS commodity website); about half of it comes from limestone and the other half from clay material. Assuming 10 gal/t for dust control (Figure 105a) for limestone and half that value for clay rocks, yields an estimated total consumption of 250 AF (assuming no stormwater is used). This estimate is corroborated by a BEG survey returned by a large cement manufacturer in the state in which its water-use coefficient for dust suppression is even smaller.

Only one zeolite-producing facility is turning out perhaps 5,000 to 10,000 t of product per year, and total production for the nation is ~60,000 t from 10 mines. Texas is ranked third in terms of production (USGS commodity website, http://minerals.usgs.gov/minerals/). Using the earlier approach, we found the contribution of this mine to water use is negligible. Although minerals such as barite and alumina are also listed in the MSHA database, they correspond to processing facilities not mines.

We applied a similar approach for lime and gypsum, which, as raw materials, are typically transported dry to the processing plant. There is probably little washing of the material for cement, lime, or gypsum plants. Any water use past the quarrying stage would be considered part of the manufacturing process (for example, to soften the material), especially if the water is used within the processing-plant boundaries.

4.5.1 Dimension Stone

Dimension-stone facilities quarry their raw material mostly from Precambrian granites in Central Texas, Permian limestones in North-Central Texas, Cretaceous limestones in Central Texas, and Triassic Limestones in West Texas (Garner, 1992). The MSHA database lists 100+ facilities in this category, and the TWDB WUS survey lists only one facility with no recent water-use data. However, given the small production (44,000 tons in 2007, USGS *Texas Minerals Yearbook*) and assuming water use is related mostly to dust control and cutting, we tentatively based their water use on the highest water use coefficient for the crushed-stone aggregate (151 gal/ton, Table 31). This calculation results in a total water use of 18.5 AF/yr, with the additional assumption that the 10 largest dimension-stone facilities consume most of the water, each using on average 1.8 AF/yr. Even increasing the water-use coefficient by one order of magnitude yields values low enough to be neglected, given the uncertainty associated with larger uses such as aggregates, particularly because many of the counties with dimension-stone facilities also host crushed-stone or lime facilities (Figure 106).

4.5.2 Industrial Sand

Industrial sand, typically used in glass making, foundry molding, and blast sands, has seen an uptick in production and use, probably owing to the large increase in hydraulic-fracturing activities in which it is used as a proppant. Production is concentrated in only a few areas/counties (Figure 107). Texas industrial sand production has increased in sync with U.S. production but seems to be growing faster in the past few years (Figure 108). Some of the operations are owned by gas companies. Current production is likely ~4 million tons (3.28 and 3.58 million tons in 2007 and 2008, respectively, as given on the USGS website (http://minerals.usgs.gov/minerals/).

Industrial sand facilities are similar to aggregate facilities and would require a similar amount of water for dust suppression on roads and conveyor systems but require more water per unit product for washing. Historical water-use coefficients for industrial sands (Table 33) show a total water use ~20 times higher than for aggregates but a higher recycling rate as well (80% in the 1980s). Water consumption averaged across the U.S. was also 10+ times higher than that of crushed stone. The few data points collected for this study agree with this figure.

The Hickory UWCD near the Llano Uplift reported 4,212 AF and 559 AF permitted in McCulloch and Mason Counties, respectively, in a total of five operations most likely related to industrial-sand (proppant) production. The UWCD also stated that actual use and permitted amounts were very close and that plant consumption (manufacturing) was not included. Other sources of information suggest that these two counties produce >1 million tons of industrial sand, particularly the Carmeuse Industrial Sand facility, and perhaps up to one-third of the state output. Assuming the latter sand production value results in a high water-use coefficient of 1,200 gal/t. A facility in Limestone County reports on the TWDB WUS database (http://www.twdb.state.tx.us/wrpi/wus/wus.asp) a consistent ~650 AF/yr throughout the year. A facility responding to the TACA/BEG survey and located in a county north of Houston reported 0.2 million tons of production, water consumption of 315 AF/yr, and a significant fraction (~93%) of the water being recycled. A quick calculation yields a water-consumption coefficient of 514 gal/t for the latter facility, which reports no water use for dust suppression.

How much stormwater is used is unclear. Note that some of the industrial sand facilities are collocated with regular aggregate facilities and that their water consumption may already be included in this category. Overall, when no other information is available, we assumed a water-use coefficient of 600 gal/t, to which we added 20 gal/t for dust control, resulting in **9.7 thousand AF** (Table 36).

4.5.3 Chemical Lime

Lime (and cement) plants tend to be sited next to the raw material (Edwards Limestone, Austin Chalk, and other pure limestones) being quarried. The year 2009 saw a short drop in lime production (1.04 million metric tons; 1.5 million metric tons in 2008), deviating considerably from the trend of the past 2 decades (according to which, production should have been over 1.7 million tons) (Figure 109). According to USGS, as well as the MSHA website (http://www.msha.gov/drs/drshome.htm), there are five lime facilities in Texas, in Bosque, Burnet, Comal, Johnson, and Travis Counties. MSHA provided the annual number of employee-hours, and we assumed that production is proportional to the number of hours worked. Most of the water use in lime facilities is associated with manufacturing. There is typically no washing; operators tend to avoid adding water because of the cost of heating it. Water use is only for dust suppression and is likely hard to separate from overall plant use. We assumed that water consumption is due only to dust suppression at 10 gal/t (Figure 105a). The result is a small total water consumption of **46 AF** (assuming no stormwater is used) (Table 37), which can be neglected.

4.5.4 Clay Minerals

Clay minerals mined in Texas fall into two categories—common clay (brick making, cement component) and specialty clays (ball clay, bentonite, fire clay, Fuller's earth, kaolin). These five types' usage and mineralogical make-up are: ball clay (kaolinitic sedimentary clays that commonly consist of 20–80% kaolinite, 10–25% mica, 6–65% quartz), which is used for ceramics; bentonite, which is used for drilling mud, among many other uses; fire clay (all clay minerals but bentonite), which is used to make refractory products; Fuller's earth (montmorillonite or palygorskite or a mixture of the two), which is used as a adsorbent; and kaolin (kaolinite), which is used for porcelain and high-quality paper (Norvell, 2009, p.6).

Clay mining is generally performed by scrappers, which remove materials and transport it to stockpiles for use in manufacturing processes, such as brick making. In some mines, excavators are used to remove and load clay onto railcars, barges, or other transport to off-site manufacturing plants. Clay mines may be online for only a few months each year to provide raw materials sufficient to support manufacturing throughout the year. No water is used in the actual mining process, although water is added during most of the manufacturing processes. In fact, clay mines are bermed to minimize rainwater inflow and must be dewatered, if necessary, to allow access and prevent excess water from affecting clay quality. Water is discharged into retention ponds or nearby surface water, and some is used for dust suppression on plant roadways. Water can be used for conveyance as slurry but cannot be included as mining use; it is instead considered as manufacturing use.

Texas clay deposits are generally contained in Tertiary formations of the Gulf Coast. Brick-making operations often tap the common clay of the Calvert Bluff Formation in Central Texas (Hunt, 2004). Altered volcanic ash layers in South Texas provide bentonite, and kaolinite is produced from the Simsboro Formation in North Texas. The main clay producers are in Gonzales (bentonite), Navarro (common clay), Limestone (kaolin), and Fayette (bentonite) Counties. Clay is also mined in an additional 20 counties.

Texas mining production in 2008 was 2.14 million tons of various clay minerals, having remained relatively constant at that level during the past decade despite a bump of ~2.7 million tons in 2006 and 2005. Less water is probably needed for dust suppression in clay operations, and stormwater probably ponds more easily than in conventional aggregate operations. However, unlike for cement, lime, and gypsum operations, the clay washing step could be included as mining use, which we ultimately decided not to do. Assuming a water-use coefficient of 30 gal/t (Figure 105c) would have yielded only **~200 AF**, a low value that falls below the uncertainty level of major users and is distributed across various operations in several counties.

4.5.5 Gypsum, Salt, and Sodium Sulfate

Gypsum is produced mostly from Permian evaporitic strata of North-Central Texas in Nolan/Fisher/Stonewall Counties and Hardeman County, as well as in Gillespie, Kimble, Wheeler, and (perhaps) Harris Counties. Texas production in 2008 was ~1.04 million metric tons and has seen large variations in production in the past decades, although seemingly relatively stable at 1.8 million tons/yr on average (Figure 110). The number of mining facilities has also changed in sync with total production (four, five, or six facilities). The result is a small total water consumption of **32 AF** (assuming no stormwater is used) (Table 38).

There are only two salt mining operations in Texas: the Grand Saline Dome in East Texas in Van Zandt County and the Hockley Dome in the Houston area in Harris County, both of which use the classic room-and-pillar mining technique. The USGS commodity website (http://minerals.usgs.gov/minerals/) reports that the Hockley and Grand saline mines had a production capacity of 400,000 and 150,000 short tons of rock salt in 2008, respectively. Texas total salt production has ranged from 9 to 10 million metric tons/ yr in the past decade (9,080 metric tons in 2008), ~20% to 25% of national production. In 2006, Morton-Thiokol's salt mine in Grand Saline in Van Zandt County reported the use of self-supplied groundwater of 384.4 AF, diversion of 43.3 AF of surface water, and groundwater purchase of 43.5 AF, totaling 471 AF/yr (Table 39) (K. Kluge, TWDB WUS, personal communication, 2006). The Harris-Galveston Subsidence District reported that the Hockley mine in Harris County uses ~0.1 to 7.0 Mgal/yr from groundwater wells. The district is also purchasing surface water from the Gulf Coast Water Authority for ~150 to 200 Mgal/yr, which comes to a total of ~535 AF/yr and **1.0 thousand AF** overall (Table 39). However, solution mining is the most common method of obtaining salt. In theory, 800 gal of water is required to recover 1 metric ton of salt with little recycling. In Texas, salt is used mostly as a chemical feedstock for producing chlorine (a key ingredient in the production of plastics) and soda ash (a key ingredient in the manufacture of glass) and the salt-saturated brine is directed toward the manufacturing process. For example, Dow Chemical in Brazoria County uses water from the Brazos River and is injected onsite to recover salt for use in the chemical plant. The ~9 million tons of salt annually produced in the state minus underground mining production and minus 0.8 Mt evaporated at Baytown brings the total salt production through brine at 7,700,000 × 800 = ~19,000 AF. This use of feedstock in the chemical industry is considered manufacturing and is not included in the mining category tallied in this report.

Sodium sulfate mining is extracted from brines underlying alkaline lakes in West Texas (Kyle, 2008; Kyle and Clift, 2008), one of two such facilities in the U.S. The TWDB WUS survey shows annual groundwater withdrawals remaining consistently at ~400 AF in Gaines County in the past decade. Norvell (2009) noted that early in this decade the facility pumped 1,440 AF/yr, 1,092 AF of which was saline water, increasing our confidence that the earlier mentioned **400 AF** is fresh groundwater, not produced brine (which should not be counted toward water use). We assume that sulfate sodium production and concomitant water use remained stable in the study period. Growth of this commodity will be covered by sources other than mining natural accumulations.

4.5.6 Talc

National production of talc decreased from 0.85 million tons in 2005 to 0.51 million tons in 2009 (USGS website, http://minerals.usgs.gov/minerals/). It is produced from seven mines. Talc in the Allamoore district of Hudspeth and Culberson Counties in West Texas is produced from several quarries at ~100,000 t/yr. The most recent TWDB WUS (2003) reports a low water use of 1 AF. However, RWPG Region L (Far West Texas) initially prepared a report (2010) citing a value of 1,500+ for Culberson County, increasing to 1,600+ in 2060 (see their section 2.4.7). The quarries are apparently in Hudspeth County, whereas the wells appear to be in Culberson County. The water consumption value was derived using a water-use coefficient approach (from USGS) and not using direct metering. Whether this figure includes processes that would belong to the manufacturing category is unclear. We were unable to collect better information, and we expect no change in water use in the decades leading to 2060, assuming water consumption to be classified as mining ~0.

4.5.7 Uranium

Although uranium could be considered a fuel for nuclear power plants, its main use, for convenience, is treated in this section. Only in situ leaching (ISL) or in situ recovery (ISR) technology is currently used to mine uranium (Campbell et al., 2007). The two main kinds of water-use consumption are (1) active mine and (2) reclamation/restoration, the latter requiring more water by far, although overall, the uranium extraction industry uses little water. A typical operation consists of injecting water with oxygen into the ore zone and producing the uranium-laden water, removing the uranium in ion-exchange resin, and reinjecting the water at a high recycling rate (>97%). The restoration phase follows, in which other soluble elements are brought back close to initial concentrations. A reverse osmosis technology is generally used. The recycling rate is lower, perhaps 33%, at least initially. As trace-element concentrations decrease, the RO system can be pushed further, resulting in a decreased waste stream. Other technologies, such as bioremediation, could consume less water. A given ISR facility often produces uranium and restores the subsurface at different nearby locations simultaneously. We retained an average value of 250 gal/ lb of uranium as an overall representation of water consumption.

Uranium production is concentrated in South Texas (Blackstone, 2005; Carothers, 2008, 2009; Nicot et al., 2010). EIA reported (http://www.eia.gov/nuclear/) that in 2009 only two ISL operations were active in Texas: Alta Mesa (Brooks County) and Kingsville Dome (Kleberg County). In 2008 two more were operational: Rosita and Vasquez, both in Duval County. In the past few years uranium production in the U.S. has been close to 4 million lb U_3O_8 (Figure 111) and was 4.145 million lb U_3O_8 in 2009. These facilities have a nominal production of 1 million lb U_3O_8 each (except Vasquez, at 0.8 million lb U_3O_8). EIA reported only aggregated data to protect individual companies. With the additional help of survey returns, we estimated Texas production at ~28% of total production (that is, ~ 1.1 million lb U_3O_8). We reached this value by contrasting (1) production capacity in Texas (5.3 million lb U_3O_8 in 2009) with that of the U.S as a whole (20.45 million lb U_3O_8), that is 28%, with (2) employment numbers at 31% in Texas and Colorado the total number of employee-years. Clift and Kyle (2008) reported a total production of ~1.34 million lb U_3O_8 in 2007, more than two-thirds of it from Brooks County (Alta Mesa Project). This level of production results, in turn, in a water consumption of 275 million gal, or **840 AF,** for all producing mines in Texas. We assumed that restoration water consumption is combined with production. Because the number of operating mines is limited, actual water consumption can be much lower if no restoration is being done. For the purpose of this study, we attributed one-third of the estimated total to each county (Table 40). Reclamation by RRC of legacy open pits produced in the second half of the 20th century is not included in this count.

4.5.8 Other Metallic Substances

Texas has many other occurrences of metallic and industrial minerals, notably in west Texas and in the Llano Uplift of central Texas (e.g. Price et al., 1983; Price et al., 1985; Kyle, 1990; Kyle, 2000). Some of these deposits have had minor production, but most known deposits are currently inactive. The scale of known resources provides little encouragement that most could represent viable mining operations in the foreseeable future. On the basis of decades-long evaluation and development activities, three deposits seem to have potential for near-term mining: (1) Shafter silver deposit, Presidio County; (2) Round Top beryllium-uranium-rare earth element deposit, Hudspeth County; and (3) Cave Peak molybdenum deposit, Culberson County. They will be examined in the ‘Future Water Use” section.

Table 36. Estimated county-level industrial sand-water consumption

County	Estimated Number of Facilities	Estimated Water Use (1000s AF)
Atascosa	3	0.43
Colorado	3	0.43
Dallas	1	0.04
El Paso	1	0.04
Guadalupe	1	0.07
Harris	1	0.14
Hood	3	0.43
Hunt	1	0.07
Johnson	1	0.04
Liberty	2	0.14
Limestone	2	1.30
Mason	1	0.56
McCulloch	4	4.21
Montgomery	2	0.76
Newton	1	0.14
Orange	1	0.07
Robertson	1	0.04
San Saba	2	0.28
Smith	1	0.07
Somervell	1	0.14
Tarrant	3	0.21
Wise	1	0.07
Total	**23**	**9.68**

Table 37. Estimated county-level lime mining-water consumption (AF)

	Water Consumption (AF)
Bosque	8.5
Burnet	2.8
Comal	6.6
Johnson	13.1
Travis	15.1
Total	**46**

Table 38. Estimated county-level gypsum mining-water consumption (AF)

	Water Consumption (AF)
Fisher	3.3
Gillespie	3.3
Hardeman	6.6
Kimble	1.5
Nolan	14.8
Wheeler	1.2
Total	**32**

Table 39. Estimated county-level salt mining-water consumption (AF)

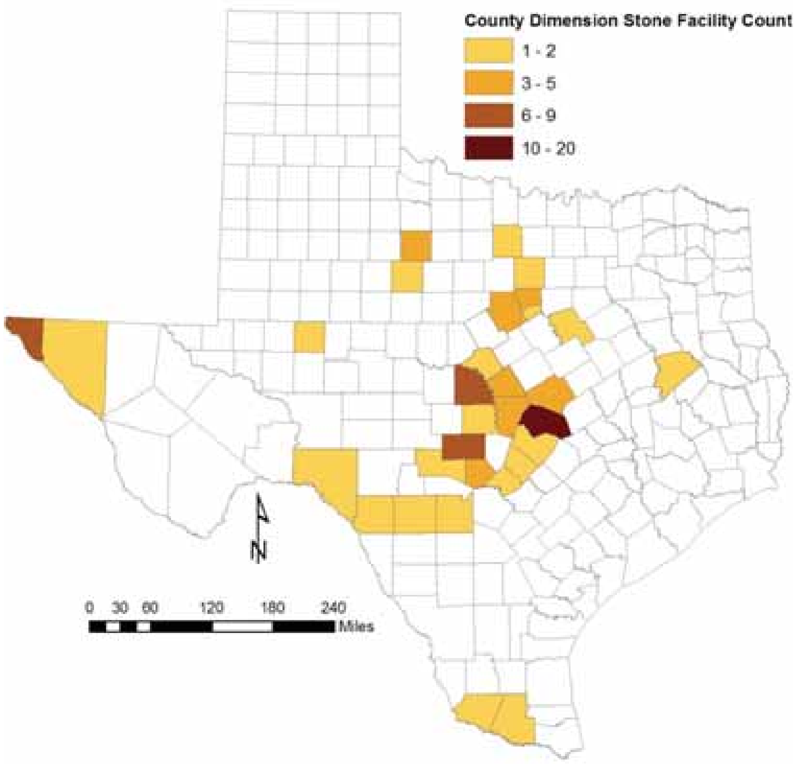
County	Water Consumption (1000s AF)
Harris	0.535
Van Zandt	0.471
Total	**1.01**

Table 40. Estimated county-level uranium mining-water consumption (2009)

County	Water Consumption (1000s AF)
Brooks	0.28
Duval	0.28
Kleberg	0.28
Total	**0.84**

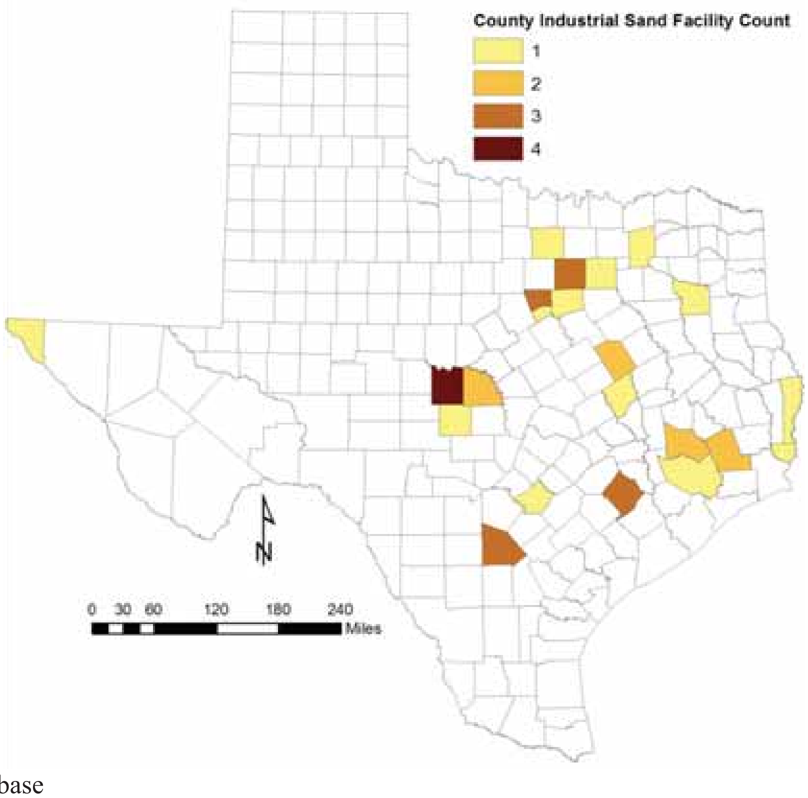
Table 41. Summary of water use not in the oil and gas, coal, or aggregate categories

Mined Substance	Estimated Water Consumption (1000s AF)
Dimension Stone	0.018
Industrial Sand	9.7
Chemical Lime	0.046
Clay Minerals	0.2
Gypsum	0.032
Salt	1.01
Sodium Sulfate	0.4
Talc	~0
Uranium	0.84
Zeolite	~0
Cement	N/A
Total	**12.25**



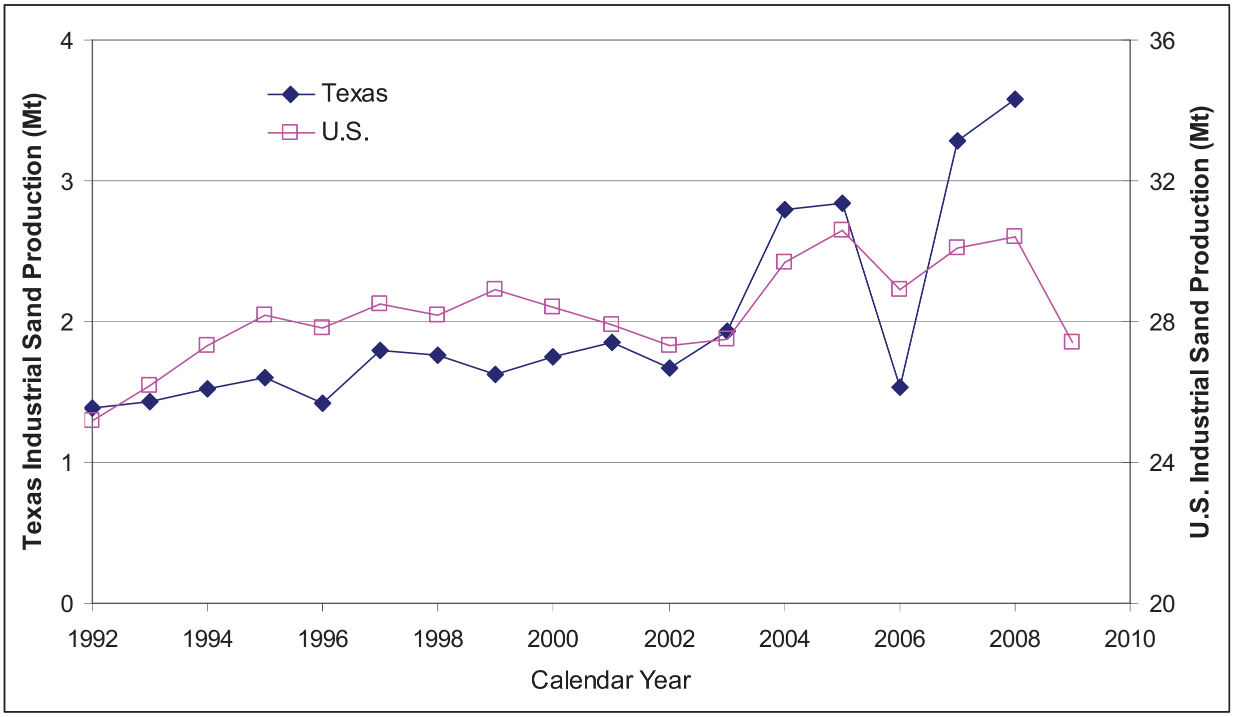
Source: MSHA database

Figure 106. County-level count of dimension-stone facilities



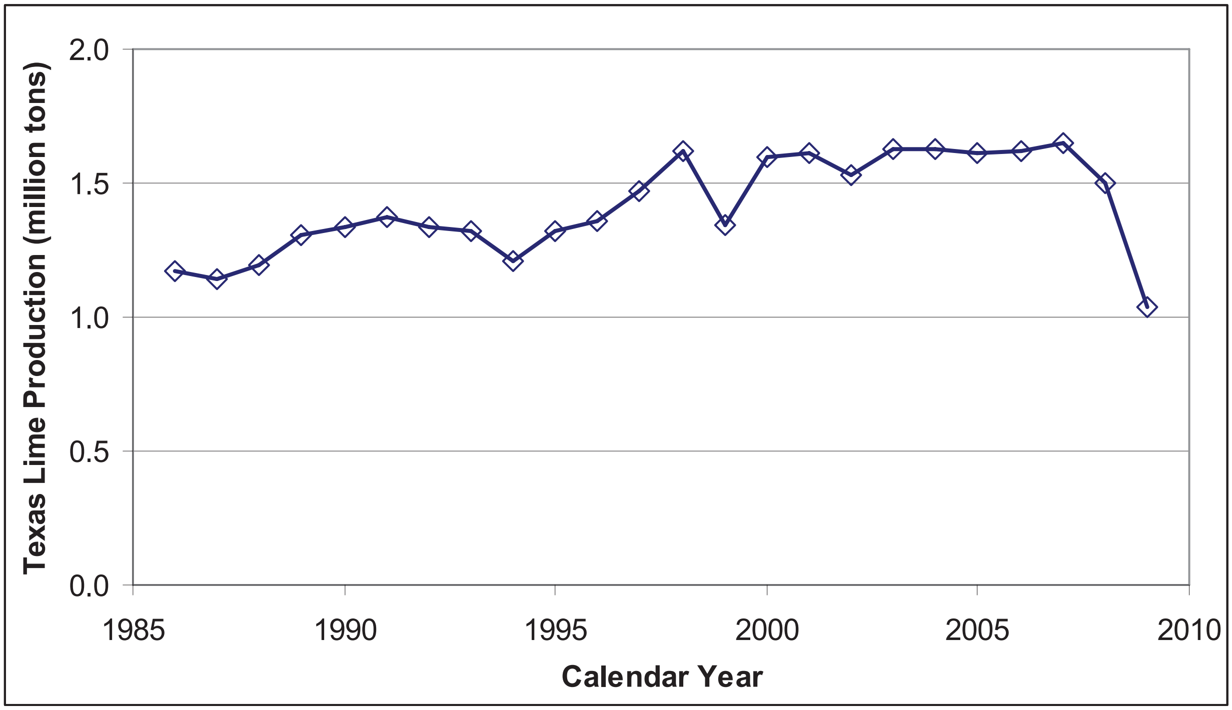
Source: MSHA database

Figure 107. County-level count of industrial-sand facilities



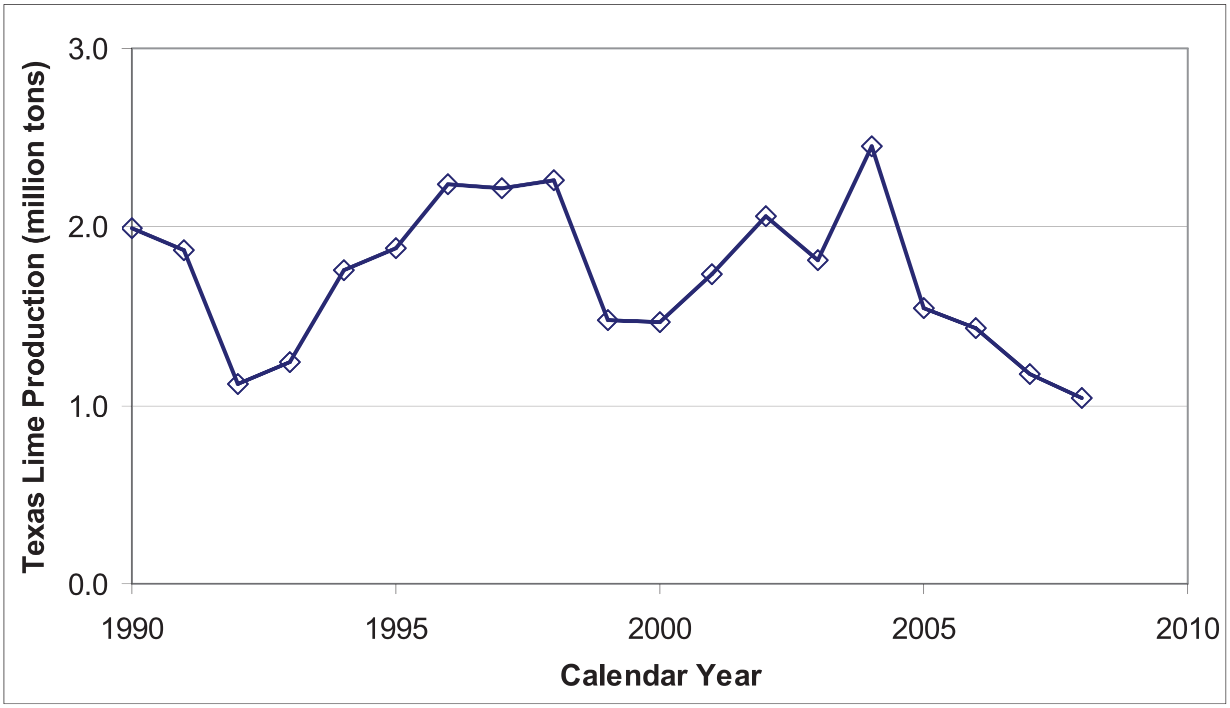
Source: USGS commodity website

Figure 108. Texas and U.S. industrial-sand production (1992–2008)



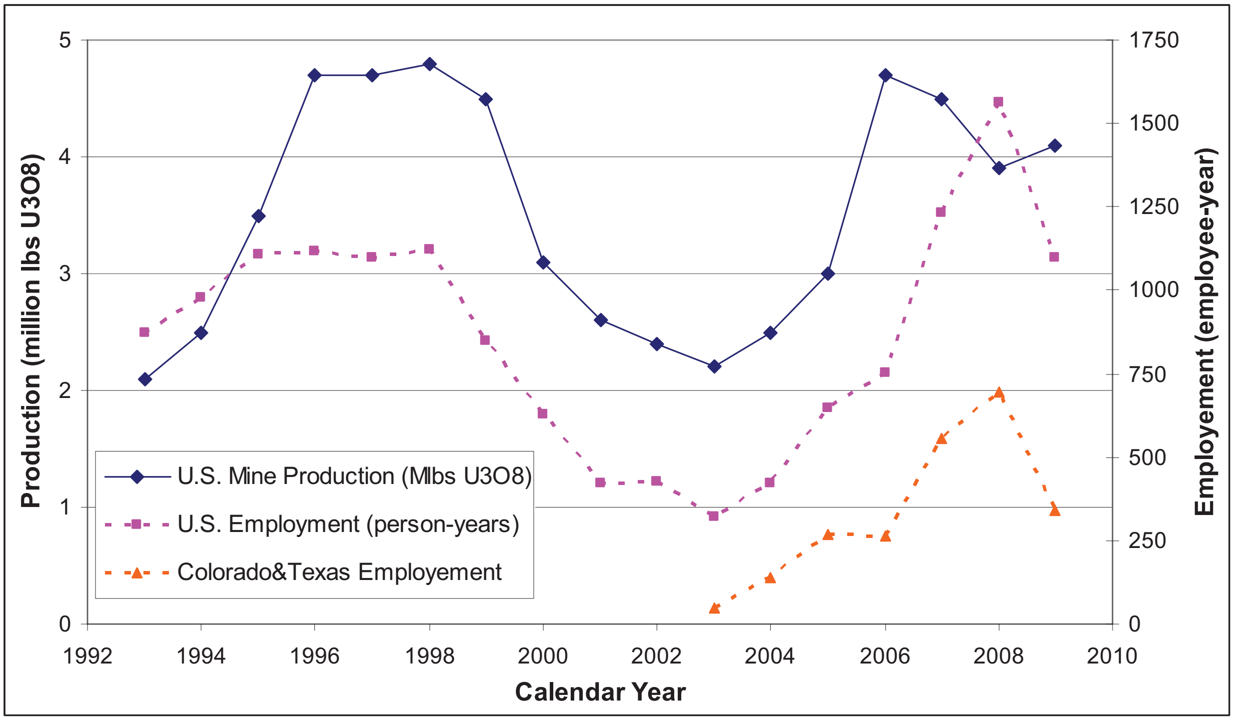
Source: USGS commodity website

Figure 109. Texas lime production (1986–2009)



Source: USGS commodity website

Figure 110. Texas gypsum production (1990–2008)



Source: EIA website

Figure 111. U.S. uranium production and employment (1993–2009)

4.6 Historical Mining with High Water Use

Although no longer active, mines once having high water use should be noted.

Sulfur

Once Texas was a major producer of Frasch sulfur from microbially altered evaporitic strata in west Texas (Hentz et al., 1989) and in salt dome cap rocks of the Gulf Coastal Plain (Kyle, 2002). More than 350 million tonnes of sulfur were produced using the Frasch process from these native sulfur deposits in Texas, Louisiana, and Mexico during the 20th century (Kyle, 2002). As recently as 1999, Frasch sulfur was produced from the Culberson deposit in Culberson County, one of the largest deposits of this type. Four smaller deposits in Pecos County had lesser amounts of Frasch sulfur production through the 1980s (Crawford, 1990).

The shallow salt domes of the Gulf Coastal Plain were the sites of significant historical sulfur production (Myers, 1968; Flawn, 1970; Greene, 1983, p. 10; Kyle, 2002). The Boling salt dome cap rock in Wharton County was the largest known Frasch sulfur producer in the United States, with more than 87 Mt of production from 1916 until 1993. Other Texas counties with multiple historical Frasch sulfur producers include Brazoria (4), Fort Bend (4), and Jefferson (2). Other counties with single producers include Chambers, Duval, Liberty, and Matagorda. Most of the economic sulfur concentrations seem likely to have been exhausted during the Frasch mining period.

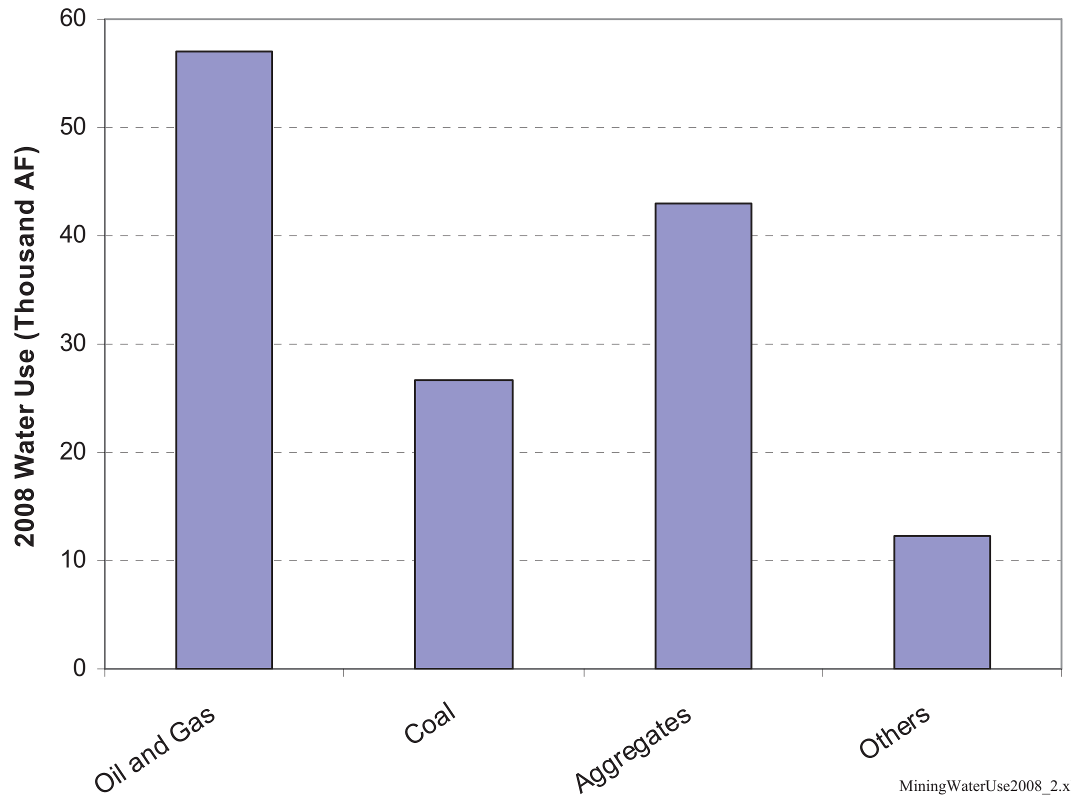
The Frasch process requires extensive amounts of superheated water to inject into the native sulfur-bearing zone to melting the sulfur, allowing the pumping of liquefied sulfur to the surface (Ellison, 1971). The economics of the Frasch process dictate extensive recovery of water and its contained heat. Water usage in association with Frasch sulfur production at the Culberson deposit was nominally 2,000 gal per tonne of sulfur produced (J. Crawford, written communication, 2010), but with only 5% of the total water being "make-up" water for the sulfur extraction, i.e. 95% of the process water is recycled. Thus, using those figures, the water demand for the Culberson operation at a rate of ~2.5 million tonnes per year totaled about 900 AF per year (1990 case; Crawford, 1990). This make-up water was supplied from wells in Reeves County, 37 miles southeast of the sulfur production site (Crawford, 1990; Crawford et al., 1998).

Bituminous Coal

Texas bituminous coal occurs in six coalfields in North-Central Texas, Maverick County, and Webb County. More specifically, coal resources occur in the Eagle Pass, Santo Tomas, Eagle Spring, San Carlos, Big Bend, and west of Fort Worth in North-Central Texas. The largest annual production of bituminous coal occurred in 1917, with >1.25 million tons of bituminous coal produced in the state, followed by a steep decline in the early 1920s that was due to competition from oil and gas. Production of bituminous coal ended in 1943 after 15 yr of low production, <100,000 t/yr (Evans, 1974). Coal from these areas has been extensively mined, and we assume no further production through the next decades.

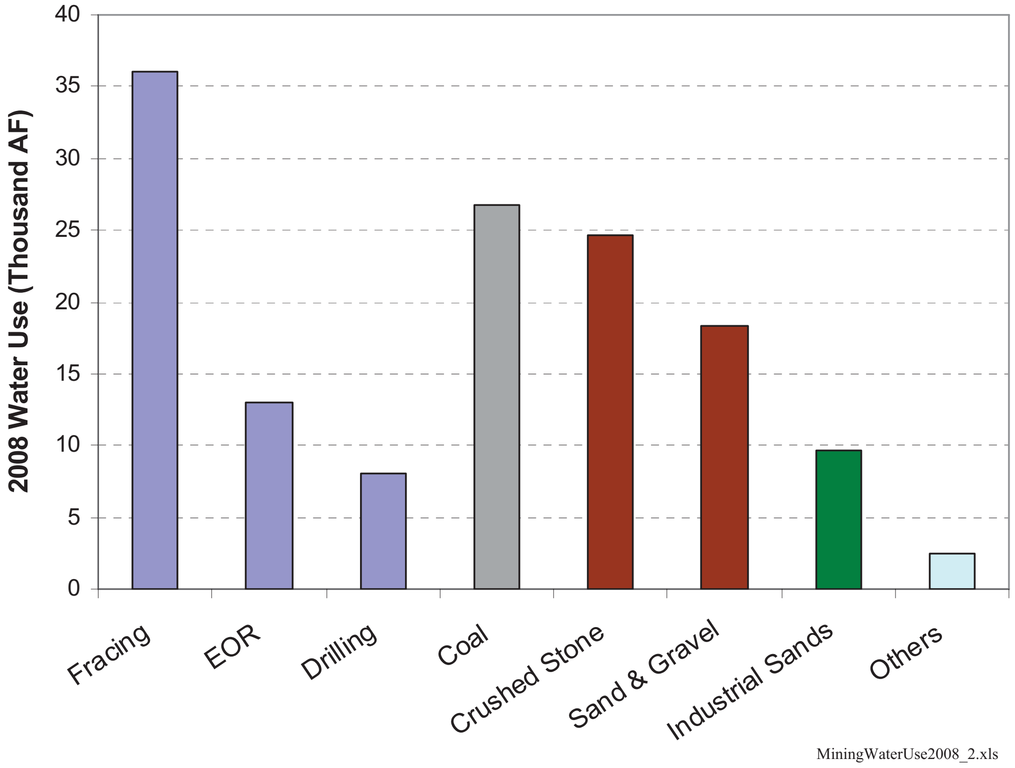
4.7 Conclusions and Synthesis for Historical Water Use

In 2008, the mining industry, defined as described in Section 4, consumed ~140 thousand AF of fresh water, distributed in a relatively balanced way between its main users (Figure 112). The oil and gas industry used ~57 thousand AF (41%), whereas the coal and aggregate industry used ~27 (19%) and ~43 (31%) thousand AF, respectively. The "other" category (~12 thousand AF, 9%) is dominated by industrial sands. A more detailed breakdown (Figure 113) shows that water use included 35.8 thousand AF for fracing wells (mostly in the Barnett Shale/Fort Worth area) and ~21.0 thousand AF for other purposes in the oil and gas industry. Aggregate industry water use is distributed between crushed stone (24.7 thousand AF) and sand and gravel (18.3 thousand AF). Remaining water use amounts to 12.2 thousand AF and is dominated by industrial sand production (~80% of total).



MiningWaterUse2008_2.xls

Figure 112. Summary of water use by mining industry segment (2008)



MiningWaterUse2008_2.xls

Figure 113. Summary of water use by category (2008)

5 Future Water Use

Most uncertainty about future water use in the mining category comes from unknowns in the rapidly evolving exploration of shales and tight formations, whose gas production is ultimately tied to national economic activity. Aggregates and coal-mining water use are better constrained and directly driven by local conditions, such as population growth, but are also connected to national economic activity. The latter is the most important driver for oil and gas long-term trends of interest to this study. An element strongly impacting future water use is the national energy policy, particularly the impact of any cap-and-trade legislation. The passage of some cap-and-trade or carbon-tax legislation during the next decade is likely to boost gas-fueled power plants, but it may also boost oil production through a greater availability of CO_2 needed for tertiary recovery of oil currently nonrecoverable (assuming the type of WAG CO_2 flood common in the Permian Basin).

In the short term, oil and gas operators are likely to focus on plays such as the Wolfberry or the combo play of the Barnett Shale or the Eagle Ford, all producing oil with significantly better economics than gas. Gas is typically a regional commodity and does not travel as well as oil, which is a world commodity. This fact is currently reflected in current oil and gas prices. In terms of BTUs contained, oil and gas prices have tracked each other fairly well until about a decade ago. It follows that variation/change in price will vary more wildly for gas. Unless lease agreements were made early in the history of the plays, Barnett Shale or Haynesville Shale operators are probably on the wrong side of the breaking even at current low gas prices. The economic slowdown has also impacted aggregate and other material demand, as well as power demand. However, overall, we refrained from trying to model this short-term episode.

5.1 Gas Shales and Tight Formations

Future water use depends on the amount of oil and gas still in the ground that is ultimately recoverable. Resources are enormous. Holditch and Ayers (2009) suggested that technically recoverable reserves in any basin are 5 to 10 times the amount of conventional gas produced and reserves are from >10 times in the Fort Worth Basin to less than the average in the Gulf Coast, and it is very likely that the industry will operate beyond the Barnett, Haynesville, and Eagle Ford shales, which it is currently focusing on. From a practical standpoint, however, this study had to rely on spatially defined resources from published information. The shale-gas industry agrees that there will be no major discovery of gas shales in Texas, whose geology is well known (e.g., Chesapeake CEO, 2010).

National organizations that develop, compile, and distribute national assessments of oil and gas reserves and resources (USGS, EIA, AAPG, PGC) have a hard time keeping up with rapid changes in the field. Figures provided by these organizations and others are not necessarily consistent as to the cutoff date for production, and other criteria may differ (resources and reserves vary through time as some are produced and additional ones are discovered), and the spatial footprint considered might be different or include areas outside of Texas. A compounding factor is that available data may not refer to a particular formation but simply a geographic area. Organizing such a large pool of information was a challenging endeavor, and we integrated the different and sometimes conflicting figures as best we could, given the time and budget constraints. As a comparison benchmark, state-level current gas production is ~7–8 Tcf/yr and increasing, whereas oil production is 0.3–0.4 Bbbl/yr. The latest figures from EIA are from 2008

(Table 43) and are categorized by RRC district (see map in Figure 9 for locations), as well as information on proved reserves. Speculative/undiscovered resources were provided by USGS (Table 43) and are not entirely consistent with data collected from other sources (Table 44). Overall, we assumed a total of 52 Tcf to be produced from the Barnett Shale. Eagle Ford and Haynesville-TX + Bossier-TX production potential is not included specifically but can be estimated at 161 Tcf and 28 + 21 Tcf, respectively. Permian Basin Barnett and Woodford USGS projections (Table 44; Schenk et al., 2008) seem optimistic and are assumed to be at ~20 Tcf. On the other hand, Wolfberry potential seems to be underestimated. Schenk et al. (2008) included only the Spraberry at a proposed ~510 million barrels of unconventional oil.

More generally, the Schenk et al. (2008) study is an example of a resource assessment performed periodically by the USGS. Unfortunately, information on other important basins in Texas has not been updated yet and the recent sharp increase in resources has not been taken into account. The Fort Worth Basin assessment (USGS, 2004) dates back to 2003, and work on the Cotton Valley and Travis Peak Formations was performed in 2002. USGS (Schenk et al., 2008) provided figures for undiscovered resources in the Permian Basin and divided them into conventional and "continuous" resources. Continuous undiscovered resources were estimated at 35 Tcf of gas and 1.3 Bbbl of oil and NGL. Overall the document may overestimate the potential of the Woodford and Barnett Shales and underestimate that of the Spraberry/Wolfberry. The same document assessed that 0.747 Bbbl oil, 5.2 Tcf gas, and 0.236 Bbbl NGL remain to be discovered, which is in addition to the ~5 Bbbl and ~0.3 Tcf of proven conventional reserves (Dutton et al., 2005b, p. 554). In the end, we estimated that the Wolfberry will produce ~1 Bbbl in the coming decades.

In general, we favor more optimistic predictions (more resources, more production, more water use) because predictions by EIA seem to have systematically underestimated actual production for the past decade because of unconventional gas. By combining proven and undiscovered recoverable resources (Table 43), we assume that the next 5 decades will see 10 Tcf produced from the Anadarko Basin, 16 Tcf from the East Texas Basin, 11 Tcf from the Gulf Coast Basin, and 15 Tcf from the Permian Basin (all tight gas and not necessarily all production).

5.1.1 Projected Future Water Use of Individual Plays

We next address gas shales individually (Barnett, Haynesville, Bossier, Eagle Ford, Pearsall, Woodford-PB and Barnett-PB) and basins with tight producing formations. Table 45 summarizes operational characteristics as collected from the literature to provide guidance for the parameters used in the production-based approach (see Methodology Sections 3.4.1.1 and 3.4.1.2). Parameters used for the production-based and resource-based projections are summarized in Table 46 (gas shales) and Table 47 (tight formations). Water use is contingent on the price of gas, and drilling activity is more sensitive to price than production. All gas plays, even with marginal permeability, will be fraced if gas prices reached $10/ Mcf, even more if the gas contains condensate, and development will be accelerated relative to that projected in this section. Conversely, if the price of gas stays below $5/Mcf for an extended period of time, projections may turn out to be too high in terms of water use.

Given the current low price of gas relative to oil in terms of BTU content, more companies have become interested in wet gas, that is, gas that contains significant amounts of ethane, propane, and butane (that can form liquid at surface conditions), whose price more closely follows that of oils. Alternatively, operators are moving altogether into the oil window of the shale. This business transition is occurring in the Barnett, Eagle Ford and Granite Wash. The net effect on water use will be to stabilize the amount used at the state level because companies will likely oscillate between dry and wet gas as a function of natural gas price.

All basins but the Gulf Coast Basin show an increase in gas production in the recent study by the PGC (PGC, 2009), in which the U.S. is divided into work areas that follow the general geology: P-320 (East Texas), P-330 (Gulf Coast), P-430 (Fort Worth Basin), and P-440 (Permian Basin, including New Mexico and West Texas) (Figure 115). The East Texas Basin has shown an increase in both production and well count in the past few years after a long period of stability. Between January 2004 and December 2008, production increased from ~3,000 to ~5,000 MMcfd, with ~10,000 incremental wells. The Fort Worth-Strawn Basins, after a slow decline in terms of production (~600 MMcfd) and well count since 1990, have shown a turnaround that started ca. 2000 and that corresponds to initial development of the Barnett Shale. Starting then, production increased to 2500 MMcfd in 2007 and increased faster to reach ~5000 MMcfd at the end of 2008. Gulf Coast production stayed more or less stable at 6,000 to 7,000 MMcfd but has been on a slow decreasing trend since 2000. The well count is stable as well. Production in the Permian Basin has remained stable at 4,000 MMcfd for the past 20 years (to the end of 2008), with an increase in well count showing the maturity of the plays and infill drilling.

Barnett Shale

The Barnett Shale represents a special case because a similar study was completed a few years ago (Nicot and Potter, 2007; Nicot, 2009a). Appendix B suggests that projections are correct so far. For the present study, we went back to initial projections at the county level (Bené et al., 2007, Table 8, Appendix 2; Nicot and Potter, 2007, Table 8), supplemented by the study by Tian and Ayers (2010), who presented an update on the prospectivity of the shale in both the oil and gas windows. We also noted that average water intensity seems to have decreased from the estimated 1.2 Mgal/1,000 ft of lateral in Nicot and Potter (2007) to ~1 Mgal/1,000 ft, despite (or thanks to) an increase in lateral length.

County-level results are presented in Table 48. Water use projections peak in 2017 at ~43 thousand AF and then decrease to almost nothing in 2040. High-water-use counties are outside the core area because it has already passed its peak of drilling activity. Parker, Tarrant, and Wise Counties, for example, have a high water use, although it will drop during the next decade as activity moves to Clay and Montague Counties in the oil window and more peripheral counties outside of the core area.

Haynesville/Bossier Shales

The part of the Haynesville/Bossier shales lying in Texas is estimated at ~35% of each play. We also added a few counties west of the salt basin slated to start producing at a later date. Projections suggest that water use will peak at 22 thousand AF around the 2020 (Table 49 and Table 50). As expected (as well as by construction), counties from the core area (Harrison, Panola, San Augustine, Shelby) are projected to peak at the same time and to contribute the most to total water use.

Eagle Ford Shale

Because of the relative lack of information on Eagle Ford wells, the Eagle Ford Shale decline curve is assumed to be similar to that of the Haynesville but scaled by a smaller EUR. Cusack et al. (2010) attempted a similar analysis in the Eagle Ford play and concluded that 50,000 wells would be needed. This study came up with twice as many wells but spread over a much larger area. The Eagle Ford Shale was projected to peak in 2031, with a water use of ~32 thousand AF (Table 51). Leading counties in terms of water use are such mostly because of their size because no core area has been delineated yet and water use is distributed over the whole play more or less evenly (but not entirely because of prospectivity variations still).

Permian Basin Barnett and Woodford Shales

Those two potentially gas-bearing shales cover large tracts of land in the Delaware Basin in West Texas and overlap (making them more attractive to operators). They have been tested several times, apparently with little success. Matthews et al. (2007) suggested that the lack of carbonates to the Barnett Permian Basin relative to the Fort Worth Basin subcrops is an unfavorable element. We also think that the level of interest is currently low. Mineral-rights owners would rather produce shallower oil with a more dependable worth. Similar to the Pearsall Shale, we assumed a delayed start of around 2020. Water-use is projected to peak at 9.8 thousand AF in 2031 (Table 52).

Pearsall Shale

The Pearsall play has not been very active in the past couple of years but has showed potential in the past. It was assumed that after a period of time, operators in the Eagle Ford would redirect their attention to this play, which is slated to use water in significant amounts around 2020 and peak in 2031 at ~8.1 thousand AF (Table 53).

Wolfberry Trend

The Wolfberry Trend is assumed continuous and is treated in a way similar to that of gas shales. Projections result in a 2023 peak year, with a water use of 11.7 thousand AF. Counties with the highest water use are Irion, Reagan, and Upton Counties (Table 54).

Tight-Gas Plays

Tight-gas plays are discontinuous and cannot be approached exactly as the gas shales were. In addition, most of them have been producing both conventional and tight gas for many years. Their water use is also smaller for these very reasons: less gas to recover and only a small fraction of a county is of interest. Water use in the East Texas Basin tight-gas plays (Table 55) is projected to peak in 2024 at 5.5 thousand AF, with no county dominating. Water-use projections for the Anadarko Basin (Table 56) peak at 3.1 thousand AF in 2020, with a strong contribution from Hemphill and Wheeler Counties. The south Gulf Coast Basin (Table 57) has a small projected water use of 2.4 thousand AF distributed over many counties at its peak (2027), in agreement with the low level of interest local plays have received in the past few years. The Permian Basin (Table 58), which has a higher potential, shows the highest water use in 2017 at 7.8 thousand AF, distributed over many counties as well.

5.1.2 Correcting Factors

Correcting factors include recycling, refracing/infill drilling, and potential development of new technologies.

5.1.2.1 Recycling

Recycling figures depend on two parameters: (1) how much of the frac water flows back and how soon after the fracing operation itself? and (2) what fraction of it is usable again with or without treatment? The amount of water ultimately flowing back from an average fraced shale-gas well is a strong function of the play. It can vary from three times the volume injected in the

Barnett Shale to a small fraction, as in the Marcellus in Pennsylvania. From a strictly operational standpoint, only the water flowing back early (10 days) in the history of the well is reusable, when all the water infrastructure is still in place (although a multiwall pad may mitigate this). The fraction of injected frac water satisfying this criterion is 16% and 5% in the Barnett and Haynesville Shales, respectively (Table 42). In addition, the quality of the such-defined flowback water is variable. Some initial flowback water can be reused with little treatment (filtration or/and mixing). Blauch (2010) stated that flowback water can be used without much treatment, mostly by straight blending with fresh water (5–10% flowback and 90–95% fresh water) and using new-generation chemical additives. However, Rimassa et al. (2009) suggested that full recycling will be hard to attain because degraded additives accumulate in the recycled water. At the other end of the spectrum, undergoing full recycling using more or less advanced treatments and producing distilled water can be expensive. However, a whole segment of the service industry has grown in the past decade to address the recycling needs of gas operators with the development of many mobile water-treatment units making use of different technologies (Horn, 2009), such as osmosis, reverse osmosis, and thermal processes.

The RRC website (http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php, accessed 10/11/2010) mentioned that a company specializing in recycling of industrial water has treated enough produced water (at 80% recovery) to generate 9.3 million barrels of fresh water thanks to several mobile units. This amount is equivalent to 1.2 thousand AF over the course of a few years (since 2005). The RRC website also announced that a stationary facility in Parker County with a capacity of 30,000 bbl/d received the go-ahead. This capacity amounts to a production of 1.13 thousand AF of recycled water a year, assuming no down time. Devon, using recycling mobile units, has recycled >400 million gallons, with an efficiency of ~80% (that is, >320 Mgal (~1 thousand AF), which was reused and >80 Mgal had to be disposed of (Devon website). This information has been reprised by RRC, as described earlier. It seems that only Devon has heavily invested in making use of flowback and treated produced water. According to the IHS database, Devon has drilled ~20% of the Barnett wells since 2005. The process did not seem competitive with new water and disposal of flowback water. It remains unclear how many operators follow a recycling program similar to that of Devon in the Barnett and elsewhere in Texas. Conservatively assuming that twice as many wells as involved in Devon's flowback recycling program have been treated results in 3% of the injected frac water having been treated (~70 thousand AF since 2005). Incorporating the fact that some flowback water was probably used without extensive treatment and not counted toward the figures presented earlier will increase this number. For example, reuse, although it probably depends on the operating company, can be as high as ~200,000 gal per well in Barnett wells with little treatment (M. Mantell, Chesapeake, personal communication, 2010), corresponding to a 6% reuse. Chesapeake does not typically reuse water from the Haynesville (too little and of poor quality). Overall, the recycling effort can be estimated in the 5–10% range in the Barnett and ~0% in the Haynesville.

The industry is bound to make tremendous technological progress in recycling, driven mostly by issues external to the state of Texas. When a critical mass of companies involved in recycling is reached, substantial progress in efficiency and rate is expected. Particularly because of specifics in the Marcellus Shale area, such as limited use of injection wells and municipal wastewater-treatment facilities, the industry will make progress in recycling (as long as there is material to recycle). In this study we assumed that a maximum of 20% of the water used for fracing will be used again.

5.1.2.2 Refracing

How much refracing of wells already fraced is taking place is unclear, and the information is conflicting. Vincent (2010) did a systematic study of restimulation from the origins of hydraulic fracturing and concluded that it works (as documented in the literature) and fails (as not documented as often). However, discussion with operators suggests that very little refracing of recent or future wells will take place. Refracing activities so far have been restricted to wells completed early in the development of the slick-water technology and, thus, may be more common for vertical wells. However, Potapenko et al. (2009, p. 2), looking back at Barnett recompletions, found that despite great success with refracing of vertical wells, little success has come from restimulation of horizontal wells. Gel fracs performed early in the history of the play perhaps somehow may have damaged the formation and that the new water fracs have restored it to its full potential (King, 2010, p. 24). Similarly, it was found that "*Some recent spacing between frac stages in horizontal wells by some operators are so close that it may be very difficult to refracture those wells as all the stages are communicated. Many earlier horizontal wells left large segments between stages unperforated for later refracturing development. Some now also believe that drilling horizontal well laterals close (250 ft.) and not simo-fracturing is leaving gas in place that may not be refractured successfully later on using current technology. Some of us believe that simo-fracturing provides gas today that might have been recovered years later through refracturing.*" (PBSN, Sept. 23, 2008). Simo-fracturing consists of fracing neighboring wells at the same time. However, the same newsletter (PBSN, May 5, 2008; Oct. 5, 2009) states "*We believe most Barnett Shale horizontal wells will be refractured within the first seven years of production.*"

This work assumes that all the possible restimulations have already been done and that there will be no need to refrac newer wells.

5.1.2.3 Infill drilling

Infill drilling takes advantage of the new technologies (horizontal drilling and hydraulic fracturing) that can then be applied to older plays and reservoirs. Infill drilling is an important factor but has no need to be included explicitly as a correcting factor. It is already implicitly part of the methodology.

5.1.2.4 New or Updated Technologies

New or updated technologies that could further decrease reliance on fresh water include use of fluids other than water (propane, N_2, CO_2), sonic fracturing with no added fluid, and other waterless approaches with specialized drilling tools. N_2 fracs may prove effective. Brannon et al. (2009) and van Hoorebeke et al. (2010) described a ~250,000-gal liquid N_2 for a multistage frac job with a 3,000-ft-long lateral. These workers noted that although this kind of frac is not widespread, Marcellus operators may find advantages in using N_2 fracs because of their limited need of water and lack of disposal issues. They went on to note that the Woodford and Barnett Shales present a favorable lithology for application of this technology. Other potential development includes cryogenic nitrogen or CO_2 and high-energy gas fracturing (Zahid et al., 2007). Friehauf and Sharma (2009) discussed the benefits of "energizing" frac fluids with gases such as N_2 or CO_2 (better). Gas addresses the water-trapping problem by creating high gas saturation in the invaded zone and facilitating gas flow. How this different approaches impact total water use is, however, unclear. As the cost of water increases, those methods potentially more expensive than water fracs could become more attractive and receive more attention. Some companies already seem to be using CO_2 fracs in the Barnett and Eagle Ford. Some technologies limit the amount to be disposed of but do not necessarily reduce the demand on local water resources, for example, using waste heat from compressors to evaporate (but not recover) water.

This work does not account for such technological progress and assumes that all plays will be produced thanks to technologies currently applied on a wide scale.

5.1.3 Conclusions on Fracing Water Use

Overall water use for fracing will increase from the current ~37 thousand AF to a peak of ~120 thousand AF by 2020–2030 (Figure 116). However, uncertainty is large. We assumed no major technological breakthrough in fracing technology and no more than small incremental annual increase in efficiency. Another way to measure uncertainty is to assess the two approaches used (production-based and resource-based approaches). Used independently, these would differ by a factor of two in terms of water use. In addition, there are still several other potential gas accumulations, particularly at larger depths than considered in this study—for example, Cotton Valley and pre-Pearsall Formations in South Texas (Ewing, 2010), Travis Peak potential tight-gas resources downdip of the current play (Li and Ayers, 2008), and Silurian, Ordovician (Simpson Group), or even Cambrian targets in the Delaware Basin or the Permian Basin (Dutton et al., 2005a)—but which are all too speculative to be included in this study. Production from these formations would mean that water use, instead of decreasing after the peak of ~120 thousand AF would stay at that level or possibly higher for a longer period of time.

Table 42. Flowback volume characteristics.

	Frac Water Volume (Mgal)	Flowback @ 10 Days (Mgal)	Ultimate Produced Water (Mgal)	Recovery Ratio
Barnett	3.8	0.6	11.730	3.1
Haynesville	5.5	0.25	4.475	0.9
Fayetteville	4.2	0.5	0.980	0.25
Marcellus	5.5	0.5	0.700	0.15

Source: M. Mantell, GWPC Annual UIC Conference, Austin, TX, January 26, 2010

Table 43. Compilation of published Texas oil and gas reserves

	Oil (Bbbl)	Gas (Tcf)	Source
Proved Reserves			
Texas	5.122 4.56	72.1 81.8	EIA (2008, Tables 4 & 5) RRC website (2010, data from 2008)
Districts 4+2 (South TXs)	0.092	0.00 Shale 10.3 Total	EIA (2008, Table 9) EIA (2008, Tables 4 & 5)
District 6 (East TX)	0.16	0.16 Shale 11.3 Total	EIA (2008, Table 9) EIA (2008, Tables 4 & 5)
Districts 8+8A+7C (~PB)	4.30	0.04 Shale 13.3 Total	EIA (2008, Table 9) EIA (2008, Tables 4 & 5)
Districts 5+9+7B (~FWB)	0.23	21.4 Shale 26.8 Total	EIA (2008, Table 9) EIA (2008, Tables 4 & 5)
District 10 (~An. B)	0.05	0.00 Shale 6.3 Total	EIA (2008, Table 9) EIA (2008, Tables 4 & 5)
Undiscovered Recoverable Resources (Mean)			
Permian Basin, including New Mexico	0.75 Conv. 0.51 Cont. 1.26 Total	5.20 Conv. 0.26 Tight 35.13 Shale 40.58 Total	USGS – NOGA website 2010*
Anadarko (TX+OK+KS)	0.40 Conv. 0.00 Cont. 0.40 Total	14.20 Conv. 0.00 Tight 0.00 Shale 14.20 Total	USGS – NOGA website 2010*
Fort Worth Basin (>Texas)	0.10 Conv. 0.00 Cont. 0.10 Total	0.47 Conv. 0.00 Tight 26.23 Shale 26.70 Total	USGS – NOGA website 2010*
Western Gulf Coast (TX+LA)	2.29 Conv. 1.09 Cont. 3.38 Total	68.09 Conv. 2.63 Tight 0.00 Shale 70.72 Total	USGS – NOGA website 2010*
East Texas**	2.76 Conv. 0.00 Cont. 2.76 Total	0.00 Conv. 0.00 Tight 0.00 Shale 0.00 Total	USGS – NOGA website 2010*

*NOGA website http://energy.cr.usgs.gov/oilgas/noga/assessment_updates.html (updates)
**The only information for East Texas is commingled with Mississippi salt-basin data
Conv. = conventional; Cont. = continuous

Table 44. Compilation of published reserves for oil and gas shales and tight formations

Play	OOIP/OGIP (Tcf/Bbbl)	Produced Amount	Total Recoverable Reserves (variable unit)	Source
Barnett		7 Tcf*		RRC website – to 2009
		8.2 Tcf 23.6 million bbl		PBSN (Nov.1, 2010) to 09/01/2010
	250 Tcf		50-60 Tcf	
			33 Tcf	EIA (2008) from website
	327 Tcf		44 Tcf	U.S. DOE (2009, p. 17)
			26.2 / 1.0 Bbbl NGL	Coleman (2009, Table 3) - Pollastro (2007)
			36 Tcf (low); 59 Tcf (BG); 102 Tcf (high)	Mohr and Evans (2010)
Eagle Ford			150 / 25 Bbbl	Basin O&G, Nov. 2010, p. 10
			226 Tcfe**	Cusack et al. (2010, p. 172)
Haynesville (TX+LA)			Up to 100 Tcf	Spain and Anderson (2010)
	717 Tcf		251	U.S. DOE (2009, p. 17)
			73 Tcf (low); 131 Tcf (BG); 250 Tcf (high)	Mohr and Evans (2010)
			60 Tcf (for TX?)	Hammes (2009)
Bossier (TX+LA)			100 Tcf	Hanson and Lewis (2010)
Permian Basin (Woodford, Barnett, Wolfberry)			35 Tcf / 1.3 Bbbl oil+NGL	Coleman (2009, Table 3)
Woodford – Delaware Basin			Undisc.: 15.1 Tcf / 0.30 Bbbl NGL	Schenk et al. (2008)
Barnett – Delaware Basin			Undisc.: 17.2 Tcf / 0.34 Bbbl NGL	Schenk et al. (2008)
Woodford+Barnett – Midland B.			Undisc.: 2.8 Tcf / 0.11 Bbbl NGL	Schenk et al. (2008)
Spraberry			Undisc.: 0.26 Tcf /0.53 Bbbl Oil+NGL	Schenk et al. (2008)

*Through 2009, RRC website http://www.rrc.state.tx.us/barnettshale/index.php

**Undisc. = Undiscovered (mean); BG = Best Guess

1 bbl oil = 5.9 Mcf or 1 Bbbl = 5.9 Tcf

Table 45. Compilation of published operational characteristics for oil and gas shales and tight formations

Play	OGIP (Bcf/section)	EUR (Bcf/well)	IP (MMcfd)	Source
Barnett	140	2.65 Bcf		F. Wang, pers. comm. (2010)
	65			U.S. DOE (2009, p. 17)
	100150			Vassilellis et al. (2010)
		3.3 Bcf (core)		XTO Energy (2009)
		3.0 Bcf		Mantell (2010)
		3.0 Bcf (Hor.) 0.74 Bcf (Ver.)		Baihly et al.(2010) at 30 years
		1.25 Bcf		Jarvie (2009) at 30 years
		1.16 Bcf Hor.		SPEE-Anonymous (2010)
Haynesville	150–170	7.5 (4.5-8.5)		F. Wang, pers. comm. (2010)
	160–240			Vassilellis et al. (2010)
		3-6 Bcf	Up to 30	Spain and Anderson (2010, p. 657)
		6.5 Bcf		Hammes (2009)
		6.5 Bcf		XTO Energy (2009)
		6.5 Bcf		Mantell (2010)
	80			U.S. DOE (2009, p. 17)
		5.9 Bcf		Baihly et al. (2010) at 30 years
		3.42 Bcf		Jarvie (2009) at 30 years
		2.6 Bcf		SPEE-Anonymous (2010)
Eagle Ford	140–212			Cusack et al. (2010)
	40–223	5-6 Bcf		Vassilellis et al. (2010)
		5-6 Bcfe		DrillingInfo (2010)
		3.8 Bcf		Baihly et al. (2010) at 30 years
Pearsall	80–120			Vassilellis et al. (2010)
Woodford		3.8 Bcf		XTO Energy (2009)
Cotton Valley		1.9 Bcf (Hor.) 1.0 Bcf (Vert.)		Baihly et al.(2010) at 30 years
Cleveland (Hor.)		0.8 Bcf (Hor.) ~0.5 Bcf (Ver.)		Baihly et al.(2010) at 30 years

Note: 1 section = 640 acres = 1 mi^2.

Table 46. Summary description of parameters used in water-use projections (shale-gas plays)

	Barnett	**Haynesville**	**Eagle Ford**	**Bossier**	**Haynes. West**	**Pearsall**	**Woodford/Barnett Delaware Basin**
Resource-based Approach							
County Coverage	80%	80%	80%	80%	80%	60%	80%
Lateral Spacing (ft)	1000	1000	1000	1000	1000	1000	1000
Intensity-Mgal/1000ft	H.: 1.0	H.: 1.1	H.: 1.25	H.: 1.1	H.: 1.1	H.: 1.0	H.: 1.0
Uncorrected total water use (Th. AF)	1,020	440	1,513	225	37	358	434
Production-based Approach							
Play EUR (Tcf Equ.) from 2010 to 2060	61 52	44 28	250 161	33 21	2.2	25	25
Peak year after start End year after start (county level)	+8 +30	+11 +50	+16 +70	+10 +50	+15 +45	+15 +70	+15 +70
Overall peak year	2015	2031	2035	2020	2033	2031	2031
Average well EUR (BCF)	H.: 2 (core) H.: 1 (non-c.) V.: 0.8	H.: 2	H.: 1.3	H.: 1.2	H.: 2	H.:1.5	H.: 1.5
Average water use /well (Mgal)	3.3	6.1	6.2	3.3	6.1	3.3	3.3
Uncorrected total water use (Th. AF)	457	278	1897	356	23	193	193
Number of wells estimate	59,636	14,712	99,120	19,013	1,255	19,040	19,040
Reuse / Recycling	-1% / year <20%	-0.5% / year <3%	-1% / year <20%	-1% / year <20%	-0.5% / year <3%	-1% / year <20%	-1% / year <20%
Total water use (final results in AF)	750	426	1070	191	36	223	270

Table 47. Summary description of parameters used in water-use projections (tight formations)

	Anadarko Basin	**East Texas**	**Wolfberry**	**Gulf Coast**	**Other Permian Basins**
Resource-based Approach					
County coverage	20%	150%	80%	8%	8%
Lateral spacing (ft)	1000	n/a	n/a	n/a	n/a
Intensity (Mgal/1000 ft)	450	n/a	n/a	n/a	n/a
Vertical well (Mgal)	0.4	0.9	1.0	0.5	0.8
Uncorrected total water use (Th. AF)	50	189	314	76	145
Production-based approach					
Play EUR (Tcf Equ.) from 2010 to 2060	10	16	1070 Bbbl	11	15
Peak year after start End year after start (county level)	+6 +22	+12 +50	+15 +50	+18 +60	+8 +35
Overall peak year	2015	2022	2023	2027	2017
Average well EUR (BCF)	H : 1.2 (50%) V. : 0.6 (50%)	H.: 2 (25%) V. : 0.5 (75%)	H. : n/a V. : 0.06 MMbbl	H.: n/a V. : 0.4	H.: n/a V. : 0.3
Average water-use /well (Mgal)	H.: 1.3 V.: 1	H.: 3 V.: 0.9	H.: n/a V.: 0.9	H.: n/a V.: 0.5	H.: n/a V.: 0.8
Uncorrected total water use (Th. AF)	46	140	94	61	182
Number of wells estimate	13,197	33,961	34,031	33,650	71,513
Reuse / Recycling	-1% / year <20%	-1% / year <20%	-1% / year <20%	0%	-1% / year <20%
Total water use (final results in AF)	49	165	283	78	150

Table 48. Projected water use in the Barnett Shale (Fort Worth Basin)

County	2010*	2020	2030	2040	2050	2060
	AF					
Archer	0	1,618	1,292	369	0	0
Bosque	913	2,547	1,065	0	0	0
Clay	634	3,731	1,663	0	0	0
Comanche	429	2,524	1,125	0	0	0
Cooke	101	282	118	0	0	0
Coryell	0	1,793	1,140	263	0	0
Dallas	620	769	271	0	0	0
Denton	1,674	587	0	0	0	0
Eastland	0	1,127	1,157	386	0	0
Ellis	325	235	63	0	0	0
Erath	2,017	2,500	882	0	0	0
Hamilton	190	1,118	498	0	0	0
Hill	1,008	1,249	441	0	0	0
Hood	1,720	990	215	0	0	0
Jack	1,835	1,706	535	0	0	0
Johnson	3,308	1,537	241	0	0	0
McLennan	0	1,380	680	62	0	0
Montague	539	3,174	1,415	0	0	0
Palo Pinto	446	2,627	1,171	0	0	0
Parker	4,003	1,787	153	0	0	0
Shackelford	0	1,121	1,151	384	0	0
Somervell	771	443	96	0	0	0
Stephens	0	1,854	1,178	272	0	0
Tarrant	3,147	1,104	0	0	0	0
Wise	4,220	1,961	308	0	0	0
Young	0	563	578	193	0	0
Total (Th. AF)	**27.9**	**40.3**	**17.4**	**1.9**	**0.0**	**0.0**

*Projected value, not actual observed water use (see Current Water Use Section) MohrDataBarnett_3.xls FinalReport-Sept.10.xls

Table 49. Projected water use in the Haynesville Shale

County	2010*	2020	2030	2040	2050	2060
	AF					
Angelina	0	426	534	367	200	33
Gregg	0	245	435	307	179	51
Harrison	344	2,506	1,848	1,211	574	0
Marion	0	413	517	356	194	32
Nacogdoches	0	1,683	1,582	1,055	527	0
Panola	308	2,242	1,654	1,083	513	0
Rusk	0	1,841	1,730	1,153	577	0
Sabine	0	856	804	536	268	0
San Augustine	221	1,613	1,189	779	369	0
Shelby	314	2,284	1,685	1,104	523	0
Upshur	0	440	781	551	321	92
Total (Th. AF)	**1.2**	**14.5**	**12.8**	**8.5**	**4.2**	**0.2**
Leon	0	57	201	183	96	9
Freestone	0	69	243	221	116	11
Total (Th. AF)	**0.0**	**0.4**	**1.4**	**1.2**	**0.6**	**0.1**

MohrDataHaynesville.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 50. Projected water use in the Bossier Shale

County	2010*	2020	2030	2040	2050	2060
	AF					
Nacogdoches	116	2,379	1,599	1,083	567	52
Sabine	210	1,411	949	643	337	31
San Augustine	213	1,432	962	652	342	31
Shelby	302	2,028	1,363	923	484	44
Total (Th. AF)	**0.8**	**7.3**	**4.9**	**3.3**	**1.7**	**0.2**

MohrDataHaynesv.TemplateBossier.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 51. Projected water use in the Eagle Ford Shale

County	2010*	2020	2030	2040	2050	2060
	AF					
Atascosa	0	1,443	2,273	1,836	1,399	962
Austin	0	48	256	279	221	163
Brazos	0	519	1,132	922	712	503
Burleson	0	594	1,295	1,055	816	576
Colorado	0	859	1,874	1,527	1,180	833
DeWitt	0	1,067	1,681	1,357	1,034	711
Dimmit	218	2,155	2,327	1,852	1,377	902
Fayette	0	842	1,838	1,497	1,157	817
Frio	0	82	438	477	378	278
Gonzales	0	79	420	458	363	267
Grimes	0	59	314	342	271	200
Karnes	0	1,113	1,350	1,080	810	540

County	2010*	2020	2030	2040	2050	2060
	AF					
La Salle	242	2,390	2,581	2,054	1,528	1,001
Lavaca	0	571	1,776	1,591	1,245	899
Lee	0	47	249	272	215	159
Leon	0	635	1,976	1,771	1,386	1,001
Live Oak	0	79	420	458	363	267
McMullen	0	1,689	2,047	1,638	1,228	819
Madison	0	278	865	775	607	438
Maverick	0	430	1,338	1,199	938	678
Washington	0	366	1,139	1,021	799	577
Webb	138	1,369	1,478	1,177	875	573
Wilson	0	473	1,473	1,320	1,033	746
Zavala	0	434	1,352	1,211	948	685
Total (Th. AF)	**0.6**	**17.6**	**31.9**	**27.2**	**20.9**	**14.6**

MohrDataHaynesv.TemplateEagleFord.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 52. Projected water use in the Woodford and Barnett Shales in the Delaware Basin

County	2010*	2020	2030	2040	2050	2060
	AF					
Crane	0	20	63	50	39	28
Culberson	0	1,324	4,120	3,230	2,528	1,826
Pecos	0	666	2,071	1,624	1,271	918
Reeves	0	893	2,778	2,179	1,705	1,231
Ward	0	44	136	107	84	60
Winkler	0	30	92	72	56	41
Total (Th. AF)	**0.0**	**3.0**	**9.3**	**7.3**	**5.7**	**4.1**

MohrDataHaynesv.TemplateDelawareWoodford+Barnett.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 53. Projected water use in the Pearsall Shale

County	2010*	2020	2030	2040	2050	2060
	AF					
Atascosa	0	244	757	594	465	336
Dimmit	0	470	1,463	1,147	898	648
Frio	0	98	306	240	188	136
La Salle	0	521	1,622	1,272	995	719
Live Oak	0	94	294	231	180	130
McMullen	0	405	1,261	989	774	559
Maverick	0	458	1,427	1,119	876	632
Webb	0	48	149	117	91	66
Zavala	0	116	360	283	221	160
Total (Th. AF)	**0.0**	**2.5**	**7.6**	**6.0**	**4.7**	**3.4**

MohrDataHaynesv.TemplatePearsall.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 54. Projected water use in the Wolfberry play

County	2010*	2020	2030	2040	2050	2060
	AF					
Andrews	71	404	383	232	97	0
Borden	42	242	229	139	58	0
Dawson	42	241	228	139	58	0
Ector	42	242	229	139	58	0
Gaines	71	405	384	233	97	0
Glasscock	171	975	924	561	235	0
Howard	172	980	929	564	236	0
Irion	197	1,124	1,065	647	271	0
Martin	172	977	926	562	235	0
Midland	171	974	923	560	234	0
Reagan	223	1,273	1,206	732	306	0
Schleicher	22	128	121	74	31	0
Sterling	44	248	235	143	60	0
Upton	234	1,336	1,266	768	321	0
Total (Th. AF)	**1.7**	**9.5**	**9.0**	**5.5**	**2.3**	**0.0**

MohrDataHaynesv.TemplateWolfberry.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 55. Projected water use in East Texas tight-gas plays

County	2010*	2020	2030	2040	2050	2060
	AF					
Anderson	0	24	83	66	41	15
Cass	0	52	66	46	25	4
Cherokee	23	254	288	188	89	0
Freestone	636	856	670	439	208	0
Gregg	132	177	138	91	43	0
Harrison	900	532	395	259	123	0
Henderson	0	259	327	225	123	21
Limestone	279	375	293	192	91	0
Marion	23	252	210	138	65	0
Nacogdoches	321	321	245	160	76	0
Panola	805	476	354	232	110	0
Robertson	287	606	487	319	151	0
Rusk	51	563	468	307	145	0
Shelby	0	228	288	198	108	18
Smith	0	103	130	90	49	8
Upshur	0	163	206	141	77	13
Total (Th. AF)	**3.5**	**5.2**	**4.6**	**3.1**	**1.5**	**0.1**

MohrDataHaynesv.TemplateEastTexas.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 56. Projected water use in Anadarko Basin tight formations

County	2010*	2020	2030	2040	2050	2060
	AF					
Hansford	74	675	61	0	0	0
Hemphill	694	364	33	0	0	0
Hutchinson	6	59	6	0	0	0
Lipscomb	123	507	46	0	0	0
Ochiltree	73	671	61	0	0	0
Roberts	183	447	41	0	0	0
Sherman	7	61	6	0	0	0
Wheeler	697	365	33	0	0	0
Total (Th. AF)	**1.9**	**3.1**	**0.3**	**0.0**	**0.0**	**0.0**

MohrDataHaynesv.TemplateAnadarko.xls

*Projected value, not actual observed water use (see Current Water Use Section)

Table 57. Projected water use in the South Gulf Coast Basin tight-gas plays

County	2010*	2020	2030	2040	2050	2060
	AF					
Aransas	9	17	22	16	11	5
Bee	23	47	58	43	29	14
Brazoria	37	75	94	70	46	21
Brooks	25	49	62	46	30	14
Calhoun	17	33	42	31	21	10
Cameron	25	50	62	46	30	14
Colorado	25	51	64	48	31	15
DeWitt	24	47	60	44	29	14
Duval	47	94	118	87	57	27
Fort Bend	23	46	58	43	28	14
Goliad	22	45	56	42	27	13
Hidalgo	42	83	105	78	51	24
Jackson	22	45	56	42	28	13
Jim Hogg	30	60	75	56	37	17
Jim Wells	23	45	57	42	28	13
Karnes	20	40	50	37	24	11
Kenedy	38	76	95	71	46	22
Kleberg	25	49	62	46	30	14
La Salle	39	77	97	72	47	22
Lavaca	25	51	64	47	31	15
Live Oak	28	56	70	52	34	16
McMullen	30	60	75	56	37	17
Matagorda	31	61	77	57	37	18
Nueces	22	45	56	42	28	13
Refugio	21	42	53	39	26	12
San Patricio	18	37	46	34	22	11
Starr	32	64	79	59	39	18
Victoria	23	46	58	43	28	14
Webb	88	177	222	165	108	51

County	2010*	2020	2030	2040	2050	2060
	AF					
Wharton	29	57	72	53	35	17
Willacy	16	31	39	29	19	9
Zapata	27	55	68	51	33	16
Total (Th. AF)	**0.9**	**1.8**	**2.3**	**1.7**	**1.1**	**0.5**

MohrDataHaynesv.TemplateGulfCoast.xls

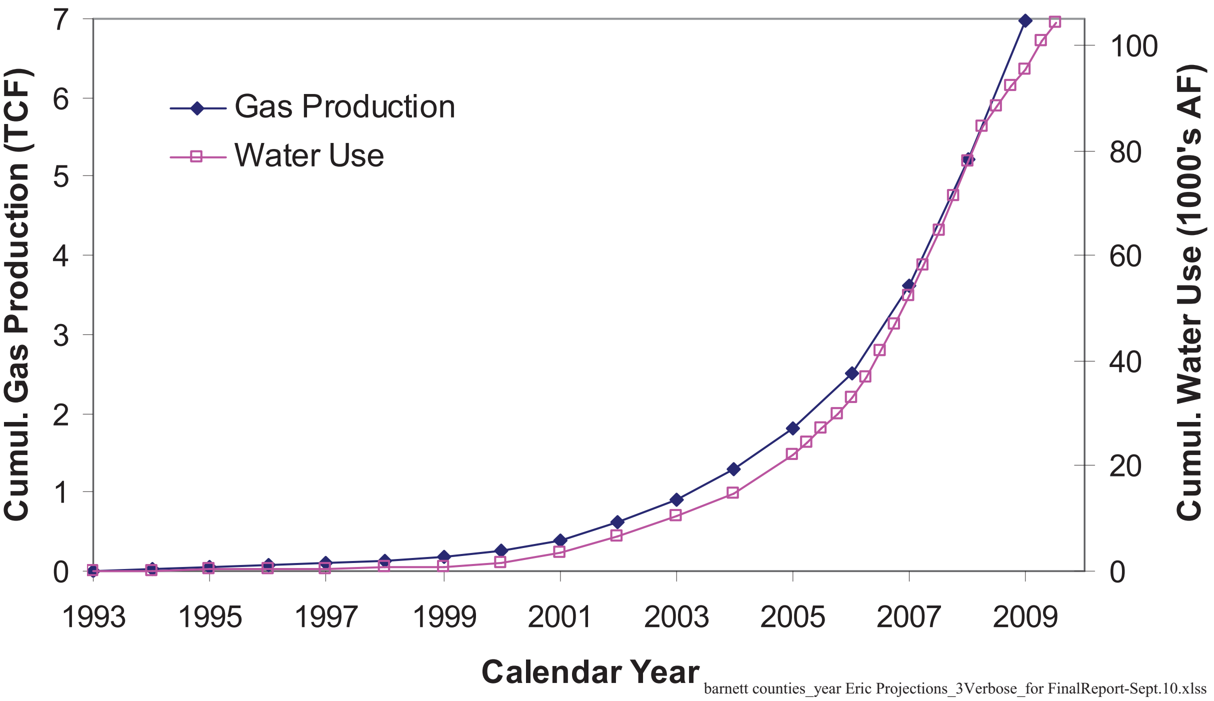
*Projected value, not actual observed water use (see Current Water Use Section)

Table 58. Projected water use in the Permian Basin tight formations

County	2010*	2020	2030	2040	2050	2060
	AF					
Andrews	231	509	297	85	0	0
Borden	68	157	91	26	0	0
Crane	121	277	161	46	0	0
Crockett	53	123	72	21	0	0
Dawson	68	156	91	26	0	0
Ector	265	328	191	55	0	0
Gaines	114	263	153	44	0	0
Garza	68	156	91	26	0	0
Glasscock	138	316	184	53	0	0
Howard	139	318	185	53	0	0
Loving	103	236	138	39	0	0
Lynn	68	157	91	26	0	0
Martin	342	285	166	48	0	0
Midland	341	284	166	47	0	0
Mitchell	68	157	92	26	0	0
Pecos	37	86	50	14	0	0
Reagan	446	371	217	62	0	0
Reeves	400	917	535	153	0	0
Scurry	69	158	92	26	0	0
Sterling	70	161	94	27	0	0
Sutton	108	248	145	41	0	0
Terrell	45	103	60	17	0	0
Terry	68	155	90	26	0	0
Upton	525	454	265	75	0	0
Val Verde	22	51	30	9	0	0
Ward	126	289	168	48	0	0
Winkler	133	307	179	51	0	0
Yoakum	61	140	81	23	0	0
Total (Th. AF)	**4.3**	**7.2**	**4.2**	**1.2**	**0.0**	**0.0**

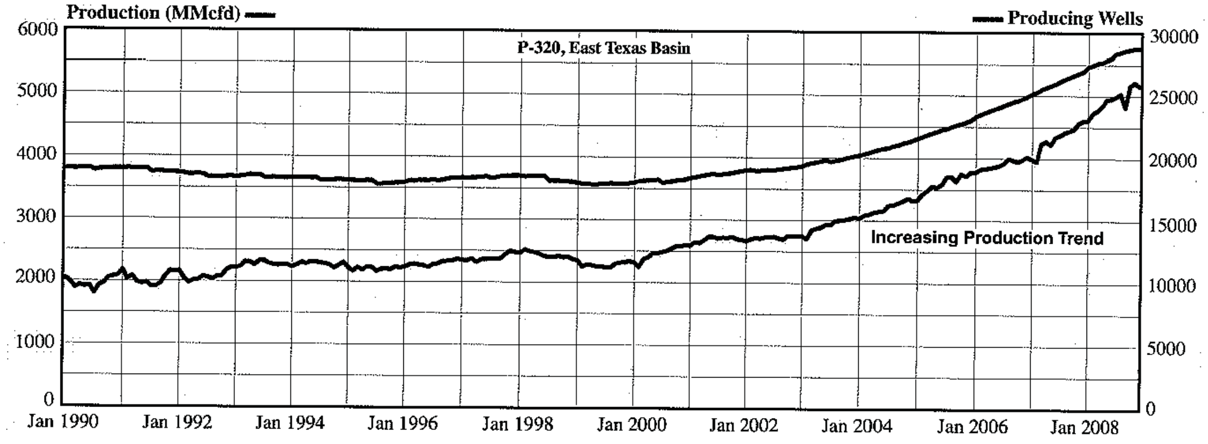
MohrDataHaynesv.TemplatePB-TG.xls

*Projected value, not actual observed water use (see Current Water Use Section)



barnett counties_year Eric Projections_3Verbose_for FinalReport-Sept.10.xlss

Figure 114. Cumulative gas production and water use in the Barnett Shale play from the origins



Source: PGC (2009); raw data from IHS Energy
Note: The most irregular curve represents gas production; a 1000-MMcfd unit in the production axis corresponds to 0.365 Tcf

Figure 115. Monthly wet-gas production and number of producing oil and gas wells (1990–2008)

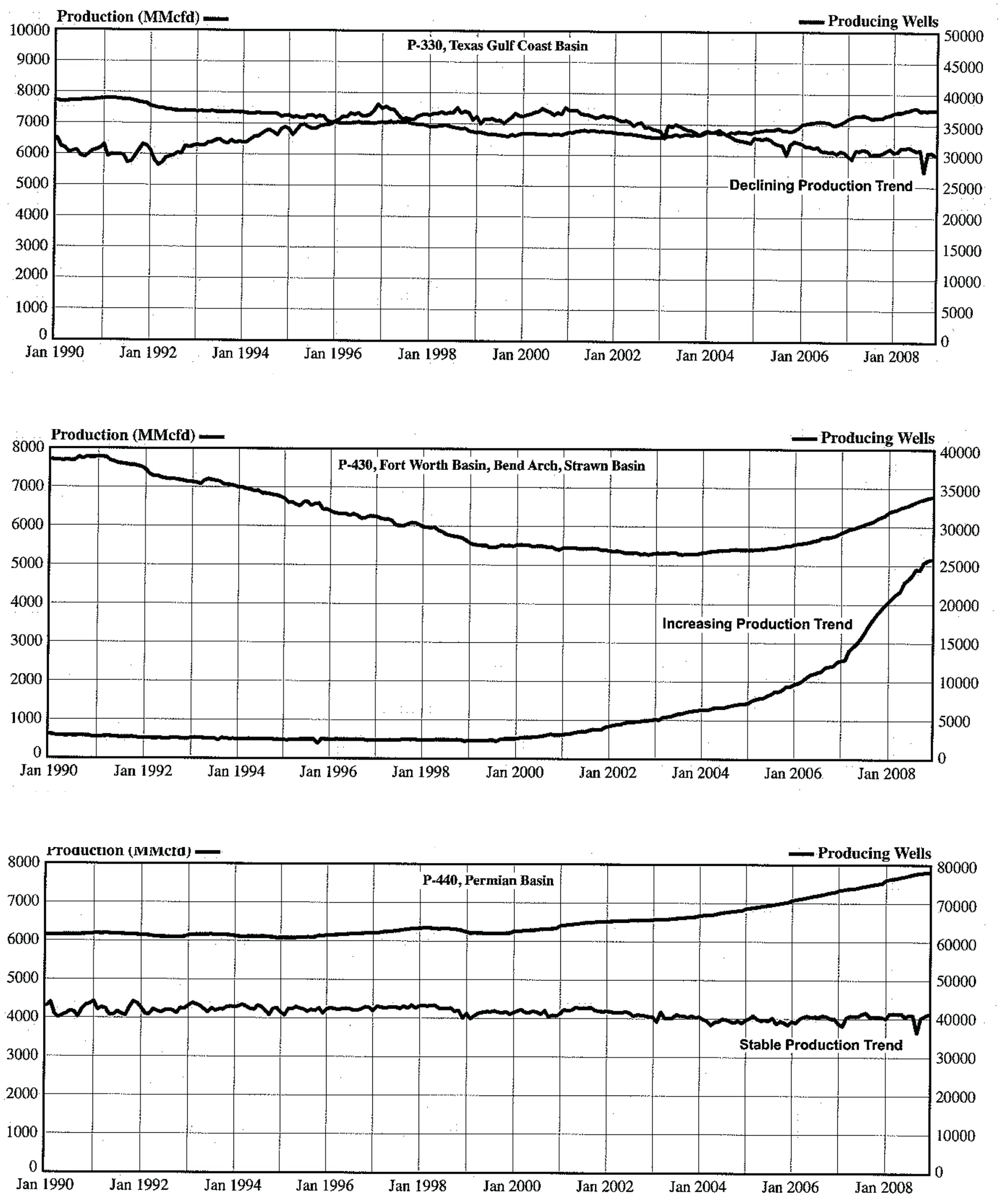


Figure 115. Monthly wet-gas production and number of producing oil and gas wells (1990–2008) (continued)

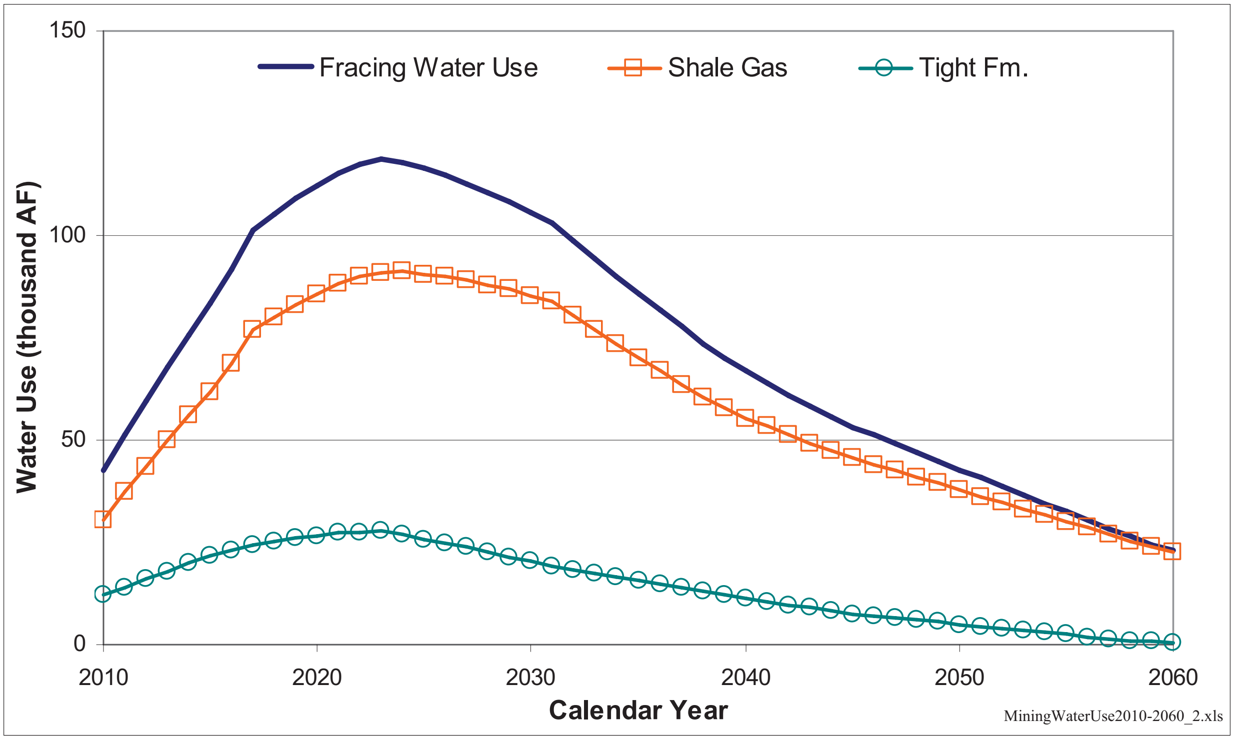


Figure 116. Projected state fracing water use

5.2 Conventional Oil and Gas

Conventional oil and gas, although beyond their peak production, are likely to remain significant for many decades as operators assess and put online new reservoirs. After peak oil in Texas in the early 1970s, the following years showed a slow, more or less linear decrease in production (despite an increase in producing wells). Starting in the late 1990s, though, a graph shows a clear leveling off of the decrease (Figure 117), one section of which can be used to extrapolate future production (Figure 118). Much anecdotal evidence suggests that conventional oil and gas resources in Texas are far from being exhausted. For example, Ewing (2010) listed several likely deep plays (>10,000 ft) in South Texas equivalent to productive formations in East Texas. And operators in the Permian Basin still have to explore for the gas that may lie deeper than current production horizons. As described earlier, USGS oil and gas assessments evaluate the resource that is deemed to be technically recoverable using current and projected techniques. Reserves are defined as a subset of the resources that can be produced economically. The USGS-based National Oil and Gas Assessments (NOGA) is tasked to evaluate those *undiscovered* petroleum resources. NOGA divides the continental U.S. into many provinces, including "West Gulf," "East TX, LA-MS Salt Basins," "Bend Arch-Fort Worth Basin," "Permian Basin," and "Marathon Thrust Belt." Except for the much smaller last province, all four other provinces go largely beyond Texas. The latest complete assessment of the U.S. was made in 1995, although updates of the assessment of some provinces were made very recently.

5.2.1 Water and CO_2 Floods

Conventional oil and gas production use water for two purposes: drilling and EOR. As seen in the current water-use section, water use for waterfloods has been decreasing steadily, and we assume that it will keep making up a smaller and smaller fraction of fluid injected for waterfloods. Fresh water use has been declining strongly in the past decades, and we expect the trend to continue (Figure 119). The general trend of oil production in West Texas has been one of more or less continuous decline since its peak in the early 1970s. Galusky (2010) produced what we think are relatively accurate numbers for the Permian Basin (~10 Bbbl to 2060). Schenk et al. (2008) estimated undiscovered resources of conventional oil in the Permian Basin at 747 million barrels. A study by the consulting firm ARI (Kuuskraa and Ferguson, 2008, Table 1) reports that Texas (including that portion of the Permian Basin in New Mexico) has >200 Bbbl of OOIP of which ~70 Bbbl is conventionally recoverable (primary and secondary recovery processes), an arguably optimistic projection. For comparison, Texas has produced ~60 Bbbl of oil since the origins.

Dutton et al. (2005a) presented a comprehensive study of all known oil and gas fields in the Permian Basin and included a section on production forecast to 2015. The lack of full overlap between the Permian Basin and Districts 08 and 8A (New Mexico had 15.6% of cumulative production through 2000, Dutton et al., 2005a, p. 351) carries some uncertainty but the error introduced by assuming the Permian Basin and RRC Districts 08 and 8A coincide is small compared to the other assumptions used in this section. Dutton et al. (2005a) projected a production of 3.25 Bbbl of oil through 2015 from which the 1.9 Bbbl produced through 2010 (since the publication of the Dutton et al., 2005a report) must be deducted yielding 1.35 Bbbl to be produced to 2015. This is consistent with Galusky (2010)'s projections at 1.44 Bbbl from 2011 to 2015. Both workers have in common the slow decline of conventional oil production at a similar rate.

The slow pace of this decline (~2% per year) reflects the steady increase in EOR production techniques (waterfloods and CO_2 floods). The general pattern of declining oil production has occurred through high-price as well as low price-intervals. It would thus seem reasonable to project this gradual decline through the forecast period of this study (2010– 2060). Oil drilling and completion activities and oil production are expected to be sustained at slowly declining levels in West Texas over the next 50 years. It is projected that EOR production methods will be responsible for 70% or more of total oil production by 2020 and beyond. Although EOR production requires copious quantities of water to sustain oil reservoir pressures, fresh water is expected to decline in use relative to brackish and saline (recycled produced) waters. Total brackish and saline water use is thought to have essentially peaked near the present estimated figure of ~38.5 thousand AF/yr and is then expected to decline over the coming decades. In contrast, total fresh-water use is expected to continue to decline from the present estimated figure of ~10,000 ac-ft/yr to less than half this level by 2020. In this study we did not investigate the possibility of having extensive waterfloods in the Gulf Coast area or elsewhere in the state. We did not include the real potential for extensive CO_2 floods as it is not clear whether operators would use a WAG technique with concomitant water use or simply inject CO_2 (which might be in abundance in the future, thanks to the presence of many coal-fired power plants along the Gulf).

Table 59 summarizes our findings per county. Projections of overall water use, estimated at ~8 thousand AF in 2010, is decreasing through time because of the built-in assumption of decreased fresh water use for the purpose of waterflood and other recovery processes.

Going back to historical reports (for example, Torrey, 1967) is insightful in the sense that it allows comparison of projections with actual production and water use. The 1967 report author makes the correct statement (p. 2) that no reasonable alternative but to extrapolate currents can be made in a 50-year projection period. The report predicts average water use in the 1990–2000 decade of ~220 thousand AF for much smaller oil production than actually occurred. Included in their water use is all nonproduced waters, of which it is unclear how much is fresh or brackish. The approach was to compute oil reserves amenable to water injection for pressure maintenance or waterflooding (25% increasing to 50% of projected production in 2010) and to apply a multiplier (average of 8.2 bbl of water used to produce 1 bbl of oil) corrected by the amount of produced water used (typically 10%– 20%, that is, most of water is makeup water, although the quality is not described).

5.2.2 Drilling

In general, drilling and completion activities are much more sensitive to short-term price cycles than production. Periods of relatively high oil prices tend to incentivize and support a proportionally greater level of drilling activity than do periods of low prices. It would be virtually impossible to predict oil prices many years into the future with any level of real confidence. Projections of water use for drilling are thus more perilous than price or production projections. Nevertheless, it seems reasonable to project a gradual decline in fresh water use for oil drilling in the coming decades, Even as oil fields become depleted, an increase in drilling activity for oil can be expected because of the renewed interest in plays similar to the Wolfberry in the Permian Basin and because of an increased interest in waterflooding, requiring drilling of new wells. This increase in drilling is likely to be more than balanced by a decrease in fresh-water use as the industry uses more and more brackish and saline water. Galusky (2010) proposed to assume that the fresh water use for drilling in the Permian Basin (which is more densely drilled than the rest of Texas) will stay relatively stable until 2020, and will gradually decrease below about half its present level by 2060. We assume that the pattern is applicable to the whole state. Despite the general decrease of fresh-water use in oil production, it is likely that the water use for drilling will keep increasing for the next few years because of shale-gas activity. The amount of fresh water used in drilling shale gas wells is variable and a function of the play (Section 4.2.2). Including water use from shale-gas activity yields a peak of 13 thousand AF within the current decade (Figure 120).

Table 59. County-level fresh and brackish water-use projections for waterflood

County	Fresh 2010	Fresh 2020	Fresh 2030	Fresh 2040	Fresh 2050	Fresh 2060	Brack 2010	Brack 2020	Brack 2030	Brack 2040	Brack 2050	Brack 2060
State Total	**7.87**	**2.39**	**1.49**	**1.29**	**1.12**	**0.96**	**29.91**	**31.49**	**31.93**	**28.34**	**24.58**	**21.26**
Anderson	0.008	0.002	0.002	0.001	0.001	0.001	0.031	0.033	0.033	0.029	0.025	0.022
Andrews	0.384	0.117	0.073	0.063	0.055	0.047	1.457	1.534	1.556	1.381	1.197	1.036
Archer	0.003	0.001	0.001	0.000	0.000	0.000	0.010	0.011	0.011	0.010	0.009	0.007
Atascosa	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.003	0.003	0.002	0.002	0.002
Baylor	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001
Borden	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Brown	0.005	0.001	0.001	0.001	0.001	0.001	0.018	0.019	0.019	0.017	0.015	0.013
Callahan	0.018	0.005	0.003	0.003	0.003	0.002	0.067	0.071	0.072	0.064	0.055	0.048
Camp	0.003	0.001	0.001	0.000	0.000	0.000	0.010	0.011	0.011	0.010	0.008	0.007
Carson	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001
Clay	0.001	0.000	0.000	0.000	0.000	0.000	0.004	0.004	0.004	0.004	0.003	0.003
Cochran	0.005	0.002	0.001	0.001	0.001	0.001	0.020	0.021	0.021	0.019	0.016	0.014
Coke	0.109	0.033	0.021	0.018	0.016	0.013	0.416	0.438	0.444	0.394	0.342	0.296
Coleman	0.021	0.006	0.004	0.003	0.003	0.003	0.080	0.084	0.085	0.076	0.066	0.057
Comanche	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.002	0.002	0.001	0.001	0.001
Concho	0.108	0.033	0.021	0.018	0.015	0.013	0.412	0.434	0.440	0.390	0.338	0.293
Cooke	0.004	0.001	0.001	0.001	0.001	0.001	0.016	0.017	0.017	0.015	0.013	0.012
Cottle	0.007	0.002	0.001	0.001	0.001	0.001	0.026	0.027	0.027	0.024	0.021	0.018
Crane	0.027	0.008	0.005	0.004	0.004	0.003	0.101	0.106	0.108	0.096	0.083	0.072
Crockett	0.007	0.002	0.001	0.001	0.001	0.001	0.025	0.026	0.027	0.024	0.021	0.018
Crosby	0.228	0.069	0.043	0.037	0.032	0.028	0.866	0.912	0.925	0.821	0.712	0.616
Culberson	0.033	0.010	0.006	0.005	0.005	0.004	0.127	0.134	0.135	0.120	0.104	0.090
Dawson	0.039	0.012	0.007	0.006	0.005	0.005	0.146	0.154	0.156	0.139	0.120	0.104

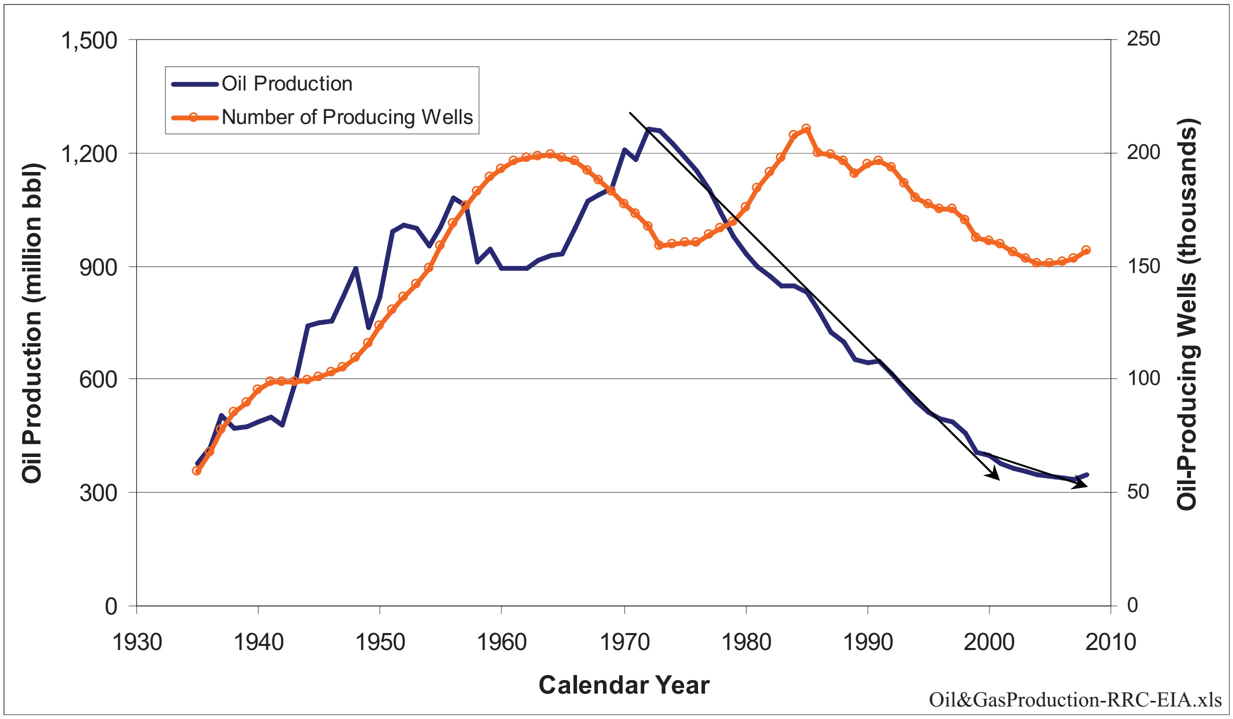
County	Fresh 2010	Fresh 2020	Fresh 2030	Fresh 2040	Fresh 2050	Fresh 2060	Brack 2010	Brack 2020	Brack 2030	Brack 2040	Brack 2050	Brack 2060
Dickens	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Dimmit	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.001	0.001
Eastland	0.070	0.021	0.013	0.012	0.010	0.009	0.267	0.281	0.285	0.253	0.219	0.190
Ector	0.019	0.006	0.004	0.003	0.003	0.002	0.072	0.075	0.077	0.068	0.059	0.051
Fisher	0.091	0.028	0.017	0.015	0.013	0.011	0.345	0.364	0.369	0.327	0.284	0.245
Floyd	0.031	0.010	0.006	0.005	0.004	0.004	0.119	0.125	0.127	0.113	0.098	0.084
Foard	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.003	0.002	0.002	0.002
Franklin	0.001	0.000	0.000	0.000	0.000	0.000	0.004	0.004	0.005	0.004	0.004	0.003
Freestone	0.001	0.000	0.000	0.000	0.000	0.000	0.005	0.005	0.005	0.004	0.004	0.003
Gaines	0.002	0.001	0.000	0.000	0.000	0.000	0.008	0.009	0.009	0.008	0.007	0.006
Garza	0.011	0.003	0.002	0.002	0.002	0.001	0.042	0.045	0.045	0.040	0.035	0.030
Glasscock	0.085	0.026	0.016	0.014	0.012	0.010	0.324	0.341	0.346	0.307	0.266	0.230
Gray	0.014	0.004	0.003	0.002	0.002	0.002	0.055	0.058	0.058	0.052	0.045	0.039
Grayson	0.001	0.000	0.000	0.000	0.000	0.000	0.004	0.005	0.005	0.004	0.004	0.003
Hale	0.271	0.082	0.051	0.045	0.039	0.033	1.031	1.085	1.100	0.977	0.847	0.733
Hansford	0.001	0.000	0.000	0.000	0.000	0.000	0.004	0.004	0.004	0.004	0.003	0.003
Hartley	0.002	0.000	0.000	0.000	0.000	0.000	0.006	0.006	0.006	0.006	0.005	0.004
Haskell	0.019	0.006	0.004	0.003	0.003	0.002	0.072	0.075	0.076	0.068	0.059	0.051
Hockley	0.001	0.000	0.000	0.000	0.000	0.000	0.005	0.005	0.005	0.005	0.004	0.003
Hopkins	0.009	0.003	0.002	0.001	0.001	0.001	0.034	0.036	0.036	0.032	0.028	0.024
Howard	0.014	0.004	0.003	0.002	0.002	0.002	0.053	0.056	0.057	0.051	0.044	0.038
Hutchinson	0.004	0.001	0.001	0.001	0.001	0.000	0.015	0.016	0.016	0.014	0.012	0.011
Irion	0.169	0.051	0.032	0.028	0.024	0.021	0.642	0.676	0.685	0.609	0.528	0.456
Jack	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.002	0.002
Jones	0.025	0.008	0.005	0.004	0.004	0.003	0.094	0.099	0.100	0.089	0.077	0.067
Kent	0.006	0.002	0.001	0.001	0.001	0.001	0.023	0.024	0.024	0.022	0.019	0.016
King	1.818	0.553	0.345	0.299	0.258	0.223	6.907	7.271	7.373	6.546	5.676	4.909

County	Fresh 2010	Fresh 2020	Fresh 2030	Fresh 2040	Fresh 2050	Fresh 2060	Brack 2010	Brack 2020	Brack 2030	Brack 2040	Brack 2050	Brack 2060
Knox	0.001	0.000	0.000	0.000	0.000	0.000	0.003	0.003	0.003	0.002	0.002	0.002
Lamb	0.136	0.041	0.026	0.022	0.019	0.017	0.518	0.545	0.553	0.491	0.425	0.368
Leon	0.011	0.003	0.002	0.002	0.002	0.001	0.043	0.045	0.046	0.041	0.035	0.031
Limestone	0.001	0.000	0.000	0.000	0.000	0.000	0.003	0.003	0.003	0.002	0.002	0.002
Lipscomb	0.003	0.001	0.001	0.000	0.000	0.000	0.011	0.011	0.011	0.010	0.009	0.008
Loving	0.074	0.023	0.014	0.012	0.011	0.009	0.282	0.297	0.301	0.267	0.232	0.200
Lubbock	1.307	0.398	0.248	0.215	0.186	0.160	4.968	5.230	5.303	4.708	4.082	3.531
Lynn	0.207	0.063	0.039	0.034	0.029	0.025	0.785	0.826	0.838	0.744	0.645	0.558
Marion	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.002	0.001
Martin	0.084	0.026	0.016	0.014	0.012	0.010	0.320	0.337	0.342	0.303	0.263	0.227
Maverick	0.001	0.000	0.000	0.000	0.000	0.000	0.003	0.004	0.004	0.003	0.003	0.002
McCulloch	0.009	0.003	0.002	0.001	0.001	0.001	0.034	0.035	0.036	0.032	0.028	0.024
McMullen	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.002	0.001	0.001	0.001
Menard	0.250	0.076	0.047	0.041	0.035	0.031	0.948	0.998	1.012	0.899	0.779	0.674
Midland	0.035	0.011	0.007	0.006	0.005	0.004	0.134	0.141	0.143	0.127	0.110	0.095
Mitchell	0.003	0.001	0.001	0.000	0.000	0.000	0.011	0.011	0.011	0.010	0.009	0.008
Montague	0.004	0.001	0.001	0.001	0.001	0.000	0.014	0.015	0.015	0.014	0.012	0.010
Moore	0.001	0.000	0.000	0.000	0.000	0.000	0.003	0.003	0.004	0.003	0.003	0.002
Motley	0.027	0.008	0.005	0.005	0.004	0.003	0.104	0.110	0.111	0.099	0.086	0.074
Navarro	0.002	0.001	0.000	0.000	0.000	0.000	0.008	0.009	0.009	0.008	0.007	0.006
Nolan	0.045	0.014	0.009	0.007	0.006	0.006	0.171	0.180	0.183	0.162	0.141	0.122
Ochiltree	0.004	0.001	0.001	0.001	0.001	0.000	0.015	0.015	0.016	0.014	0.012	0.010
Oldham	0.003	0.001	0.001	0.001	0.000	0.000	0.012	0.012	0.013	0.011	0.010	0.008
Palo Pinto	0.018	0.005	0.003	0.003	0.003	0.002	0.068	0.071	0.072	0.064	0.056	0.048
Pecos	0.066	0.020	0.012	0.011	0.009	0.008	0.249	0.262	0.266	0.236	0.205	0.177
Potter	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.001	0.001
Reagan	0.024	0.007	0.004	0.004	0.003	0.003	0.090	0.094	0.096	0.085	0.074	0.064

County	Fresh 2010	Fresh 2020	Fresh 2030	Fresh 2040	Fresh 2050	Fresh 2060	Brack 2010	Brack 2020	Brack 2030	Brack 2040	Brack 2050	Brack 2060
Red River	0.001	0.000	0.000	0.000	0.000	0.000	0.003	0.004	0.004	0.003	0.003	0.002
Reeves	0.019	0.006	0.004	0.003	0.003	0.002	0.071	0.075	0.076	0.068	0.059	0.051
Runnels	0.060	0.018	0.011	0.010	0.009	0.007	0.228	0.240	0.243	0.216	0.187	0.162
Rusk	0.011	0.003	0.002	0.002	0.002	0.001	0.044	0.046	0.046	0.041	0.036	0.031
Schleicher	0.030	0.009	0.006	0.005	0.004	0.004	0.112	0.118	0.120	0.106	0.092	0.080
Scurry	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Shackelford	0.046	0.014	0.009	0.007	0.006	0.006	0.173	0.182	0.185	0.164	0.142	0.123
Sherman	0.002	0.001	0.000	0.000	0.000	0.000	0.007	0.007	0.007	0.007	0.006	0.005
Smith	0.004	0.001	0.001	0.001	0.001	0.001	0.016	0.017	0.017	0.015	0.013	0.012
Stephens	1.086	0.330	0.206	0.178	0.154	0.133	4.126	4.343	4.404	3.910	3.390	2.932
Sterling	0.007	0.002	0.001	0.001	0.001	0.001	0.027	0.029	0.029	0.026	0.022	0.019
Stonewall	0.132	0.040	0.025	0.022	0.019	0.016	0.503	0.530	0.537	0.477	0.414	0.358
Sutton	0.001	0.000	0.000	0.000	0.000	0.000	0.005	0.006	0.006	0.005	0.005	0.004
Taylor	0.015	0.005	0.003	0.002	0.002	0.002	0.057	0.060	0.061	0.054	0.047	0.041
Terrell	0.106	0.032	0.020	0.017	0.015	0.013	0.401	0.423	0.429	0.380	0.330	0.285
Terry	0.019	0.006	0.004	0.003	0.003	0.002	0.072	0.076	0.077	0.068	0.059	0.051
Throckmorton	0.042	0.013	0.008	0.007	0.006	0.005	0.160	0.169	0.171	0.152	0.132	0.114
Titus	0.002	0.001	0.000	0.000	0.000	0.000	0.006	0.007	0.007	0.006	0.005	0.004
Tom Green	0.011	0.003	0.002	0.002	0.002	0.001	0.042	0.045	0.045	0.040	0.035	0.030
Upshur	0.007	0.002	0.001	0.001	0.001	0.001	0.028	0.030	0.030	0.027	0.023	0.020
Upton	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.001	0.001
Van Zandt	0.012	0.004	0.002	0.002	0.002	0.001	0.044	0.047	0.047	0.042	0.036	0.032
Ward	0.003	0.001	0.001	0.000	0.000	0.000	0.012	0.012	0.012	0.011	0.009	0.008
Wheeler	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.002	0.001	0.001
Wichita	0.012	0.004	0.002	0.002	0.002	0.002	0.047	0.050	0.050	0.045	0.039	0.033
Wilbarger	0.002	0.000	0.000	0.000	0.000	0.000	0.006	0.006	0.006	0.006	0.005	0.004
Wilson	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001

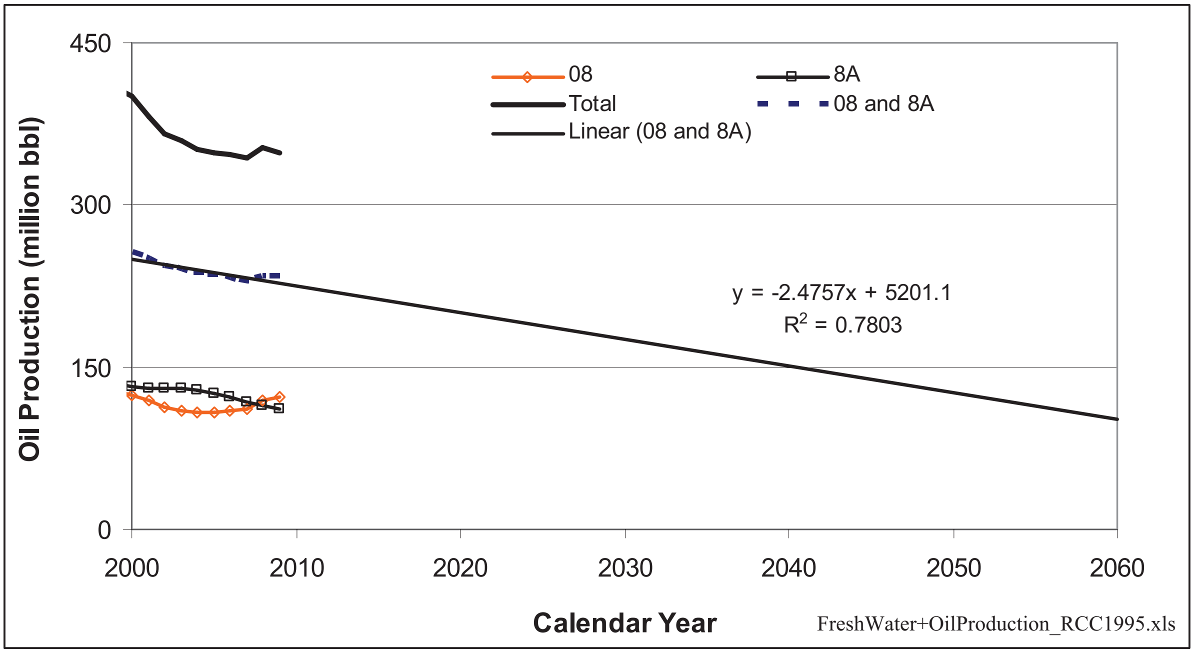
County	Fresh 2010	Fresh 2020	Fresh 2030	Fresh 2040	Fresh 2050	Fresh 2060	Brack 2010	Brack 2020	Brack 2030	Brack 2040	Brack 2050	Brack 2060
Winkler	0.022	0.007	0.004	0.004	0.003	0.003	0.083	0.088	0.089	0.079	0.069	0.059
Wood	0.004	0.001	0.001	0.001	0.001	0.000	0.014	0.015	0.015	0.013	0.011	0.010
Yoakum	0.219	0.067	0.041	0.036	0.031	0.027	0.832	0.875	0.888	0.788	0.683	0.591
Young	0.002	0.000	0.000	0.000	0.000	0.000	0.006	0.006	0.006	0.006	0.005	0.004

InjectionVolume_2002_RRC_+1998-2001_1.xls



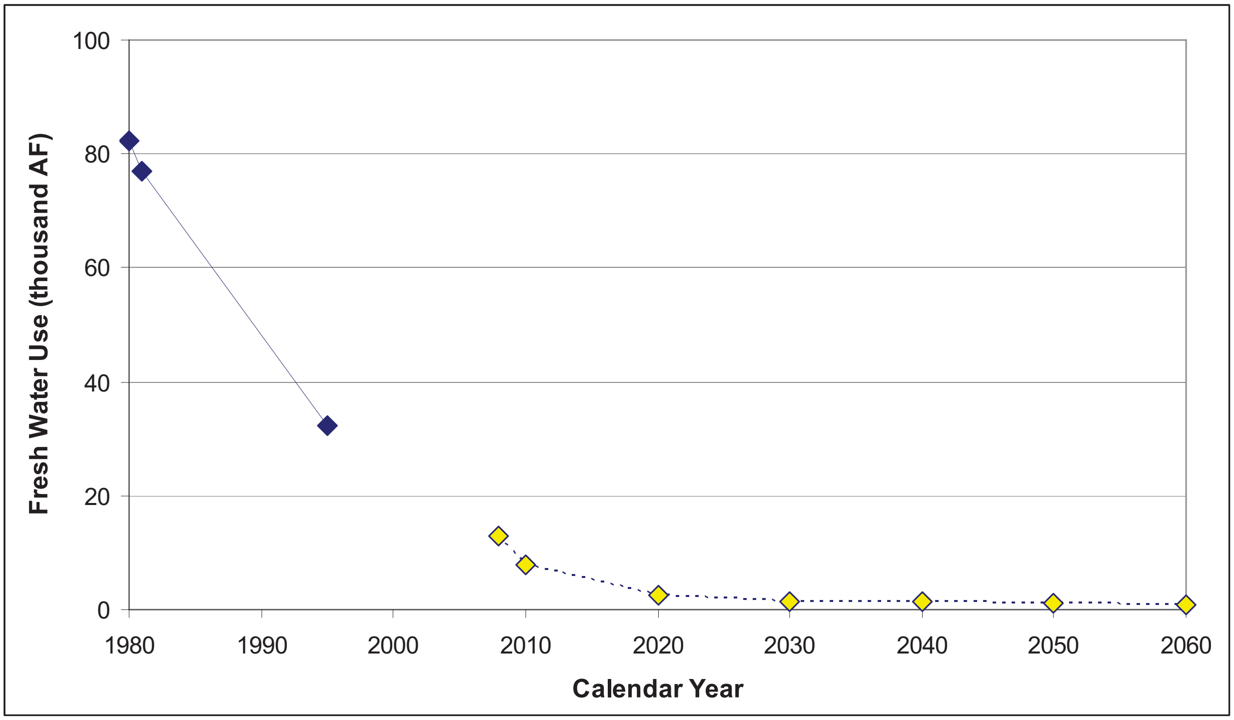
Source: EIA website

Figure 117. Annual oil production in Texas (1936–2009)



Source: RRC online system http://webapps.rrc.state.tx.us/PDQ/generalReportAction.do (historical data)

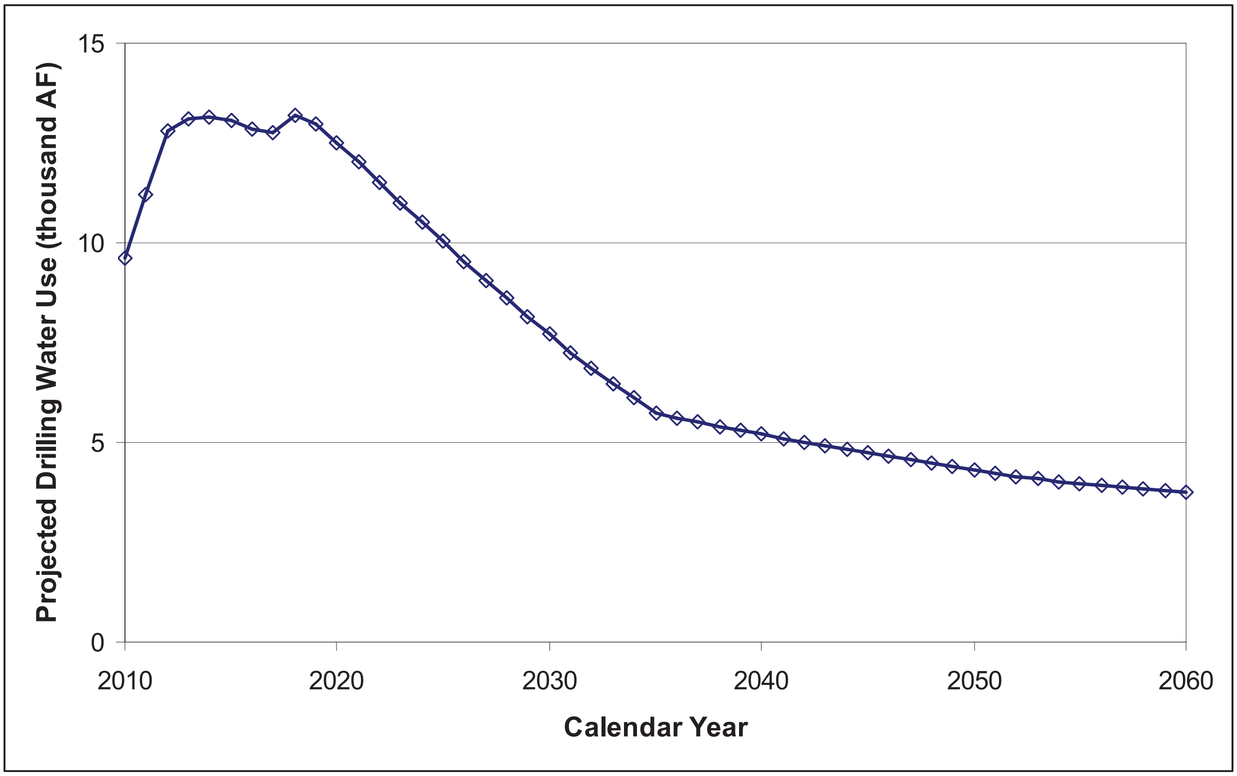
Figure 118. Future annual oil production, Districts 8, 8A, and Texas



Source: RRC (1982) and De Leon (1996) for historical data

Historical Injection 2=fromRRC1982Report.xls

Figure 119. Historical and projected fresh-water use in secondary and tertiary recovery operations



DrillingWaterUse.xls

Figure 120. Projected drilling-water use

5.3 Coal

Coal resources are plentiful in Texas and are unlikely to be exhausted within the next 5 decades at the current average production rate. Kaiser et al. (1980) gave an overview of the lignite resource in Texas and estimated reserves at >6 billion short tons. More recently, Warwick et al. (2002) identified 7.7 billion short tons of Central Texas lignite reserves, excluding resources within coal-mine lease areas. All mines currently in production, except Jewett mine, which is slated to end production around 2025, are assumed to keep producing at a rate similar to the current one. Three Oaks mine came on line recently (2005) after Sandow mine retired. Two new mines will come on line in the next few years: Kosse mine in Limestone County and Twin Oaks mine in Robertson County. Future water-use breakdown for these two mines was estimated from Jewett and Calvert mines, respectively. At the state level, water use is assumed to ramp up from ~25,000 AF/yr to 40,000 AF/yr, mostly because of Three Oak and Twin Oak mines (Figure 121). Other mines' water use remains relatively steady (Figure 122). Results per mine/per county are listed in Table 60. Robertson County exhibits higher water use, starting at ~7,500 AF currently and increasing to 10,000+ AF after 2040. All of the water is groundwater, very little of which is consumed and most of which is discharged to streams.

The scenario we favor is one in which potential increase in energy needs will be covered by western coal (which has been competing with local coal for decades, Figure 123), by other fossil fuels (gas?), or by a different energy source (nuclear?), but not by a massive extension of mouth-of-mine coal-fired power plants and concomitant increase in water use. In any case, a return to underground mining of subbituminous reserves is deemed unlikely.

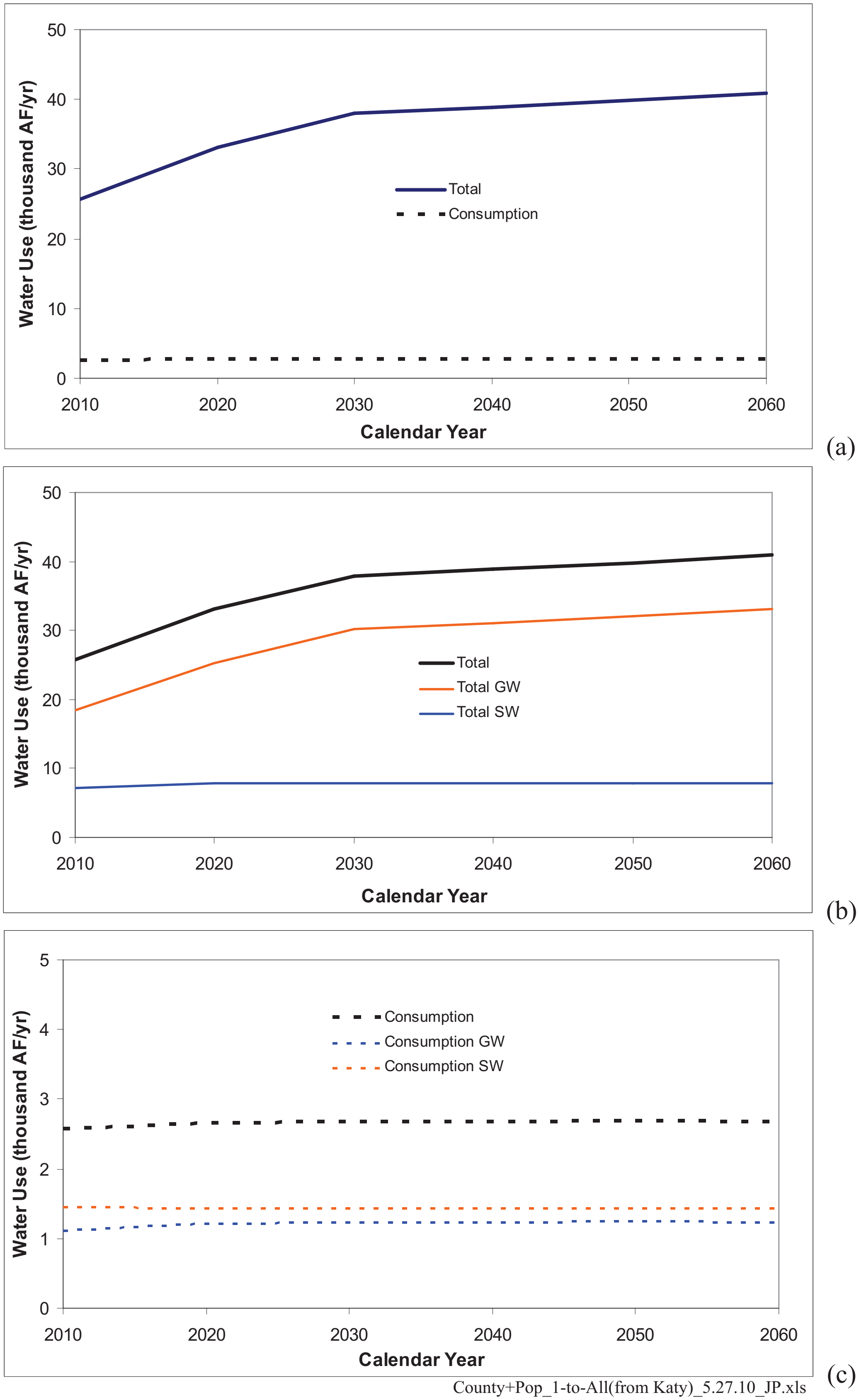
Table 60. Projected lignite-mine water use per county in AF/yr (2010–2060)

		TOTAL PUMPAGE						**TOTAL CONSUMPTION**					
		2010	2020	2030	2040	2050	2060	2010	2020	2030	2040	2050	2060
San Miguel	Atascosa	0	0	0	0	0	0	0	0	0	0	0	0
½Three Oaks	Bastrop	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
Big Brown, ⅓Jewett	Freestone	3,129	3,833	3,000	3,000	3,000	3,000	124	152	135	135	135	135
South Hallsville	Harrison	5,800	6,380	6,380	6,380	6,380	6,380	6	6	6	6	6	6
Monticello Thermo	Hopkins	920	900	900	900	900	900	205	201	201	201	201	201
½Three oaks	Lee	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
⅓Jewett	Leon	667	833	0	0	0	0	13	17	0	0	0	0
⅓Jewett, Kosse Strip	Limestone	694	4,333	3,500	3,500	3,500	3,500	41	87	70	70	70	40
Martin Lake	Panola	982	982	1,500	1,500	1,500	1,500	855	855	855	855	855	855
Calvert, Twin Oak	Robertson	7,436	8,180	8,998	9,897	10,887	11,976	74	82	90	99	109	120
Oak Hill	Rusk	1,265	1,668	1,668	1,668	1,668	1,668	582	582	582	582	582	582
Monticello Winfield	Titus	619	1,000	1,000	1,000	1,000	1,000	619	619	619	619	619	619
TOTAL		**25,689**	**33,110**	**37,946**	**38,845**	**39,835**	**40,924**	**2,562**	**2,650**	**2,668**	**2,677**	**2,687**	**2,668**
		PUMPAGE GROUNDWATER						**CONSUMPTION GROUNDWATER**					
		2010	2020	2030	2040	2050	2060	2010	2020	2030	2040	2050	2060
San Miguel	Atascosa	0	0	0	0	0	0	0	0	0	0	0	0
½Three Oaks	Bastrop	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
Big Brown, ⅓Jewett	Freestone	3,129	3,833	3,000	3,000	3,000	3,000	124	152	135	135	135	135
South Hallsville	Harrison	6	6	6	6	6	6	6	6	6	6	6	6
Monticello Thermo	Hopkins	735	719	719	719	719	719	21	20	20	20	20	20
½Three oaks	Lee	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
⅓Jewett	Leon	667	833	0	0	0	0	13	17	0	0	0	0
⅓Jewett, Kosse Strip	Limestone	694	4,333	3,500	3,500	3,500	3,500	41	87	70	70	70	40
Martin Lake	Panola	554	554	1,072	1,072	1,072	1,072	428	428	428	428	428	428
Calvert, Twin Oak	Robertson	7,436	8,180	8,998	9,897	10,887	11,976	74	82	90	99	109	120
Oak Hill	Rusk	741	1,144	1,144	1,144	1,144	1,144	58	58	58	58	58	58
Monticello Winfield	Titus	310	691	691	691	691	691	310	310	310	310	310	310
TOTAL		**18,449**	**25,294**	**30,130**	**31,030**	**32,020**	**33,109**	**1,116**	**1,209**	**1,227**	**1,236**	**1,246**	**1,227**

County+Pop_1-to-All(from Katy)_5.27.10_JP.xls

Table 60. Projected lignite-mine water use per county in AF/yr (2010–2060) (continued)

		PUMPAGE SURFACE WATER						**CONSUMPTION SURFACE WATER**					
		2010	2020	2030	2040	2050	2060	2010	2020	2030	2040	2050	2060
San Miguel	Atascosa	0	0	0	0	0	0	0	0	0	0	0	0
½Three Oaks	Bastrop	0	0	0	0	0	0	0	0	0	0	0	0
Big Brown, ⅓Jewett	Freestone	0	0	0	0	0	0	0	0	0	0	0	0
South Hallsville	Harrison	5,794	6,374	6,374	6,374	6,374	6,374	0	0	0	0	0	0
Monticello Thermo	Hopkins	185	181	181	181	181	181	185	181	181	181	181	181
½Three oaks	Lee	0	0	0	0	0	0	0	0	0	0	0	0
⅓Jewett	Leon	0	0	0	0	0	0	0	0	0	0	0	0
⅓Jewett, Kosse Strip	Limestone	0	0	0	0	0	0	0	0	0	0	0	0
Martin Lake	Panola	428	428	428	428	428	428	428	428	428	428	428	428
Calvert, Twin Oak	Robertson	0	0	0	0	0	0	0	0	0	0	0	0
Oak Hill	Rusk	524	524	524	524	524	524	524	524	524	524	524	524
Monticello Winfield	Titus	310	310	310	310	310	310	310	310	310	310	310	310
TOTAL		**7,240**	**7,815**	**7,815**	**7,815**	**7,815**	**7,815**	**1,446**	**1,442**	**1,442**	**1,442**	**1,442**	**1,442**
		PUMPAGE FRESH WATER						**CONSUMPTION FRESH WATER**					
		2010	2020	2030	2040	2050	2060	2010	2020	2030	2040	2050	2060
San Miguel	Atascosa	0	0	0	0	0	0	0	0	0	0	0	0
½Three Oaks	Bastrop	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
Big Brown, ⅓Jewett	Freestone	3,095	3,792	3,000	3,000	3,000	3,000	124	152	135	135	135	135
South Hallsville	Harrison	5,800	6,380	6,380	6,380	6,380	6,380	6	6	6	6	6	6
Monticello Thermo	Hopkins	920	900	900	900	900	900	205	201	201	201	201	201
½Three oaks	Lee	2,089	2,500	5,500	5,500	5,500	5,500	21	25	55	55	55	55
⅓Jewett	Leon	633	792	0	0	0	0	13	17	0	0	0	0
⅓Jewett, Kosse Strip	Limestone	661	4,292	3,500	3,500	3,500	3,500	41	87	70	70	70	40
Martin Lake	Panola	982	982	1,500	1,500	1,500	1,500	855	855	855	855	855	855
Calvert, Twin Oak	Robertson	7,436	8,180	8,998	9,897	10,887	11,976	74	82	90	99	109	120
Oak Hill	Rusk	1,265	1,668	1,668	1,668	1,668	1,668	582	582	582	582	582	582
Monticello Winfield	Titus	619	1,000	1,000	1,000	1,000	1,000	619	619	619	619	619	619
TOTAL		**25,589**	**32,985**	**37,946**	**38,845**	**39,835**	**40,924**	**2,562**	**2,650**	**2,668**	**2,677**	**2,687**	**2,668**



County+Pop_1-to-All(from Katy)_5.27.10_JP.xls

Figure 121. Projected lignite-mine water use (2010–2060)

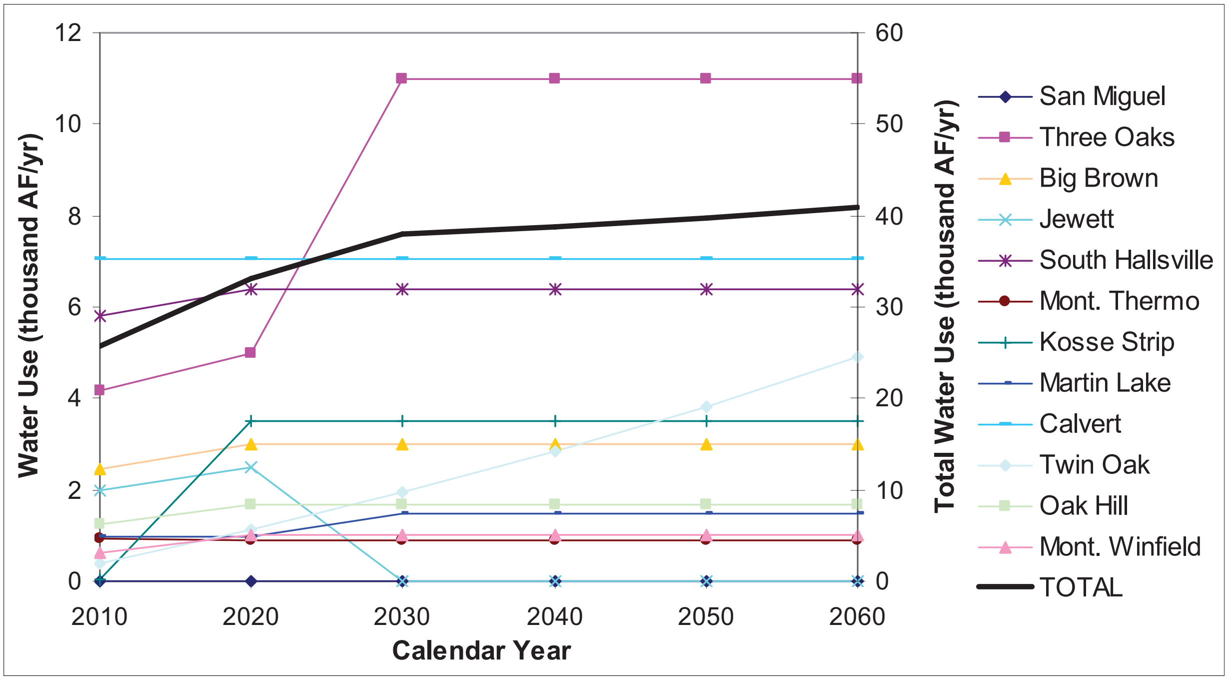


Figure 122. Total water use for each coal-mining facility

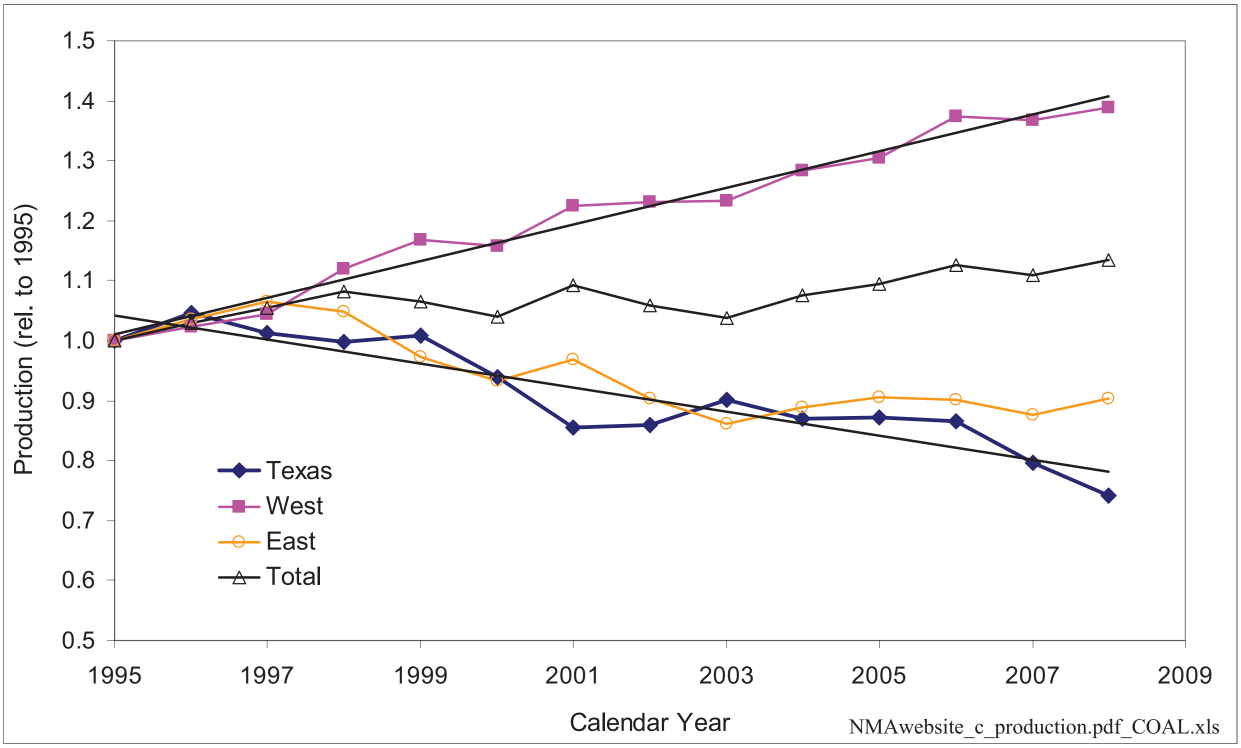


Figure 123. Relative growth of Texas (negative) and western (positive) coal

5.4 Aggregates

Key parameters for future aggregate water use relating population and aggregate production are presented in Table 61, Figure 124, and Figure 125. We assumed that crushed stone and construction sand and gravel will follow a trajectory similar to that of the past 2 decades. The production trajectory considered deviates from strict linear extrapolation of historical data and is somewhat flattened. The increased gap between crushed-stone and sand and gravel operations (Figure 125) is consistent with the societal trend of having large operations at one location for a long period of time, rather than having dispersed generally smaller sand and gravel operations. However, both categories are expected to grow in the future. The overall growth rate is 1.5%–2% (Table 61). Some analysts have projected an annual growth in the industry of 3%–5% (Walden and Baier, 2010). Although industry has been significantly impacted by the current economic recession, it is anticipated that demand for aggregate products will continue to grow with the population and the need for roadway and other building materials. It is not clear, however, how a 3% annual growth (translating into a production of ~1,200 million tons/yr in 2060) can be sustained in terms of water use without increasing water recycling or developing dry processes. The aggregate water use projections presented in this report can therefore be construed as either modest annual growth with no change from current practices or higher annual growth with concomitant decrease in water use. In addition, although most mining facilities are operated for at least 20 years, and although some larger operations have 100 years or more of reserves, small "mom & pop" quarries may be operated for as little as 5 years and are often associated with specific development projects or other short-term, localized demands. This observation carries the understanding that many small facilities could appear in counties not listed in Table 63, which shows sand and gravel water-use projections. Table 62 does the same for crushed stone. Table 64 summarizes projections displayed at the county level in Figure 126 and Figure 127. Overall aggregate will increase from ~50 thousand AF/yr in 2010 to ~100 thousand AF/yr in 2060.

Table 61. Historical and projected population and aggregate production

Year	Crushed Stone (million tons)	Sand and Gravel (million tons)	Population	Average Annual Population Change
1990	55	42	16,986,510	
2000	110	74	20,851,820	386,531
2010	164	105	25,388,403	453,658
2020	198	124	29,650,388	426,199
2030	232	144	33,712,020	406,163
2040	268	165	37,734,422	402,240
2050	307	187	41,924,167	418,975
2060	346	210	46,323,725	439,956

Table 62. Crushed-stone water use projections per county through 2060

County	2008	2010	2020	2030	2040	2050	2060
Bell	0.747	0.803	1.039	1.278	1.460	1.681	1.914
Bexar	3.108	3.341	4.051	4.603	5.038	5.502	6.070
Brown	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Burnet	0.280	0.301	0.384	0.460	0.535	0.598	0.678
Callahan	0.131	0.140	0.141	0.141	0.136	0.133	0.129
Comal	3.634	3.907	4.739	5.473	6.123	6.651	7.378
Cooke	0.818	0.880	1.133	1.349	1.576	1.893	2.181
Coryell	0.275	0.296	0.355	0.397	0.429	0.463	0.505
Eastland	0.150	0.161	0.168	0.178	0.211	0.213	0.225
Ector	0.168	0.181	0.196	0.212	0.218	0.229	0.240
Ellis	2.898	3.115	3.564	4.213	5.047	6.004	6.827
Floyd	0.169	0.182	0.190	0.195	0.202	0.208	0.213
Glasscock	0.095	0.102	0.107	0.112	0.114	0.117	0.121
Hidalgo	0.170	0.183	0.244	0.310	0.364	0.415	0.477
Hutchinson	0.127	0.137	0.152	0.172	0.186	0.193	0.207
Jack	0.238	0.256	0.302	0.322	0.363	0.405	0.450
Johnson	3.091	3.323	3.816	4.479	5.347	6.337	7.197
Kaufman	2.063	2.218	2.492	2.903	3.507	4.263	4.864
Lampasas	0.293	0.314	0.374	0.417	0.449	0.483	0.526
Limestone	0.210	0.226	0.250	0.280	0.294	0.332	0.359
Maverick	0.052	0.056	0.065	0.072	0.077	0.079	0.085
Medina	0.287	0.308	0.360	0.397	0.425	0.453	0.491
Montague	0.104	0.111	0.129	0.150	0.181	0.205	0.232
Nolan	0.023	0.025	0.025	0.025	0.024	0.023	0.022
Oldham	0.165	0.177	0.204	0.244	0.275	0.288	0.315
Parker	0.170	0.183	0.218	0.264	0.318	0.372	0.425
Potter	0.192	0.206	0.235	0.275	0.305	0.318	0.345
Reeves	0.014	0.015	0.016	0.016	0.017	0.018	0.019

County	2008	2010	2020	2030	2040	2050	2060
Sabine	0.053	0.057	0.060	0.063	0.066	0.069	0.072
San Patricio	0.340	0.366	0.419	0.464	0.491	0.510	0.546
Stonewall	0.019	0.021	0.020	0.019	0.019	0.018	0.017
Taylor	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Travis	0.135	0.145	0.188	0.230	0.272	0.310	0.355
Uvalde	0.055	0.059	0.072	0.078	0.081	0.086	0.093
Walker	0.454	0.488	0.660	0.842	1.086	1.337	1.572
Webb	0.226	0.243	0.331	0.435	0.521	0.611	0.710
Williamson	2.273	2.444	3.152	3.796	4.412	5.046	5.750
Wise	1.422	1.529	1.882	2.263	2.685	3.177	3.639
Young	0.035	0.038	0.040	0.043	0.045	0.049	0.052

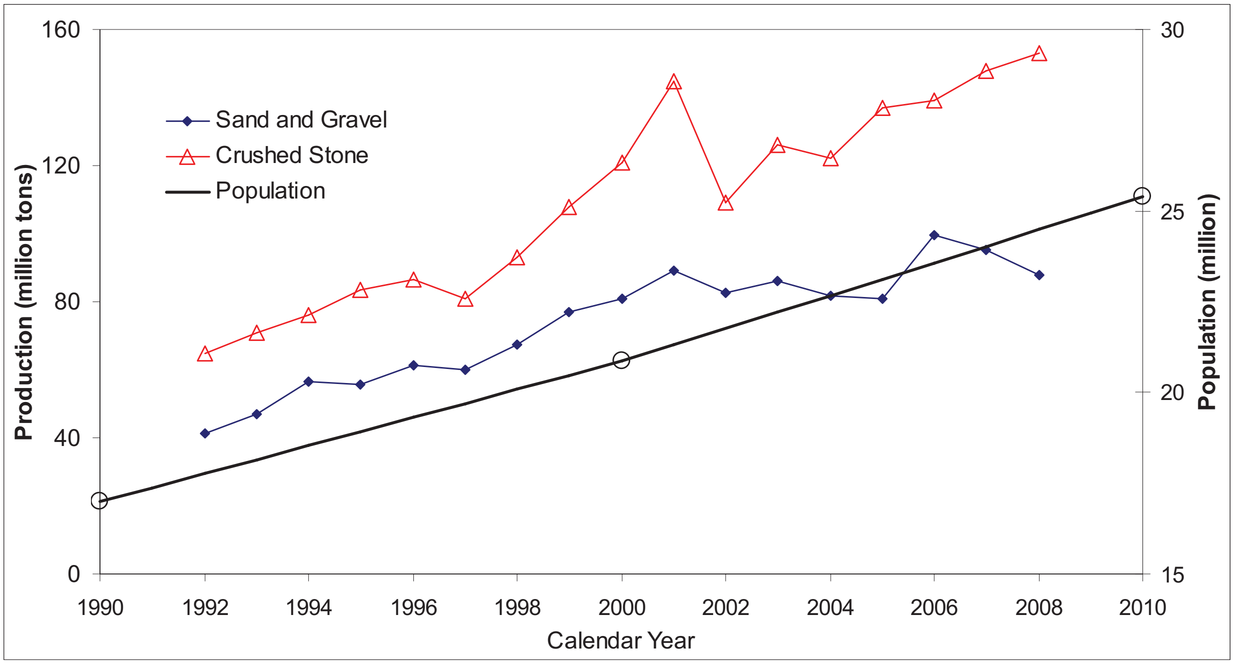
Table 63. Sand and gravel water-use projections per county through 2060

County	2008	2010	2020	2030	2040	2050	2060
Atascosa	0.350	0.420	0.526	0.615	0.698	0.755	0.846
Bastrop	0.063	0.076	0.113	0.162	0.225	0.310	0.387
Bell	0.346	0.415	0.523	0.622	0.710	0.800	0.907
Bexar	1.028	1.233	1.233	1.233	1.233	1.233	1.233
Borden	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Bosque	0.013	0.015	0.018	0.018	0.019	0.021	0.023
Brazoria	0.565	0.678	0.866	1.064	1.289	1.533	1.790
Brazos	0.230	0.276	0.347	0.403	0.495	0.474	0.521
Burnet	0.031	0.037	0.050	0.064	0.079	0.100	0.120
Coke	0.003	0.004	0.004	0.005	0.005	0.006	0.006
Colorado	1.540	1.848	2.033	2.190	2.372	2.440	2.543
Comal	0.099	0.119	0.180	0.242	0.305	0.382	0.464
Cooke	0.026	0.031	0.040	0.048	0.066	0.073	0.085
Dallas	1.574	1.889	1.889	1.889	1.889	1.889	1.889
Denton	1.262	1.514	2.106	2.678	3.332	4.293	5.191
Duval	0.604	0.725	0.796	0.846	0.810	0.748	0.713
El Paso	0.581	0.697	0.880	1.063	1.266	1.482	1.721
Fannin	0.006	0.007	0.011	0.016	0.023	0.027	0.033
Fayette	0.082	0.098	0.123	0.145	0.183	0.241	0.287
Fort Bend	0.000	0.000	0.000	0.000	0.001	0.001	0.001
Galveston	0.282	0.339	0.375	0.402	0.444	0.480	0.514
Grayson	0.041	0.049	0.061	0.073	0.089	0.106	0.125
Guadalupe	0.186	0.224	0.318	0.422	0.541	0.674	0.816
Harris	2.494	2.993	2.993	2.993	2.993	2.993	2.993
Henderson	0.115	0.138	0.181	0.235	0.304	0.395	0.477
Hidalgo	0.603	0.723	1.045	1.444	1.850	2.272	2.750
Hutchinson	0.023	0.027	0.028	0.027	0.026	0.027	0.026

County	2008	2010	2020	2030	2040	2050	2060
Jefferson	0.131	0.157	0.180	0.202	0.230	0.280	0.315
Johnson	0.075	0.090	0.121	0.162	0.214	0.281	0.342
Jones	0.010	0.012	0.013	0.013	0.013	0.013	0.013
Kaufman	0.195	0.234	0.296	0.386	0.491	0.646	0.783
Kerr	0.059	0.071	0.076	0.080	0.100	0.102	0.111
Lampasas	0.012	0.015	0.017	0.019	0.021	0.023	0.025
Liberty	0.108	0.129	0.165	0.206	0.253	0.310	0.365
Lubbock	0.415	0.498	0.554	0.601	0.676	0.745	0.807
McLennan	1.025	1.230	1.444	1.732	1.868	2.228	2.509
Medina	0.063	0.076	0.097	0.117	0.138	0.157	0.180
Montague	0.010	0.012	0.013	0.014	0.015	0.017	0.018
Montgomery	0.028	0.033	0.050	0.071	0.101	0.135	0.167
Navarro	0.062	0.075	0.096	0.123	0.155	0.198	0.236
Nueces	0.445	0.534	0.654	0.780	0.892	0.981	1.104
Oldham	0.002	0.002	0.002	0.001	0.001	0.000	0.000
Orange	0.136	0.163	0.176	0.191	0.220	0.238	0.256
Parker	0.253	0.304	0.393	0.424	0.503	0.580	0.674
Potter	0.308	0.370	0.456	0.583	0.711	0.790	0.909
Reeves	0.008	0.010	0.011	0.013	0.015	0.016	0.018
San Patricio	0.055	0.067	0.086	0.107	0.125	0.144	0.166
Smith	0.106	0.127	0.154	0.184	0.246	0.317	0.376
Somervell	0.386	0.463	0.552	0.613	0.636	0.668	0.715
Starr	0.142	0.170	0.229	0.296	0.357	0.418	0.491
Tarrant	1.093	1.312	1.312	1.312	1.312	1.312	1.312
Travis	0.718	0.862	0.862	0.862	0.862	0.862	0.862
Val Verde	0.031	0.037	0.046	0.054	0.060	0.065	0.072
Victoria	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ward	0.016	0.020	0.022	0.023	0.025	0.028	0.029
Washington	0.018	0.022	0.024	0.026	0.030	0.032	0.035
Webb	0.005	0.006	0.009	0.012	0.016	0.020	0.024
Wise	0.229	0.275	0.345	0.445	0.584	0.734	0.886

Table 64. Summary of aggregate water-use projections

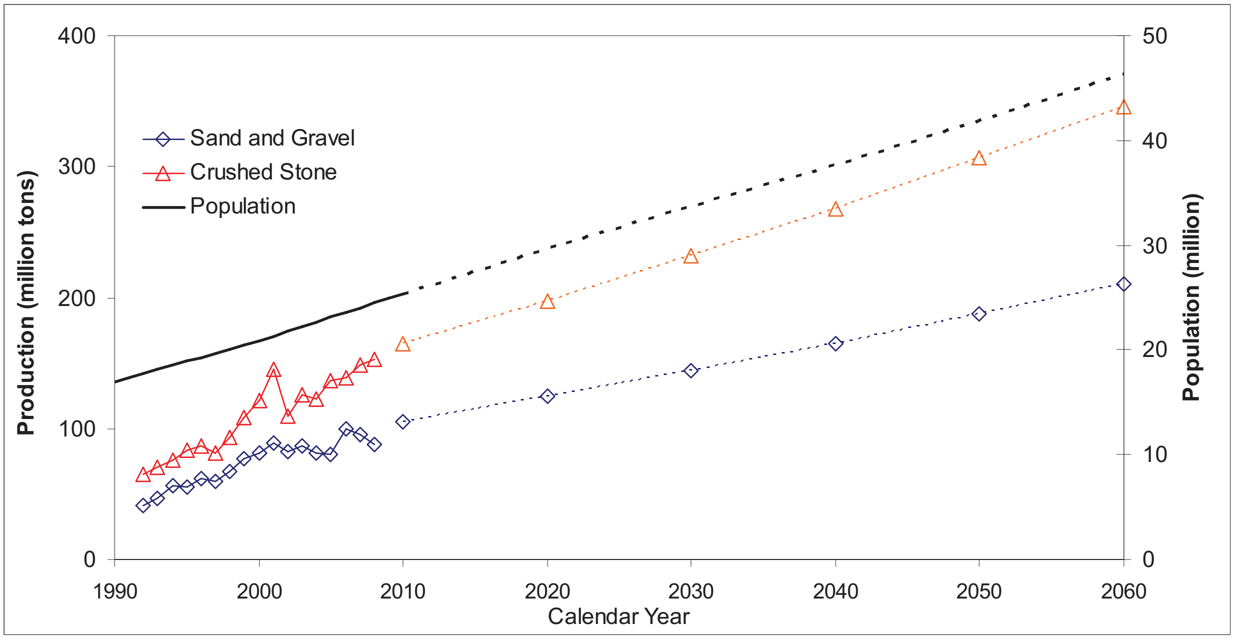
	2010	2020	2030	2040	2050	2060
Water-Use Projection (1000s AF)						
Crushed Stone	26.5	31.8	37.2	42.9	49.1	55.3
Sand and Gravel	22.0	25.2	28.6	32.1	36.1	40.3
Total	48.5	57.0	65.7	75.0	85.2	95.6



Results Summary revised 9-20-10_JP_3=SetUrbanAreasLow.xls

Source: USGS (Aggregate production) and TWDB (population)

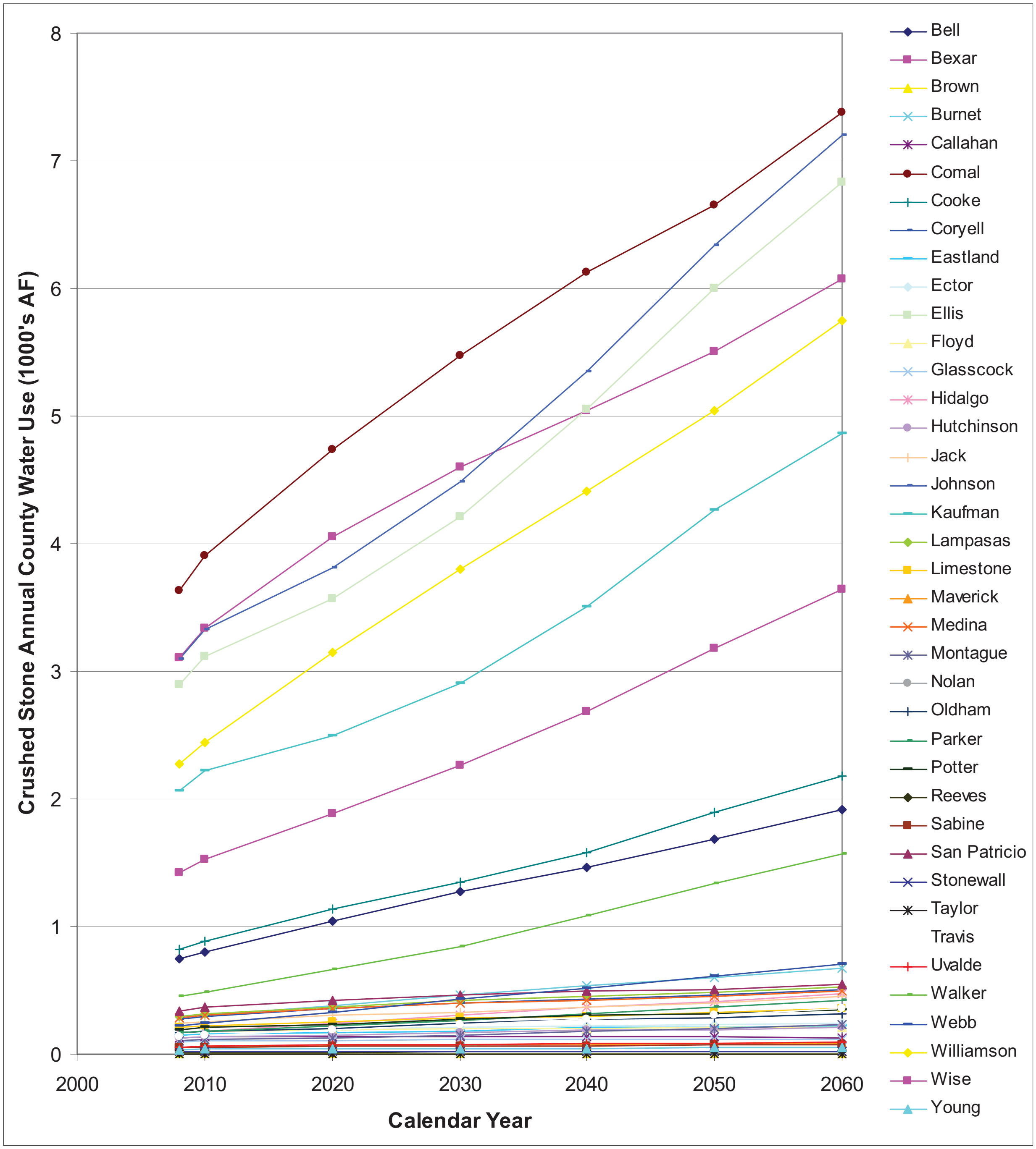
Figure 124. Historical population and aggregate production in Texas



Results Summary revised 9-20-10_JP_3=SetUrbanAreasLow.xls

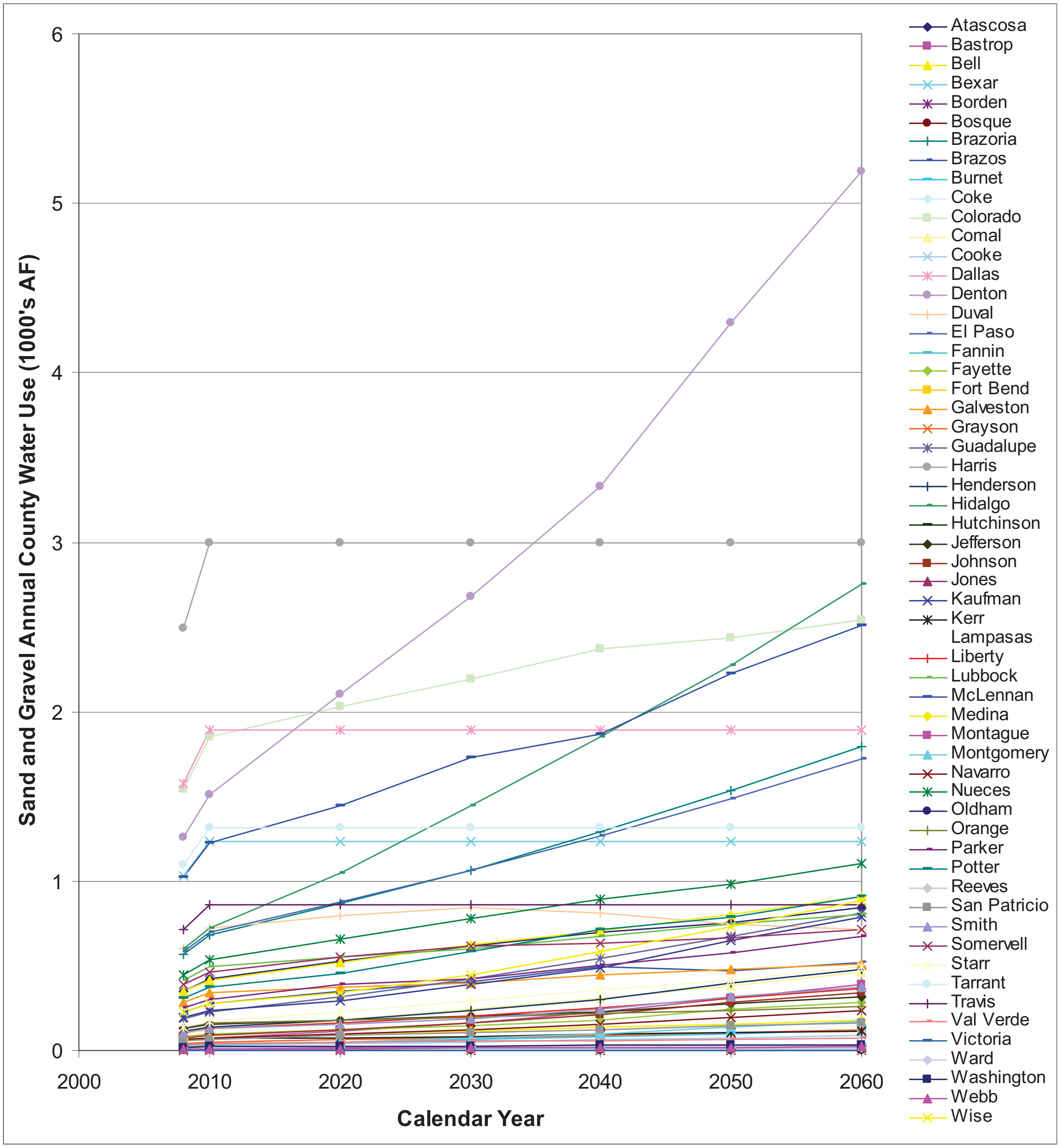
Source: USGS (aggregate production to 2008) and TWDB (population through 2060)

Figure 125. Historical population and projection for population and aggregate production in Texas



Results Summary revised 9-20-10_JP_3=SetUrbanAreasLow.xls

Figure 126. Crushed-stone water-use projections per county through 2060



Results Summary revised 9-20-10_JP_3=SetUrbanAreasLow.xls

Figure 127. Sand and gravel water-use projections per county through 2060

5.5 *Industrial Sand*

As seen in the Current Water Use section, industrial-sand mining is more water intensive than the closely related category of aggregate and consumes almost 10 thousand AF. Industrial-sand production is clearly connected to the increase in well stimulation/fracing through the use of proppants, although proppant sand used in Texas can be imported from out of state and sand produced in Texas exported out of state. There is no doubt that a significant fraction of the locally produced sand is used by the oil and gas industry. Assuming that a proppant loading of 1 lb/gal translates into 0.163 million tons/ thousand AF of frac water, then 35.8 thousand AF (2008 fracing water use) would correspond to 5.8 million tons. This figure is above the current Texas production of 3.58 million short tons in 2008 (Figure 128), suggesting that a significant fraction of the proppant is either not necessarily all natural sand or that it comes from out of state. A close examination of the production plot shows that departure from the background trend can be attributed to use to the oil and gas industry and that 1.5 million tons of industrial sand (only a fraction of the amount needed) was used, along with 38.5 thousand AF, to frac wells in Texas. We then assumed that this proportion stays constant in the next few decades (that is, that local production and imports from out of state grow at the same rate) and applied it to the water-use projections for fracing. We then distributed the results as they were distributed between counties and facilities in the Current Water Use section without incorporating important elements such as mining reserves or proximity to oil and gas plays. We assumed that the water coefficient would linearly improve from the current 620 gal/t to a value of 350 gal/t in 2060. The maximum water use close to 18 thousand AF is projected to be reached in the 2020–2030 decade (Table 65).

5.6 *Other Nonfuel Minerals*

In this section, we extrapolate from figures presented in the Current Water Use section. As we did previously, we neglect water use in the dimension-stone industry. We use extrapolation from current trends for lime and gypsum (Table 66 and Table 67) and expect no change in water use in clay, salt, sodium sulfate, or talc categories.

5.6.1 Uranium

The South Texas uranium province has already produced ~80 million lb U_3O_8. In 2003, EIA (2010) projected that 27 million lb U_3O_8 at 0.089% U_3O_8 on average and 40 million lb U_3O_8 at ~0.062% U_3O_8 on average remained in the ground in Texas, for a market price of \$50 and \$100/lb U_3O_8, respectively. As of January 2011, market price hovered at ~\$60/lb. These reserves are, however, dwarfed by reserves in the western states (Wyoming, New Mexico, Arizona, Colorado, Utah), with 462 and 1,034 million lbs U_3O_8, for the same price cutoffs of \$50 and \$100/lb, respectively. In addition to the three counties with permits active in 2010 (Brooks, Duval, Kleberg), a sixth permit is pending at TCEQ in Goliad County; it has generated vigorous public participation. The RRC website lists exploration permits as of January 2011 in nine counties: Atascosa, Bee, Brooks, Duval, Goliad, Jim Hogg, Karnes, Kleberg, and Live Oak (and an additional permit in Briscoe County in the Texas Panhandle), to which can be added DeWitt, Jim Wells, McMullen, and Webb Counties (Figure 129). However, we assumed no change in current water use or of its distribution.

5.6.2 Other Metallic Minerals

On the basis of decades-long evaluation and development activities, three deposits seem to have potential for near-term mining: (1) Shafter silver deposit, Presidio County; (2) Round Top beryllium-uranium-rare earth element deposit, Hudspeth County; and (3) Cave Peak molybdenum deposit, Culberson County.

5.6.2.1 Shafter Deposit

The Shafter deposit in Presidio County, 18 miles north of the Rio Grande, is the closest to actual production (http://www.aurcana.com/s/NewsReleases.asp?ReportID=439022), as plans for silver production by mid-2012 have been announced. This deposit is the downdip extension of the ore zone of the Presidio silver mine that was in production from 1883 until the early 1940s. The planned silver production follows a decade of activity by several predecessor companies, all building on an extensive exploration and limited development program in the late 1970s and early 1980s. The designed production rate for this underground mine is 1500 tons of ore per day, with measured and indicated reserves for more than 5 years of production, and additional resources for an additional 5 years of production, given favorable economic conditions. Burgess (2010) provided a detailed feasibility study for the Shafter mine, including plans for water management as: "*Two distinct phases in the water management plan are envisaged. The first phase will involve mining operations performed above the water table with no ground water being produced from this activity. During this phase, mining operations will be a small net consumer of water in the form of drill water and dust control water. Process plant make-up water will be obtained from the old underground workings in Block 1 which lie below the water table and are flooded with an estimated 20 million gallons of water. These old workings are recharged from a deep aquifer at a rate of 350 gpm, this figured being based on the inflows observed by Gold Fields when they were developing Block 1 in the early 1980's. During this first phase of operations, no excess water will be generated as only the net requirements of the process plant and the underground workings will be drawn from the old workings of Block 1.*" and "*The second phase is when the decline face encounters the water table at approximately 900 Level, prior to which the 20 million gallons of water standing in the test mine in Block 1 will be pumped out through the Gold Fields shaft. By dewatering the Goldfields Shaft and Block 1 test mine in this manner, the water table will be lowered in advance of the decline face to reduce the amount of ground water encountered. The second phase also entails mining operations simultaneously occurring above the water table in Blocks 2 to 5. Mining Block 1 entails removing standing water (estimated at 20 million gallons) and groundwater inflows. This phase will produce a net excess of water of 350 gpm from ground water flowing into the underground mine which will be clarified in underground settling sumps to reach compliance with EPA criteria and then disposed of by discharge to the environment in a dry creek at the south west corner of the property (Arroyo del Muerto).*"

The Shafter ore zone is below the water table, so dewatering of the ore zone prior to and during production will more than account for any water used in mining per se. Furthermore, a considerable excess of water required for all of the Shafter operation will be produced. For the stated rate of ore production for the 5-year period, Burgess' s analysis indicates that total water used by the operation will average 104 AF per year, of which less than 20 AF per year will be used in mining and surface use around the mine. Source water derived from pumping of the ore zone will average 565 AF per year for the designed ore production rate of 1500 tons per day (even accounting for a nominal 10% ore dilution and development headings). Thus, **excess water production for the five-year period will average more than 500 AF per year (groundwater)**. If the current silver resources prove economically viable to extend production beyond the initial five-year period, there is little reason to doubt that these relative figures would also apply to that extended amount and period of production.

5.6.2.2 Round Top Deposit

The Round Top beryllium-uranium-rare earth element deposit near Sierra Blanca in Hudspeth County is currently being reevaluated (http://www.standardsilvercorp.com/projects/round-top/), building on an extensive exploration program for beryllium in the 1980s (Rubin et al., 1990). The impetus for Round Top exploration has been boosted by the current emphasis on developing domestic REE sources to counter restricted supply from foreign sources, notably China. Although the mineralization controls at Round Top are only broadly understood, it is worth noting that this geologic environment is represented throughout a considerable portion of west Texas, suggesting regional potential for additional deposits. However, at this point, production even from the Round Top deposit would be hypothetical, and thus water needs are not possible to constrain.

5.6.2.3 Cave Peak Deposit

The molybdenum and associated metals deposit at Cave Peak in Culberson County has an exploration history also dating to the 1960s (Sharp, 1979). Following a considerable period of inactivity, the Cave Peak property has recently attracted renewed interest (http://www.quaterraresources.com/projects/cave_peak/). While geologically similar molybdenum deposits are sites of significant mining operations in other states, it is too early in the evaluation process to determine if Cave Peak represents an economically viable resource, let alone assess any potential water needs and impacts.

5.6.3 Conclusions

Uranium solution mining is likely to continue in Texas but a large increase in production and water use is not expected because of the competition of other deposits in the U.S. and elsewhere.

The planned Shafter mine has a life-expectancy in the decade range (currently 2012-2022), so barring discovery of substantial new resources locally, its water use (actually the mine's local supply of excess water) would not have a long term impact on regional water issues. Should any of the other metallic and industrial mineral deposits prove economically viable even at modest mining rates, even though the total water consumption likely would be relatively small, there could be significant impacts on local (ground)water supplies in the arid west Texas region.

Although Frasch sulfur is not produced anymore in Texas, sulfur remains a widely used industrial chemical, notably in the production of agricultural fertilizers, but the domestic and global sulfur supply currently is dominated by "nondiscretionary" sulfur recovery from refineries of sour crude oil and natural gas and from metal refineries as mandated by the Clean Air Act. Thus, it seems unlikely that Frasch sulfur production will ever return to economic viability in Texas, but should it do so, it could affect local water demand, particularly in west Texas. There are additional metal resources, namely zinc, lead, and silver, in association with some salt dome cap rocks that could represent a hypothetical mining activity over an extended timeframe (Kyle, 1999).

Table 65. Projected county-level industrial-sand water consumption

County	2008	2020	2030	2040	2050	2060
Atascosa	0.43	0.79	0.72	0.54	0.44	0.35
Colorado	0.43	0.79	0.72	0.54	0.44	0.35
Dallas	0.04	0.07	0.07	0.05	0.04	0.03
El Paso	0.04	0.07	0.07	0.05	0.04	0.03
Guadalupe	0.07	0.13	0.12	0.09	0.07	0.06
Harris	0.14	0.26	0.24	0.18	0.14	0.12
Hood	0.43	0.79	0.72	0.54	0.44	0.35
Hunt	0.07	0.13	0.12	0.09	0.07	0.06
Johnson	0.04	0.07	0.07	0.05	0.04	0.03
Liberty	0.14	0.26	0.24	0.18	0.14	0.12
Limestone	1.30	2.37	2.18	1.64	1.32	1.07
Mason	0.56	1.02	0.94	0.71	0.57	0.46
McCulloch	4.21	7.69	7.07	5.32	4.27	3.46
Montgomery	0.76	1.39	1.28	0.96	0.77	0.62
Newton	0.14	0.26	0.24	0.18	0.14	0.12
Orange	0.07	0.13	0.12	0.09	0.07	0.06
Robertson	0.04	0.07	0.07	0.05	0.04	0.03
San Saba	0.28	0.51	0.47	0.35	0.28	0.23
Smith	0.07	0.13	0.12	0.09	0.07	0.06
Somervell	0.14	0.26	0.24	0.18	0.14	0.12
Tarrant	0.21	0.38	0.35	0.27	0.21	0.17
Wise	0.07	0.13	0.12	0.09	0.07	0.06
Total	**9.68**	**17.68**	**16.26**	**12.24**	**9.82**	**7.95**

Table 66. Projected county-level lime-mining water consumption (AF)

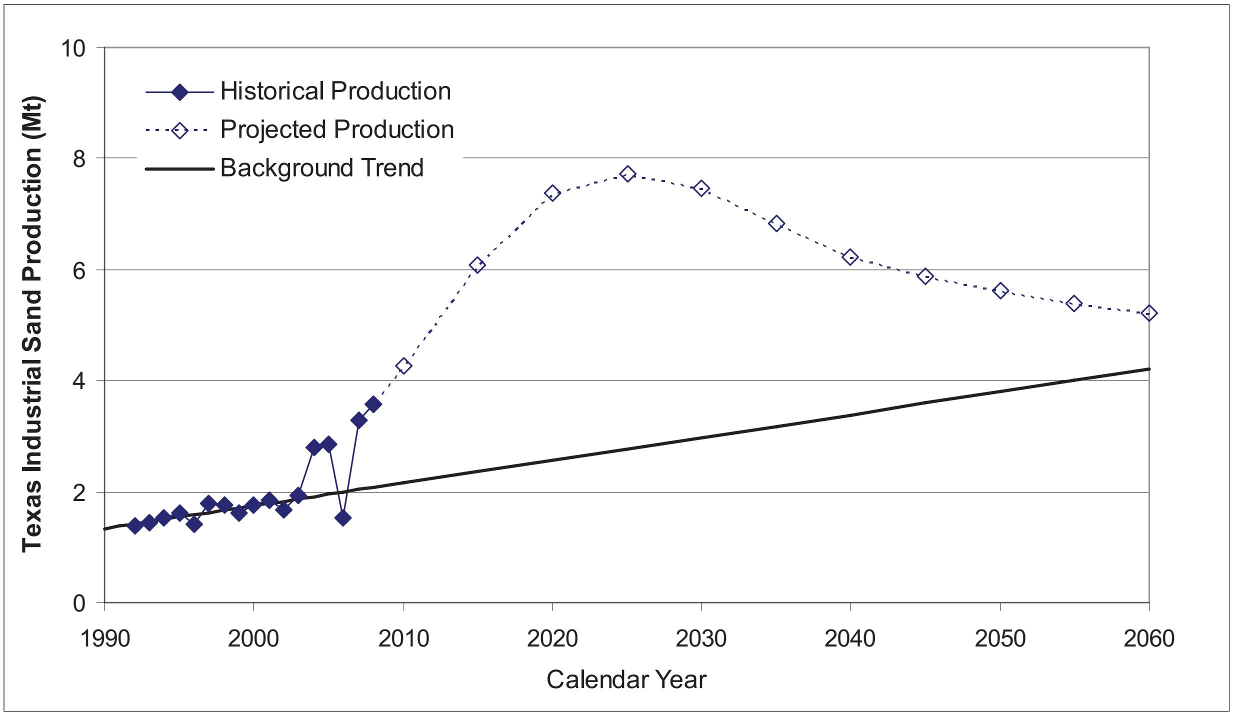
	2008	2020	2030	2040	2050	2060
Bosque	8.5	11.3	12.7	14.1	15.4	16.8
Burnet	2.8	3.7	4.1	4.5	5.0	5.4
Comal	6.6	8.7	9.8	10.8	11.9	12.9
Johnson	13.1	17.4	19.5	21.7	23.8	25.9
Travis	15.1	20.0	22.5	24.9	27.3	29.8
(AF)	**46**	**61**	**69**	**76**	**83**	**91**

Lime_count.xls

Table 67. Projected county-level gypsum-mining water consumption (AF)

	2008	2020	2030	2040	2050	2060
Fisher	3.3	4.0	4.0	4.0	4.0	4.0
Gillespie	3.3	4.0	4.0	4.0	4.0	4.0
Hardeman	6.6	8.0	8.0	8.0	8.0	8.0
Kimble	1.5	1.8	1.8	1.8	1.8	1.8
Nolan	14.8	17.8	17.8	17.8	17.8	17.8
Stonewall	1.2	1.4	1.4	1.4	1.4	1.4
Wheeler	1.2	1.4	1.4	1.4	1.4	1.4
(AF)	**32**	**38**	**38**	**38**	**38**	**38**

Gypsum_count.xls



IndustrialSand_count.xls

Figure 128. Projection of industrial-sand production

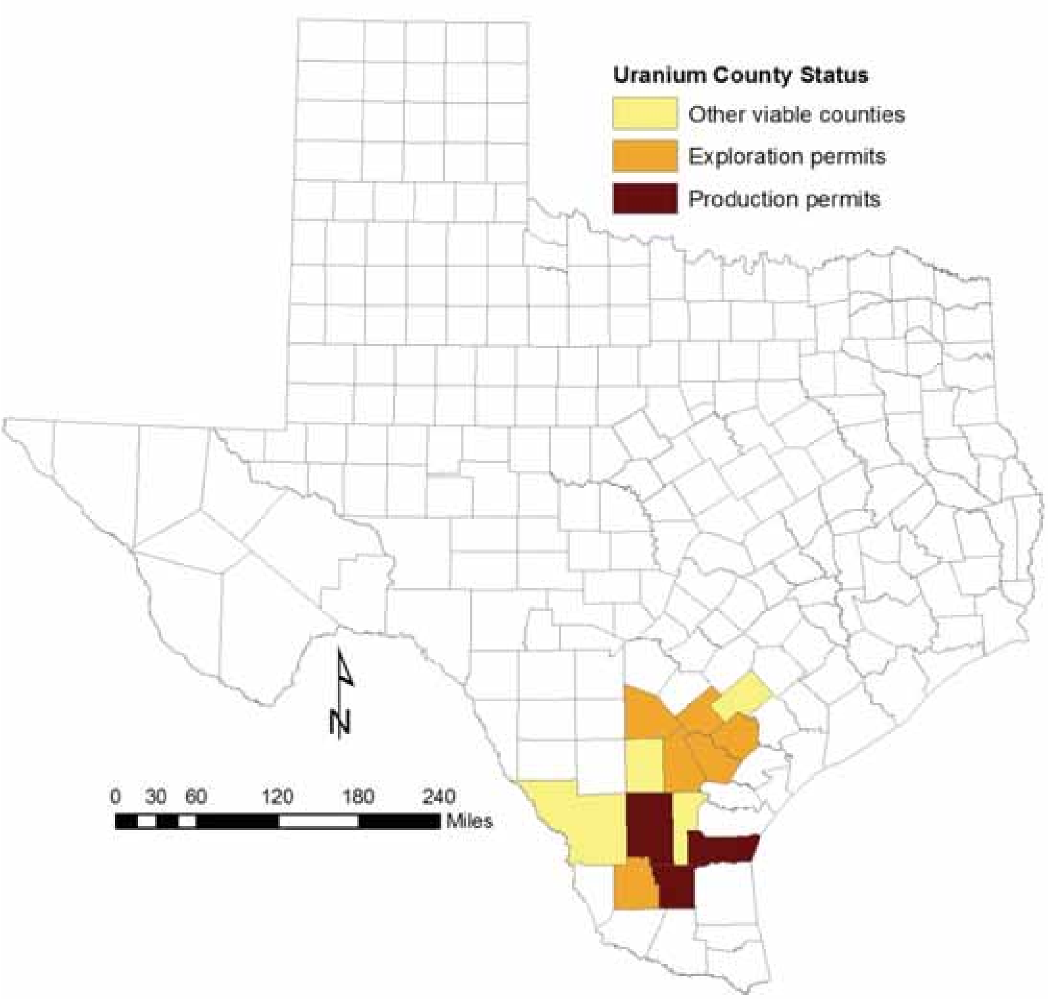


Figure 129. Counties prospective for uranium mining as of 2010

5.7 Water Use for Speculative Resources

Given that these resources are fairly speculative at this point and that even order-of-magnitude projections are impossible, their water use was not included in the projections. Information is provided, however, to alert stakeholders that it may be an option in the future when market conditions are favorable.

5.7.1 Heavy Oil

Large resources exist across the country and North America (for example, Veil and Puder, 2006; Veil and Quinn, 2008). Texas contains perhaps the largest heavy oil/tar sands reserves in the U.S after Utah. Heavy oil is generally defined as having an API density of between 10º and 20º. Below 10º API, the term *tar* (or *bitumen*) is generally used. Tar sands (called *oil sands* in Canada) of interest are San Miguel D and Anacacho of Cretaceous age in mostly Kinney, Maverick, Medina, Ulvalde, and Zavala Counties in the Maverick Basin. Asphaltic material (residue that occurs where a reservoir crops out after evaporation of the volatile or after water washing such as a reservoir subject to shallow groundwater systems) is still being produced in quarries operated by Vulcan Materials and by Martin-Marietta (Ewing, 2009, p. 27). Seni and Walter (1993) also mentioned heavy-oil deposits of Eocene age along the South Texas Gulf Coast (whether these accumulations have been or are currently produced through conventional means is unclear). Reserves of at least 3 Bbbl are reported (4.8 Bbbl in Kuuskraa et al., 1987), but they could be as high as 10 Bbbl (Ewing, 2009, p. 17). The *Oil&Gas Journal* (Moritis, 2010) claimed 7–10 Bbbl of OOIP. Heavy-oil deposits are different from oil shales, in which oil has not left the source rock and may still be in the form of kerogen, the chemical precursor to oil.

A typical production method consists of elevating the temperature of the deposits to lower the viscosity of the oil and allow it to flow to the production wells, which is done through steam injection or in situ combustion. Steam injection is used if the heavy oil is not too deep (<3,000 ft) because of heat loss along the well bores. Deposits, if shallow, can also simply be mined in open pits (as is done in Canada) and processed using steam. Stang and Soni (1984) mentioned a steam:oil ratio of 10.9 and 8.2 on two 1+-year-long test sites. U.S. DOE (ca. 2007) described the <3 ratio of Canada tar sands as being particularly favorable. Veil and Quinn (2008, p. 47) mentioned a ratio of 9 bbl/bbl for the Chevron operations in Kern River field in California, about half of the water being recycled. They also discussed other field-water use, ranging from 2 to 12 bbl/bbl. Figures in Torrey (1967, Table 6) projecting water use for the whole state of Texas suggest an average ratio of 3.9 bbl/bbl (for an oil production of ~2.7 Bbbl). The *Oil&Gas Journal* (Koottungal, 2010) reported that a steam flood is operating in Anderson County, although it is unclear what the target of the flood is. In a hypothetical case that 50% of the resource is recoverable (Tyler, 1984, p. 147; Stang and Soni, 1984), recovered solely through steam injection, and that it will be exhausted in 50 years, this scenario could be represented as 5×10^9 bbl /2 /50 yr × 5 bbl/bbl × 42 gal/bbl /325,851 gal/AF/1,000 = 32 thousand AF/yr, that is, 16 thousand AF/yr with a recycling of 50%. This amount does not include potentially needed dewatering of the shallow aquifers. Other much smaller deposits also exist across the state (Tyler, 1984), but their potential production contribution is dwarfed by the uncertainty of the South Texas deposits.

Cyclic interest (20–30 year cycle?) in these resources generally occurs when the price is oil is reasonably high—as it is currently (new tests were very recently performed) and as it was in the early 1980s. In the 1960s, although oil prices were stable, Texas underwent a steady growth in field development as well, interrupted by the 1971 RRC decision to lift the production limit (Nicot, 2009b).

5.7.2 Enhanced Coalbed Methane Recovery

Coalbed methane (CBM) is generally produced by depressurization (that is, water production) of the formation that the coal seams are part of. A drop in pressure releases some of the methane sorbed to the coal matrix. PGC (2010, Table 91 and p. 359) mentioned a figure of 3.4 Tcf of gas in the speculative category (compared with 156.2 Tcf in the combined probable, possible, and speculative categories) for Texas and Louisiana Gulf Coast Pliocene-Eocene lignites. These figures are not entirely accurate at present because CBM is currently produced from Louisiana coal (Echols, 2001; Clayton and Warwick, 2006; Foss, 2009), although they do underline the small potential. Louisiana and East Texas Wilcox coal seams have a low dip, resulting in a large economical surface footprint whereas Central Texas Wilcox has a steeper dip resulting in a smaller potential for economic production (P. Warwick, USGS, personal communication, 2010); that is, coal plunges quickly beyond economical depth. The coal may have been charged through local bioprocesses (MacIntosh et al., 2010) or by thermogenic gas migrating from deeper in the basin (Arciniegas, 2006; McVay et al., 2007). How much of that water required being extracted would be fresh, brackish, or saline is unclear.

In addition, a company has apparently successfully tested the gas potential of Olmos coals in the Maverick Basin (San Filipo, 1999; PGC, 2010, p. 359). PGC (2010, p. 360) pointed out that, despite the presence of Pennsylvanian-Permian coal, the Fort Worth/Strawn Basins do not seem to contain potentially recoverable resources, in disagreement with an interpretation by Hackley et al. (2009b).

5.7.3 Coal to Liquid

The production of coal and, thus, water through dewatering, may also be affected by an increasing interest in coal-to-liquids (or coal liquefaction) technologies (CTL). CTL involves the conversion of solid coal through direct or indirect coal liquefaction into liquid fuels and chemicals by breaking down coal’s molecular structure and adding hydrogen. Whereas no known pilot plants exist in Texas (one is planned in Natchez, Mississippi), future interest in the possibility of creating liquid fuel from lignite may increase coal production in the long term. Because lignite is cheap and abundant within Texas, its practical application is for mine-of-mouth operations. There are, therefore, no transportation costs, offsetting the cost of burning lower grade coal, a more dependable and local source of fuel. However, the need for liquid fuels to compete with oil and natural gas may increase the possibility that coal will be used for CTL production. A discussion of the implications, management strategies, and obstacles facing CTL production will provide insight into its application as a liquid fuel rather than a source of electricity.

Because the need for a nearby abundant water supply can be a problem for many CTL plants, it would be logical to mine lignite where depressurization is needed, that is, the Wilcox lignite of Central Texas. An estimate comes to ~5 to 8 bbl of water per barrel of CTL (this is, manufacturing water use) (Hebel, 2010, Chapter 3). An average of 1.5 to 1.8 bbl of CTL is produced per ton of coal. Full-scale CTL plants are expected to operate at 30,000 to 80,000 bpd. At the low end, a plant would consume ~6.5 million tons of coal per year (Hebel, 2010, Chapter 4), as well as 8.5 thousand AF/yr of water. The ability to use the water pumped from depressurization and dewatering needs of a coal mine would enhance the sustainability of a CTL plant by not putting additional pressure on the groundwater resources. Also, it is likely that a CTL would need deep water wells as the nearby coal-mine operations draw down the aquifer, which increases the amount of energy needed to pump the water. Overall, start of coal-to-liquid operations will increase coal mining and water use in both manufacturing and mining sectors.

5.8 *Conclusions and Synthesis for Future Water Use*

Combining all water uses, projections suggest that peak mining-water use will occur in the 2020–2030 decade at ~250 thousand AF, sustained by oil and gas activities (Figure 130). Hydraulic fracturing represents the most significant fraction of oil and gas mining use (Figure 131). Percentages of oil and gas water use currently below 50% of total water use, would reach its largest fraction at 50+% in 2015–2030. Fracing is dominant in that use (Figure 132). Eventually oil and gas water use will be slowly taken over by aggregate-water use, which is projected to constitute >50% of total mining-water use by 2050 (Figure 133).

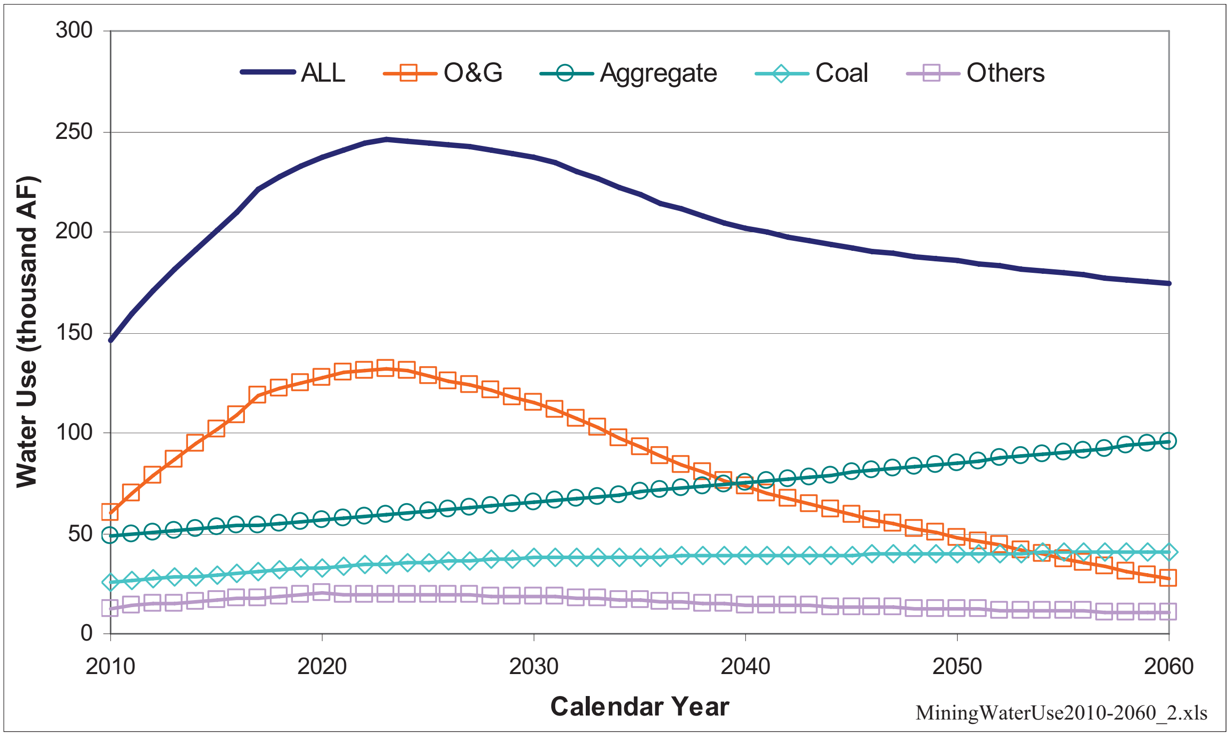


Figure 130. Summary of projected water use by mining-industry segment (2010–2060)

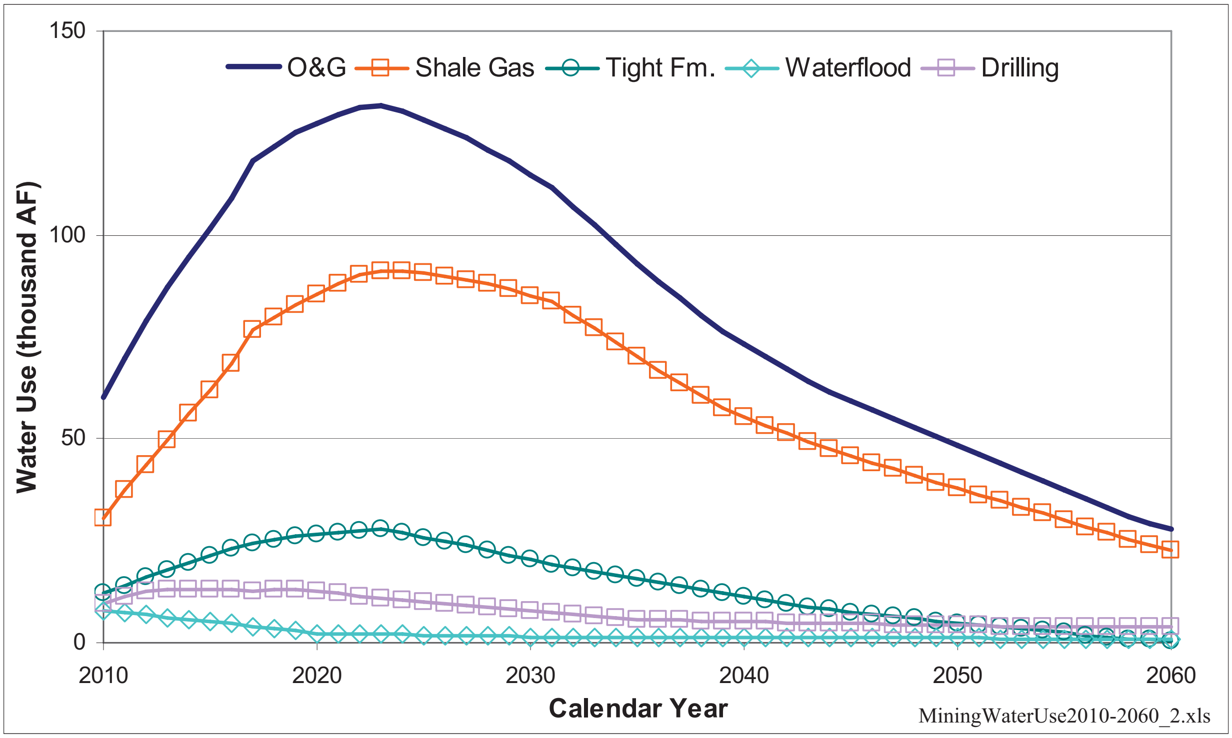


Figure 131. Summary of projected water use in the oil and gas segment (2010–2060)

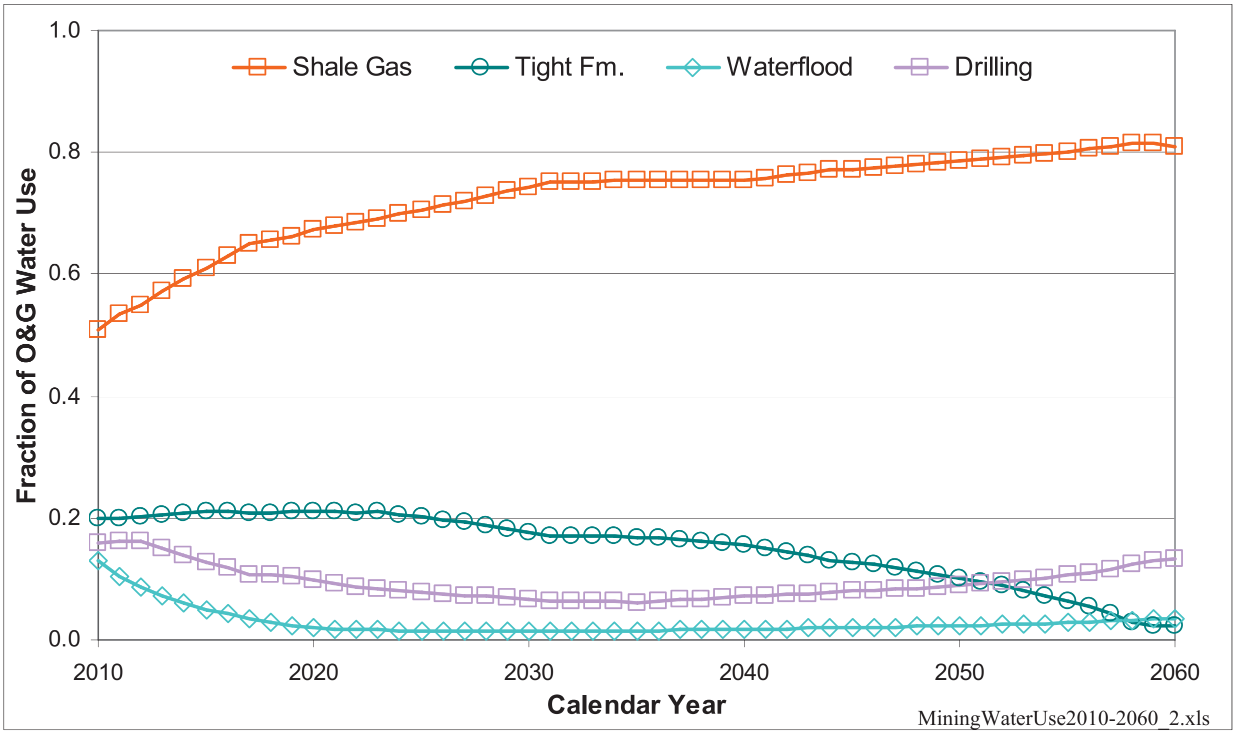


Figure 132. Summary of relative fraction of projected water in the oil and gas segment (2010–2060)

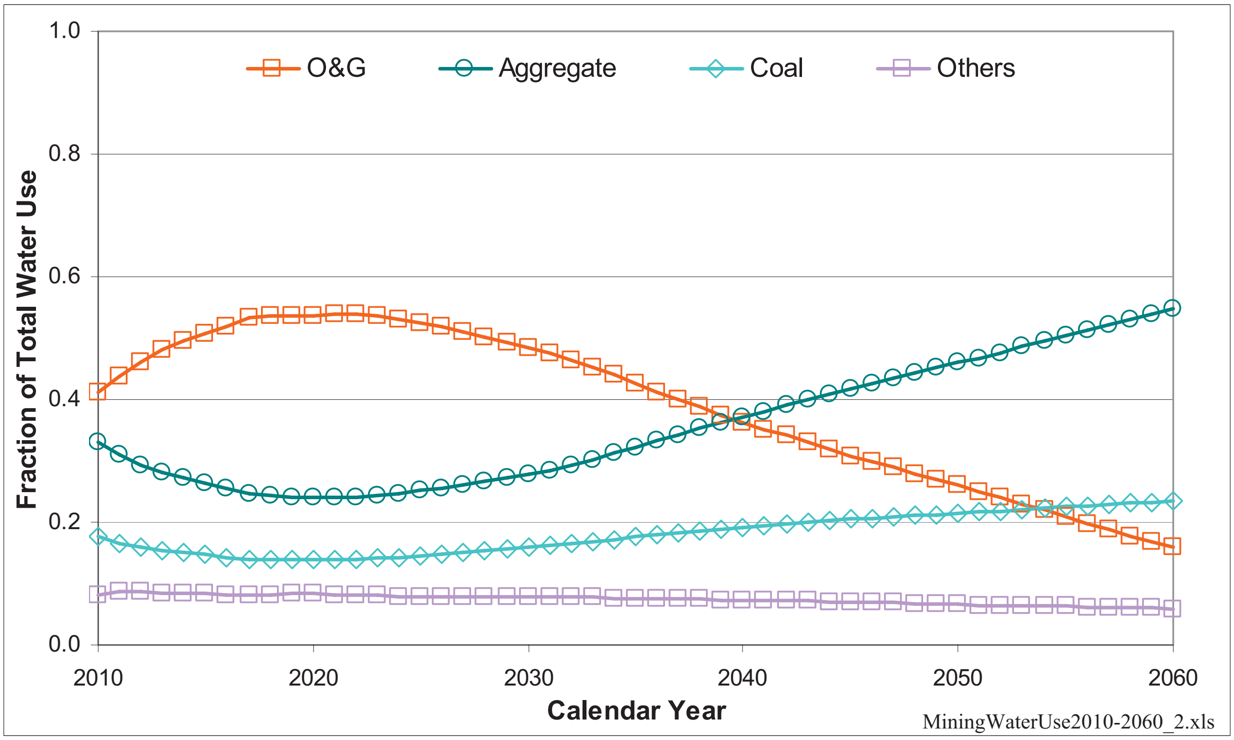


Figure 133. Summary of relative fraction of projected water use by mining-industry segment (2010–2060)

6 Conclusions and Recommendations

This study was undertaken to help in constraining water use in the mining industry. Overall in 2008, the industry as a whole consumed ~140 thousand AF of fresh water. The uncertainty associated with this value is relatively high as only figures from the coal industry (26.7 thousand AF) are well known because of legal requirements. Water usage for fracing in the oil and gas industry is also relatively well-constrained (35.8 thousand AF) because reported to the RRC with other parameters gathered during well completion. Other water uses in the oil and gas industry such as for drilling and waterfloods (21 thousand AF) are known by about a factor 2. Fresh water use for aggregate and similar commodities (lime, industrial sand, etc) production are not well-known and rely on educated guesses supported by limited survey results. We also estimate that fresh-water use is known by about a factor 2 for sand and gravel operations and maybe by a factor of 1.5 for generally larger crushed stone and industrial sand operations. Water use from some large facilities or some small contributors (uranium, metallic substances) are well documented but they make up only a small fraction of the total state water use. Applying those uncertainty factors implies that the true water use is within the 105-195 thousand AF range but those bounds are much less likely than the value of ~140 thousand AF derived in this document (Figure 134). Table 68 presents year 2008 overall water use results at the county leve. Clearly the uncertainty increases as the area of interest decreases in size, particularly if it contains unaccounted-for aggregate facilities or if the facility size has been overestimated. Comparison between published TWDB estimates and results of this work (Figure 135) shows that, by selecting the top 20 high water user counties in the mining category, only 10 of them overlapped.

County-level projections for the 2010-2060 period are given in Table 69. They suggest that peak mining-water use will occur in the 2020–2030 decade at ~250 thousand AF, decreasing to ~175 thousand AF by 2060. Many assumptions went into the building of the projections, in particular related to the activities of the oil and gas industry. Water use for those counties in which a large component of the mining water use is from shale gas fracing or those counties overlying currently little-known (mostly deep) oil or gas accumulations can deviate dramatically from the projections owing to political/legal and economic factors. Water use projections could be improved if the starting point, current water use, was better known.

This study emphasized the difficulties in gathering information on water use and the disappointing limitations of voluntary surveys, in particular whether the surveyed entities are representative of their respective mining segment as a whole. In other words, our survey sampling is likely biased. The low response rate may reflect the general reluctance of the mining industry to provide competitively sensitive information that is not required or to divert staff resources to obtain and submit data that is not routinely kept for business purposes.

Continuing to work with trade associations and expanding that cooperation to include other organizations appears to be necessary and appropriate to improve data collection. Lessons learned from this study can be used to develop refined, focused data collection, designed in consultation with a small workgroup of mining-industry representatives and related agencies and organizations, to effectively ground-truth water use/consumption and production assumptions in the industry and to calculate water-use coefficients on the basis of an acceptable, reproducible methodology. A useful alternative approach would be to make use of the recent progress in analyzing satellite imagery (in particular through time) to complement/confirm data obtained through surveys.

Table 68. County-level summary of mining water use (oil and gas drilling not included)

County	Mining Water Use (AF)	County	Mining Water Use (AF)	County	Mining Water Use (AF)
Anderson	13	Gillespie	3	Moore	1
Andrews	684	Glasscock	346	Morris	0
Angelina	90	Goliad	9	Motley	4
Aransas	0	Gonzales	0	Nacogdoches	384
Archer	7	Gray	24	Navarro	70
Armstrong	0	Grayson	43	Newton	141
Atascosa	781	Gregg	128	Nolan	112
Austin	0	Grimes	0	Nueces	453
Bailey	0	Guadalupe	256	Ochiltree	77
Bandera	0	Hale	109	Oldham	171
Bastrop	2,152	Hall	0	Orange	206
Baylor	0	Hamilton	0	Palo Pinto	235
Bee	6	Hansford	4	Panola	1,926
Bell	1,093	Hardeman	7	Parker	2,191
Bexar	4,136	Hardin	1	Parmer	0
Blanco	0	Harris	3,169	Pecos	238
Borden	126	Harrison	6,673	Polk	0
Bosque	21	Hartley	3	Potter	501
Bowie	0	Haskell	31	Presidio	0
Brazoria	568	Hays	0	Rains	0
Brazos	239	Hemphill	721	Randall	0
Brewster	0	Henderson	143	Reagan	460
Briscoe	0	Hidalgo	847	Real	2
Brooks	295	Hill	1,137	Red River	1
Brown	8	Hockley	1,881	Reeves	153
Burleson	34	Hood	2,584	Refugio	0
Burnet	314	Hopkins	935	Roberts	216
Caldwell	0	Houston	13	Robertson	7,684
Calhoun	3	Howard	56	Rockwall	0
Callahan	160	Hudspeth	0	Runnels	27
Cameron	0	Hunt	70	Rusk	1,836
Camp	4	Hutchinson	156	Sabine	53
Carson	1	Irion	105	San Augustine	88
Cass	0	Jack	323	San Jacinto	0
Castro	0	Jackson	4	San Patricio	398
Chambers	0	Jasper	0	San Saba	280
Cherokee	120	Jeff Davis	0	Schleicher	16
Childress	0	Jefferson	131	Scurry	39
Clay	22	Jim Hogg	2	Shackelford	75
Cochran	390	Jim Wells	0	Shelby	0
Coke	37	Johnson	11,678	Sherman	3
Coleman	35	Jones	51	Smith	235
Collin	0	Karnes	0	Somervell	697
Collingsworth	0	Kaufman	2,258	Starr	209

County	Mining Water Use (AF)	County	Mining Water Use (AF)	County	Mining Water Use (AF)
Colorado	1,972	Kendall	0	Stephens	1,786
Comal	3,740	Kenedy	27	Sterling	67
Comanche	1	Kent	297	Stonewall	238
Concho	27	Kerr	59	Sutton	1
Cooke	1,081	Kimble	1	Swisher	0
Coryell	275	King	121	Tarrant	6,450
Cottle	2	Kinney	0	Taylor	25
Crane	403	Kleberg	280	Terrell	12
Crockett	113	Knox	1	Terry	99
Crosby	20	Lamar	0	Throckmorton	69
Culberson	64	Lamb	13	Titus	622
Dallam	0	Lampasas	305	Tom Green	32
Dallas	1,690	La Salle	27	Travis	868
Dawson	250	Lavaca	18	Trinity	0
Deaf Smith	0	Lee	2,089	Tyler	0
Delta	0	Leon	740	Upshur	43
Denton	4,013	Liberty	248	Upton	1,313
DeWitt	13	Limestone	2,469	Uvalde	55
Dickens	9	Lipscomb	145	Val Verde	33
Dimmit	49	Live Oak	3	Van Zandt	492
Donley	0	Llano	0	Victoria	0
Duval	904	Loving	68	Walker	454
Eastland	277	Lubbock	774	Waller	0
Ector	509	Lynn	51	Ward	87
Edwards	2	McCulloch	4,220	Washington	18
Ellis	2,994	McLennan	1,025	Webb	349
El Paso	621	McMullen	44	Wharton	6
Erath	295	Madison	0	Wheeler	1,074
Falls	0	Marion	30	Wichita	20
Fannin	6	Martin	569	Wilbarger	3
Fayette	82	Mason	560	Willacy	5
Fisher	153	Matagorda	8	Williamson	2,273
Floyd	169	Maverick	75	Wilson	1
Foard	1	Medina	350	Winkler	30
Fort Bend	4	Menard	2	Wise	3,938
Franklin	2	Midland	700	Wood	6
Freestone	3,631	Milam	0	Yoakum	863
Frio	4	Mills	0	Young	38
Gaines	3,033	Mitchell	75	Zapata	107
Galveston	282	Montague	691	Zavala	0
Garza	196	Montgomery	788	**SUM**	**129,662***

*: oil and gas drilling not included

MiningWaterUse2010-2060_2.xls

Table 69. County-level summary of 2010-2020 projections for mining water use (oil and gas drilling not included)

County	2010	2020	2030	2040	2050	2060
Anderson	8	26	84	67	42	16
Andrews	678	1,014	743	377	152	47
Angelina	0	426	534	367	200	33
Aransas	9	17	22	16	11	5
Archer	3	1,619	1,293	370	0	0
Armstrong	0	0	0	0	0	0
Atascosa	851	2,998	4,368	3,672	3,055	2,497
Austin	0	48	256	279	221	163
Bailey	0	0	0	0	0	0
Bandera	0	0	0	0	0	0
Bastrop	2,164	2,613	5,662	5,725	5,810	5,887
Baylor	0	0	0	0	0	0
Bee	23	47	58	43	29	14
Bell	1,218	1,562	1,901	2,170	2,481	2,821
Bexar	4,574	5,284	5,836	6,271	6,736	7,304
Blanco	0	0	0	0	0	0
Borden	109	395	318	165	58	0
Bosque	937	2,576	1,096	33	37	40
Bowie	0	0	0	0	0	0
Brazoria	716	941	1,157	1,359	1,578	1,812
Brazos	276	865	1,534	1,418	1,187	1,024
Brewster	0	0	0	0	0	0
Briscoe	0	0	0	0	0	0
Brooks	305	329	342	326	310	294
Brown	5	1	1	1	1	1
Burleson	0	594	1,295	1,055	816	576
Burnet	341	437	528	619	704	804
Caldwell	0	0	0	0	0	0
Calhoun	17	33	42	31	21	10
Callahan	158	146	145	139	135	131
Cameron	25	50	62	46	30	14
Camp	3	1	1	0	0	0
Carson	0	0	0	0	0	0
Cass	0	52	66	46	25	4
Castro	0	0	0	0	0	0
Chambers	0	0	0	0	0	0
Cherokee	23	254	288	188	89	0
Childress	0	0	0	0	0	0
Clay	635	3,731	1,664	0	0	0
Cochran	5	2	1	1	1	1
Coke	114	38	26	23	21	20
Coleman	21	6	4	3	3	3
Collin	0	0	0	0	0	0
Collingsworth	0	0	0	0	0	0

County	2010	2020	2030	2040	2050	2060
Colorado	2,304	3,728	4,851	4,490	4,087	3,744
Comal	4,033	4,928	5,725	6,438	7,044	7,855
Comanche	429	2,524	1,125	0	0	0
Concho	108	33	21	18	15	13
Cooke	1,016	1,457	1,516	1,643	1,966	2,267
Coryell	296	2,147	1,537	692	463	505
Cottle	7	2	1	1	1	1
Crane	144	297	225	99	43	31
Crockett	58	121	71	21	1	1
Crosby	228	69	43	37	32	28
Culberson	33	1,334	4,126	3,236	2,533	1,830
Dallam	0	0	0	0	0	0
Dallas	2,549	2,731	2,227	1,940	1,930	1,922
Dawson	147	404	324	170	63	5
Deaf Smith	0	0	0	0	0	0
Delta	0	0	0	0	0	0
Denton	3,188	2,693	2,678	3,332	4,293	5,191
DeWitt	24	1,114	1,740	1,402	1,063	725
Dickens	0	0	0	0	0	0
Dimmit	218	2,625	3,790	2,999	2,275	1,551
Donley	0	0	0	0	0	0
Duval	1,052	1,170	1,243	1,177	1,085	1,020
Eastland	231	1,317	1,348	608	223	234
Ector	499	762	630	413	290	243
Edwards	0	0	0	0	0	0
Ellis	3,440	3,799	4,276	5,047	6,004	6,827
El Paso	737	953	1,131	1,317	1,523	1,754
Erath	2,017	2,500	882	0	0	0
Falls	0	0	0	0	0	0
Fannin	7	11	16	23	27	33
Fayette	98	965	1,982	1,680	1,398	1,104
Fisher	94	32	21	19	17	15
Floyd	213	200	201	207	212	217
Foard	1	0	0	0	0	0
Fort Bend	23	47	58	44	29	14
Franklin	1	0	0	0	0	0
Freestone	3,766	4,862	4,268	3,984	3,493	3,026
Frio	0	180	744	717	566	414
Gaines	584	1,060	933	676	498	400
Galveston	339	375	402	444	480	514
Garza	77	155	91	27	2	1
Gillespie	3	4	4	4	4	4
Glasscock	492	1,414	1,230	740	364	131
Goliad	22	45	56	42	27	13
Gonzales	0	79	420	458	363	267
Gray	14	4	3	2	2	2
Grayson	50	62	73	89	107	125

County	2010	2020	2030	2040	2050	2060
Gregg	132	422	573	398	222	51
Grimes	0	59	314	342	271	200
Guadalupe	294	446	540	629	745	873
Hale	271	82	51	45	39	33
Hall	0	0	0	0	0	0
Hamilton	190	1,118	498	0	0	0
Hansford	75	675	62	0	0	0
Hardeman	7	8	8	8	8	8
Hardin	0	0	0	0	0	0
Harris	3,668	3,784	3,763	3,705	3,670	3,643
Harrison	7,044	9,418	8,624	7,850	7,076	6,380
Hartley	2	0	0	0	0	0
Haskell	19	6	4	3	3	2
Hays	0	0	0	0	0	0
Hemphill	694	364	33	0	0	0
Henderson	138	440	562	529	518	498
Hidalgo	948	1,372	1,858	2,292	2,738	3,251
Hill	1,008	1,249	441	0	0	0
Hockley	1	0	0	0	0	0
Hood	2,150	1,775	937	544	436	353
Hopkins	929	903	902	901	901	901
Houston	0	0	0	0	0	0
Howard	321	1,293	1,111	618	238	2
Hudspeth	0	0	0	0	0	0
Hunt	70	128	118	88	71	58
Hutchinson	174	240	206	213	221	233
Irion	366	1,176	1,097	674	295	21
Jack	2,091	2,008	857	363	405	450
Jackson	22	45	56	42	28	13
Jasper	0	0	0	0	0	0
Jeff Davis	0	0	0	0	0	0
Jefferson	157	180	202	230	280	315
Jim Hogg	30	60	75	56	37	17
Jim Wells	23	45	57	42	28	13
Johnson	6,774	5,565	4,969	5,633	6,682	7,598
Jones	37	20	18	17	17	16
Karnes	20	1,153	1,399	1,117	834	551
Kaufman	2,452	2,788	3,289	3,998	4,908	5,648
Kendall	0	0	0	0	0	0
Kenedy	38	76	95	71	46	22
Kent	6	2	1	1	1	1
Kerr	71	76	80	100	102	111
Kimble	1	2	2	2	2	2
King	1,818	553	345	299	258	223
Kinney	0	0	0	0	0	0
Kleberg	305	329	342	326	310	294
Knox	1	0	0	0	0	0

County	2010	2020	2030	2040	2050	2060
Lamar	0	0	0	0	0	0
Lamb	136	41	26	22	19	17
Lampasas	329	391	437	470	506	551
La Salle	280	2,989	4,300	3,398	2,570	1,742
Lavaca	25	621	1,839	1,638	1,276	914
Lee	2,089	2,547	5,749	5,772	5,715	5,659
Leon	678	1,680	2,701	2,431	1,732	1,034
Liberty	269	420	441	430	452	480
Limestone	2,500	7,333	6,258	5,630	5,242	4,928
Lipscomb	126	508	47	0	0	0
Live Oak	28	229	784	741	577	414
Llano	0	0	0	0	0	0
Loving	174	251	148	50	11	9
Lubbock	1,805	952	849	891	931	967
Lynn	273	214	128	59	29	25
McCulloch	4,219	7,690	7,073	5,324	4,274	3,460
McLennan	1,230	2,825	2,413	1,930	2,228	2,509
McMullen	30	2,154	3,383	2,682	2,038	1,395
Madison	0	278	865	775	607	438
Marion	24	665	728	494	259	33
Martin	588	1,279	1,103	622	247	10
Mason	560	1,023	941	708	568	460
Matagorda	31	61	77	57	37	18
Maverick	57	954	2,837	2,395	1,893	1,395
Medina	384	457	514	563	610	671
Menard	250	76	47	41	35	31
Midland	537	1,260	1,090	612	239	4
Milam	0	0	0	0	0	0
Mills	0	0	0	0	0	0
Mitchell	69	153	90	26	0	0
Montague	666	3,317	1,579	197	222	250
Montgomery	793	1,438	1,348	1,062	906	792
Moore	1	0	0	0	0	0
Morris	0	0	0	0	0	0
Motley	27	8	5	5	4	3
Nacogdoches	436	4,384	3,426	2,298	1,170	52
Navarro	77	97	124	156	198	236
Newton	140	256	235	177	142	115
Nolan	85	56	51	49	47	45
Nueces	556	699	837	934	1,009	1,118
Ochiltree	77	673	62	1	1	0
Oldham	182	207	246	277	289	315
Orange	233	304	309	308	309	314
Palo Pinto	464	2,632	1,174	3	3	2
Panola	2,095	3,700	3,507	2,815	2,123	1,500
Parker	4,489	2,398	840	821	952	1,098
Parmer	0	0	0	0	0	0

County	2010	2020	2030	2040	2050	2060
Pecos	102	769	2,132	1,648	1,280	926
Polk	0	0	0	0	0	0
Potter	576	692	859	1,016	1,108	1,254
Presidio	0	0	0	0	0	0
Rains	0	0	0	0	0	0
Randall	0	0	0	0	0	0
Reagan	679	1,640	1,420	796	310	3
Real	0	0	0	0	0	0
Red River	1	0	0	0	0	0
Reeves	431	1,815	3,330	2,362	1,742	1,270
Refugio	21	42	53	39	26	12
Roberts	183	447	41	0	0	0
Robertson	7,763	8,859	9,552	10,267	11,079	12,009
Rockwall	0	0	0	0	0	0
Runnels	60	18	11	10	9	7
Rusk	1,328	4,075	3,868	3,130	2,391	1,669
Sabine	268	2,327	1,816	1,244	674	102
San Augustine	435	3,044	2,152	1,431	711	31
San Jacinto	0	0	0	0	0	0
San Patricio	451	542	616	651	676	723
San Saba	280	511	470	354	284	230
Schleicher	52	137	127	78	35	4
Scurry	67	154	90	25	0	0
Shackelford	46	1,135	1,160	391	6	6
Shelby	616	4,540	3,335	2,225	1,114	62
Sherman	9	61	6	0	0	0
Smith	201	386	433	425	437	443
Somervell	1,373	1,251	945	813	810	830
Starr	202	292	376	416	456	510
Stephens	1,086	2,184	1,384	450	154	133
Sterling	119	406	328	170	61	1
Stonewall	154	61	46	42	38	34
Sutton	106	241	141	40	0	0
Swisher	0	0	0	0	0	0
Tarrant	4,669	2,799	1,665	1,577	1,525	1,484
Taylor	15	5	3	2	2	2
Terrell	149	132	78	34	15	13
Terry	84	156	91	28	3	2
Throckmorton	42	13	8	7	6	5
Titus	621	1,001	1,000	1,000	1,000	1,000
Tom Green	11	3	2	2	2	1
Travis	1,022	1,070	1,115	1,159	1,200	1,247
Trinity	0	0	0	0	0	0
Tyler	0	0	0	0	0	0
Upshur	7	605	988	694	400	105
Upton	744	1,776	1,522	842	321	0
Uvalde	59	72	78	81	86	93

County	2010	2020	2030	2040	2050	2060
Val Verde	59	96	83	68	65	72
Van Zandt	483	475	473	473	473	472
Victoria	23	46	58	43	28	14
Walker	488	660	842	1,086	1,337	1,572
Waller	0	0	0	0	0	0
Ward	145	347	323	179	112	90
Washington	22	391	1,166	1,051	831	612
Webb	475	1,934	2,296	1,995	1,705	1,425
Wharton	29	57	72	53	35	17
Wheeler	699	367	35	1	1	1
Wichita	12	4	2	2	2	2
Wilbarger	2	0	0	0	0	0
Willacy	16	31	39	29	19	9
Williamson	2,444	3,152	3,796	4,412	5,046	5,750
Wilson	0	474	1,473	1,320	1,033	746
Winkler	151	334	270	125	60	44
Wise	6,094	4,315	3,133	3,358	3,982	4,583
Wood	4	1	1	1	1	0
Yoakum	278	202	120	59	31	27
Young	40	604	621	238	49	52
Zapata	27	55	68	51	33	16
Zavala	0	550	1,712	1,494	1,169	845
SUM	**136,639***	**224,749***	**229,263***	**196,538***	**181,116***	**170,893***

*: oil and gas drilling not included

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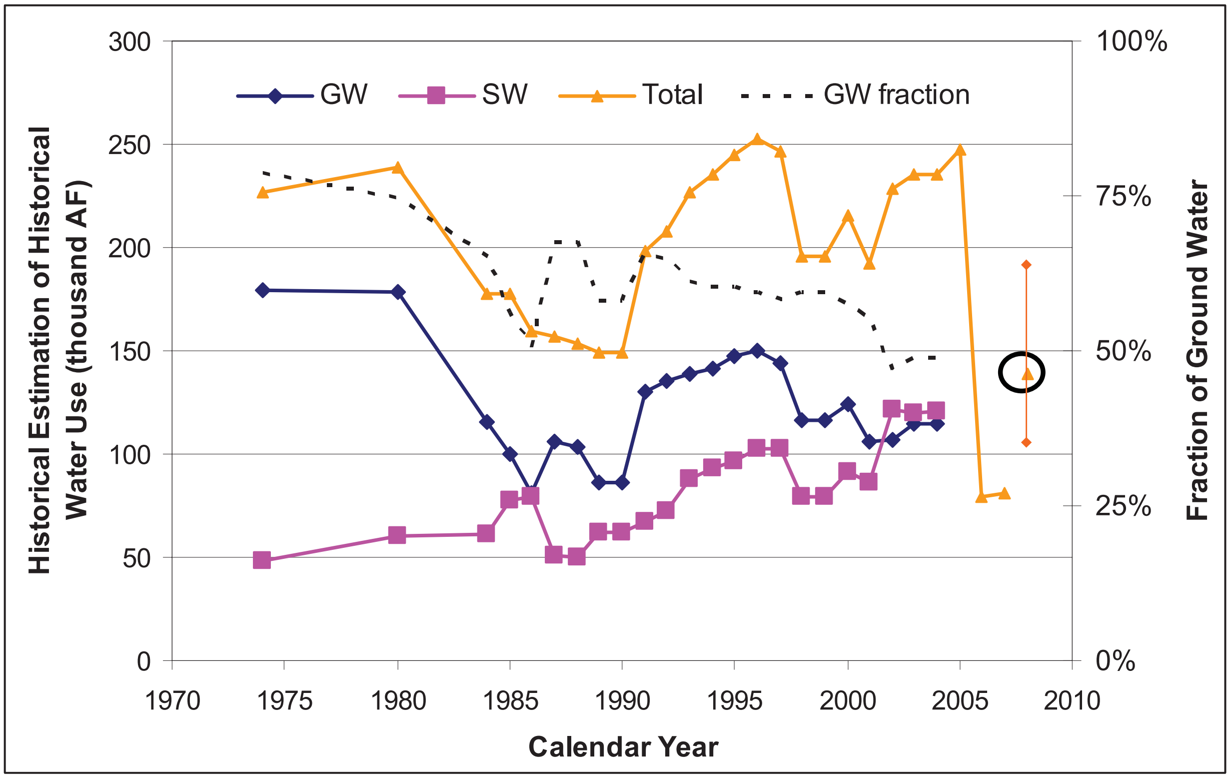
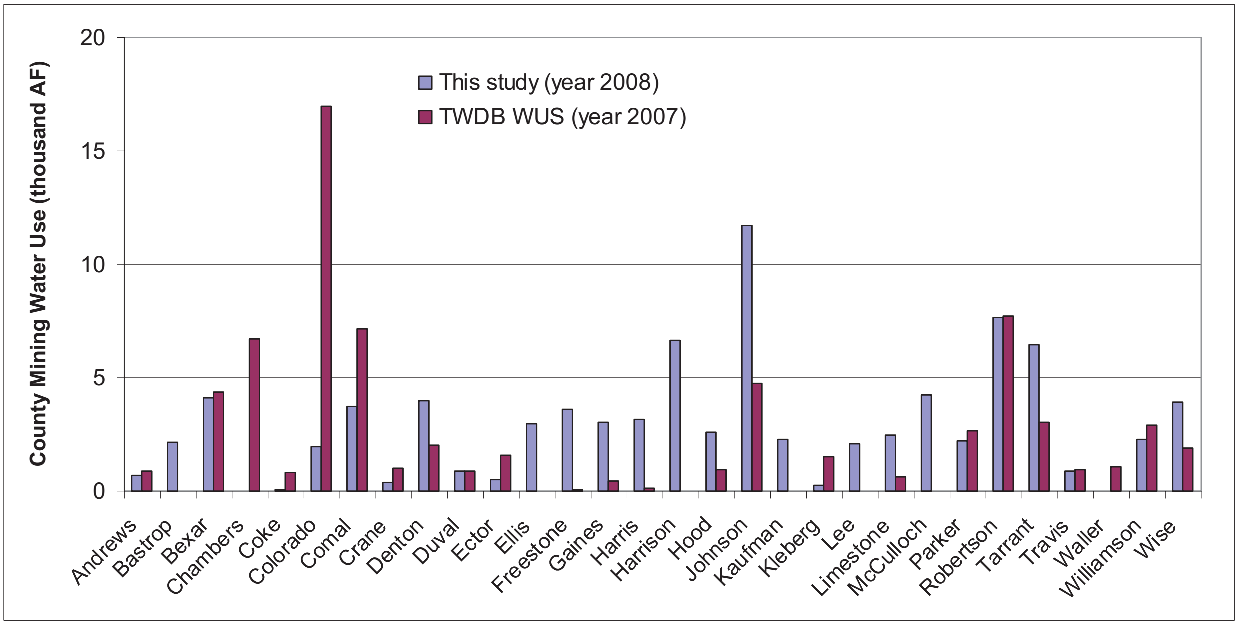


Source: TWDB website rptWaterUseSummaryByState_TWDB-WUS_1974-2004_+to 2007_JP.xls

Figure 134. Historical estimation of historical mining-water use
Most likely year 2008 water use is highlighted by the large circle. Also shown is the range of uncertainty.



MiningWaterUse2008_2.xls

Figure 135. Comparison of high mining water use

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9 Appendix A: Relevant Websites

All categories
USGS mineral production: http://minerals.usgs.gov/minerals/
USGS water use: http://water.usgs.gov/watuse/
USGS e-library: http://pubs.er.usgs.gov/
U.S. Census Bureau: http://www.census.gov/econ/www/mi0100.html;
http://www.census.gov/mcd/
TWDB water use survey (WUS): http://www.twdb.state.tx.us/wrpi/wus/wus.htm
MSHA mine database (including abandoned mines): http://www.msha.gov/drs/drshome.htm
http://www.msha.gov/drs/asp/extendedsearch/statebycommodityoutput2.asp
EIA: http://www.eia.doe.gov/
BEG publications: http://www.beg.utexas.edu/publist.php

Aggregates:
Trade journals:
Aggregate Manager: http://www.aggman.com/
Pit & Quarry: http://www.pitandquarry.com/
Rock Products: http://rockproducts.com/
Mining Engineering: http://www.smenet.org/
Trade Associations:
National Stone, Sand, and Gravel Association (NSSGA): http://www.nssga.org/
TMRA: http://www.tmra.com/
TACA: http://www.tx-taca.org/

Oil and Gas:
Operators
Chesapeake: http://www.chesapeake.com/Pages/default.aspx
http://www.chk.com/Pages/default.aspx
Devon Energy: http://www.devonenergy.com
Barnett Shale Water Conservation & Management Committee:
http://www.barnettshalewater.org/
Trade Associations:
TXOGA: http://www.txoga.org/
Regulators:
RRC H10 query: http://webapps.rrc.state.tx.us/H10/h10PublicMain.do
Permit application: http://www.rrc.state.tx.us/forms/publications/HTML/index.php
All RRC forms: http://www.rrc.state.tx.us/forms/forms/og/purpose.php
Fresh-water questionnaire: http://www.rrc.state.tx.us/forms/publications/HTML/fw-ques.php
UIC query: http://webapps2.rrc.state.tx.us/EWA/uicQueryAction.do
RRC Barnett Sh.: http://www.rrc.state.tx.us/barnettshale/index.php
RRC Haynesville Sh.: http://www.rrc.state.tx.us/bossierplay/index.php
RRC Eagle Ford Sh.: http://www.rrc.state.tx.us/eagleford/index.php
USGS NOGA:
1995 assessment: http://energy.cr.usgs.gov/oilgas/noga/1995.html
Gulf Coast: http://energy.er.usgs.gov/regional_studies/gulf_coast/gulf_coast_assessment.html

Coal
CBM in Gulf Coast: http://energy.cr.usgs.gov/oilgas/cbmethane/pubs_data_gulf.html
RRC maps of coal resources: http://www.rrc.state.tx.us/forms/maps/historical/historicalcoal.php

RRC table of coal production: http://www.rrc.state.tx.us/data/production/index.php

Energy
Future of power generation in Tx: http://www.twdb.state.tx.us/RWPG/rpfgm_rpts.asp
Coal and uranium: http://www.rrc.state.tx.us/industry/smrd.php

Other useful sites:
Information about drilling rig count: http://www.rigdata.com/index.aspx;
http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm
IHS Energy: http://energy.ihs.com/
Drilling info: http://www.info.drillinginfo.com/
Aggregate industry: http://www.pitandquarry.com/pit-quarry-content/quarryology-101
IMPLAN by MIG, Inc.: http://implan.com/V4/Index.php

10 Appendix B: Postaudit of the 2007 BEG Barnett Shale Water-Use Projections

In the 2007 TWDB update of the Northern Trinity GAM (Bené et al., 2007), BEG (Nicot and Potter, 2007, summarized in Nicot, 2009a) proposed a methodology for estimating future water use related to Barnett Shale activities for 2 decades through 2025. The purpose of this appendix is to compare water-use projections with actual water use for the 2007–2009 (report used data through mid- to late 2006). At the October 2009 GSA meeting in New Orleans, Nicot and Ritter (2009) presented an initial postaudit, which is completed here.

2007 Report Methodology

The following steps are a summary of the methodology applied in the 2007 report:

Step 1: Derive the geographic extent in which frac jobs are likely to take place by integrating gas window, formation thickness, and well economics, defining high, low, and medium cases (somewhat subjectively).

Step 2: Use historical data to define average water use per well or per linear of lateral (Figure 136). Vertical well water use is nicely distributed along a normal distribution around a mean of 1.2 Mgal/well. Because defective database entries yielded unnatural water use at both low and high ends, averages used in the analysis are computed using data only between the 10th and 90th percentiles. The raw average and average of the values between the 10th and 90th percentiles for vertical wells is 1.25 and 1.19 Mgal, respectively. The raw average for horizontal wells (2005–2006) is 3.07 Mgal/well, whereas the truncated average is 2.65 Mgal/well. The relatively more abundant frac jobs with low water use (Figure 136a), generating a dissymmetric histogram result from the addition of acid jobs and other common well-development and completion practices outside of strictly defined frac jobs. In contrast to vertical wells that have a relatively narrow range of lengths/depths, horizontal wells have laterals of very variable length (although the vertical sections, as for the vertical wells, belong to a relatively narrow range) that translates into a more uniform distribution (Figure 136b). Only those frac jobs performed in 2005 and 2006 were included in the histogram of Figure 136b to avoid bias due to early trials of the slick-water frac technology. Using water-use intensity (volume of water per linear of lateral) instead of absolute water use per well yields a better-defined histogram (Figure 136c). The averages of values truncated beyond two complementary percentiles vary somewhat because of the additional uncertainty due to the lateral length, although a value of 2,400 gal/ft seems conservatively reasonable for the medium scenario. Values of 2,000 and 2,800 gal/ft were retained for low and high scenarios, respectively, for the 2007 report.

Step 3: Define a maximum water use at the county level by assuming that the county is drilled up and apply an average water use per vertical well or per linear of lateral. This step assumes a vertical well spacing of at least 40 acres (see Table 70 for details) and a constant distance between horizontal well laterals. All horizontal wells were assumed to be parallel to each other and to the main fault direction (under the assumption made at the time that operators would not want to drill through a large fault because of the risk of watering out the well). This assumption results in an extremely large water volume (Figure 137) that needs to be corrected and distributed through time.

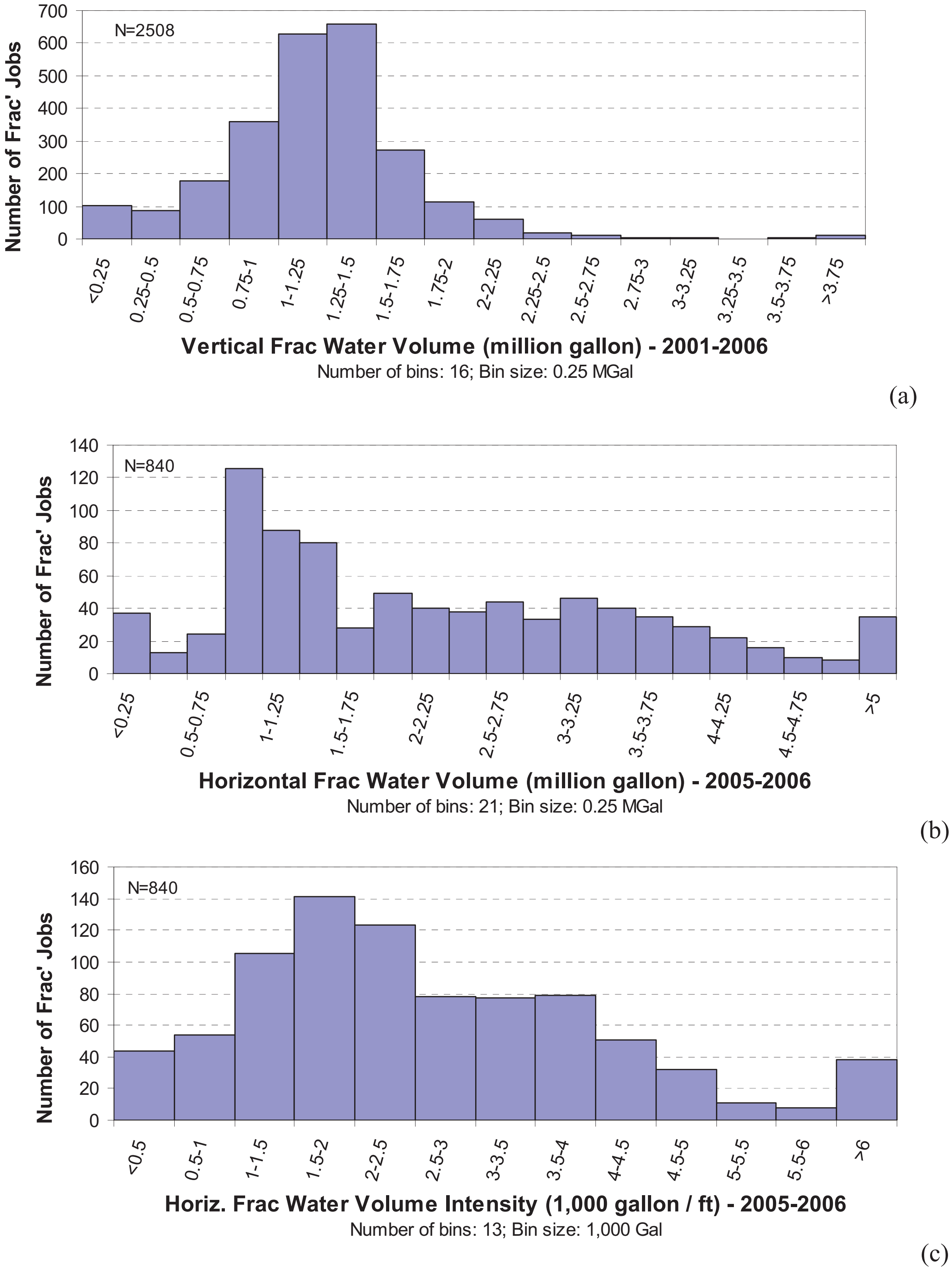
Step 4: Apply time-independent correction factors: karst, operations, prospectivity. The sag avoidance (“karst”) correction factor was assumed to take into account some reluctance from the operators to drill through disrupted Barnett Shale strata that was due to karstic features in the underlying Ellenburger Formation. Early on, in the vertical well phase, drilling to and connection to the Ellenburger Formation was detrimental to operators because of excessive water production. The Ellenberger is a well-known regional (saline water) aquifer. It was thought at the time that operators would avoid karstic feature-rich areas because they were avoiding well-known faults. It turned out to be less of a concern than thought. Prospectivity represents the overall maturity of the shale and its likelihood to contain large economic resources in a given county or fraction of county. Prospectivity/risk factor can be understood either as a fraction of the area that will be developed or, more accurately, as the mean of the probability distribution describing the likelihood of having the county polygon developed (already given the high, medium, or low scenario condition). This factor is used simply as a multiplier of hypothetical maximum water use. The 2007 report used a prospectivity factor of 1 for core-area counties but one of 0.7 and 0.5 in Montague and Clay Counties, respectively. These oil-prone counties turned out to be more interesting than initially thought. The oil potential was thought to be not very prospective and, in fact, a hindrance to gas production.

Step 5: Add correction factors associated with time-dependent constraints. Growth of recycling techniques was assumed to reach a maximum of 20% of total water use in 2025. Recompletion/restimulation frequency remains unclear. The 2007 report assumes no recompletion for horizontal wells and that a large fraction of the vertical wells would be recompleted. The last and most controlling factor is the availability of drilling rigs. There are a limited number of active drilling rigs around the country, and their number at a given play is a complex function of play activity, oil/gas price, economic climate, relative location of other plays, etc. Galusky (2007) reported ~57 and ~93 active rigs in the Barnett Shale play in 2005 and 2006, respectively, resulting in 12 to 13 wells being drilled per year per rig, on average. The 2007 report assumes that there would be no more than 3,000 recompletions a year, starting in 2010 and ~2,400 in 2008, both in the “high” scenario case (Figure 138). This number turned out to be an underestimation in 2008. The actual number climbed to 2,500+ horizontal wells in 2008.

Step 6: Apply activity weighting curve to each county. This factor takes into account the life cycle of hydrocarbon production: initial production, relatively quick increase to peak production, peak sustained for a relatively short interval, relatively quick production, followed by a slow decrease. The 2007 report based the activity curve on that of Wise County that was on its past-peak decreasing limb in 2006 and applied it to all other counties or fractions of counties. Start date of each county activity was a function of geographic proximity to the core area and prospectivity.

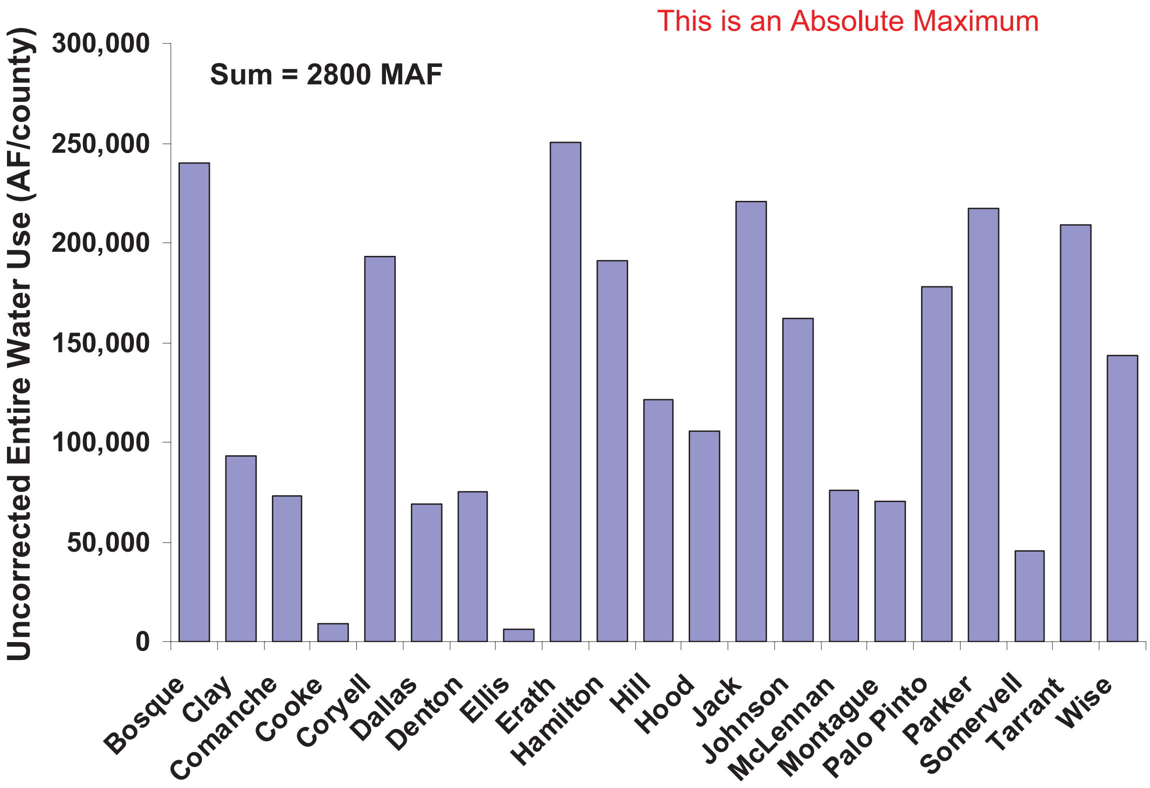
Step 7: Apply GW/SW split. The 2007 report assumes increased reliance on groundwater. Groundwater use would reach 60% to 100% of total water use in 2025.

Resulting final output of the 2007 report is presented in Figure 139. The high scenario yields a total groundwater use of 417,000 AF, an annual average groundwater use of 22,000 AF over the 2007–2025 period, and a cumulative areal groundwater use of 0.05 AF/acre. The medium and low scenarios utilize a total 183,000 and 29,000 AF of groundwater for an annual average of ~10,000 and 1,500 AF and a cumulative areal groundwater use of ~0.04 and 0.009 AF/acre, respectively. A survey completed in the same period (Galusky, 2007) showed that projections were accurate in the short term and were bounded by the high and medium scenarios. The next section analyzes medium-term projections to the 2010 horizon and compares them to actual figures.



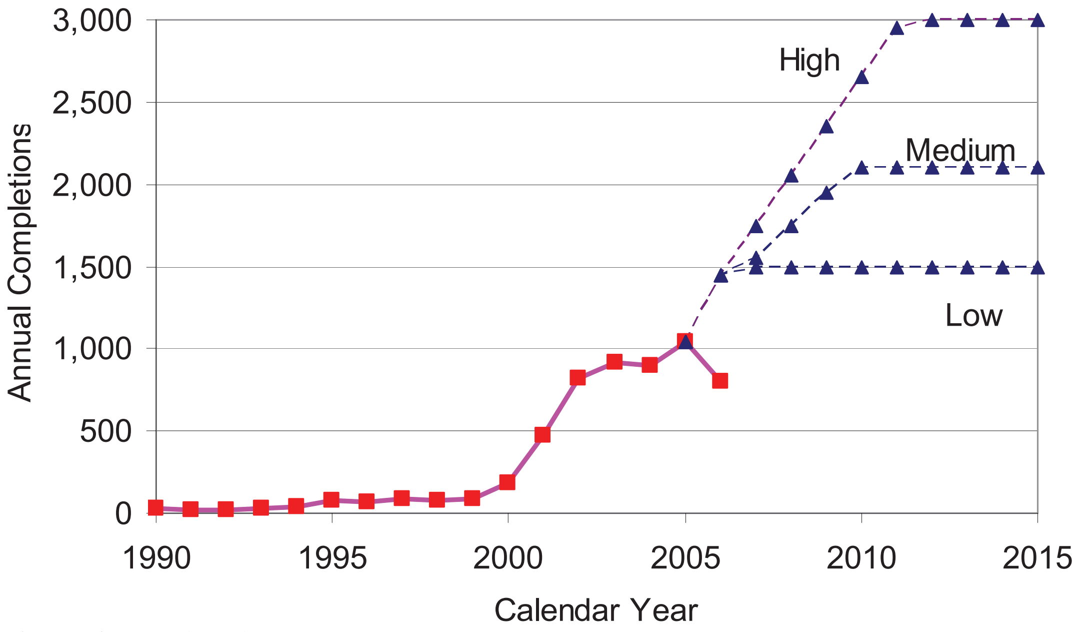
Source: Nicot and Potter (2007)

Figure 136. Distribution of water use for vertical wells (a), horizontal wells (b), and per linear of lateral of horizontal wells (c).



Source: Nicot and Potter (2007)

Figure 137. Uncorrected entire water use



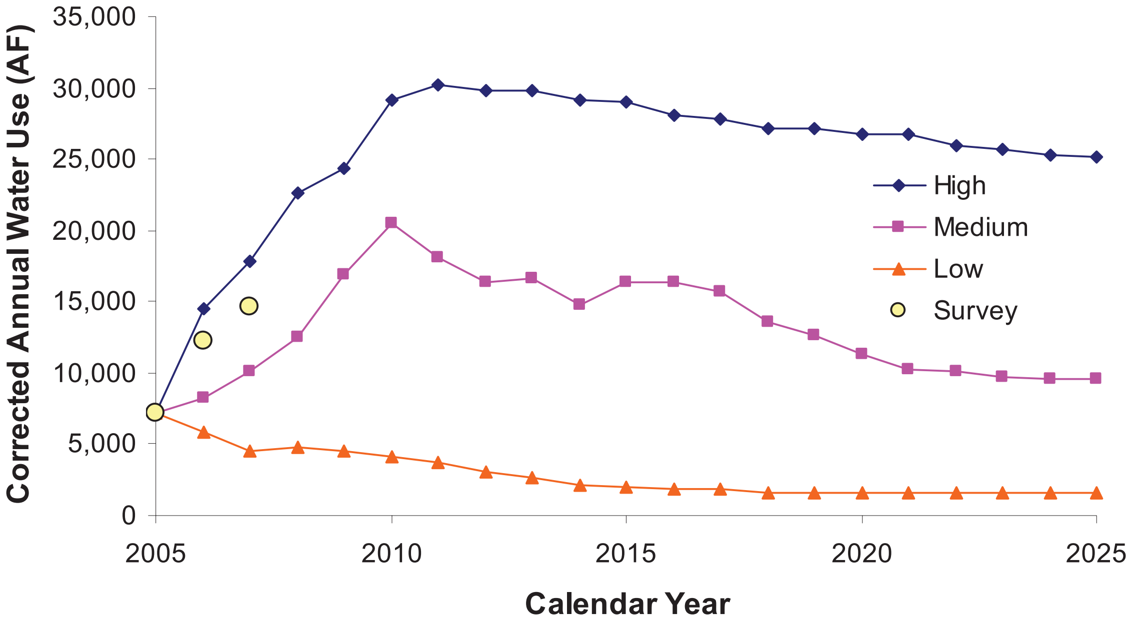
Source: Nicot and Potter (2007)

Figure 138. Projected annual completions

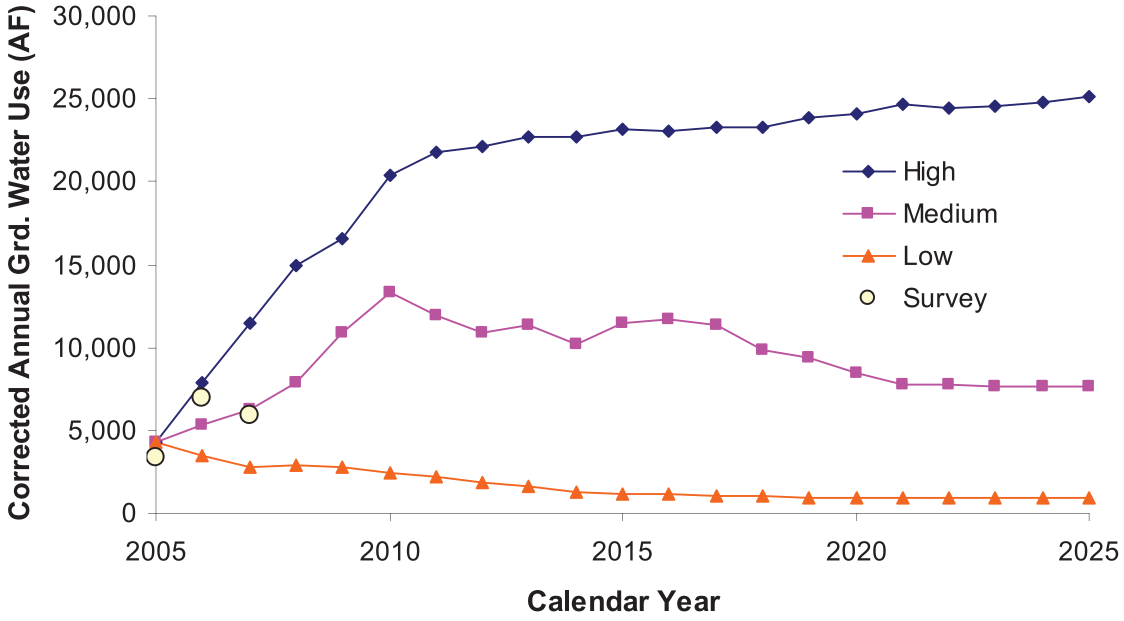
Table 70. Summary description of parameters used in 2007 report water-use projections

Category	Comment	High Water Use	Medium Water Use	Low Water Use
County Polygon	There are three binary variable couples: rural/urban—horizontal/vertical wells—within Viola footprint or not, resulting in four main categories: (1) Viola/urban (only horizontal wells), (2) Viola/rural (both horizontal and vertical wells), (3) no Viola/urban (only horizontal wells), and (4) no Viola/rural (only horizontal wells)			
Footprint Fraction	A county polygon cannot be covered by >90% (vertical wells) or 80% (horizontal wells) of the maximum possible well coverage.			
Vertical Well Spacing		1 well/40 acres	0.5 well/40 acres	0.25 well/40 acres
Horizontal Well Lateral Spacing	No Viola and/or urban	800 ft	1,000 ft	2,000 feet
	Viola rural	800 × 4 ft	1,000 × 4 ft	2,000 × 4 ft
Sag Feature Avoidance (“Karst”)	Vertical well	100%		
	Horizontal well	100%	75%	40%
Average Water Use	Vertical well	1.2 million gal		
	Horizontal well (spread reflects uncertainty)	2,800 gal/ft	2,400 gal/ft	2,000 gal/ft
Water-Use Progress Factor^A	(variations reflect technological progress)	1%	0%	0%
		Water-use annual incremental improvement as a fraction of total water use, e.g., 100% of current use in 2005 with a 1% increment translates into 80% of water use in 2025 compared with the same frac job executed in 2005		
Recompletion	Vertical well	100%	50%	0%
		of initial completions executed 5 years before		
	Horizontal well	0%	0%	0%
Recycling^A		1%	0.33%	0%
		Recycling annual increment as a fraction of total water use (e.g., 0% in 2005 with a 1% increment translates into 20% recycling in 2025)		
Maximum Number of Sustained Annual Completions		3,000 completions/year	2,100 completions/year	1,500 completions/year
Additional Water Use in Overlying Formations		0%	0%	0%
Barnett Groundwater Use Expressed as % of Total Barnett Water Use	In year 2005–2006	60%	60%	60%
	Annual increment in following years	2%	1%	0%
	In year 2025	100%	80%	60%

Note: ^{A} These parameters do not maximize water use, but the likely competition for water in the high scenario suggests that recycling and water-use intensity will get better through time.
Source: Nicot and Potter (2007)



(a)



(b)

Source: Nicot and Potter (2007) and Nicot (2009a); survey data points by Galusky (2007)
Note: The data points used in a previous version of the same plot (Nicot, 2009a) are slightly lower because Galusky (2007) included drilling-water use. Nicot (2009a) was estimated at 20% of total water use whereas in this document, it is estimated at only 10%. "Survey" point for year 2007 in Galusky (2007) is also a projection but directed by data from the first few months of the year.

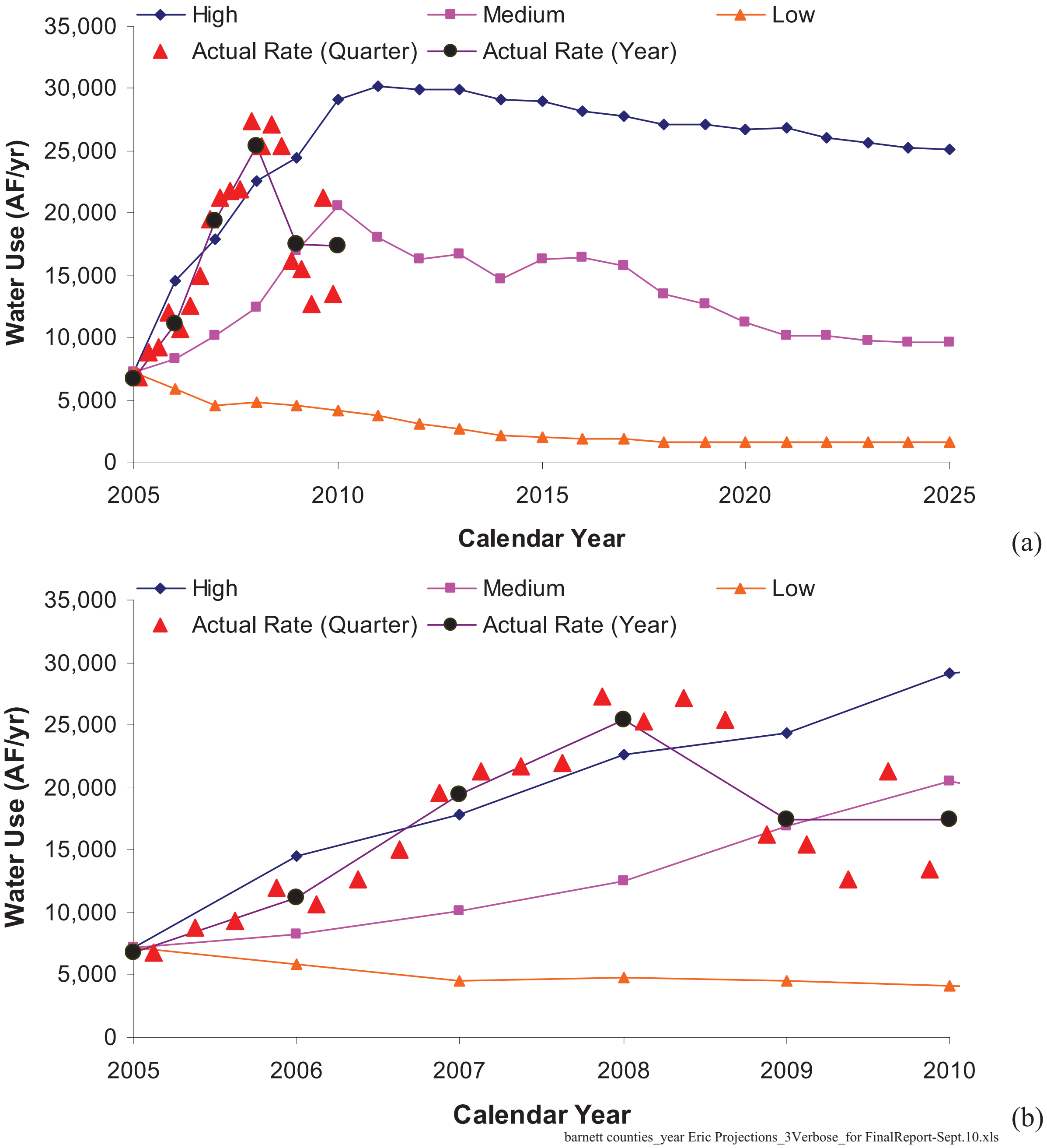
Figure 139. 2007 report projected frac total water use (a) and projected frac groundwater use (b)

Postaudit:

The recent downturn in gas prices has showed us that we cannot expect a linear development of the play but that it will go through periods of intense activity followed by calmer phases. I Because predicting these cycles is impossible in the long term, we only need to recognize that they exist and understand that actual water use will fluctuate around some projected average. Nicot and Potter (2007) suggested that peak water use (but not necessarily peak gas production) would occur around 2011 (Figure 140a, early years magnified in Figure 140b) after a quick ramp-up, followed by a slow decline. Superimposed on the projections are actual water-use figures as extracted from the IHS database in the summer of 2010. Initial growth overshot projections of the high scenario before crashing down below projected values of the medium scenario in 2009 because of the economic downturn. The figure depicts both quarterly water use (expressed in AF/yr) and annual values. Cumulative water use falls between high and medium scenarios (Figure 141).

If the match between actual and projected numbers is good at the aggregate level, it is somewhat less so at the county level. Water use from four of the counties with significant figures (Denton, Johnson, Tarrant, and Wise) are plotted in Figure 142. Individual county matches are acceptable, but trends are better preserved by aggregating the four counties. A cross-plot comparison at the county level (Figure 143) also suggests that the general trend was well captured regionally but that deviations exist at the county level. Comparison of actual data is made against the high scenario in Figure 143a (linear scale) and Figure 143b (log scale). The high scenario was constructed as bounding—that is, most of the points should be below the unit slope line. Neglecting the 2009 points, they are for the most part. The 2009 points are located above the line (projected > actual) because of the economic downturn.

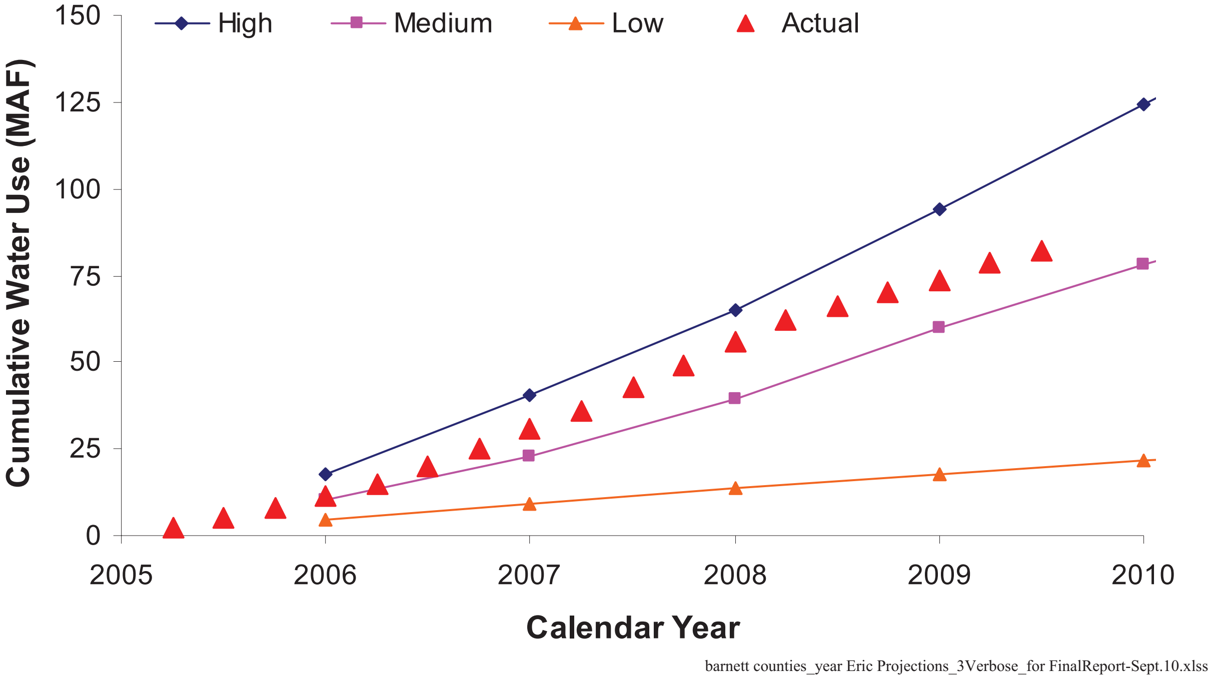
Several important conclusions can be drawn from this exercise: (1) it is possible to make sensible projections, at least at a 5-year horizon; (2) projections deviate from actual values as the size of the area of interest decreases— county-level projections seem to be noisy and more uncertain than projections made for larger geographic areas; (3) county-level projections can be off by a factor of 2 or more, even if projections are acceptable at the aggregate level.



barnett counties_year Eric Projections_3Verbose_for FinalReport-Sept.10.xls

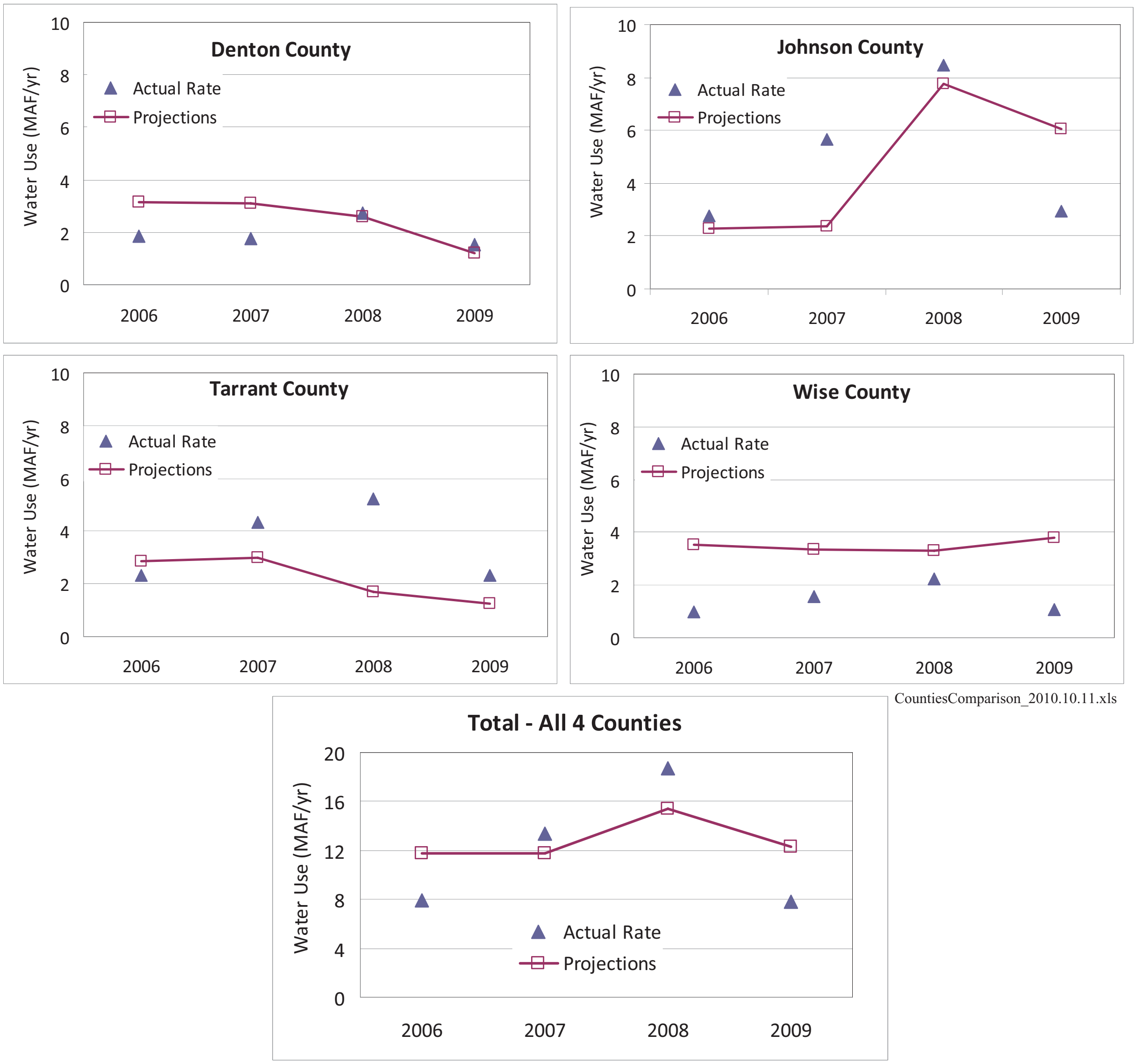
Source: Projections from Nicot and Potter (2007); actual water use from IHS database
Note: Tick for calendar year corresponds to the middle of the year (06/30); water use for each quarter (expressed in AF/yr) of a given year is on both sides of the calendar-year tick; 2010 yearly water use assumed that overall water use for the year will stay as in the first 2 quarters.

Figure 140. Comparison of water-use projections and actual figures in the Barnett Shale (2005–2010)



Source: Projections from Nicot and Potter (2007); actual water use from IHS database
Note: Tick for calendar year represents the end of the year (12/31); origin of both projection and actual water use is set on 01/01/2006; MAF = thousand AF

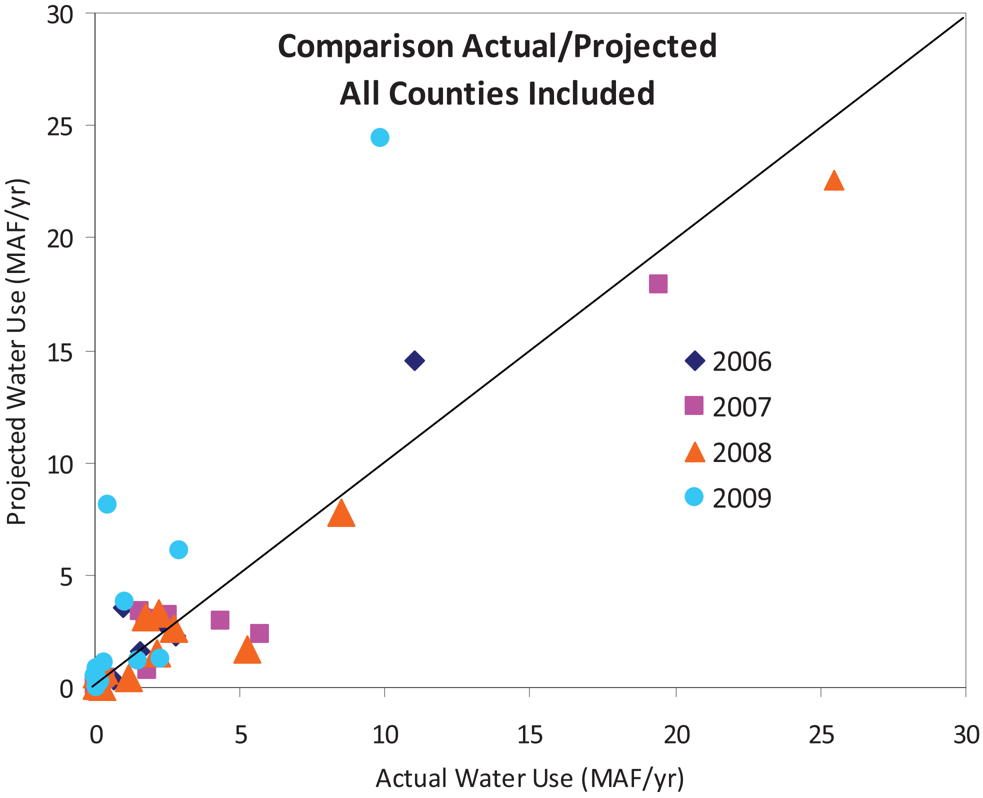
Figure 141. Comparison of cumulative water-use projections and actual figures in the Barnett Shale (2006–2010)

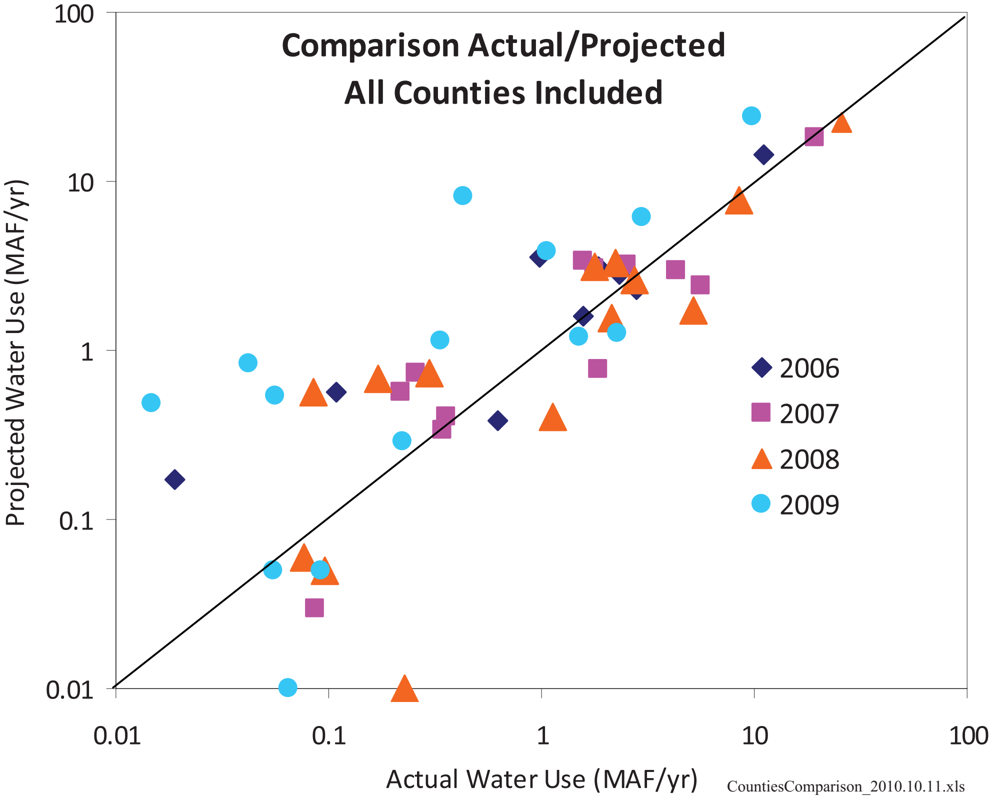


CountiesComparison_2010.10.11.xls

MAF = thousand AF

Figure 142. Comparison of actual vs. projected (high scenario) water use for four counties: Denton, Johnson, Tarrant, and Wise.





MAF = thousand AF

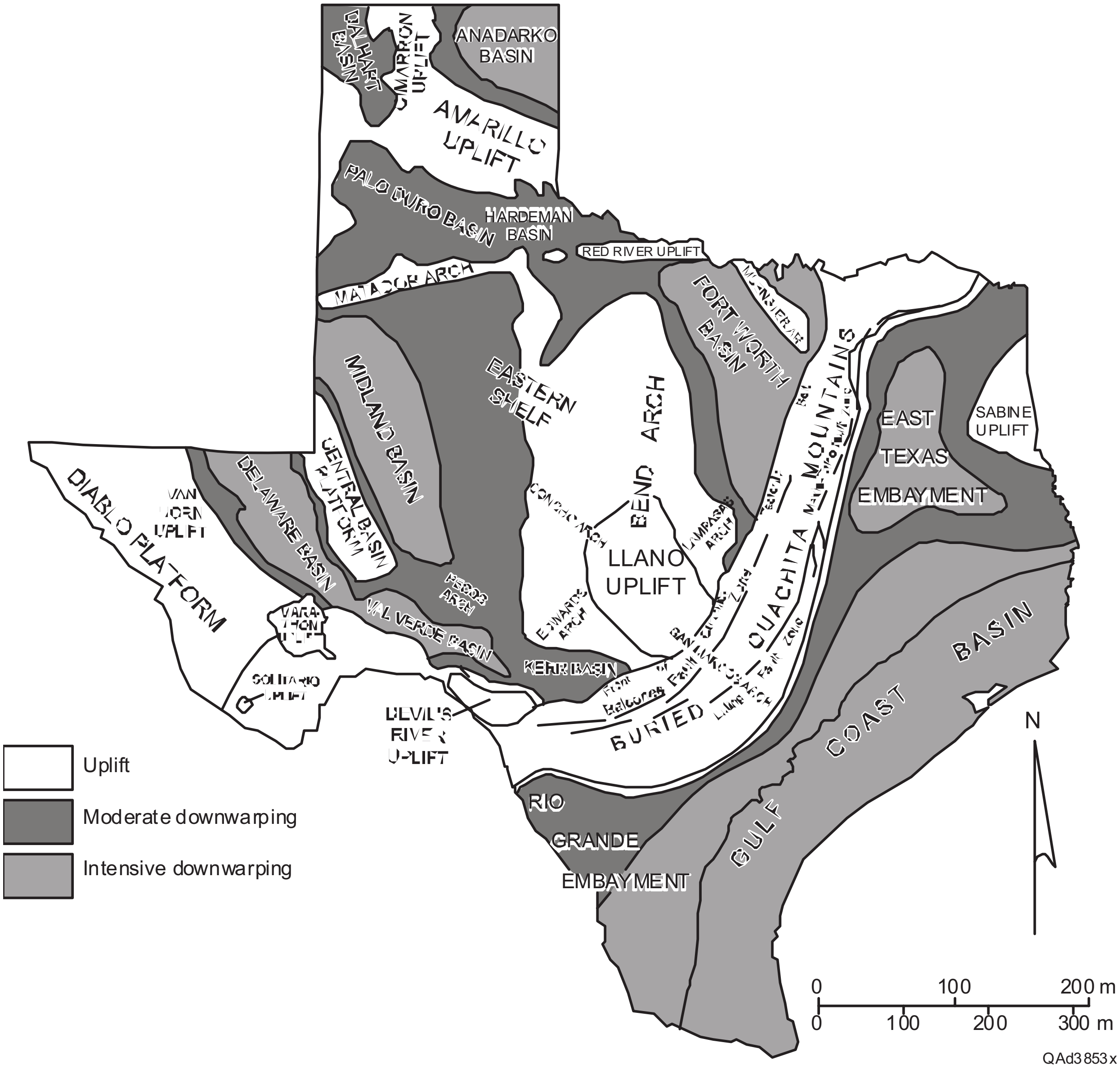
Figure 143. Comparison of actual vs. projected (high scenario) water use for all Barnett Shale counties

10 Appendix C: Relevant Features of the Geology of Texas

This appendix provides an overview of the geology of Texas at it applies to hydrocarbon accumulations summarized from Ewing (1991). The state can be divided into basins (Figure 144). Most of West and Central Texas is underlain by Precambrian rocks that crop out mostly in the Llano Uplift in Central Texas and locally in the Trans-Pecos area. Starting in the Cambrian period, ~550 million years ago, failed continental rifting resulted in widespread deposition of shelf sediments on a stable craton (e.g., Ellenburger Group). Carbonate and clastic deposition continued until the late Devonian, 350 million years ago. Thickness of the deposits varies, with a maximum in the ancestral Anadarko Basin and total removal by erosion of some formations along a broad arch oriented NW-SE on the Amarillo-Llano Uplift axis. Beginning in the Mississippian period (starting 350 million years ago), the passive-margin history of rifting and subsidence was replaced by extensive deep-marine sedimentation and tectonic convergence on the eastern flank of the continental margin. This convergence episode yielded the so-called Ouachita Mountains, now eroded and buried, whose trace approximately follows the current Balcones Fault Zone that runs west from San Antonio and northeast through Austin to the east of Dallas. Behind the orogenic belt, during and after the compressive event, sedimentation continued in and around several inland marine basins, north and west of the current Balcones Fault Zone. Sedimentation was thicker in the basins and thinner or absent on platforms and arches. During these times (320– 270 million years ago) major subsidence and sediment accumulation, partly fed by the erosion of the Ouachita Mountains, occurred in the Permian Basin, including the Delaware and Midland Basins separated by the Central Platform Uplift. Farther north, the Anadarko Basin is separated from the Midland Basin by another basin and two structural highs. The Anadarko Basin also underwent abundant sedimentation during the Pennsylvanian and Permian and included coarse granitic detritus ("granite wash") from the Amarillo Uplift. The Fort Worth Basin is also filled with Pennsylvanian and Permian sediments.

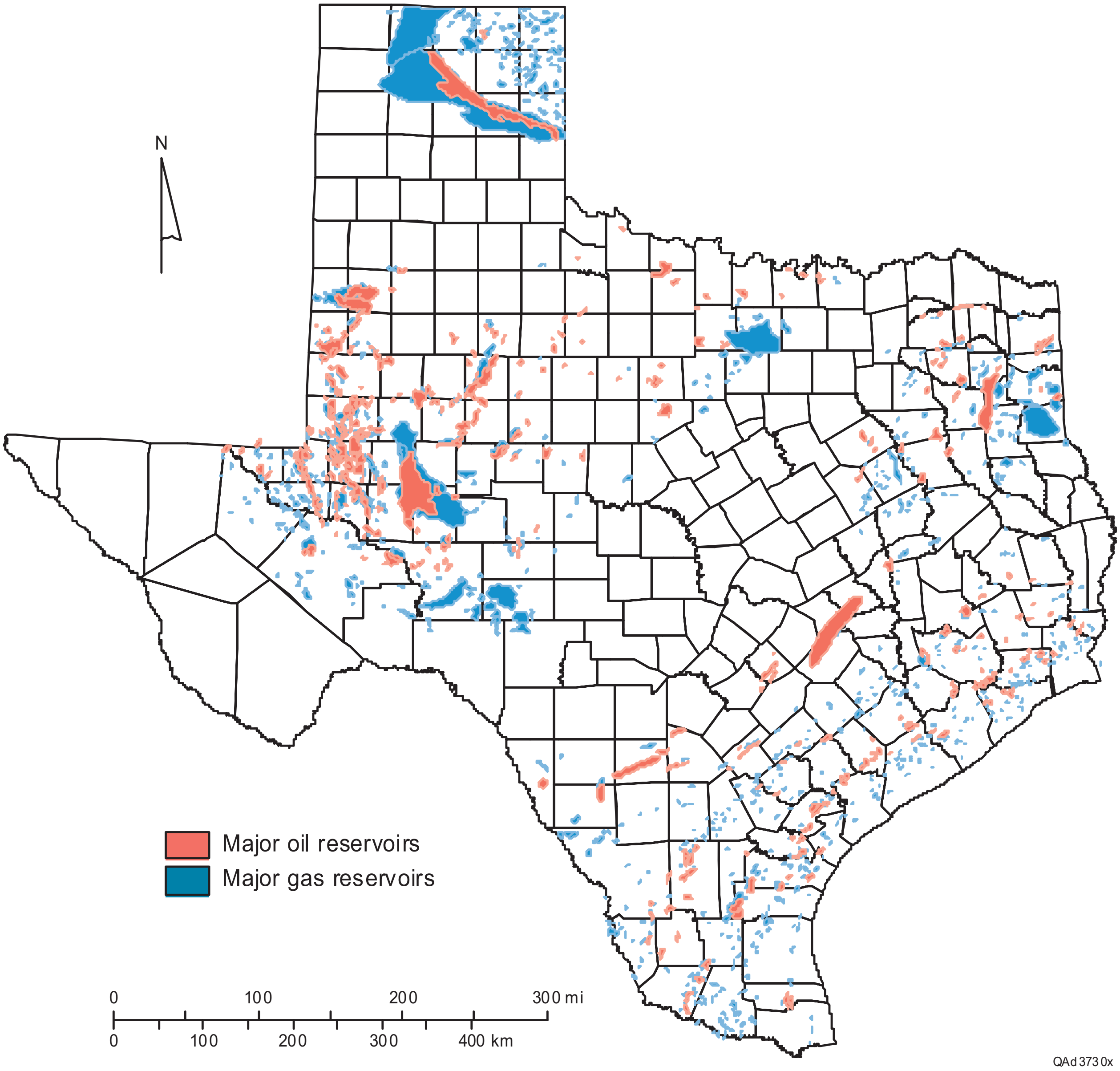
Beginning in Triassic time (250 million years ago), Texas was again subject to extension and volcanism, leading to Jurassic rifting of the continental margin and creation of the Gulf of Mexico and Atlantic Ocean. The focus of major geologic events shifted to the eastern part of the state. The small rift basins that initially formed were buried under abundant salt accumulation (Louann Salt). As the weight of sediments increased, the salt became unstable and started locally to move upward in diapirs, a phenomenon still locally active today. During the Cretaceous, sediments deposited from shallow inland seas formed broad continental shelves that covered most of Texas. Abundant sedimentation in the East Texas and Maverick Basins occurred during the Cretaceous. In the Tertiary (starting 65 million years ago), as the Rocky Mountains to the west started rising, large river systems flowed toward the Gulf of Mexico, carrying an abundant sediment load, in the fashion of today's Mississippi River. All the area west of the old Ouachita Mountain range was also lifted, generating a local sediment source, including erosional detritus from the multiple Tertiary volcanic centers in West Texas and Mexico. Six major progradation events, where the sedimentation built out into the Gulf Coast Basin, have been described.

Many Texas basins contain hydrocarbons (Figure 145). Their stratigraphy is detailed for oil and gas productive formations in Figure 146 and Figure 147 for the Gulf Coast and East Texas Basins and in Figure 148 and Figure 149 for the North-Central and West Texas Basins.



Source: modified from Kreitler (1989)

Figure 144. Generalized tectonic map of Texas showing location of sedimentary basins



Source: BEG map from Galloway et al. (1983) and Kosters et al. (1989)

Figure 145. Map of major oil and gas fields in Texas

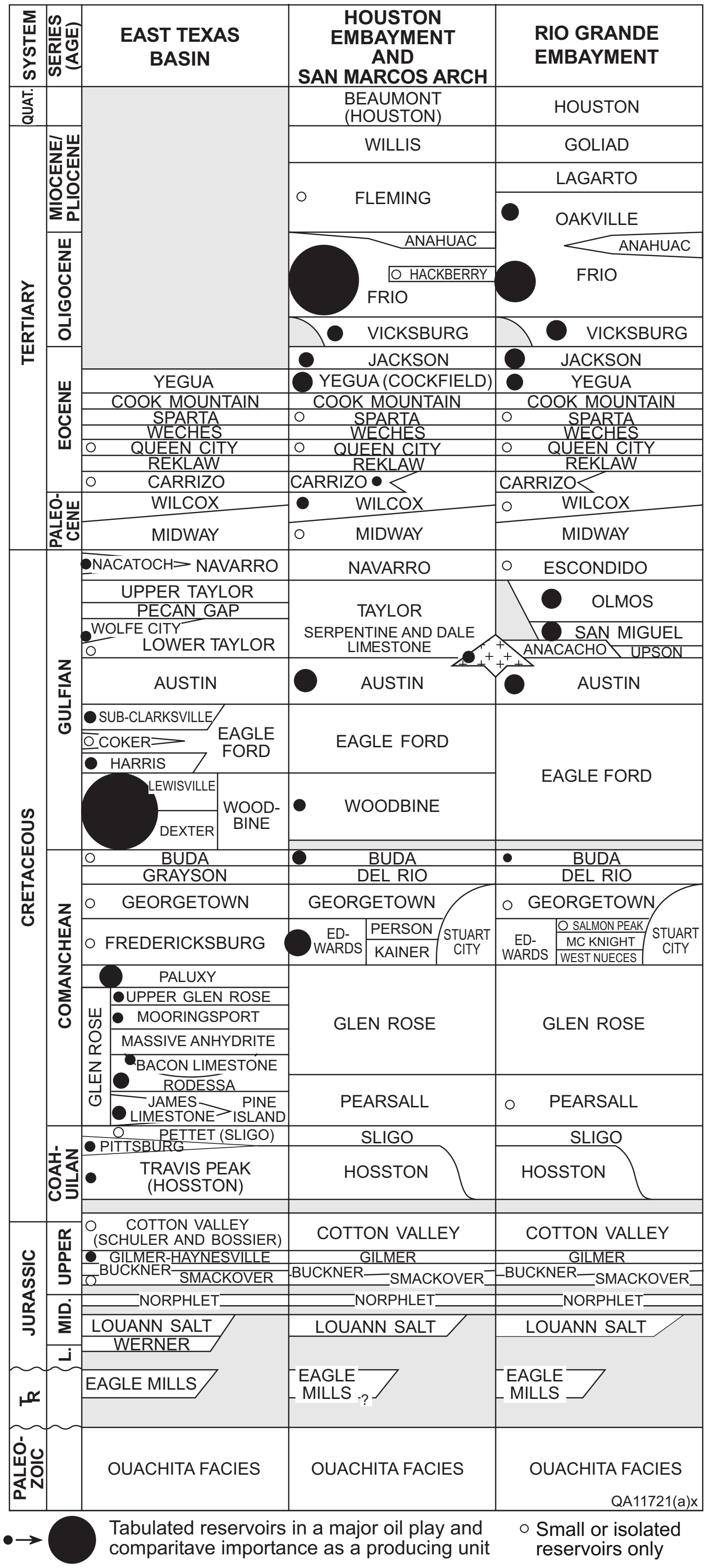


Figure 146. Stratigraphic column and relative oil production for the Gulf Coast and East Texas Basins (after Galloway and others, 1983)

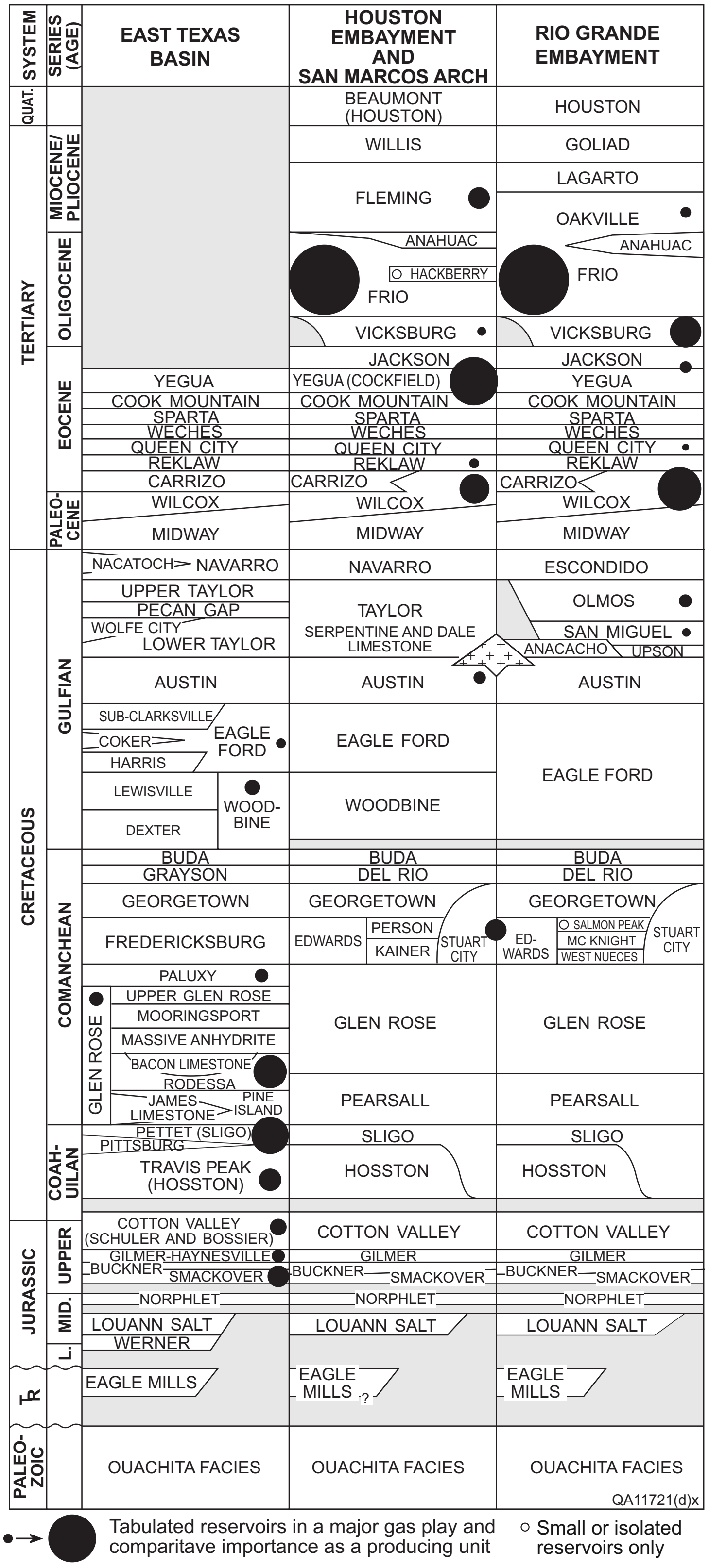


Figure 147. Stratigraphic column and relative gas production for the Gulf Coast and East Texas Basins (after Galloway and others, 1983)

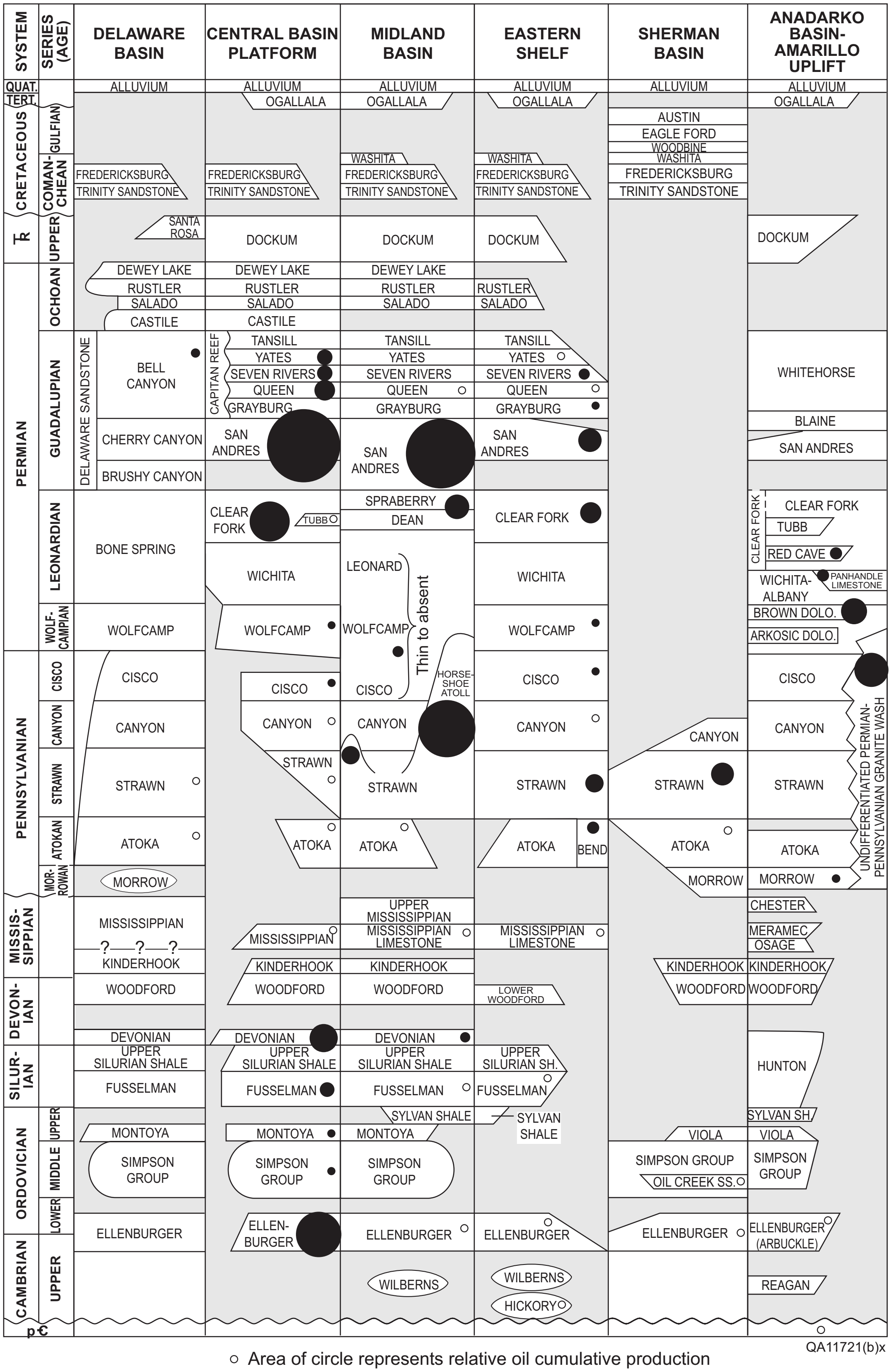
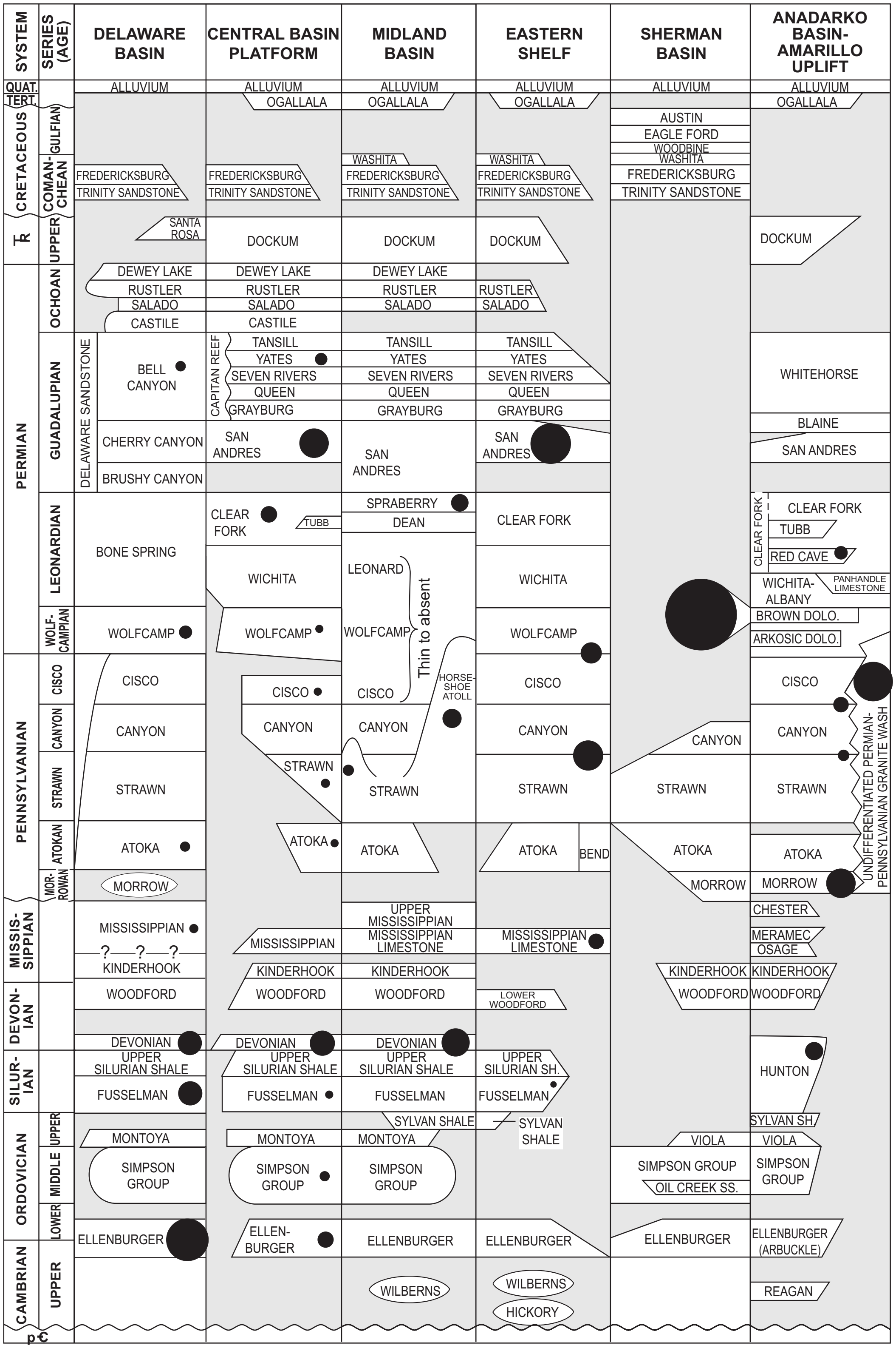


Figure 148. Stratigraphic column and relative oil production for the North-Central and West Texas Basins (after Kosters and others, 1989)



Area of circle represents relative gas cumulative production

QA11721(e)x

Figure 149. Stratigraphic column and relative gas production for the North-Central and West Texas Basins (after Kosters and others, 1989)

11 Appendix D: Survey Questionnaires

During the course of this study, we performed two types of surveys: (1) one aimed at water users through trade associations: TMRA and TACA, and (2) one geared toward water suppliers/Groundwater Conservation Districts (GCDs). We performed an additional survey of oil operators in Texas to inquire about their waterflooding activities.

11.1 Survey of Facilities

As part of this study, we enlisted the assistance of two of the major associations representing the mining industry in Texas: the Texas Aggregate and Cement Association (TACA) and the Texas Mining and Reclamation Association (TMRA). With the endorsement of each association, letters were sent on behalf of the TWDB to all of the association member companies with a survey form. Forms were provided as both Word documents with narrative questions and as Excel documents in spreadsheet format. Examples of the forms are given at the end of this appendix. Survey questionnaires were sent to TMRA members in December 2009, and the association asked that all responses be returned for review of sensitive or proprietary information. Company survey questionnaires were sent to TACA members in February 2010 and handled the same way.

11.1.1 About the Trade Associations

The Texas Mining and Reclamation Association (TMRA) has a variety of members—in addition to individual members and consultancy, its membership includes the following companies: Clay Mining: Acme Brick Company, Boral Bricks, Inc., Elgin Butler Company, Southern Clay Products, U.S. Silica Company; Utilities/Lignite/Coal Mining: Luminant Mining, North American Coal Corporation, Texas Westmoreland Coal Company, Walnut Creek Mining Company, American Electric Power, NRG Energy, San Miguel Electric Cooperative, Inc., Texas Municipal Power Agency; Sand, Gravel and Stone Mining: Capitol Aggregates, LTD, Hanson Aggregates Central, Inc., Trinity Materials Company, Chemical Lime Company; and Uranium Mining: South Texas Mining Venture, Mestena Uranium, LLC, Rio Grande Resources Corporation, Signal Equities, LLC, Uranium Energy Corporation, Uranium Resources, Inc.
The Texas Aggregate and Cement Association (TACA) does not release the list of its membership but does include many small aggregate producers.

11.1.2 Response Rates

Aggregates: 6 companies representing 27 sites provided responses to the BEG. Complete responses are provided in Appendix G and include

Coal/Lignite: we received information back from all lignite mines in Texas (~100% success rate)

Uranium: we received information from several operators

11.2 Survey of GCDs

LBG-Guyton was charged with the task of researching and evaluating groundwater use for mining in Texas. We compiled a packet of the mine data that we were able to obtain through statewide public sources to send to all GCDs so that they might address any changes to water usage that they might be aware of. To begin with, a series of maps and tables of mineral mine data and locations throughout Texas were produced so that each district could see what data were available publicly. These maps and tables were included in a mailed packet, along with a survey requesting any mining information the district had available, an explanation of the data included in the packet, and a letter explaining the purpose of the study. The GIS maps contain all Texas GCDs and mine locations (active and inactive) in the TCEQ SWAP project database, and the data tables include mine data from MSHA and mining water-use projections from TWDB's 2007 *Water for Texas Report*.

Forty-seven (47) out of one hundred (100) questionnaires (47%) that were sent to GCDs were returned. Figure 150 is a map showing the districts that replied, as well as the mine sites that the TCEQ report lists as active in the state of Texas. Districts that replied to the survey are colored and labeled; all other districts are gray. Questions included in this packet are predominantly yes or no questions with requests for explanations of the answers if confirmed. The questions are listed in Table 71, with the answer percentage (using only those 47 GCDs that returned responses). In addition to the leading questions, explanation was requested if the answer was reported as yes. Studying these comments helped us discover some general findings among the survey questionnaires returned. In general, we found that few GCDs had extensive knowledge of mineral mining or mining water use within the district. Some districts had a general idea of what mining operations were active and inactive and could speculate as to how much water was being used according to permits, but none of the districts monitored actual water use.

Also, more districts thought that water use from mining data that had been reported in the TWDB report (such as presented in Table 75) was incorrect, excluding those that did not know. Few had contacted any of the mining entities, and even fewer had contacted the RRC to obtain data on mines. However, nine districts did report some quantitative knowledge of permitted volume of water use for specific mining entities. Table 72 details TWDB water use for mining WUG predictions from 2010 through 2060 and each of the district's own reported volumes for comparison.

Table 71. GCD mine-data questions and response percentages

Question	Total Answers	% Yes	% No	% Unk[†]	% >0
1. Does your district independently estimate water use by mining?	45	16 %	84 %		
2. Have you contacted Texas Railroad Commission to obtain data on mines?	45	4 %	96 %		
3. Do you have any way of validating the mining use estimates in Table 3?	45	18 %	82 %		
4. What portion of total water use in your district is used for mining?*	36			42 %	36 %
5. Have you contacted any of the entities listed in Table 1 or 2?	44	14 %	86 %		
6. Do you feel the data in Table 3 are accurate?	45	9 %	18 %	73 %	
7. Do you know of other mining facilities not included on the map?	43	9 %	91 %		
8. Do you have any additional information regarding groundwater or surface water use at the facilities?	40	15 %	85 %		

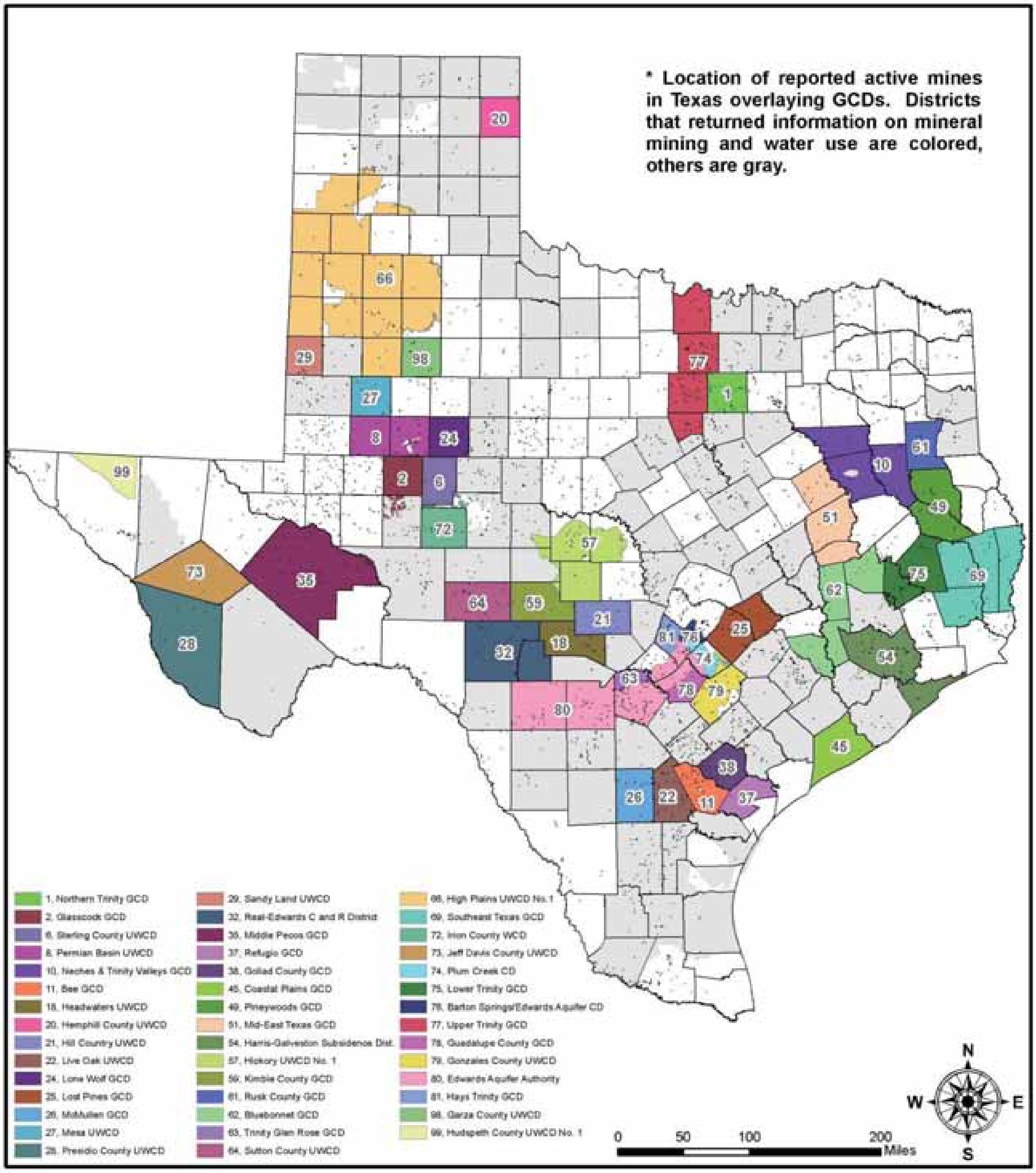
[†] Unknown—answered "Don't know"

*18 % reported 0 % water use for mining

Table 72. Mining water-use changes reported by certain GCDs

GCD	Volume (ac-ft)							Ratio of Reported/ Predicted 2010 Values	District Notes
	2010	2020	2030	2040	2050	2060	District Reported		
Barton Springs/Edwards Aquifer CD	1699	1821	1902	1982	2060	2116	826	49%	District-reported mine water use reported as industrial WUG.
Bee GCD	36	40	42	44	46	48	**105	292%	**% water use (201 ac-ft) split between Bee Co. and Live Oak Co. not specified so was assumed to be half for this exercise.
Harris-Galveston Subsidence District	1547	1713	1815	1917	2020	2112	25	2%	Other water use reported as commercial or industrial WUG.
Headwaters UWCD	167	165	164	163	162	161	109	65%	
Hickory UWCD No. 1	394	395	396	397	398	400	4771	1211%	
Live Oak UWCD	3894	4319	4583	4845	5108	5341	**105	3%	**% water use (201 ac-ft) split between Bee Co. and Live Oak Co. not specified so was assumed to be half for this exercise.
Lost Pines GCD	10483	10485	10486	5487	51	52	4410	42%	Reported use by ALCOA in 2009 for lignite mining.
McMullen GCD	195	203	207	211	215	218	1	1%	
Post Oak Savannah GCD	4025	4024	4024	3024	1524	1524	15000	373%	ALCOA water use reported as industrial WUG. Water rights end in 2038.

*Of those districts that replied with volume calculations, ⅔ reported lower volumes of mining water use than in the 2007 state water plan



* Location of reported active mines in Texas overlaying GCDs. Districts that returned information on mineral mining and water use are colored, others are gray.

Figure 150. GCDs that have returned information on mineral mining water use in their district

11.3 Questionnaire Forms

To coal mining operators (modified to save space):

Date:
Name of Company and of Mining Operation (including SIC or SICs):
County of Mine Location:
Contact Name, Phone, E-mail, and Address:
Coal Production

1. Please rank factors affecting the amount of coal you produce from year to year in order from most (#1) to least important?
 a. General economy (rank=)
 b. Electricity demand projections (rank=)
 c. Production capacity (rank=)
 d. Other ________________________________ (rank=)
 e. Other ________________________________ (rank=)

Water Source

1. Please indicate the approximate amount of water pumped each year as well as the unit used (acre-feet, gallons, etc.)
________________________ (unit: __________)

2. Please circle the sources of the water pumped at your operations and indicate the approximate percentage of each applicable source:
 a. Overburden dewatering (______%)
 b. Pit dewatering (______%)
 c. Depressurization (_____%)
 d. Other ________________________ (______%)

Choice (d) is intended for facilities at which additional water not ultimately originating from dewatering or depressurization is needed (e.g., river, another aquifer)

3. Please circle factors affecting the amount of water pumped? (check all that apply)
 Dewatering
 a. The amount of coal to be produced
 b. Proximity to surficial aquifer
 c. Other ________________________________
 Depressurization
 a. The amount of coal to be produced
 b. The safety factor to prevent floor heave
 c. Proximity to aquifer
 d. Other ________________________________
 Other
 a. The amount of coal to be produced
 b. Other ________________________________

4. What is the quality (Total Dissolved Solids) of the water pumped at your operations for:
 Dewatering
 a. Fresh (<1000 mg/L)
 b. Brackish (> 1000 mg/L and < 10,000 mg/L)
 c. Saline (> 10,000 mg/L and < 35,000 mg/L)
 d. Very Saline (> 35,000 mg/L)
 Depressurization

a. Fresh (<1000 mg/L)
b. Brackish (> 1000 mg/L and < 10,000 mg/L)
c. Saline (> 10,000 mg/L and < 35,000 mg/L)
d. Very Saline (> 35,000 mg/L)

Other Source ____________________ :
a. Fresh (<1000 mg/L)
b. Brackish (> 1000 mg/L and < 10,000 mg/L)
c. Saline (> 10,000 mg/L and < 35,000 mg/L)
d. Very Saline (> 35,000 mg/L)

5. How often do you monitor the **rate and volume of water** pumped for depressurization/dewatering?
a. Daily
b. Monthly
c. Every 2-5 months
d. Yearly
e. Other:______________

6. How often do you monitor the **quality of water** pumped for depressurization/dewatering?
a. Daily
b. Monthly
c. Every 2-5 months
d. Yearly
e. Other:______________

7. Do you report the rate and quality of water pumped to a federal, state or local agency?
a. None
b. Texas Railroad Commission
c. Texas Water Development Board
d. Local Groundwater Conservation District
e. Other (please list) ______________

<u>Water Use</u>

1. For what specific mining activities do you consume the water pumped from dewatering/depressurization? (circle all that apply, provide approximate % if possible)
a. Dust suppression for mining (______%)
b. Dust suppression for hauling (______%)
c. Reclamation/revegetation (______%)
d. Coal washing (______%)
e. Transportation (______%)
f. Drilling (______%)
g. Other (please list) ______________ (______%)

2. Do you report the rate and quality of water consumed to a federal, state or local agency?
a. None
b. Texas Railroad Commission
c. Texas Water Development Board
d. Local Groundwater Conservation District
e. Other (please list) ______________

3. Do you supply water to other entities? Please circle all that apply.
a. None
b. Municipality (Name(s): ________________________)
c. Water supplier (other than municipality) (Name(s): _______________________)
d. Local farmers/ranchers/landowners

5. What factors affect whether or not pumped water is provided to these other entities? (circle all that apply)
a. Quality of water
b. Quantity and consistency of the amount pumped
c. Request from outside water users
d. Fee provided by outside water users
d. Other (please list) ______________________________

Water Discharge

1. Where do you discharge the water not consumed during operations? (provide approximate percentage as needed)

Dewatering

a. Freshwater lake or stream	(_______%)
b. Retention pond then lake or stream	(_______%)
c. Deep-well injection	(_______%)
d. Other _______________________	(_______%)
Depressurization	
a. Freshwater lake or stream	(_______%)
b. Retention pond then lake or stream	(_______%)
c. Deep-well injection	(_______%)
d. Other _______________________	(_______%)
Other Source	
a. Freshwater lake or stream	(_______%)
b. Retention pond then lake or stream	(_______%)
c. Deep-well injection	(_______%)
d. Other _______________________	(_______%)

2. Is the amount of water discharged monitored?
a. Yes
b. No

3. Do you report the monitored quantity to a federal, state or local agency?
a. None
b. Texas Railroad Commission
c. Texas Water Development Board
d. Local Groundwater Conservation District
e. Other (please list) ______________

Future of Lignite mining in Texas

1. Do you foresee any future developments in coal production that would make it more efficient or less water intensive? (Please list or describe any new technologies and the extent to which produced water would be decrease)

2. Do you expect water depressurization and dewatering pattern to remain the same over the short-term (1-9 years)?
a. Yes
b. No *If not, why?*

3. Do you expect water depressurization and dewatering pattern to remain the same over the long-term (10-50 years)?
a. Yes
b. No
If not, why?

To aggregate and other industrial mineral operators (modified to save space):

Date:
Name of Company & Mining Operation (including SIC or SICs):
County of Mine Location:
Contact Name, Phone, E-mail, and Address:

1) Please provide a brief description of your mining process, the ways that water is used at the facility, and the ways that water use is monitored or estimated (flow charts are OK). Please separate, if possible, the industrial mineral mining operations from other product manufacturing (cement, brick, etc.) that may occur on the same property.

2) Water Amount and Water Use. Please report the amount (specify unit: gallons, acre feet, etc.) of water used, the amount recycled (actual or percentage), and the net amount consumed in mining operations annually (or another time unit, in all cases, specify).

   Please break this into amounts for each type of use (extraction, rock washing, roadway watering, dust suppression on conveyor systems, etc.), if possible.

   Please break this into amounts obtained from surface water, groundwater, storm water, etc. and name the source water (stream, lake, aquifer, etc.). Please also note the water quality (fresh, brackish, saline)

   Please report the amount of water typically used in rock washing equipment in gallons per minute/ton per hour (gpm/tph) of mineral product processed.

   Is water discharge out of the facility boundaries sometimes needed? When? How much? Which water type?

   Are these monitored or estimated values? Based on what years?

3) Production. Please report maximum aggregate, sand & gravel, or other industrial mineral mining production (in tons) authorized per year, and an estimate of the range of typical production in recent years. Is production expected to increase, decrease, or remain unchanged in coming years?

4) Future Water Use. How many years has the mine been in operation and what is the projected life of the facility? Are any new industrial mineral mining operations by your company anticipated (if so, where and when)?

   What, if any, plans have been made to reduce water use or identify alternative water sources if water supply is reduced or becomes more expensive?

   What techniques or technologies could be utilized to reduce water use in the industrial mineral mining industry? Is use of saline or brackish water possible or likely to become more common?

   What are the key issues or challenges regarding water use being faced by your industry today or in the future?

To aggregate and other industrial mineral operators (alternate format in excel)

Name of Company & Mining Operation: Date:
County of Mine Location: Type of Mine/SIC:
Contact Name, Phone, E-mail, and Address:

Brief description of your mining process, the ways that water is used at the facility, and the ways that water use is monitored or estimated.

	Quantity of Water Used (Total)	Quantity of Water Recycled	Quantity of Water Consumed (Lost)	Quantity of Water Used in Extraction	Quantity of Water Used for Rock Washing
fresh					
brackish					
saline					

	Quantity of Water Used for Roadway Watering	Quantity of Water Used for Dust Suppression	Quantity of Water Discharged if any	Where? How often?	Rate of Wash Water Use (gpm/tph)
fresh					
brackish					
saline					

	Surface Water (%)	Name of Water Source(s) (lake X, river Y, storm water, etc.)	Groundwater (%)	Name of Water Source(s) (aquifer X, local alluvium, etc.)
fresh				
brackish				
saline				

	Product Name	Typical Production (tpy)	Authorized Production (tpy)	Number of Years of Mine Operation	Projected Life of Facility
Product1					
Product2					
Product3					

Is water use estimated or monitored? Which is the base year?
Is production expected to increase, decrease, or remain unchanged in coming years?
Are any new mineral mining operations by your company anticipated (if so, where and when)?
What, if any, plans have been made to reduce water use or identify alternative water sources if water supply is reduced or becomes more expensive?
What techniques or technologies could be utilized to reduce water use in your industry? Is use of saline or brackish water possible or likely to become more common?
What are the key issues or challenges regarding water use being faced by your industry today or in the future?

To uranium operators (modified to save space):

Date:
Name of Company & Mining Operation (including SIC or SICs):
County of Mine Location:
Contact Name, Phone, E-mail, and Address:

1) Please provide a brief description of your mining process, the ways that water is used at the facility, and the ways that water use is monitored or estimated (flow charts are OK). Please separate, if possible, the mining operations from other operations that may occur on the same property.

2) Water Amount and Water Use. Please report the amount (specify unit: gallons, acre feet, etc) of water used, the amount recycled (actual or percentage), and the net amount consumed in mining operations annually.

   Please break this into amounts for each type of use (subsurface ISR operations, surface ion exchange operations, dust suppression, etc.), if possible.

   Please break this into amounts obtained from surface water, groundwater, storm water, etc. and name the source water (stream, lake, aquifer, etc.). Please also note the water quality (fresh, brackish, saline)

   Please report the amount of water typically used/consumed (specify) in gallons per pound of product (specify U, U_3O_8, yellow cake, etc.) if possible.

   Is water discharge out of the facility boundaries sometimes needed (deep well injection during restoration)? When? How much? Which water type?

   Are these monitored or estimated values? Based on what years?

3) Production. Please report production or an estimate of the range of typical production in recent years. Is production expected to increase, decrease, or remain unchanged in coming years?

4) Future Water Use. How many years has the mine been in operation and what is the projected life of the facility? Are any new uranium mining operations by your company anticipated (if so, where and when)?

   What, if any, plans have been made to reduce water use or identify alternative water sources if water supply is reduced or becomes more expensive?

   What techniques or technologies could be utilized to reduce water use in your industry? Is use of saline or brackish water possible or likely to become more common?

   What are the key issues or challenges regarding water use being faced by your industry today or in the future?

11.4 Survey of West Texas Oil Operators

For oil wells:

Water Use

		Fresh Water (<3,000 TDS)		Brackish Water (3,000–10,000 TDS)		Saline Water (>10,000 TDS)		
Item	**Unit**	**From GW**	**From SW**	**From GW**	**From SW**	**From GW**	**From SW**	**Notes/Explanation**
Water used in 2010 for well drilling	bbl							Project/estimate through 2010.
Water used in 2010 for well completion (& fracturing)	bbl							Project/estimate through 2010.
Water used in 2010 for waterflood operations	bbl							Project/estimate through 2010.
Water used for CO2 flood operations	bbl							Project/estimate through 2010.
Other substantial 2010 water use	bbl							Please note type of use and enter units as appropriate.

Operational Statistics				
Item	**Units**		**Notes/Explanation**	
No. **vertical** oil wells drilled in 2010	number		Estimate/project through year's end.	
Average well depth for **vertical** wells	ft		Estimate	
No. **horizontal** oil wells drilled in 2010	number		Estimate	
Average total lateral length for **horizontal** oil wells	ft		Estimate	
No. wells "fraced" in 2010	number		Estimate/project through year's end.	
Average depth/length of wells being "fraced"	ft		Estimate	
No. acres in active waterflood	number		Estimate	
No. acres in active CO2 flood	number		Estimate	
Estimated total 2010 oil production from waterfloods	bbl		Estimate	
Estimated total 2010 oil production from CO2 floods	bbl		Estimate	
Estimated total 2010 associated gas production from waterfloods	MMcf		Estimate	
Estimated total 2010 associated gas production from CO2 floods	MMcf		Estimate	

For gas wells

Water Use

		Fresh Water (<3,000 TDS)		Brackish Water (3,000–10,000 TDS)		Saline Water (>10,000 TDS)		
Item	**Unit**	**From GW**	**From SW**	**From GW**	**From SW**	**From GW**	**From SW**	**Notes/Explanation**
Water used for 2010 well drilling	bbl							Project/estimate through 2010.
Water used for 2010 well completion (& fracturing)	bbl							Project/estimate through 2010.
Other substantial 2010 water use	bbl							Please note type of use and enter units as appropriate.

Operational Statistics

Item	**Units**		**Notes/Explanation**
No. **vertical** gas wells drilled in 2010	number		Project/estimate through 2010.
Average well depth for **vertical** gas wells	ft		Estimate
No. **horizontal** gas wells drilled in 2010	number		Project/estimate through 2010.
Average total lateral length for **horizontal** gas wells	ft		Estimate
No. wells "fraced" in 2010	number		Estimate/project through year's end.
Average depth of vertical gas wells being "fraced"	ft		Estimate
Average total lateral length of horizontal gas wells being "fraced"	ft		Estimate

To GCDs:

Several figures and tables (following questionnaires) were sent to each GCD in Texas, along with the following questionnaire requesting information about the district's knowledge of mining operations within its borders.

When answering the following questions, we asked that GCDs not include water use for oil/gas activities.

1. Does your district independently estimate water use by mining?
    a. If yes – please describe
2. Have you contacted Texas Railroad Commission to obtain data on mines?
3. Do you have any way of validating the mining use estimates in Table 3? (*TWDB projections*)
    a. If yes – please describe method and result
4. What portion of total water use in your district is used for mining?
5. Have you contacted any of the entities listed in Table 1 or 2?
    a. If yes – please describe what you found
6. Do you feel the data in Table 3 are accurate?
    a. If yes – why?
    b. If no – why?
7. Do you know of other mining facilities not included on the map?
    a. If yes – do you have an estimate of the water use?
8. Do you have any additional information regarding groundwater or surface water use at the facilities?

In addition to figures similar to Figure 7 (Introduction section), we provided the GCDs with tables extracted from (1) the SWAP database (Table 73), (2) the MSHA database (Table 74), and (3) projections for the TWDB 2007 water plan for the counties included whole or in part in the GCD (Table 75). Only the last table gives some indication of mining water use.

Table 73. Example of information provided by the SWAP database (Lost Pines GCD)

Mine Sites in the Lost Pines GCD

PSOC ID	SITE ID	SITE NAME	LATITUDE (DD)	LONGITUDE (DD)	HORIZONTAL DATUM	LOCATION METHOD	AGENCY	ACTIVE	MINE TYPE	COMMODITY	GEOLOGIC FORMATION
4343	021BSW201		30.118900	-97.432800	27	MAP-M2	BEG	N		SAND, GRAVEL	WILLIS FORMATION
4344	021ELE301		30.363100	-97.268600	27	MAP-M2	BEG	Y		CLAY-COMMON	
4345	021ELE501		30.321899	-97.323303	27	MAP-M2	BEG	Y		CLAY-COMMON	
4346	021ELE502		30.332800	-97.292503	27	MAP-M2	BEG	Y		CLAY-COMMON	
4347	021ELE601		30.322201	-97.285301	27	MAP-M2	BEG	Y		CLAY-COMMON	
4348	021LAB401	Powell Bend	30.187500	-97.333336	27	MAP-M1	TNRCC	N	STRIP MINE	COAL-LIGNITE	CALVERT BLUFF FORMATION
4349	021LAB701		30.163601	-97.340797	27	MAP-M2	BEG	Y		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4350	021LAB702		30.156900	-97.339996	27	MAP-M2	BEG	N		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4351	021PAI701		30.128300	-97.124199	27	MAP-M2	BEG	Y		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4352	021SMI201		30.091101	-97.200798	27	MAP-M2	BEG	N		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4353	021SMI202		30.090000	-97.202202	27	MAP-M2	BEG	N		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4354	021SMI901		30.015600	-97.164200	27	MAP-M2	BEG	N	PIT	SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4355	021SNW201		30.228300	-97.175598	27	MAP-M2	BEG	N		SAND, GRAVEL	REKLAW FORMATION
4356	021TOG201		29.988300	-97.169998	27	MAP-M2	BEG	Y		SAND, GRAVEL	WILLIS FORMATION
4357	021TOG301		29.979200	-97.163300	27	MAP-M2	BEG	N		SAND, GRAVEL	WILLIS FORMATION
4359	021TOG303		29.988300	-97.129700	27	MAP-M2	BEG	Y		SAND, GRAVEL	WILLIS FORMATION
4361	021TOG305		29.973600	-97.134697	27	MAP-M2	BEG	Y		SAND, GRAVEL	WILLIS FORMATION
4362	021TOG306		29.975000	-97.137497	27	MAP-M2	BEG	Y		SAND, GRAVEL	WILLIS FORMATION
4363	021UTY101		30.223600	-97.464699	27	MAP-M2	BEG	N		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4364	021UTY401		30.208099	-97.490303	27	MAP-M2	BEG	Y		SAND, GRAVEL	ALLUVIUM
4365	021UTY601		30.175600	-97.413300	27	MAP-M2	BEG	Y		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
4366	021WEP101		29.988100	-97.095802	27	MAP-M2	BEG	N	STRIP MINE	SAND, GRAVEL	ALLUVIUM
4367	021WEP102		29.987499	-97.099403	27	MAP-M2	BEG	N		SAND, GRAVEL	FLUVIAL TERRACE DEPOSITS
11080	287BEA701		30.411400	-97.250000	27	MAP-M2	BEG	N	PIT	SAND, GRAVEL	SIMSBORO SAND
11081	287BEA702		30.392799	-97.237503	27	MAP-M2	BEG	N	PIT	CLAY	SPARTA SAND
11082	287DIB201		30.343599	-96.805000	27	MAP-M2	BEG	Y	PIT	SAND, GRAVEL	YEGUA FORMATION
11083	287DIB202		30.343100	-96.796898	27	MAP-M2	BEG	N	PIT	SAND, GRAVEL	YEGUA FORMATION
11084	287DIB203		30.343300	-96.792503	27	MAP-M2	BEG	N	PIT	SAND, GRAVEL	YEGUA FORMATION
11085	287DIB204		30.342199	-96.795303	27	MAP-M2	BEG	Y	PIT	SAND, GRAVEL	YEGUA FORMATION

Table 74. Example of information provided by the MSHA database sent to GCDs

Texas MSHA Mine Database

Mine ID	Mine Name	Status	Type	Primary Commodity	Secondary Commodity	Operator Name	County	Street	PO Box	City	State	Zip	Nearest Town
4100249	Athens Plant & Pits	Intermittent	Surface	Common Clays NEC		Hanson Brick	Henderson	200 Athens Brick Road		Athens	TX	75751	Athens
4100252	Balcones Pit & Plant	Active	Surface	Common Clays NEC		Balcones Minerals Corp	Fayette	233 Balcones Lane		Flatonia	TX	78941	Flatonia
4100253	Barrett Base Plt	Active	Surface	Crushed, Broken Limestone NEC		Alamo Concrete Products Ltd	Bexar	6889 EAST EVANS ROAD		SAN ANTONIO	TX	782662813	San Antonio
4100262	Kosse Plant	Active	Surface	Common Clays NEC		U S Silica Company	Limestone	FM 2749		Kosse	TX	76653	Kosse
4100264	Standard Pit	Intermittent	Surface	Clay, Ceramic, Refractory Mnls.		Acme Brick Company	Bastrop	1776 Old McDade Road		Elgin	TX	78621	Elgin
				Common Clays		Elgin-Butler Brick							

Table 75. Example of information provided by the 2007 TWDB water plan sent to GCDs (Lost Pines GCD)

RWPG	County Name	WUG ID	WUG Name	Basin Name	TWD 2010	TWD 2020	TWD 2030	TWD 2040	TWD 2050	TWD 2060	Regional Comments
G	LEE	071003144	MINING	BRAZOS	5450	5450	5450	5450	13	13	
K	BASTROP	111003011	MINING	GUADALUPE	7	8	8	8	8	8	
K	BASTROP	111003011	MINING	COLORADO	5016	5018	5018	18	19	20	
K	BASTROP	111003011	MINING	BRAZOS	10	9	10	11	11	11	

12 Appendix E:
Supplemental Information Provided by GCDs

Some GCDs provided useful information. Some have already been mentioned in Appendix D (Table 72). As mentioned previously, few responses contained information useful to quantifying total groundwater usage by mining operations in Texas GCDs. However, a few are worth summarizing here because their account of groundwater usage varies from what is reported in the 2007 *Water for Texas Report*.

In addition, none of the GCDs located in the mining belt reported information regarding lignite mining. However, lignite mines and water use shown on the maps within these districts were not contested in any of the surveys we received. Five major areas in West Texas produce oil and/or gas: Andrews, Stephens, Hockley, Gaines, and Yoakum Counties. Three of these counties have a governing groundwater district: Hockley (High Plains UWCD), Gaines (Llano Estacado UWCD), and Yoakum (Sandy Land UWCD). We contacted these GCDs as well as Stephens and Andrews Counties' AgriLife Extension Offices. The three GCDs replied to our requests but let us know that they do not retain any records of oil/gas water use within their respective districts. The two county offices contacted did not reply with any information.

See Appendix A of LBG-Guyton (2010) for a more detailed summary table and scanned copies of responses received from the GCDs that were sent information.

- The Barton Springs/Edwards Aquifer Conservation District reported one limestone mining operation not listed, as well as one mining operation listed as an active quarry that is no longer in use.
- Bee County and Live Oak GCDs reported that they are unaware of any uranium mines that are using any water because the uranium mines have been closed, are still in reclamation phase, and should not use much or any water. It is conservatively reported that 201 ac-ft of groundwater is used for uranium mining between the two districts.
- Harris-Galveston Subsidence District reported back on five known mining operations and their permitted water use: Swiley and Pit Plant (est. use, 100,000 gal/yr), Hockley Mine (est. use, 1 million gal/yr), Densimix (est. use, 0.1 million gal/yr), Megasand Enterprises (est. use, 3,960 gal/yr), and Petroleum Coke Grinding (est. use, 0 gal/yr). See Appendix A f LBG-Guyton (2010) for details on these water users by HGSD.
- Headwaters UWCD provided a table of mine-water users and their information. It is noted in the table that the Wheatcraft pit has a groundwater permit for 62 ac-ft and that Martin Marietta has a groundwater permit for 47 ac-ft. See Appendix A of LBG-Guyton (2010) for details provided on these water users by HUWCD.
- Hickory UWCD seemed to have the largest discrepancy between permitted mine-water use and reported estimates of water use in the 2007 WFT report. In a table including all but two mining operations, permitted water use was reported for McCulloch and Mason Counties. The total water permitted for McCulloch County came to 4,212 ac-ft, and the total permitted in Mason County, 559 ac-ft. These estimates are much larger than the 171 and 6 ac-ft (respectively) reported in the 2007 WFT report.
- Lost Pines GCD reported use of groundwater for lignite mining only. It reported the groundwater use by ALCOA in 2009 to be 4,410 ac-ft.
- McMullen GCD reported that all sand and gravel pits in the district stopped operating and stopped using water 20 years ago. This fact may reduce assumed water use in this district

- Mesa UWCD reported very little water being used for mining currently.
- Neches and Trinity Valleys GCDs reported that the amounts reported by the 2007 WFT report may be excessive because they are ~6% of total current water production in the district.
- Post Oak Savannah GCD reported a 15,000-ac-ft permit for groundwater use by ALCOA that ends in 2038.
- Sutton County UWCD reported no mining operations in Sutton County and that there should be no water used for such operations.
- Red Sands GCD returned only a hand-drawn map showing known mining operations within the district, some of which were not shown on the GIS map that had been sent out.

13 Appendix F: Water-Rights Permit Data and 2008 Water-Rights Reporting Data

The following two tables (Table 76 and Table 77) list data dump from of the TCEQ database concerning surface-water rights.

Table 76. 2008 Water-rights reporting data

			Annual	Annual	Annual
		River	Diverted	Return	Consumed
Year	Name of Company	Basin	Amount	Flow	Amount
2008	AKIN	Sabine	0	0	0
2008	ALAMO CONCRETE PRODUCTS LTD	Brazos	165.424	150.205	15.219
2008	ALCOA INC	Brazos	0	0	0
2008	ALCOA INC	Brazos	0	0	0
2008	ALON USA REFINING INC	Colorado	21.3	0	21.3
2008	ASH GROVE TEXAS LP	Trinity	289.3	0	289.3
2008	BASELINE OIL & GAS CORP	Brazos	1000	0	82.61
2008	BELL SAND COMPANY	Neches	4.75	0	0
2008	BLUE SKY OILFIELD SERVICE LLC	Brazos	0	0	0
2008	BLYTHE	Colorado	0	0	0
2008	BOWIE, CITY OF	Trinity	1.3738	0	1.3738
2008	BRAZOS RIVER AUTHORITY	Brazos	5268	0	5268
2008	BRAZOS RIVER AUTHORITY	Brazos	426	0	426
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	0	0	0
2008	BRAZOS RIVER AUTHORITY	Brazos	13	0	13
2008	BRAZOS WATER STATION	Brazos	29.09	0	29.09
2008	BRECKENRIDGE GASOLINE CO	Brazos	0	0	0
2008	BURLINGTON RESOURCES OIL & GAS CO LP	Brazos	10	0	10
2008	BURLINGTON RESOURCES OIL & GAS CO LP	Brazos	10	0	10
2008	CAMPBELL CONCRETE & MATERIALS LP	Brazos	1135	997	140
2008	CAPITOL AGGREGATES LTD	Brazos	53.61	0	53.61
2008	CAPITOL AGGREGATES LTD	Colorado	0	0	0
2008	CARAWAY	Brazos	0	0	0
2008	CAVERN DISPOSAL INC	Trinity	36	0	36
2008	CERVENKA	Colorado	0	0	0
2008	CHAMBERS-LIBERTY COS ND	Trinity	0	0	0
2008	CHESAPEAKE ENERGY INC	Brazos	0	0	0
2008	CHEVRON PHILLIPS CHEMICAL CO LP	Brazos-Colorado	453.71	339.71	0

Year	Name of Company	River Basin	Annual Diverted Amount	Annual Return Flow	Annual Consumed Amount
2008	CITATION 1994 INVESTMENT LTD PARTNERSHIP	Brazos	0	0	0
2008	CITATION 1998 INVESTMENT LTD PARTNERSHIP	Brazos	0	0	0
2008	CITATION 1998 INVESTMENT LTD PARTNERSHIP	Brazos	58.4567	0	58.4567
2008	CLEBURNE, CITY OF	Brazos	0	0	0
2008	COLORADO RIVER MWD	Colorado	9	0	0
2008	COLORADO RIVER MWD	Colorado	843.2	0	0
2008	COLORADO RIVER MWD	Colorado	0	0	0
2008	COLORADO RIVER MWD	Colorado	0	0	0
2008	COLORADO RIVER MWD	Colorado	0	0	0
2008	CONOCOPHILLIPS CO	Brazos-Colorado	0	0	0
2008	DALLAS, CITY OF	Trinity	0	0	0
2008	DEVON ENERGY PRODUCTION CO LP	Brazos	0	0	0
2008	EASTLAND INDUSTRIAL FOUNDATION	Brazos	0	0	0
2008	EBAA IRON INC	Brazos	0	0	0
2008	EL PASO CO WID 1	Rio Grande	0	0	0
2008	ENCANA OIL & GAS USA INC	Brazos	0	0	0
2008	EOG RESOURCES INC	Brazos	0	0	0
2008	EOG RESOURCES INC	Brazos	0	0	0
2008	EOG RESOURCES INC	Brazos	0	0	0
2008	EOG RESOURCES INC	Brazos	0	0	0
2008	FAIR OIL LC	Cypress	0	0	0
2008	FRANKLIN LIMESTONE COMPANY	Brazos	0	0	0
2008	GEOCHEMICAL SURVEYS	Brazos	0	0	0
2008	GRAHAM, CITY OF	Brazos	0	0	0
2008	GREEN	Canadian	0	0	0
2008	GREENBELT M&I WA	Red	0	0	0
2008	GULF COAST WATER AUTHORITY	Brazos	0	0	0
2008	H R STASNEY & SONS LTD	Brazos	54.51	0	0
2008	HALLWOOD PETROLEUM	Brazos	0	0	0
2008	HANSON AGGREGATES CENTRAL INC	Trinity	2392.24	2221.34	2392.24
2008	HANSON AGGREGATES CENTRAL INC	Trinity	0	0	0
2008	HANSON AGGREGATES WEST INC	Trinity	0	0	0
2008	HANSON AGGREGATES WEST INC	Trinity	125.75	114.44	125.75
2008	HENRIETTA, CITY OF	Red	0	0	0
2008	HUDSPETH COUNTY CRD 1	Rio Grande	0	0	0
2008	INGRAM ENTERPRISES LP	Brazos	43.85	0	43.85

Year	Name of Company	River Basin	Annual Diverted Amount	Annual Return Flow	Annual Consumed Amount
2008	J & W SUPPLY INC	Brazos	30	0	30
2008	JACKSON SAND & GRAVEL INC	Trinity	0	0	0
2008	JANES GRAVEL CO	Brazos	446.23	0	0
2008	KEECHI VALLEY CATTLE CO	Brazos	0	0	0
2008	KERSH	Neches	4.75	0	0
2008	LATTIMORE MATERIALS COMPANY	Brazos	63.53	0	63.53
2008	LATTIMORE MATERIALS COMPANY	Brazos	572.14	0	572.14
2008	LEONARD WITTIG GRASS FARMS INC	Brazos-Colorado	0	0	0
2008	LOWER COLORADO RIVER AUTHORITY	Colorado	0	0	0
2008	LOWER COLORADO RIVER AUTHORITY	Colorado	0	0	0
2008	LUMINANT GENERATION CO LLC	Cypress	492	0	492
2008	LUMINANT MINING CO LLC	Sabine	376	0	376
2008	LUMINANT MINING CO LLC	Sabine	0	0	0
2008	MARTIN MARIETTA MATERIALS SOUTHWEST INC	Trinity	0.25	0	0.25
2008	MINERAL WELLS SAND & GRAVEL	Brazos	0	0	0
2008	MOBLEY COMPANY INC	Colorado	0	0	0
2008	MOBLEY COMPANY INC	Colorado	0	0	0
2008	MOBLEY COMPANY INC	Colorado	0	0	0
2008	MOHR	Colorado	0	0	0
2008	MORTON SALT COMPANY INC	Sabine	76.34	0	0
2008	NORTH CENTRAL TEXAS MWA	Brazos	0	0	0
2008	NORTH RIDGE CORPORATION	Brazos	0	0	0
2008	NORTH TEXAS LIVING WATER RESOURCES LLC	Brazos	0	0	0
2008	NORTH TEXAS LIVING WATER RESOURCES LLC	Brazos	0	0	0
2008	OCCIDENTAL PERMIAN LTD	Brazos	0	0	0
2008	PITCOCK BROTHERS READY-MIX	Brazos	0	0	0
2008	PLAINS PETROLEUM OPERATING CO	Brazos	0	0	0
2008	PREMCOR PIPELINE CO	Neches-Trinity	51.468	0	51.468
2008	PUMPCO INC	Brazos	2.7496	0.4677	2.7496
2008	QUICKSILVER RESOURCES INC	Brazos	1709.11	0	1709.11
2008	RED RIVER AUTHORITY	Red	0	0	0
2008	SABINE MINING COMPANY	Sabine	157.76	0	0
2008	SABINE MINING COMPANY	Sabine	0	0	0
2008	SAN JACINTO RIVER AUTHORITY	San Jacinto	0	0	0
2008	SAN JACINTO RIVER AUTHORITY	Trinity	0	0	0
2008	SANCO MATERIALS CO	Colorado	25.6	0	25.6

			Annual	Annual	Annual
		River	Diverted	Return	Consumed
Year	Name of Company	Basin	Amount	Flow	Amount
2008	SANCO MATERIALS CO	Colorado	8.76	0	8.76
2008	SCHKADE	Brazos	0	0	0
2008	SHUMAKER ENTERPRISES INC	Colorado	249.74	0	249.74
2008	SOUTHWESTERN GRAPHITE CO	Colorado	0	0	0
2008	SWANSON MULESHOE RANCH LTD	Brazos	0	0	0
2008	SWEPI LP	Brazos	0	0	0
2008	TARRANT INVESTMENT CO INC	Brazos	0	0	0
2008	TARRANT REGIONAL WATER DISTRICT	Trinity	316	0	316
2008	TARRANT REGIONAL WATER DISTRICT	Trinity	0	0	0
2008	TARRANT REGIONAL WATER DISTRICT	Trinity	0	0	0
2008	TARRANT REGIONAL WATER DISTRICT	Trinity	0	0	0
2008	TARRANT REGIONAL WATER DISTRICT	Trinity	0	0	0
2008	TAYLOR	Colorado	0	0	0
2008	TERRY JACKSON INC	Colorado	0	0	0
2008	TERRY JACKSON INC	Colorado	0	0	0
2008	TEX IRON INC	Neches	0	0	0
2008	TEXAS INDUSTRIES INC	Trinity	0	0	0
2008	TEXAS INDUSTRIES INC	Colorado	0	0	0
2008	TEXAS MUNICIPAL POWER AGENCY	Brazos	0	0	0
2008	TEXAS MUNICIPAL POWER AGENCY	Brazos	0	0	0
2008	THISTLE DEW RANCH	Brazos	0	0	0
2008	TLC INVESTMENTS LLC	Brazos	0	0	0
2008	TRINITY MATERIALS INC	Brazos	0	0	0
2008	TRINITY MATERIALS INC	Trinity	0	0	0
2008	TRINITY MATERIALS INC	Trinity	51.9814	0	0
2008	TXI OPERATIONS LP	Brazos	0	0	0
2008	TXU BIG BROWN MINING CO LP	Trinity	0	0	0
2008	TXU MINING COMPANY LP	Sabine	0	0	0
2008	TXU MINING COMPANY LP	Sabine	307	0	307
2008	TXU MINING COMPANY LP	Brazos	0	0	0
2008	TXU MINING COMPANY LP	Cypress	0	0	0
2008	TXU MINING COMPANY LP	Sabine	0	0	0
2008	TXU MINING COMPANY LP	Cypress	0	0	0
2008	TXU MINING COMPANY LP	Sulphur	65	0	65
2008	TXU MINING COMPANY LP	Cypress	132	0	132
2008	TXU MINING COMPANY LP	Sabine	0	0	0
2008	TXU MINING COMPANY LP	Sulphur	0	0	0
2008	UNDERWOOD	Brazos	15.81	0	15.81

Year	Name of Company	River Basin	Annual Diverted Amount	Annual Return Flow	Annual Consumed Amount
2008	UNION OIL COMPANY OF CALIF	Neches	0	0	0
2008	UNITED STATES DEPT OF ENERGY	Neches-Trinity	50.69	0	50.69
2008	UNITED STATES OF AMERICA	Rio Grande	0	0	0
2008	UPPER NECHES RIVER MWD	Neches	0	0	0
2008	US DEPARTMENT OF ENERGY	Brazos	81.06	0	81.06
2008	VULCAN CONSTRUCTION MATERIALS LLP	Brazos	139.34	0	0
2008	W F COMPANY LTD	Colorado	0	0	0
2008	WAGGONER	Red	0	0	0
2008	WALNUT CREEK MINING COMPANY	Brazos	0	0	0
2008	WEATHERFORD, CITY OF	Trinity	0	0	0
2008	WEIRICH BROTHERS INC	Colorado	0	0	0
2008	WEIRICH BROTHERS INC	Colorado	0	0	0
2008	WEST CENTRAL TEXAS MWD	Brazos	45.91	0	0
2008	WESTERN COMPANY OF TEXAS INC	Brazos	1031.33	0	1031.33
2008	WHARTON COUNTY GENERATION LLC	Brazos-Colorado	0	0	0
2008	WHITE RIVER MWD	Brazos	7.75	0	7.75
2008	WHITE RIVER MWD	Brazos	0	0	0
2008	WHITESIDE	Red	0	0	0
2008	WICHITA CO WID 2	Red	22	0	22
2008	WILLIAMS PRODUCTION GULF COAST LLP INC	Brazos	0.346	0	0
2008	ZEBRA INVESTMENTS INC	Brazos	53.4	0	53.4
	Totals		**564,147.36**	**259,933.12**	**168,660.45**

Source: TCEQ Central Registry database

Table 77. Water-rights permit data

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
UPPER NECHES RIVER MWD		Anderson			AM 10/14/92,9/28/99,3/1/00.MULTI-EVERYTH
SAN MIGUEL ELECTRIC COOP INC	SAN MIGUEL LIGNITE MINE	Atascosa	120.00		SEDIMENTATION CONTROL AND DUST SUPPRESSION PURPOSES
NORTH CENTRAL TEXAS MWA		Baylor	500.00		
BRAZOS RIVER AUTHORITY		Bell			MAX RATE "UNSPECIFIED"
BRAZOS RIVER AUTHORITY		Bell			
FRANKLIN LIMESTONE COMPANY		Bell	138.00	69.00	
CAPITOL AGGREGATES INC	CAGNON SAND & GRAVEL PLANT	Bexar	431.00	5.00	AMEND 2/93,7/94,9/96,10/98.SC,08/28/02
CAPITOL AGGREGATES INC	CAGNON SAND & GRAVEL PLANT	Bexar	769.00	10.00	AMEND 2/93,7/94,9/96,10/98.SC,08/28/02
CAPITOL AGGREGATES INC	CAGNON SAND & GRAVEL PLANT	Bexar	3,304.00	585.00	AMEND 2/93,7/94,9/96,10/98.SC,08/28/02
JOHN MCPHERSON ET AL		Bosque			AMENDED 5/15/2009: CHANGE TO MULTI-USE; ADDED MINING USE
CHEVRON PHILLIPS CHEMICAL CO LP	CLEMENS TERMINAL	Brazoria	3,000.00		
CHEVRON PHILLIPS CHEMICAL CO LP	CLEMENS TERMINAL	Brazoria	2,350.00		
UNITED STATES DEPT OF ENERGY	BRYAN MOUND SPR SITE NEAR FREEPORT	Brazoria	52,000.00		TOTAL 215K. AM 7/31/89, 3/26/2001
APACHE CORPORATION		Brazos	20.00		
LOWER COLORADO RIVER AUTHORITY		Burnet			SEE 5482-6.AM 10/89,3/90,3/96.AM C ABAND
SOUTHWESTERN GRAPHITE CO	DIV OF DIXON TICONDEROGA	Burnet	400.00		
GUADALUPE-BLANCO RIVER AUTHORITY		Calhoun			AM 4/91,5/04,9/04,5/1/2007:STAT DISTRICT
UNION CARBIDE CHEM & PLASTICS		Calhoun			AMEND 4/17/91.PART OWNER WITH GBRA
DOUGLAS M BRICE		Cameron			AMEND 3/13/95, 6/4/99
JOEL RUIZ ET UX		Cameron			RATE:23-2707.AMEND 10/30/84,7/2/99

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
MICHAEL A MACMAHON		Cameron	9.62		AMEND 6/6/97:DIVPTS 8 COS BELOW AMISTAD
PABLO A RAMIREZ INC		Cameron			" " .5 COUNTIES."
TXU MINING COMPANY LP	MONTICELLO-LEESBURG LIGNITE MINING AREA	Camp	685.00		SCs.DUST SUPPR,CNSTR,EQUIP.AM A:CORR DPs
CHAMBERS-LIBERTY COS ND		Chambers			AMEND 10/25/04:ADD USES & IBT TO 80000AF
CHAMBERS-LIBERTY COS ND		Chambers	800.00		
CITY OF HENRIETTA		Clay	1.00		
COLORADO RIVER MWD		Coke	8,427.00		MAY DIVERT 6000 AF IN CO 168. "
COLORADO RIVER MWD		Coke	1,000.00		MAY DIVERT 6000 AF IN CO 168. "
PATTY LOIS CERVENKA		Coke	100.00		& CO 200.AMEND 5/10/2007:ADD MINING USE
RAMONA A TAYLOR		Coke	40.00		& IRRIGATION. 3 DIVPTS. AMEND 11/12/99
SANCO MATERIALS CO		Coke	35.00		DIVERT 309 AF.AMEND 10/96,10/98.3 DIVPTS
SANCO MATERIALS CO		Coke	32.00		DIVERT 320 AF.SC.AM 10/98,9/99.2 DIVPTS
BRAZOS RIVER AUTHORITY		Comanche			
R E JANES GRAVEL CO		Crosby	450.00		
WHITE RIVER MWD		Crosby	2,000.00		
CITY OF DALLAS		Dallas			AM 84,85,86,1/96,3/1/96,6/02,11/04,10/06
H S JACKSON SAND & GRAVEL INC		Denton	3.00		8/07 MAIL RETD: RTS/BOX CLOSED/UTF
CHARLES LYDELL THALMANN		Dimmit	1.00		AMEND 2/26/90
GREENBELT M&I WA		Donley	750.00		
EASTLAND INDUSTRIAL FOUNDATION		Eastland	607.00		
EBAA IRON INC		Eastland	1,000.00		
EL PASO CO WID 1	MESILLA, AMERICAN, RIVERSIDE DIV DAMS	El Paso			ADJUDICATED FROM 5433-1
HUDSPETH COUNTY CRD 1		El Paso			& HUDSPETH CO. ADJUDICATED FROM 244/236-1 IN 2007
UNITED STATES OF AMERICA	MESILLA, AMERICAN, RIVERSIDE DIV DAMS	El Paso			ADJUDICATED FROM 5433-1
ASH GROVE TEXAS LP		Ellis	82.00	50.00	AMENDED 1/5/2001: INCREASE DIV RATE
TARRANT INVESTMENT CO INC		Erath	30.00		USE 1 UNDER ADJ 4026. "; 7/09 MAIL RTD;RTS/ANK/UTF
CAMPBELL CONCRETE & MATERIALS LP		Fort Bend	2,300.00	230.00	AMEND 4/12/2000:ADD DIVPT,IMPOUNDMENT

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
GULF COAST WATER AUTHORITY		Fort Bend			WHICH PRIORITY DATE?
CAVERN DISPOSAL INC		Freestone	31.00		129 AF USE 4 EXPIRED 12/92
TARRANT REGIONAL WATER DIST		Freestone			ALSO CO 175. AMEND 1/4/2000, 2/8/2005
TARRANT REGIONAL WATER DIST	DISTRICT RETURN FLOWS	Freestone			AMEND 2/8/05:DISTRICT RETURN FLOWS.2 DPs
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone	5.00		SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
TXU BIG BROWN MINING CO LP	BIG BROWN CREEK	Freestone			SC. 7 DIV PTS
CITATION 2002 INVESTMENT LP		Garza	200.00		AMEND 8/93; WITH WSC 2418
WHITE RIVER MWD		Garza	4,000.00		8/4/2005: CONSTR EXTENDED TO 7/24/2012. 1/21/2009: CONSTR EXTENDED TO 7/24/2016
WAYNE E MOHR		Gillespie	30.00		AMND 1/24/96:2ND DIV PT:30.272N/98.781W
WEIRICH BROTHERS INC		Gillespie	50.20		WASH GRAVEL. AMEND 8/25/95
RED RIVER AUTHORITY		Grayson	100.00		
G R AKIN ET AL		Gregg	5.20		
TEXAS MUNICIPAL POWER AGENCY	GIBBONS CREEK LIGNITE MINE	Grimes			AMEND 1/24/05:ADD USES 7, 8, 11
TEXAS MUNICIPAL POWER AGENCY	GIBBONS CREEK LIGNITE MINE	Grimes	200.00		AMEND 12/16/04:ADD USES
FAIR OIL LC		Harrison	165.21		& CO 158
SABINE MINING COMPANY	PIRKEY POWER PLANT	Harrison	200.00		
SABINE MINING COMPANY	SOUTH HALLSVILLE #1 SURFACE LIGNITE MINE	Harrison			REDIRECT ALL OF BRANDY BR TO HATLEY CRK
TARRANT REGIONAL WATER DIST		Henderson			AMEND 7/93, 1/4/2000, 2/8/05
TARRANT REGIONAL WATER DIST	DISTRICT RETURN FLOWS	Henderson			AMENDED 2/8/05:ADD DISTRICT RETURN FLOWS
TEX IRON INC		Henderson			STORED GROUNDWATER. CRUSHED STONE WASHING
DOUGLAS M BRICE		Hidalgo			AMEND 3/13/95, 6/4/99

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
HIDALGO CO IRR DIST 2		Hidalgo	100.00		7/14/81,6/10/87,5/15/90,5/8/95,4/13/2000
HIDALGO CO WID 3		Hidalgo	100.00		AMENDED 10/10/78, 9/8/95
HIDALGO COUNTY IRR DIST 16		Hidalgo	200.00		AMEND 8/11/95, 7/12/96
JOEL RUIZ ET UX		Hidalgo			RATE:23-2707.AMEND 10/30/84,7/2/99
LUCIO E GONZALEZ JR		Hidalgo	5.00		
PABLO A RAMIREZ INC		Hidalgo			" " .5 COUNTIES."
RUFINO GARZA ET AL		Hidalgo	125.00		AMENDED 11/1/93, 8/30/94, 1/8/99
SERGIO GALINDO		Hidalgo	100.00		AMENDED 4/25/2007:CHG IRR TO MINING
BRAZOS RIVER AUTHORITY		Hill			
CITY OF CLEBURNE		Hill			
BRAZOS RIVER AUTHORITY		Hood			
BURLINGTON RESOURCES OIL & GAS CO LP		Hood	600.00		AMMENDED 2/6/2009- INCREASED DIVERSION AMT FROM 400 AC-FT TO 600 AC-FT
CARRIZO OIL & GAS INC		Hood	15.00		
CHESAPEAKE ENERGY INC		Hood	2,000.00		
ENCANA OIL & GAS USA INC		Hood	17.00		REPLACED 12179-9
EOG RESOURCES INC		Hood	680.00		
EOG RESOURCES INC EASTERN DIVISION		Hood	300.00		
LOWELL UNDERWOOD		Hood	100.00		
QUICKSILVER RESOURCES INC		Hood	1,400.00		
WESTERN COMPANY OF TEXAS INC		Hood	1,000.00		SYSOP
WILLIAMS PRODUCTION GULF COAST LLP INC		Hood	86.00		
TXU MINING COMPANY LP	MONTICELLO-THERMO LMA	Hopkins	220.00		DUST SUPPR,CONSTR,MISC.4 DPS,3 RES.SCs
ALON USA REFINING INC		Howard	215.00		OIL WELL FLOODING; & USE 2
COLORADO RIVER MWD	BEALS CREEK PROJECT	Howard	2,200.00	2,000.00	& WATER QUALITY IMPROVEMENT
COLORADO RIVER MWD	NATURAL DAM LAKE PROJECT	Howard	2,500.00		&CO 159;& USE 8-WATER QUALITY CTRL; IMP
W F COMPANY LTD		Howard	800.00		NOTIFY CLEANRIVERS OF CHG.MAIL RETD 6/07

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
TEXAS INDUSTRIES INC	BOONESVILLE PLANT	Jack			50 AF PURCHASED FROM TARRANT CO WCID 1
PREMCOR PIPELINE CO		Jefferson	76.70		
UNITED STATES DEPT OF ENERGY	BIG HILL SPR SITE	Jefferson	30,000.00		AMND 7/12/90.87291 AF ABANDONED 3/20/96
TRINITY MATERIALS INC	CLEBURNE PLANT	Johnson	125.00		CONSUMPTIVE USE UNDER WSC#2210
GEOCHEMICAL SURVEYS		Jones	40.00		2 LAKES.6/06 MAIL RETD:RTS/ANK/UTF
RICHARD SCHKADE		Jones	5.00		CLEANING AND REUSE IN ROCKSAW COOLING
TLC INVESTMENTS LLC		Jones	338.00		
TRINITY MATERIALS INC	SEAGOVILLE SAND & GRAVEL #280	Kaufman	100.00		WITH WSC 2300. AMEND 12/21/2006: MOVE DIVPT. MAIL RETD 3/09: RTS/NO MAIL RECEPTACLE/UTF
OCCIDENTAL PERMIAN LTD	COGDELL CANYON REEF UNIT	Kent	3,525.00		
OCCIDENTAL PERMIAN LTD	COGDELL CANYON REEF UNIT	Kent	2,375.00		
DARRELL G LOCHTE ET AL		Kerr	143.00		123 AF NONCONSUMPTIVE.9/07 MAIL RETD:RTS
WHEATCRAFT INC		Kerr			AM 8/7/2000:CONTRACT.10/04/2006:MU, DPs
WHEATCRAFT INC		Kerr			AMEND 4/18/2006: ADD MINING (MULTI-USE)
WEIRICH BROTHERS INC	KIMBLE CO PLANT	Kimble	60.00	6.00	
PLAINS PETROLEUM OPERATING CO		Knox	235.00		SECONDARY OIL RECOVERY. W/WSC _____
SAN JACINTO RIVER AUTHORITY		Liberty			MULTI-USES,COUNTY,PRI. AMEND 5/95, 10/3/06
TXU MINING COMPANY LP	KOSSE LIGNITE MINE	Limestone	1,000.00		DUST SUPPRESSION, CONSTRUCTION, & MISC MINING ACTIVITIES
COLORADO RIVER MWD	O H IVIE RESERVOIR	Martin			DIV 2500 AF TOTAL FROM EITHER RESERVOIR FOR INDUSTRIAL OR MINING USE
TERRY JACKSON INC		Mason			1.5 AF CONTRACT WATER. WITH WSC 12254-9
ALAMO CONCRETE PRODUCTS LTD		Maverick	78.00	15.00	AMEND 4/22/87,12/12/94.15 AF CONSUMPTIVE
DE LOS SANTOS READY MIX		Maverick	2.00		AMEND 1/24/91,3/14/01,4/18/01,11/03/03
DOUGLAS M BRICE		Maverick			AMEND 3/13/95, 6/4/99
EW RITCHIE III ET AL		Maverick			
KATHRYN RITCHIE COTTER ET AL		Maverick	10.00		AMEND 7/6/93
MILDRED GOODSON		Maverick			AMEND 3/27/02, SPECIAL COND

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
JIMMY A MUMME ET UX		Medina	15.00		AMENDED 10/20/04:ADD DIV PT,FLOW RESTRIC
MOBLEY COMPANY INC		Menard	3.00		
ALCOA INC	SANDOW MINE RECLAMATION PROJ	Milam			STORE GW IN RESERVOIRS.SEE 5816-1.SCs
ALCOA INC		Milam			STORE GW IN RESERVOIRS.SEE 5803-1.SCs
CITY OF BOWIE		Montague	200.00		
CLARICE BENTON WHITESIDE		Montague	9.00		
SAN JACINTO RIVER AUTHORITY		Montgomery	5,500.00		
CITY OF CORPUS CHRISTI		Nueces	12.00		TRANSBASIN TO BASINS 20, 22.ORDER 4/2001
CITY OF CORPUS CHRISTI	JC ELLIOTT LANDFILL & ADJACENT CITY PROP	Nueces			SC
TOM W GREEN		Oldham	30.00		
3 N1 WATER SOLUTIONS		Palo Pinto	250.00		
3 N1 WATER SOLUTIONS		Palo Pinto	250.00		
BASELINE OIL & GAS CORP		Palo Pinto	1,000.00		REPLACED 2420-9
BLUE SKY OILFIELD SERVICE LLC		PALO PINTO	15.00		
BRAZOS RIVER AUTHORITY		Palo Pinto			
BRAZOS WATER STATION		Palo Pinto	100.00		AMENDMENT CHANGES EXPIRE DATE TO 12/31/2009
BRAZOS WATER STATION		Palo Pinto	50.00		
BURLINGTON RESOURCES OIL & GAS CO LP		Palo Pinto	200.00		AMMENDED 2/6/09- CHANGE DIVERSION AMT FROM 400 AC-FT TO 200 AC-FT
CITATION 1998 INVESTMENT LTD PARTNERSHIP		Palo Pinto	175.00		GOES W/ APP#5359(UPSTREAM CONTRACT)
DART OIL & GAS CORP		Palo Pinto	10.00		
DEVON ENERGY PRODUCTION CO LP		Palo Pinto	100.00		
EOG RESOURCES INC		Palo Pinto	320.00		AMENDMENT ADDS A DIVERSION PT.
EOG RESOURCES INC WESTERN DIVISION		Palo Pinto	190.00		
INGRAM ENTERPRISES LP		Palo Pinto	50.00		
LATTIMORE MATERIALS COMPANY		Palo Pinto	300.00		

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
MINERAL WELLS SAND & GRAVEL INC		Palo Pinto	15.00		
NORTH RIDGE CORPORATION		Palo Pinto	235.00		
NORTH TEXAS LIVING WATER RESOURCES LLC		Palo Pinto	2,700.00		MULTIUSE=MINING & IRRIGATION
NORTH TEXAS LIVING WATER RESOURCES LLC		Palo Pinto	650.00		MULTIUSE=MINING & IRRIGATION
PIONEER NATURAL RESOURCES USA INC		Palo Pinto	129.00		REPLACED 12062-9
R J CARAWAY		Palo Pinto	41.00		
RANGE RESOURCES CORPORATION		PALO PINTO	90.00		
THISTLE DEW RANCH		Palo Pinto			
VULCAN CONSTRUCTION MATERIALS LLP		Palo Pinto	2,000.00		REPLACED 1315-9
LUMINANT MINING CO LLC	MARTIN LAKE LMA	Panola	250.00		3 RES, 3 DIV PTS. ALSO RUSK CO. MINING, D&L, SEDIMENT CONTROL. AMENDED 5/11/2009: COMBINE 5004 INTO 5889
TXU MINING COMPANY LP	MARTIN LAKE LIGNITE MINING AREA	Panola	600.00		21 DIV PTS.SCs.EXEMPT RES.AMN 3/30/07
TXU MINING COMPANY LP	MARTIN LAKE LIGNITE MINING AREA	Panola	400.00		AMEND 3/30/07:ADD 400AF,RESES,USES
TXU MINING COMPANY LP		Panola	150.00		11 DIV PTS. SCs
XTO ENERGY INC		Panola	720.00		
CITY OF WEATHERFORD		Parker			AMEND 9/8/04
TXI OPERATIONS LP	TIN TOP	Parker			
APACHE CORPORATION		Robertson	20.00		
BRAZOS RIVER AUTHORITY		Robertson			
TXU MINING COMPANY LP	TWIN OAKS LIGNITE MINING AREA	Robertson	685.00	53.00	TOTAL OF 12 DIVPTS.SCs. GW FROM DEWATER
TXU MINING COMPANY LP	TWIN OAKS LIGNITE MINING AREA	Robertson			TOTAL OF 12 DIV PTS.SCs
TXU MINING COMPANY LP	TWIN OAKS LIGNITE MINING AREA	Robertson			TOTAL OF 12 DIV PTS.SCs

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
TXU MINING COMPANY LP	TWIN OAKS LIGNITE MINING AREA	Robertson			TOTAL OF 12 DIV PTS.SCs
WALNUT CREEK MINING COMPANY		Robertson			LIGNITE MINE SEDIMENTATION POND
BONNIE JO BLYTHE ET AL		Runnels	70.00		2 TRACTS 531.4 ACRES, SC. "
LUMINANT MINING CO LLC	OAK HILL LIGNITE MINING AREA	Rusk	680.00		SC
LUMINANT MINING CO LLC	OAK HILL LIGNITE MINING AREA	Rusk			SC
LUMINANT MINING CO LLC	OAK HILL LIGNITE MINING AREA	Rusk			SC
LUMINANT MINING CO LLC	OAK HILL LIGNITE MINING AREA	Rusk			SC
LUMINANT MINING CO LLC	OAK HILL LIGNITE MINING AREA	Rusk			SC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk	680.00		DP1. DUST SUPPR, CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP2.DUST SUPPR,CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP3. DUST SUPPR, CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP4. DUST SUPPR, CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP5. DUST SUPPR, CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP6. DUST SUPPR, CONSTR, EQUIP WASH,MISC
TXU MINING COMPANY LP	OAK HILL LIGNITE MINE AREA	Rusk			DP7. DUST SUPPR, CONSTR, EQUIP WASH,MISC
MOBLEY COMPANY INC		Schleicher	3.00		
COLORADO RIVER MWD		Scurry			&CO 17.AMEND 9/26/2001:DIV PTS, ADD IRR
H R STASNEY & SONS LTD		Shackelford			AMEND 5/13/2009: CHANGE TO MULTI-USE: LIVESTOCK, DOMESTIC, & MINING PURPOSES
BELL SAND COMPANY		Smith	60.00	6.00	SAND WASHING

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
R E KERSH		Smith	57.00	6.00	SAND AND GRAVEL WASHING
CLEMMACO LTD		Starr			AMEND 9/19/97, 7/30/2008: COMBINATIONS
DOUGLAS M BRICE		Starr			AMEND 3/13/95, 6/4/99
JOEL RUIZ ET UX		Starr			RATE:23-2707.AMEND 10/30/84,7/2/99
PABLO A RAMIREZ INC		Starr	30.00		" " .5 COUNTIES."
ROSITA GRAVEL INC		Starr	22.50		AMENDED 11/14/97: CHANGE USE 3 TO USE 4
BRECKENRIDGE GASOLINE CO		Stephens			6/06 MAIL RETD:RTS/NDAA/UTF
SWANSON MULESHOE RANCH LTD		Stephens	218.00		AMEND 8/12/86: REVERTS TO REC USE
WEST CENTRAL TEXAS MWD		Stephens			AMEND 3/6/91,10/11/2002
CITATION 1994 INVEST LTD PART		Stonewall	235.00		WITH CONTRACT #1995 (? CONTRACT EXPIRED)
MOBLEY COMPANY INC		Sutton	3.00		
TARRANT REGIONAL WATER DIST	TO FT WORTH HOLLY WWTP	Tarrant			B&B CONVEYANCE OF PIPELINE WATER. MAX RATE NOT TO EXCEED DISCHARGED RATE
TARRANT REGIONAL WATER DISTRICT		Tarrant			AMEND 5/14/85, 1/4/2000, 2/21/2005. MAX RATE UNSPECIFIED
LUMINANT GENERATION CO LLC	MONTICELLO STEAM ELECTRIC STATION	Titus			DUST SUPPRESSION,EQUIP WASHDOWN & MISC
TXU MINING COMPANY LP	MONTICELLO LIGNITE MINING AREA	Titus	50.00		SCs. 13 DIVPTS, 7 RESERVOIRS
TXU MINING COMPANY LP	MONTICELLO LMA	Titus	135.00		6 DPS, 2 RES. SCs.
TXU MINING COMPANY LP	MONTICELLO LIGNITE MINING AREA	Titus	200.00		3 DIV SEGMENTS & 5 RES. SCs
UPPER COLORADO RIVER AUTH		Tom Green			AMENDED 12/19/97, 5/30/2008, 6/13/2008
CAPITOL AGGREGATES LTD	AUSTIN SAND-GRAVEL PLANT READY MIX	Travis	2,540.00	340.00	AMENDED 8/15/97: COMBINED WITH 5378-6; PERMIT EXPIRES UPON PERMANENT CESSATION OF MINING OPS
CAPITOL AGGREGATES LTD	AUSTIN SAND-GRAVEL PLANT READY MIX	Travis	242.00	0.00	AMENDED 8/15/97: COMBINED WITH 5378-6. THIS IS NONCONSUMPTIVE MINING USE
LOWER COLORADO RIVER AUTHORITY		Travis			SEE 5478.AMEND 10/12/89,3/8/90,10/31/91
SHUMAKER ENTERPRISES INC		Travis	300.00		REPLACED 2208-9;AMENDED 11/01
TERRY JACKSON INC		Travis	1.50		1.5 AF CONTRACT WATER. SEE PERMIT 12244-1

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
TEXAS INDUSTRIES INC	GREEN SAND AND GRAVEL PLANT	Travis	110.00	11.00	690 A/F EXP 12/31/93; ALL WATER RIGHTS EXPIRE WHEN MINING ENDS OR UPON EXPIRATION OF LEASE; FLOW RESTR ON EXPIRED WATER
TYLER SAND COMPANY		Upshur	200.00		1/99: SEE SC A, CO DEFUNCT; WUR/NOT N
CAPITOL AGGREGATES INC	DEL RIO PLANT	Val Verde	166.00	17.00	AM 11/2/87.6/28/2001:ADD DIVPT & PLACE
MORTON SALT COMPANY INC		Van Zandt	251.00		EXEMPT LAKE
UNION OIL CO OF CALIFORNIA		Van Zandt	400.00		
UNION OIL CO OF CALIFORNIA		Van Zandt	270.00		
UNION OIL CO OF CALIFORNIA		Van Zandt	500.00		
BRAZOS RIVER AUTHORITY		Washington			
ALBERT F MULLER JR		Webb	2.38		
ALICE SOUTHERN EQUIP SERVICE		Webb	145.00		AMEND 7 & 11/93,12/94,10/30/98
ALICE SOUTHERN EQUIP SERVICE		Webb	175.00		AMENDED 10/30/98
BARBARA T FASKEN	FARCO MINE DAM AREA	Webb	200.00		
BEN-HUR ENTERPRISES LTD		Webb			AMEND 1/24/91,3/14/2001,4/18/2001.2705-6
CHRISTINE MCKEE		Webb	1.00		AMEND 6/20/87. USE 4 IN ZAPATA & WEBB
CITY READY MIX INC		Webb	100.00		AMEND 10/15/91, 11/23/92
DOUGLAS M BRICE		Webb	131.56		AMEND 3/13/95, 6/4/99
H B O'KEEFE ESTATE		Webb	100.00		AMENDED 8/14/98: 100 AF USE 3 TO USE 4
HACHAR REAL ESTATE COMPANY		Webb	23.00		AMEND 6/30/86
J & B CONTRACTORS INC		Webb	2.00		AMEND 3/29/94
JOEL RUIZ ET UX		Webb			RATE:23-2707.AMEND 10/30/84,7/2/99
LAREDO SAND & GRAVEL CO		Webb	20.00		
LOUIS C LECHENGER ET AL		Webb	20.00		AMEND 4/14/88
MANDEL PROPERTIES LTD		Webb	100.00		AMEND 10/13/95
MICHAEL ALLEN MACMAHON		Webb	120.00		6/18/90
RANCHO BLANCO CORPORATION		Webb	300.00		AMEND 11/2/87,9/25/89,10/11/94,8/25/95
RODOLFO GARCIA		Webb	75.00	10.00	
RODOLFO GARCIA		Webb	62.00		
SAMUEL A MEYER ET AL		Webb	30.00		AMEND 10/17/94
SAN ISIDRO NORTH LTD		Webb			AMEND 12/18/91, 5/31/96. AMEND 3/19/2008: ADD MINING USE. AMEND 7/2/2008: ADD INDUSTRIAL USE

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
STEPHEN A MCKENDRICK TRUSTEE		Webb	2.38		W H MCKENDRICK TRUST
TOPAZ POWER PROPERTY MGMT II LP		Webb			AMEND 2/7/97.REUSE 731.5 OF THE 2194.5
UNION PACIFIC OIL & GAS CO		Webb	5.00		AMEND 6/16/92
WILLIAM H MCKENDRICK III		Webb	8.33		
CONOCOPHILLIPS CO		Wharton			
LEONARD WITTIG GRASS FARMS INC		Wharton	1,000.00		
WHARTON COUNTY GENERATION LLC	NEWGULF POWER FACILITY	Wharton			
WICHITA CO WID 2 ET AL		Wichita	2,000.00		
W T WAGGONER ESTATE		Wilbarger	30.00		FROM MIDWAY LAKE
JOEL RUIZ ET UX		Willacy			RATE:23-2707.AMEND 10/30/84,7/2/99
PABLO A RAMIREZ INC		Willacy			" " .5 COUNTIES."
ALAMO CONCRETE PRODUCTS LTD	WEIR PLANT	Williamson	300.00	30.00	AM 6/92,5/02.FORMERLY SOUTHWEST MATERIAL
BRAZOS RIVER AUTHORITY		Williamson			
BRAZOS RIVER AUTHORITY		Williamson			
CAPITOL AGGREGATES LTD	GEORGETOWN QUARRY	Williamson	118.00		AMENDED 8/15/97, 5/28/99: ADDED DIV PT
GENE H BINGHAM ET AL		Williamson	240.00	24.00	MAY CONSUMPTIVELY USE 24AFY
HANSON AGGREGATES CENTRAL INC	BRIDGEPORT STONE PLANT #2	Wise	345.00	69.00	
HANSON AGGREGATES CENTRAL INC	BRIDGEPORT STONE PLANT #2	Wise	1,505.00	301.00	
HANSON AGGREGATES CENTRAL INC	CHICO CRUSHED STONE PLANT	Wise	510.00		AMEND 5/7/91
HANSON AGGREGATES WEST INC		Wise	1,475.00		
HANSON AGGREGATES WEST INC		Wise	177.00	177.00	
MARTIN MARIETTA MATERIALS SOUTHWEST INC		Wise	1,200.00		
TARRANT REGIONAL WATER DIST		Wise	7,500.00		COS 249, 220
TARRANT REGIONAL WATER DIST		Wise			AMEND 5/5/89,1/4/2000. COS 249,119

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
TRINITY MATERIALS INC	DECATUR PLANT #205	Wise	25.00		SC. W/WSC#1970
CITY OF GRAHAM		Young	500.00		
PITCOCK BROTHERS READY-MIX		Young	100.00		
ANTONIO R SANCHEZ SR ESTATE		Zapata	50.00		3/87,8/87,9/88,7/89,5/10/2000.9 COUNTIES
ANTONIO R SANCHEZ SR ESTATE		Zapata	50.43		3/87,8/87,9/88,7/89,5/10/2000.9 COUNTIES
DOUGLAS M BRICE		Zapata			AMEND 3/13/95, 6/4/99
EDWIN H FRANK III		Zapata	6.00		AMEND 1/4/90
EL CAMPO FARM COMPANY		Zapata	25.00		SEE 23-2787 FOR RATE
FENDER EXPLORATION & PRODUCTION CO LLC		Zapata	20.00		AMEND 10/25/2000:CHG 20 AF TO MINING USE
FLF LTD		Zapata	7.46		AMEND 1/4/90
GALBERRY PROPERTIES LLC		Zapata	5.60		AMEND 1/4/90
HERRADURA RANCH		Zapata	6.30		AMEND 1/4/90
JAMES C GUERRA ET AL		Zapata	12.50		AMEND 8/14/98: CHG POFD & USE 3 TO 4
JAVIER ZAPATA ET AL		Zapata	146.00		
JOEL RUIZ ET UX		Zapata	20.00		RATE:23-2707.AMEND 10/30/84,7/2/99
KCS RESOURCES INC		Zapata	25.00		
LARRY G HANCOCK		Zapata	6.10		AMEND 1/4/90
LONE STAR LA PERLA LP		Zapata	5.64		AMEND 1/4/90
MARIA EVA URIBE RAMIREZ		Zapata	10.00		AMEND 7/12/90
MARTINEZ QUARTER HORSE RANCH LTD		Zapata			AM 5/3/06:ADD MINING.6/13/07:ADD ACRES
MARTINEZ QUARTER HORSE RANCH LTD		Zapata	2.80		AMEND 1/4/90
MICHAEL T THRASHER		Zapata	6.10		AMEND 1/4/90
NEUHAUS & CO LTD		Zapata	17.10		AMEND 1/4/90
PABLO A RAMIREZ INC		Zapata			" " .5 COUNTIES."
RAMIRO V MARTINEZ		Zapata			AMEND 3/16/05:ADD IND & MINING USES
ROBERTO J VIDAURRI		Zapata			AM 5/92,6/93,08/02,9/26/02,7/31/2009:MULTI-USE,DIV
ROSEMARIE ANN GEARY		Zapata			AM 12/1/86,4/12/94,7/27/01,11/4/03:MULTI
SDK FARMS		Zapata	12.90		AMEND 1/4/90
SDK FARMS LLC		Zapata			AM 5/3/06:ADD MINING.6/13/07:ADD ACRES

Owner Name	Site Name	County	Amount Diverted (acre-feet)	Amount Consumed (acre-feet)	Remarks
TECOMATE CAPITAL PARTNERS LTD		Zapata	4.00		AMEND 1/4/90
UNICO CONSTRUCTION CO		Zapata	11.24		AMEND 5/31/85,3/13/2003:CHG USE TO 4/AG
WICHITA PARTNERSHIP LTD		Zapata			AM 1/30/95.6/21/2007:MULTIUSE.3/13/08:CM
ZAVALA-DIMMIT CO WID 1		Zavala	4.00		
ZAVALA-DIMMIT CO WID 1		Zavala			
ZAVALA-DIMMIT CO WID 1		Zavala			
CITY OF HOUSTON					

Source: TCEQ Central Registry database

14 Appendix G:
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15 Appendix H:

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16 Appendix I: yyyyy

17 Appendix J:
List of Files Submitted to TWDB and Content

17.1 List of Files with Nonproprietary Content

17.2 List of Files with Proprietary Content

18 Appendix K:
Responses to Review Comments

Responses to Review Comments

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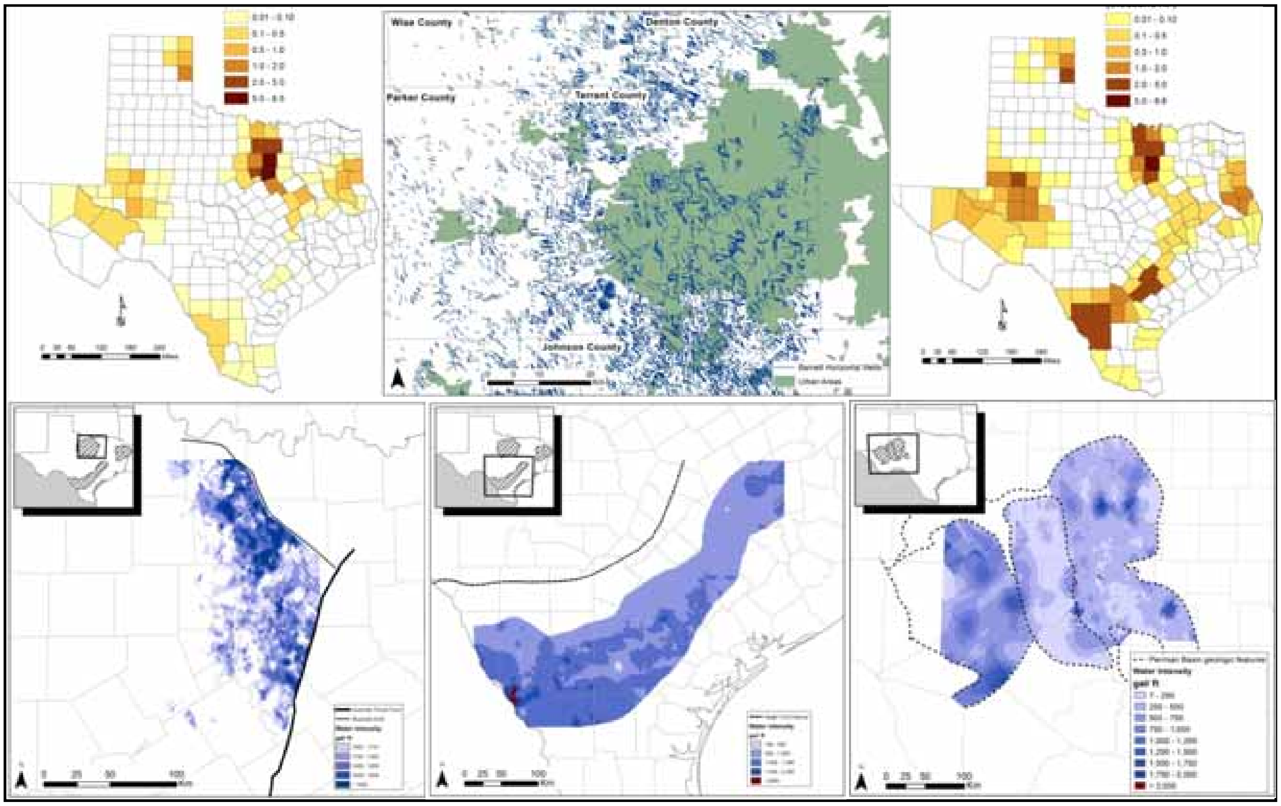
September 2012

Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report



Prepared for
Texas Oil & Gas Association, Austin, Texas

Bureau of Economic Geology
Scott W. Tinker, Director
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The University of Texas at Austin
Austin, Texas 78713-8924

Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report

Jean-Philippe Nicot, P.E., P.G., Robert C. Reedy, P.G.,
Ruth A. Costley, and Yun Huang, P.E.

STATE OF TEXAS
JEAN-PHILIPPE NICOT
90429
LICENSED PROFESSIONAL ENGINEER

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Executive Summary

In Spring 2012, we undertook an update of the hydraulic fracturing sections of the TWDB-sponsored report titled “Current and Projected Water Use in the Texas Mining and Oil and Gas Industry” that we published in June 2011 (Nicot et al., 2011). The 2011 report provided estimated county-level water use in the oil and gas industry in 2008 and projections to 2060. This 2012 update was prompted by two main events: (1) a major shift of the oil and gas industry from gas to oil production, displacing production centers across the state and impacting county-level amounts; (2) rapid development of technological advances, resulting in more common reuse and in the ability to use more brackish water. The timely update was enabled by a faster than anticipated development, translating into abundant statistical data sets from which to derive projections, and by an increased willingness of the industry to participate in providing detailed information about water use in its operations. This document follows the same methodology as the 2011 report but differs from it in two ways. Our current update clearly distinguishes between water use and water consumption. The 2011 report does not include reuse from neighboring hydraulic fracturing jobs, recycling from other industry operations or other treatment plants, and use of brackish water. Our update also presents three scenarios: high, low, and most likely water use and consumption with a focus on water consumption. This update has been reviewed by the TWDB and should supersede oil and gas industry projections from the 2011 report.

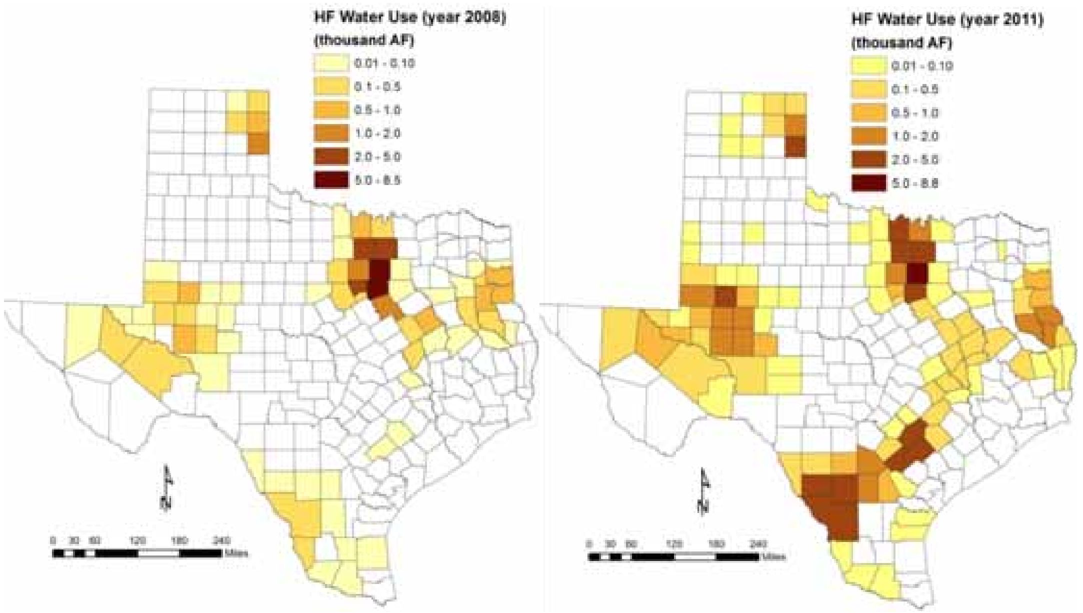

Figure ES1. Spatial distribution of hydraulic fracturing water use in 2008 (~36,000 AF) and 2011 (~81,500 AF).

Overall we find that, if the total water use for hydraulic fracturing has increased from 36,000 AF in 2008 to ~81,500 AF in 2011 (Figure ES1), the amount of recycling/reuse and the use of brackish water have also increased (~17,000 AF in 2011, or 21%). Hydraulic fracturing has expanded to the southern and western, drier parts of the state and, by necessity, the industry has had to adapt to those new conditions. Collected information tends to suggest that the industry has been decreasing its fresh-water consumption despite the increase in water use. Total water use information is relatively easy to access (through the private database vendor IHS), but true consumption is harder to gauge.

The updated hydraulic fracturing projections at the state level do not show a major departure from and are essentially consistent with the previous report but have a more subdued peak and a longer tail (Figure ES2). This is due to the increased likelihood that the industry has hydraulically fractured more formations that can be placed into the tight oil and gas category. The annual peak water use previously estimated at 145,000 AF in the early 2020's is now thought to be a broad peak plateauing at ~125,000 AF/yr during the 2020's. However, fresh water consumption is estimated to stay at the general level of ~70,000 AF/yr and to decrease in future decades. Adding other oil and gas industry water uses, such as waterflooding and drilling, brings projected maximum water use up to ~180,000 AF/yr during the 2020-2030 decade with a much lower consumption which brings the total mining water use to a maximum of ~340,000 AF/yr around the year 2030. These values remain small compared to the state water use (Figure ES3). In 2010, hydraulic fracturing water use represented about 0.5% of the water use in the state. However, the hydraulic fracturing water use is unevenly distributed across the state and may represent locally a higher fraction of the total water use.

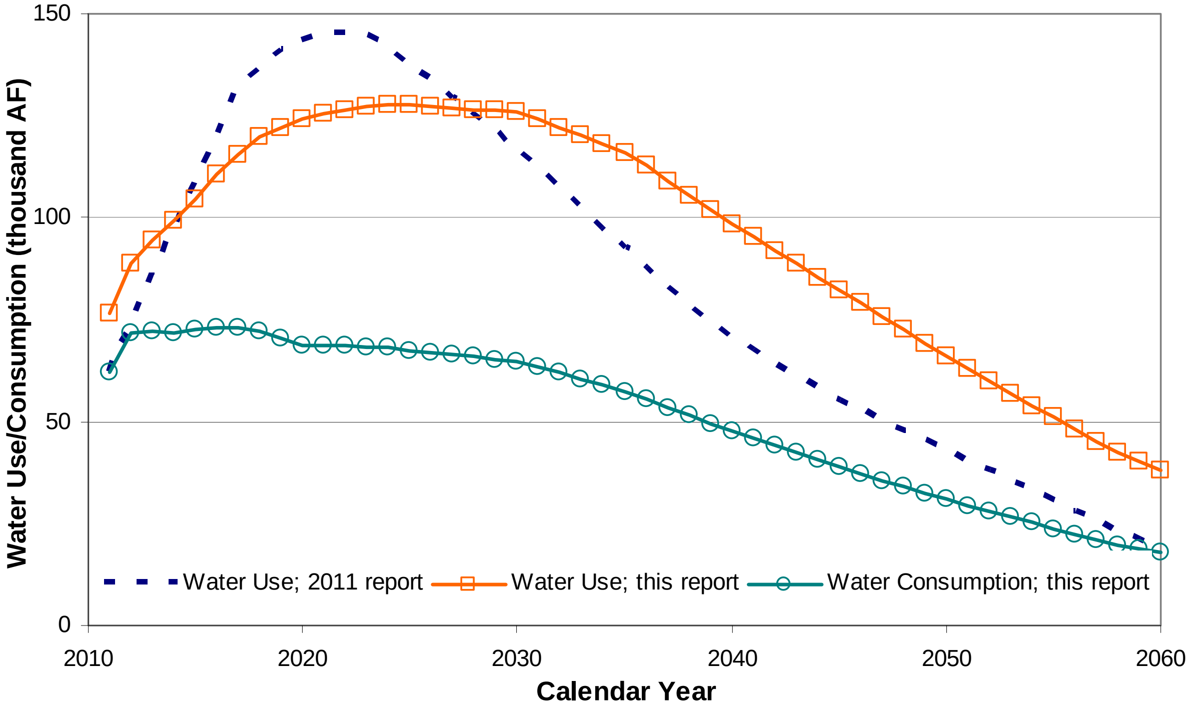

Figure ES2. State-level projections to 2060 of hydraulic fracturing water use and fresh-water consumption and comparison to earlier water projections.

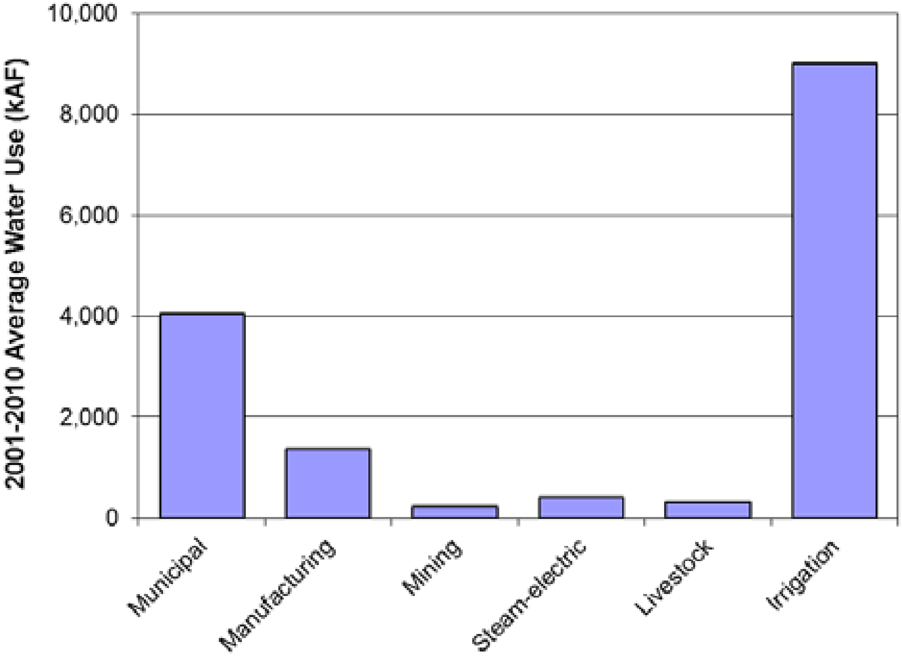

Figure ES3. Average state level water use (all categories) in 2001-2010.

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Acknowledgments

The authors would like to thank engineers and staff from many oil and gas operating companies for giving their time in answering our requests and sharing their knowledge of the hydraulic fracturing process. Special thanks to C. J. Tredway for managing the project, to Dr. Dan Hardin (TWDB) and his staff for reviewing the report, and to BEG internal reviewers, particularly Dr. Bridget Scanlon. Thanks too to L'Oreal Stepney and her staff at TCEQ for providing useful information. We are also grateful to IHS for providing free access to their Enerdeq database, which was used extensively in the course of this work. The report also benefited from a thorough editing by Amanda R. Masterson of the Bureau of Economic Geology at The University of Texas at Austin.

Acronyms

AF	Acre-foot
BEG	Bureau of Economic Geology
EOR	Enhanced Oil Recovery
Fm.	Formation
GW	Groundwater
HF	Hydraulic fracturing
kAF	Thousand acre-feet
Mgal	Million gallons
PSD	Powell Shale Digest
RRC	Railroad Commission (of Texas)
SW	Surface water
TCEQ	Texas Commission on Environmental Quality
TDS	Total dissolved solids
TWDB	Texas Water Development Board
TXOGA	Texas Oil & Gas Association

I. Introduction

This work is an update of the "Current and Projected Water Use in the Texas Mining and Oil and Gas Industry" (Nicot at al., 2011) report released in 2011 by the Texas Water Development Board (TWDB) and prepared by the Bureau of Economic Geology (BEG). The 2011 report documents future and projected water use in all segments of the mining industry: oil and gas, aggregates, coal, and other industrial and metallic substances. In particular, it looked at three main water categories in the upstream segment of the oil and gas industry: drilling, waterflooding and enhanced oil recovery (EOR), and hydraulic fracturing (HF).

How is this report different from the 2011 Report?

This report focuses on HF water use and associated drilling; the information in the 2011 report relating to waterflooding and EOR water use as well as drilling not associated with hydraulically-fractured wells did not require updating. This update also benefited from more participation from the industry, especially for information not typically available or easily extractable from state records. We also have a longer record for many plays, indicating trends and allowing for better future projections. In addition, we presented three scenarios for water use and water consumption for each play (high, medium, low) as was done in Bené et al. (2007) but not in the 2011 report. Furthermore we made the distinction between water use and water consumption more explicit. Water use is the amount of water used in an operation regardless of the water source provided; water is either fresh or brackish. Fresh water is defined as any water with a total dissolved solids (TDS) content of <1,000 mg/L; the upper limit for brackish water is 35,000 mg/L, but often in this document the limit will be <10,000 mg/L. Water consumption is fresh water use excluding recycling and reuse. Reuse is understood as the water originating from previous HF operations whereas recycling is more general and could include, for example, produced water from conventional wells or waste water obtained from other industries or municipalities.

Scope of work

As in the 2011 report, this update's scope of work includes two main tasks: (1) documenting current (year 2011) and past water use from HF; and (2) estimating projected water use. Both tasks are completed at the county level for the entire state of Texas. Task 1 consists of gathering water use data and establishing statistics needed for the projection phase in the spirit of what was done in the 2011 report but with a more detailed processing of the data. Task 2 is to produce a projection of county- level water use to 2060 using previously derived statistics and input from the industry.

This current document is organized in the following way. We first describe the methodology and its caveats as well as the challenges to making projections. We then examine the 2011 water use and compare our new findings to the 2011 projections made in 2008 as a way to validate our approach. We then present projections to 2060 according to three scenarios: high estimates, most likely estimates, and low estimates.

II. Methodology

II-1. Historical and Current Water Use

We followed a methodology similar to that used in the 2011 report, making use of the IHS Enerdeq database (http://www.ihs.com/products/oil-gas-information/data-access/enerdeq/browser.aspx). The IHS data were cross-checked with information from individual companies (number of oil/gas wells, of vertical/horizontal wells, amount of proppant) through discussion with company experts. In addition to production data, the Enerdeq database contains completion information submitted by operators to the Railroad Commission (RRC) of Texas through the W-2 and G-1 forms for oil and gas, respectively. In the best cases, and as noted by statistics provided in forthcoming sections of this report, the database contains all information of interest to us: API number, location of the well, well geometry, amount of water used, and amount of proppant used. Because, across plays, the completeness of the data is variable and because typographical errors are not infrequent, we developed several indicators for quality control: water intensity (amount of water used per unit length of lateral or useful vertical section) and proppant loading (amount of proppant per unit water volume). When either water intensity or proppant loading for a given well is out of range, the well is flagged and obvious errors corrected (for example, reporting water use in gal but displaying bbl as the unit instead of gal). Details on the approach follow.

The three primary data types used to estimate HF water volumes include reported values of fluid and proppant used to fracture each well and the total well length over which fracturing procedures were performed. Data were extracted separately from the IHS database for individual producing formations having a significant number (> ~100 to 200) of wells located in Texas that were completed between January 1, 2005 and December 31, 2011 that upon preliminary accounting had been fractured using > 100,000 gal of fluids. These include the Barnett, Eagle Ford, Haynesville, Cotton Valley, and Olmos formations, and several formations in the Anadarko Basin (Granite Wash, Cleveland, Marmaton) and the Permian Basin (Wolfcamp, Spraberry, Canyon, Clear Fork, San Andres, and Grayburg). For this analysis, the Wolfcamp and Spraberry were combined and the San Andres and Grayburg were combined.

As we did in the 2011 report we relied on the IHS database to recognize the currently active plays by downloading basic information on all wells drilled in Texas since 2010 (included early 2012 but with many gaps in the reporting). Our interest was not in computing water use but in determining those plays with enough activity to warrant a more detailed study. Many additional wells were fractured in other plays and did count toward the total water use in 2011, but they were not part of the detailed analyses of those plays cited earlier. Those minor plays are, however, accounted for in the general Gulf Coast and Permian Basin count.

II-1-1 Indicator for Quality Control

For producing formations having a sufficient number of wells completed during this period, the data were analyzed by annual intervals. Wells having actual or estimated total HF water use of <100,000 gal (i.e., small-scale traditional fracturing performed primarily on vertical/directional wells) were omitted from calculations as they account for comparatively insignificant water volumes compared to the fracturing currently being practiced in many plays. This minimum volume distinction was applied to vertical/directional wells only, and all horizontal wells were included in the estimates.

Critical evaluation and editing of the raw data was required. The purpose of the editing process was, through a step-wise logical procedure, to exclude wells that used or (in the absence of accurate data) were likely to have used <100,000 gal of HF fluids while retaining and accounting for wells that used or (again, in the absence of accurate data) were likely to have used ≥100,000 gal of HF fluids. For many wells, one or more of the reported data values is absent, incomplete, or inaccurate, due either to clerical errors or to partial reporting (omission errors). Clerical errors include the incorrect assignment of units (gal vs. bbl, lb vs. ton, etc.) and/or typographical errors. Omission errors primarily include the non-reporting or under-reporting of fluid volumes (proppant amounts seem to be accurately reported much more consistently than fluid volumes).

The data were screened for errors by examining ratios between the different values, including the total reported volume of fluids used per linear foot of the total fractured well depth interval (water use intensity, gal/ft), the total mass of proppant per total volume of HF fluids (proppant loading, lb/gal), and the total mass of proppant per linear foot of the total fractured well depth interval (proppant intensity, lb/ft). These ratios were examined for outliers and inaccuracies by sorting hierarchically through the data based on the various ratios. Edits were performed on the raw data where rectifiable errors could be identified, the most prevalent consisting of modifying units where such changes resulted in ratios consistent with other similar wells. In some cases, sufficient details were reported in the data comments to correct inaccurate data values, although this type of edit was extremely limited.

In general, proppant loading (lb/gal) was used as the primary data screening ratio because of the generally consistent reporting of total proppant amounts. HF fluid volumes resulting in proppant loading values (average of all stages) >5 lb/gal were deemed as under-reported. Barring a unit's error, these values generally reflect reported fluid volumes that include only acid treatments and in some cases raw gel product volumes and do not also include the volumes of water used. For vertical/directional wells having reported proppant amounts and with absent or under-reported HF volumes, wells with <100,000 lb of proppant were excluded from the estimates based on an assumed 1.0 lb/gal loading ratio.

A finer level of resolution in the water use data could be achieved by binning the hydraulic fracturing stages into slickwater, gel, and cross-linked gel systems with the latter two having a smaller water use intensity. Unfortunately the database does not allow for an accurate count in each category. The information, however, was used in a qualitative way, checking its consistency with common practices in a play.

Following the data screening and editing procedures, the data were classified into two main groups: 1) wells judged to have accurately reported fluid volumes and 2) wells judged to have inaccurately reported fluid volumes. The average (annual) water use intensity (gal/ft) values of the Group 1 wells were multiplied by the (annual) sum total fractured length (ft) of the Group 2 wells to produce annual estimates of the total water use of the Group 2 wells. The average intensity values represent truncated averages based on 90% of the data that were calculated by eliminating values less than the 5th percentile or greater than the 95th percentile of the Group 1 population to reduce the impacts of extreme values. The Group 2 annual total estimates were then added to the Group 1 annual total values to produce estimates of actual annual total water use. Values are reported for the major producing formations listed above by year and by county. County locations were assigned based on the wellhead coordinates.

A separate estimate using the same procedures was calculated for the HF water used during 2011 for all wells meeting the minimum 100,000 gal criteria but that were not completed in one of the producing formations listed above and for which insufficient data exist for temporal trend analysis.

II-1-2 Hydraulically-fractured Length

HF lengths for individual wells were determined using five approaches, each relying on different information in the database. All five approaches were applied to varying degrees to determine horizontal well HF lengths while only the first two were applied to vertical/directional wells. The first approach used the difference between the minimum and maximum reported test treatment depths and is referred to as the “test” length. This was the primary length used in an estimated minimum of 95% of all wells. The second approach used the difference between the minimum and maximum perforation depths, which was identical in most cases to that of the test length and is referred to as the “perf” length. The “perf” length was used in place of the test length in a few cases that resulted in more realistic use intensity values. The test and “perf” lengths are considered to be the most accurate length information available for most wells.

A third approach utilized the survey information and is referred to as the “survey” length. In this approach, the angle relative to the horizontal plane between successive well survey points was calculated. The horizontal length of the well was determined as the difference between the minimum depth at which that angle became less than 2.5 degrees and the maximum well depth. This approach also provided the average depth of the horizontal well section and additionally the beginning and ending X-Y coordinate locations of the horizontal well section used to map well density in GIS for the various plays. If no information was available to calculate a test or perf length, the survey length was considered to be the next-best available length information. In most cases where all three were available, the survey length is in good agreement with both the test and perf lengths. This value was used only in a few cases where neither a test nor a perf length was available.

A fourth length value was calculated as the difference between the reported driller’s well depth and the bottom hole true depth, referred to as the “true value” or “TV” length and a fifth length value was calculated as the simple horizontal linear distance between the X-Y coordinates of the well surface and bottom hole coordinates (“GIS” length). Both of these values are considered to be only general estimates of the horizontal section length and were used in a very limited number of instances where more accurate information was not available. For a very few instances (<<1%) no length values were available for a given well. In these cases, the annual (truncated) average well length for that producing formation was assigned.

The fourth and fifth approaches, simpler to use, were adopted in the 2011 report. The HF water intensity for horizontal wells is computed slightly differently from the approach in the 2011 report. Instead of using the distance between the wellhead of the toe of the lateral, we used a shorter distance defined by the operator-defined “test length” more representative of the true length of the lateral. The test length is consistent with the “test” length but consistently smaller by 10 to 25%. The lateral length value matters as it used to compute water intensity, itself used to make projections. There is relatively little difference between the different approaches (Figure 1) but the "test" approach used in this document is systematically smaller than the "GIS" approach used in the 2011 document, that is, water intensity values reported in this document are systematically greater than those in the 2011 report. The median value of water intensity using the "test" and "survey" approaches are 26% and 23% larger than the "GIS" median value (Figure 2) in the Barnett Shale play. The "test" water intensity median in the Eagle Ford play is 16% larger than the "GIS" median value (Figure 2d).

II-1-3 Beyond the Database

In the 2011 report we made the explicit distinction between shale plays and tight gas plays. Although, as explained in the 2011 report, there are real differences between them, from an operational standpoint the difference is blurred (for example, wells taping Wolfcamp shale oil and Spraberry tight oil) and, in this update, we did not try systematically to assign one of either category to some plays.

For each of the plays with sufficient data we extracted yearly information, presented in the Results Section, about:

- Total number of wells
- Total water use, including estimation of data gaps
- Average/median length of laterals
- Water use in Mgal/ft
- Water intensity in gal/ft
- Proppant loading in lb/gal

The IHS database provides only water use, that is, the amount of water used during a given HF job regardless of the water source(s). In actuality, water can come from several sources. It can be "new" water or it can also be recycled or reused water. "New" water can be surface water or groundwater or it can be from an alternative source such as municipal water or treated waste water. Water also be fresh (<1,000 mg/L) and its use can directly compete with other more conventional users (municipal use, irrigation use). It can be brackish or even more saline than sea water (that is, >~35,000 mg/L). Water consumption is simply defined as the water use which is not from recycled or reused water and from which brackish and saline water use is taken out. Note, however, that this simple definition does not capture a more complex reality. Use of brackish water in areas with limited fresh water supplies could compete with conventional users. This document does not try to sort out such issues; we simply define water consumption as water use minus recycled/reused water volumes and minus brackish or saline water volumes.

Access to detailed information about water sources on the provider side is difficult. Large water suppliers do not necessarily track the ultimate usage of their water. Groundwater conservation districts (GCD's) do not always collect information about withdrawal amounts and eventual use of the water. A request to the Texas Commission on Environmental Quality (TCEQ) on reuse of treatment water yielded a helpful list of facilities but not the amount of water transferred, and further this does not account for direct reuse at a site. The demand side, that is, operators, is very fragmented.

We collected information not present in the IHS database but of interest to TWDB and the general public about: (1) nature of the water source (river, lake, city water, groundwater, stock pond/gravel pit / quarry, wholesaler, treated industrial waste water) and it status (private, public). The ultimate goal is to determine the groundwater and surface water (GW/SW) split. Optimally, this issue would be resolved at the county level but it may not be possible; (2) amount of water injected from reuse of flow back water, recycled water can include water from commercial and municipal waste water treatment facilities; (3) TDS of the new water [fresh (<1000 mg/L), slightly brackish (1000-3000 mg/L), brackish (3000-10,000 mg/L or 10,000-35,000 mg/L), saline (>35,000 mg/L)].

In this document, we applied to all counties within a play / region the same brackish water use, recycling/reuse fraction, and GW/SW split. Undoubtedly, this is an approximation but the amount of information available does not allow accurate assessments at the county level.

II-2. Future Water Use Projections

The 2011 report followed a mixed approach to estimate projected water use, the so-called resource-based and production-based approaches. Although both approaches are somehow interdependent, we believe that the resource-based approach gives the best results and is used in this document. As described in more details in the 2011 report, it consists of four steps:

(1) Gather historical data in terms of average well water use and average well spacing. It is important to establish these elements through time to see trends rather than just focusing on the past few months.
(2) Estimate ultimate well density across the play; it is a function of several factors, such as geological prospectivity (for example, within play core or not, shale thickness) and cultural features (urban/rural). In this step, ultimate boundaries of the play are identified.
(3) Compute approximate total number of wells needed.
(4) Distribute through time and space, constrained by the assumed number of drilling rigs available (see earlier comment).

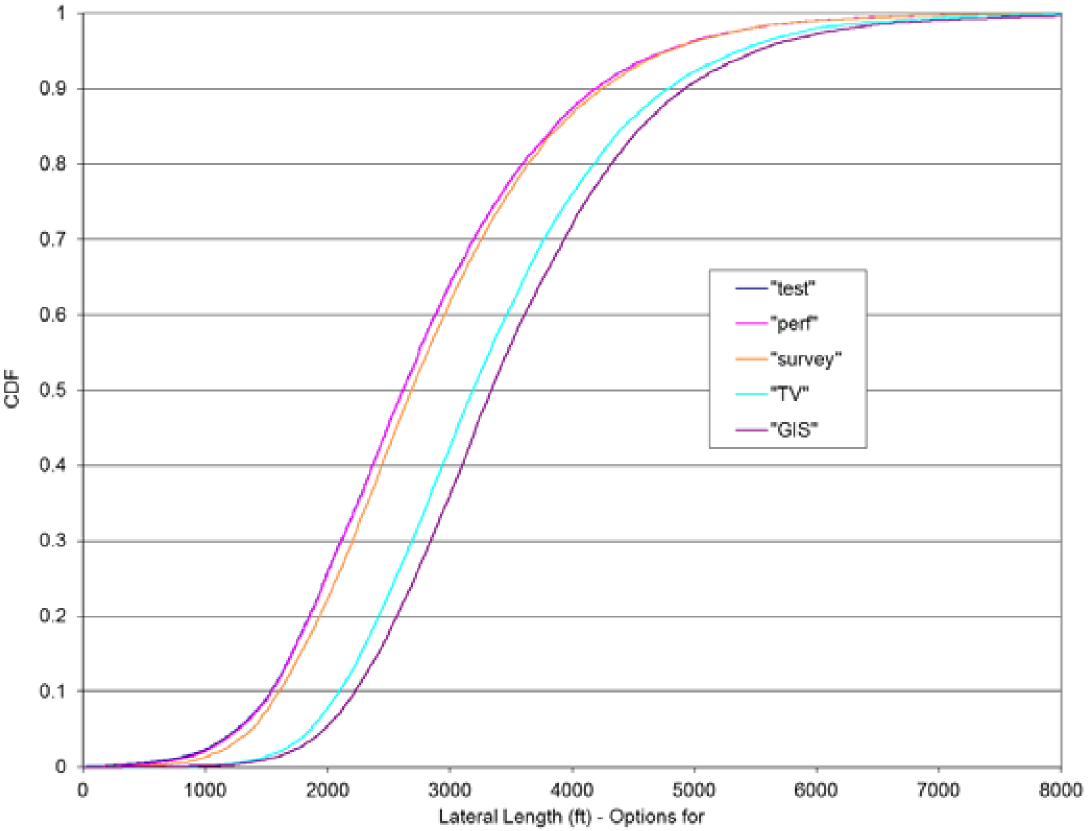
After obtaining water use, correction factors to account for recycling/reuse and use of non-fresh water are applied. We asked industry operators for projected recycling/reuse, brackish water use, and groundwater / surface water split in 2020. Given the rapid pace of change in the industry, the values obtained are somewhat speculative. Although not a guarantee for accuracy, those values are, however, consistent with what industry observers report and consistent with our own knowledge of treatment techniques and state of surface water and groundwater withdrawals across the state. The basic reporting unit for the water use projections is the county. Projections for recycling / reuse, brackish water use beyond 2020 to 2060, were made accounting for the typical current volume of flow back (limiting reuse) and for brackish water resources / lack of fresh water in the area of interest.

As discussed in the 2011 report, despite our best efforts, it is likely that the projected water use amounts will be more accurate at the play than at the county level. As done in the 2011 report, we did not assume any repeat HF, as discussions with industry experts and recent publications (Sinha and Ramakrishnan, 2011) suggest that little repeat HF will take place.

The 2011 report provides only one annual estimate. However, in an earlier report on the Barnett Shale only (Nicot and Potter, 2007; Bené et al, 2007), BEG made use of high, medium, and low water use scenarios. The different scenarios were based on various level of prospectivity and anticipated gas price. This update also makes use of three scenarios, high, most likely, and low water use, but in addition to prospectivity and gas price, they take into account level of recycling/reuse and use of brackish and saline water.

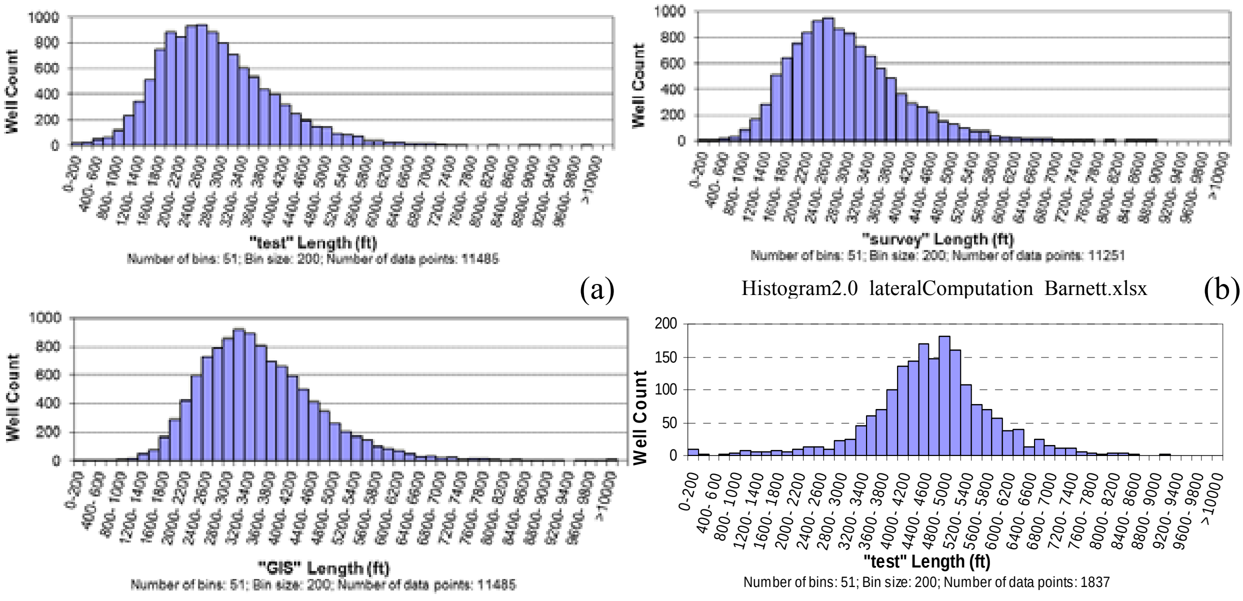
II-3. Notes on Collected Information

We obtained information on all the major plays, some with better coverage, by contacting operators. Fraction of HF wells drilled by contacted operators in the 2010-2012 period is documented by play and provides an estimate of the uncertainty. The coverage (Table 1) was calculated by adding the number of wells completed in the 2010-early 2012 period by contacted operators and normalizing that sum by the total number of wells completed during the same period. We collected information about recycling/reuse, use of brackish water, surface water/groundwater split. Coverage varies from 40% (Barnett Shale) to 10.5% (Permian Far West). Consistency in information from operators in a given play suggests that even low percentages are representative of the industry as a whole in that play despite some variability among operators (Figure 3). The figure shows a slight overall increase in water use intensity with increasing depth but it also shows that operators can have different approaches.



Histogram2.0 lateralComputation Barnett.xlsx

Figure 1. Comparison of five approaches to computing lateral length (Barnett Shale play).



Number of bins: 51; Bin size: 200; Number of data points: 11485

(a)

Number of bins: 51; Bin size: 200; Number of data points: 11251

Histogram2.0 lateralComputation Barnett.xlsx (b)

Number of bins: 51; Bin size: 200; Number of data points: 11485

(c)

Number of bins: 51; Bin size: 200; Number of data points: 1837

Histogram2.0 lateralComputation EagleFord.xls (d)

Figure 2. Histograms of lateral lengths according to various approaches: (a) “test”; (b) “survey”; (c) “GIS” (Barnett Shale play); and (d) “test” (Eagle Ford Shale play).

Table 1. Representivity of collected information

Play/Region	Consumption information (%)
Permian Far West	10.5%
Permian Midland	23%
Anadarko Basin	11%
Barnett Shale	40%
Eagle Ford Shale	31.2%
East Texas Basin	14.5%
All Plays	27.2%

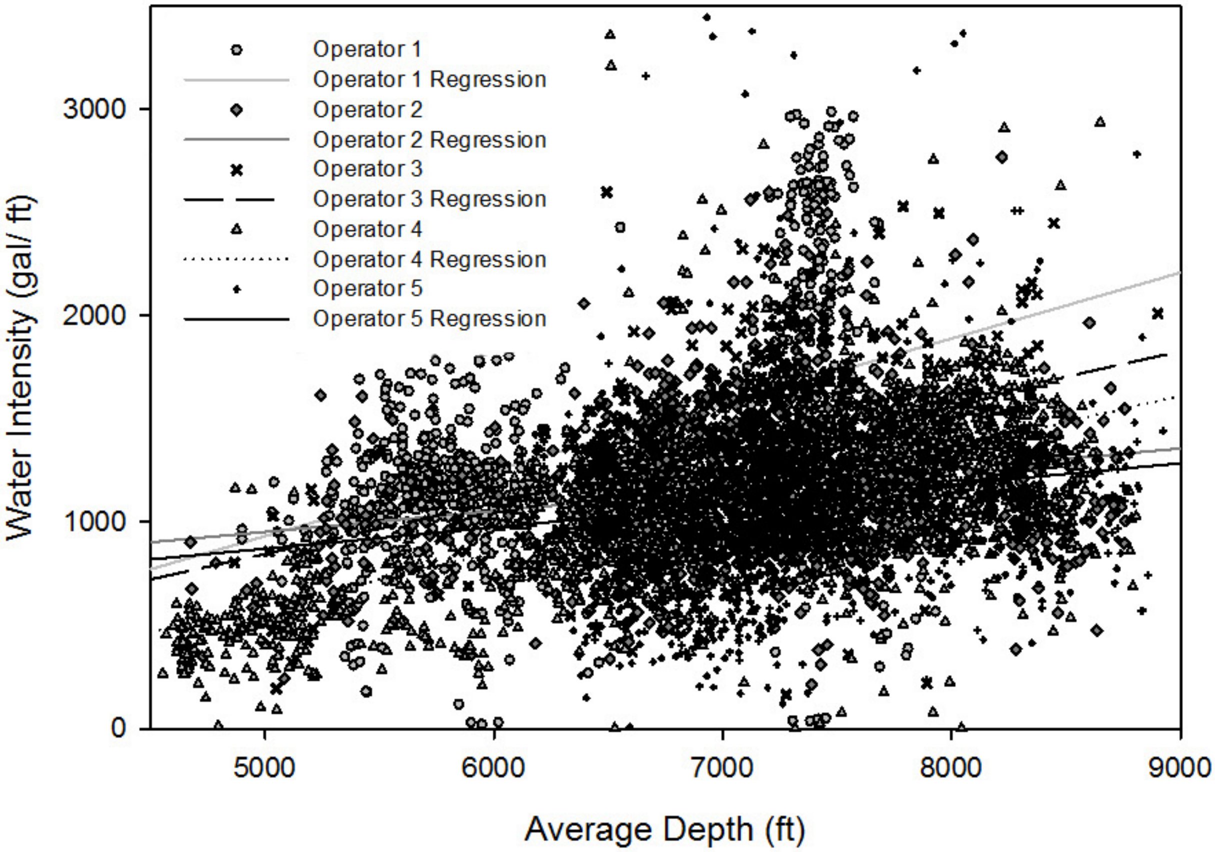


Figure 3. Water use intensity in the Barnett Shale play, showing comparison among between top operators in the play.

III. Historical and Current Water Use

After a short description of the major HF plays in Texas (Section III-1), we present water use and consumption numbers (Section III-2) that we compare to findings of the 2011 report (Section III-3). We also briefly address drilling water use (Section III-4).

III-1. Play Description

In this section we describe relevant features of each play which will then be used in the Projections Section (Section IV). Note that water use intensity and proppant loading values represent an average of the sometimes time-varying mix of slickwater / gel systems applied to the play at a given time. For example, a decrease in water use intensity may mean a better water efficiency in a technique or a move to a more water-efficient technique.

III-1-1 Barnett Shale

The Barnett Shale is the first in Texas and around the world to submit to intense slick-water HF since the mid-1990's, first using vertical wells. After a transition period, Barnett Shale operators use currently horizontal wells almost exclusively. After a strong growth in the mid-2000's (>2000 wells completed per year), the play has seen a relative decrease in the total number of wells completed in a year (Figure 4a) because of the reduced demand following the economic slump and the decreasing price of gas. Although drilling activity has abated at the edges of the play core, it is very vigorous in the core itself (Denton, Johnson, Tarrant, and Wise counties) and has considerably picked up in the so-called combo play in the northern confines of the play in Cooke and Montague counties. A weekly newsletter, the Powell Shale Digest (PSD; May 29, 2012) noted a sharp increase in oil production since mid-2010. Substantial amounts of oil and condensate have made those counties attractive to operators. Overall the total amount of water used is relatively steady at 25 kAF/yr (Figure 4b). The Barnett play is the Texas play with the highest degree of reporting water use at >90% (Table 2). Note that the bottom four plots of composite Figure 4 (as well as on similar figures in this document) show the fraction of wells used to compute the parameter on the secondary axis. High well reporting, allied with the large number of wells, gives us confidence that the water use values are particularly accurate in this play. The length of the laterals has been slowly increasing in the past few years (~3,500 ft in 2011) with a concomitant water use increase (Figure 4c and d). However water intensity (water amount per unit length) has stayed steady at ~1,200 gal/ft (Figure 4e). Note that the water intensity as reported in this document is higher than that reported in the 2011 report because of a slight change in computing it (see Section II-1-2). In contrast to water intensity, proppant loading has been increasing slightly over time to ~0.8 lb/gal in 2011 (Figure 4f).

In order to better understand water intensity and in an effort to modulate it across a play, we plotted water intensity against depth and thickness (Figure 5a and c). The trend seems upwards with increasing depth and thickness but is very noisy and tenuous at best. Water intensity appears to be rather dependent on the well operator (Figure 5b) and, thus, somehow difficult to vary across a play. Nevertheless, spatial distribution of water intensity shows a higher intensity in Denton County and in the eastern half of Wise County, areas in which the Barnett is the deepest as well as in Montague County in the oil window (Figure 6a).

In agreement with our methodology, it is also useful to understand the cumulative length of laterals in a given area or within a county. A key input to the projected water use is to assume that the entire county will be hypothetically drilled up by parallel laterals extending from one side of the county to the other side and at regularly spaced intervals (at, for example, a 1,000- ft interval [see Nicot et al., 2011 for details]). Figure 6b displays such density of well laterals, which is fairly high in Johnson County and the southern half of Tarrant County. The average lateral spacing, which is simply the inverse of the lateral density, is shown in Figure 7 and detailed in Table 3 (it is calculated in those sections of the county with an actual shale footprint). The county with the highest relative cumulative length of laterals (Johnson County) yields an average spacing between assumed parallel laterals of ~1,700 ft. This is still removed from the operational distance between laterals of 1,000 ft or even 500 ft, suggesting that this county, despite its past activity will still see further significant activity as illustrated by the coverage gaps in Figure 8. The decrease in well completion activity in Johnson County as seen in Figure 9a is more related to price gas than to a true depletion of the resource in the county.

III-1-2 Eagle Ford Shale

The Eagle Ford Shale play has seen tremendous development in the past 2 years. Initially started as a new Barnett Shale, it quickly turned into a different type of play when the extent of the oil window became clear. In addition to the fast increase in wells completed (~1,400 in 2011) (Figure 10a) and the subsequent increase in water use at ~24 kAF in 2011 (Figure 10b), the Eagle Ford Shale has the unique feature among all the plays examined in this document to experience a sharp decrease in water intensity (Figure 10e) decreasing almost in half in 4 years to ~850 gal/ft in 2011. This is seemingly due to operational changes moving from high-volume slick water HF operations to gel fracs that can carry as much proppant with much less water. The use of cross-link gels for oil production requires a higher proppant loading (Fan et al., 2011). This decrease in water intensity combined with an increase in average lateral length (~5,000 ft, Figure 10c) still translates into a decrease in water use per well to ~5 million gallons/well (Figure 10d). Not surprisingly, the proppant loading has considerably increased to 1 lb/gal in 2011 (Figure 10f). The question we will not try to answer despite its relevance to water use projection is how transferable to other plays is this switch to gel fracs and whether it could happen elsewhere on a large scale. The percentage of wells with consistent data sets is only ~47% (Table 2), making the Eagle Ford data set more uncertain that than of the Barnett Shale.

The cross-plots of water intensity vs. depth and thickness are inconclusive and even misleading (Figure 11a and b). They show no real trend except perhaps a decrease in water intensity with depth. However, Figure 12a clearly shows a higher water intensity in the down dip sections of the play, suggesting an intensity as high as 1400 gal/ft in the gas-rich area and 800 gal/ft in the oil-rich area. Densities of lateral (Figure 12b) and average lateral spacing (Figure 13, Table 4) suggest that the Eagle Ford Shale play has two cores: next to the Mexican border in Dimmit, LaSalle, and Zavala Counties and south of San Antonio in Karnes and De Witt Counties. The low average lateral spacing (>10,000 ft) suggests that many more wells will be drilled and completed there in the future.

III-1-3 TX-Haynesville Shale and East Texas Basin

This document deals only with the Texas section of the Haynesville Shale. In East Texas the Haynesville is a deep gas play, despite a report that one company has located a liquid-rich area in the Haynesville in Panola County with 350 horizontal drill sites (PSD, May 29, 2012). These are expensive wells, but they are located in an area with multiple stacked formations amenable to

HF. The Texas section of the play has seen a quick increase in the number of wells drilled (~250 in 2011, Figure 14a) and a subsequent increase in water use (~1.6 kAF, Figure 14b). This play, with the Cotton Valley Fm., also in East Texas, has the smallest fraction of wells with usable data (32% in 2011, Table 2). Lateral length (~5,00 ft), well water use (~8 million gal/well), and water intensity (~1,400 gal/ft in 2011) have all increased in the past 3 years (Figure 14c, d, and e) whereas proppant loading has stayed stable at 0.8 lb/gal (Figure 14f). Water intensity as a function of depth and thickness does not show any reliable pattern (Figure 15). Water intensity (Figure 16b) and density of lateral (Figure 16c) are spatially correlated. The highest correlations are in Harrison County and where Shelby and San Augustine counties meet (Harrison, Shelby, San Augustine, and Panola counties are all in the TX-Haynesville core area). County-level average lateral spacing (Figure 17and Table 5) with a minimum value at ~24,000 ft suggests that many more wells will be completed in this play.

III-1-4 Permian Basin

The Permian Basin, comprising the Midland Basin to the East and the Delaware Basin to the West, with the Central Platform in between, has a long history of mostly oil production. It has also received much attention recently because of hydraulically fractured vertical wells in the so-called Wolfberry play (Wolfcamp and Spraberry, Figure 18). More recently, attention has shifted to horizontal wells in the Wolfcamp Shales (Figure 19), one of the source rocks of the many oil accumulations in the Permian Basin. Several other plays are also being hydraulically fractured in the basin such as the Canyon Formation (Figure 20), the Clear Fork Formation (Figure 21), and the San Andres (Figure 22 and Figure 23) among others.

The Wolfberry was the first play in the Permian Basin to benefit from the technological progress made in the Barnett Shale play. The wells are vertical and have grown from <500 wells/yr to >1,500 wells in 2011 (Figure 18a). The annual amount of water use had also increased to almost 8 kAF in 2011 (Figure 18b). Approximately 80% of the wells have consistently good data. As the length of the productive vertical section has increased from 1.500 ft to >2,500 ft in the past few years (Figure 18c), so has the average water use per well which is >1 million gal/well in 2011, relatively small volume compared to that of horizontal wells in shale plays. As productive sections become longer, the water intensity increased slightly to ~400 gal/ft (Figure 18e), but proppant loading remained constant at ~0.9 lb/gal (Figure 18f). Water intensity seems to be higher in the Wolfberry of the Delaware Basin (Figure 24a), but that basin contains very few wells (Figure 25a), (and they might even be misnamed). The well density is the highest in Glasscock and Reagan Counties.

Slick water horizontal wells have been jumped in 2011 from a low level of <50 wells/yr to 160 wells (Figure 19a), with a concomitant increase in total water use (~1.5 kAF in 2011, Figure 19b). Lateral length (~5,000 ft in 2011), well water use (~5 million gal/well in 2011), and water intensity (800 gal/ft in 2011) all increased too (Figure 19c, d, and e), but average proppant loading stayed steady at ~1 lb/gal (Figure 19f). Water intensity is higher in the center of the Midland Basin (Figure 24b), and the density of lateral is the highest in Ward County (Figure 25b) but the average lateral spacing is still very high at ~23,000 ft (Figure 26), which suggests that many wells remain to be drilled and completed.

Other, less publicized plays also received increased interest, as shown by water intensity rising or remaining steady (Figure 20e, Figure 21e, Figure 22e, and Figure 23e). Other plays, not targeted for the same scrutiny, have also seen a development of HF. They were included in a miscellaneous file that included all fractured wells not included in a targeted play. Overall the Permian Basin has a high fraction (~85%) of wells with a consistent data set (Table 2), thus giving us confidence that that the water use values are relatively accurate (especially for those formations hosting a large number of wells).

III-1-5 Anadarko Basin

The Anadarko Basin contains several formations of interest, in particular the Granite Wash (Figure 27) but also the Cleveland and Marmaton formations (Figure 28 and Figure 29). Similarly to the development of the horizontal wells in the Wolfcamp in an area where HF was done on mostly vertical wells, the Anadarko Basin is seeing a shift toward horizontal wells. The Granite Wash has seen an increase from a few horizontal wells in 2006 to >300 in 2011 (Figure 27a) with a parallel increase in water use to <4 kAF in 2011 (Figure 27b). In the same time the length of the lateral has grown to ~4,500 ft (in 2011) (Figure 27c) and the average well water use to >5 million gallons (Figure 27d). Water intensity has reached a value of ~1,200 gal/ft (Figure 27e), but the proppant loading has remained steady at ~0.6 lb/gal (Figure 27f). The Cleveland and Marmaton horizontal wells display a similar evolution but for a smaller number of wells (~150 and ~40, respectively) and smaller water intensity at ~300 gal/ft (Figure 28e and Figure 29e). the fraction of wells with directly usable information was calculated at ~70% (Table 2). Water intensity as a function of depth failed to show a clear trend (Figure 30 and Figure 31).

Spatial distribution of Granite Wash water intensity (Figure 32a) and density of lateral (Figure 32b) confirms that Wheeler County is the most attractive county. At the county level, Wheeler County shows the smallest lateral spacing and plenty of room for additional wells (Figure 33 and Table 6). HF activities in the Cleveland and Marmaton Formations are focused on Hemphill, Lipscomb, and Ochiltree Counties (Figure 34 and Figure 35). Combining information from the three plays illustrates that the county with the smallest average lateral spacing (Lipscomb County) still allows for significant development at ~11,000 ft (Figure 36), as illustrated in Figure 37.

III-1-6 East Texas Basin

The East Texas Basin contains many formations susceptible to being hydraulically fractured. This section focuses on the Cotton Valley Fm., but, as was done for the Permian Basin and the Gulf Coast Basin, all water use data from wells in formations that were not part of the plays targeted for detailed study were still added to the total water use.

The Cotton Valley Fm. has been producing for decades and has been subjected to HF for almost as long. However, as observed in the rest of the state, there is a general shift from vertical to horizontal wells. Annual completions of vertical wells have been decreasing from ~1500 wells per year in 2007 to ~300 in 2011 (Figure 38a), whereas horizontal wells have been increasing from almost none in 2005 to ~100 in 2011 (Figure 39a). Total water use has followed the same path from ~1.5 kAF/yr to ~0 and from ~0 to 0.6 kAF/yr, respectively (Figure 38b and Figure 39b). In 5 years, the length of lateral has increased from ~1,000 ft to ~4,000 ft in 2011 (Figure 39c) with the associated water use increase to 4 million gallons per well in 2011 (Figure 39d). In the same period, water intensity has stayed steady at ~1,000 gal/ft (Figure 39e) and proppant loading has remained at ~0.8 lb/gal (Figure 39f). The overall representivity of the usable data set is at a steady ~70% for the horizontal wells but decreasing to only 25% for the vertical wells. A water intensity vs. depth cross-plot (Figure 40) displays no obvious trends but maps of well density (Figure 41 and Figure 42) show that horizontal wells are being completed in the same areas as where the vertical wells were drilled and that there is a good overlap of the high density values.

III-1-7 Gulf Coast Texas

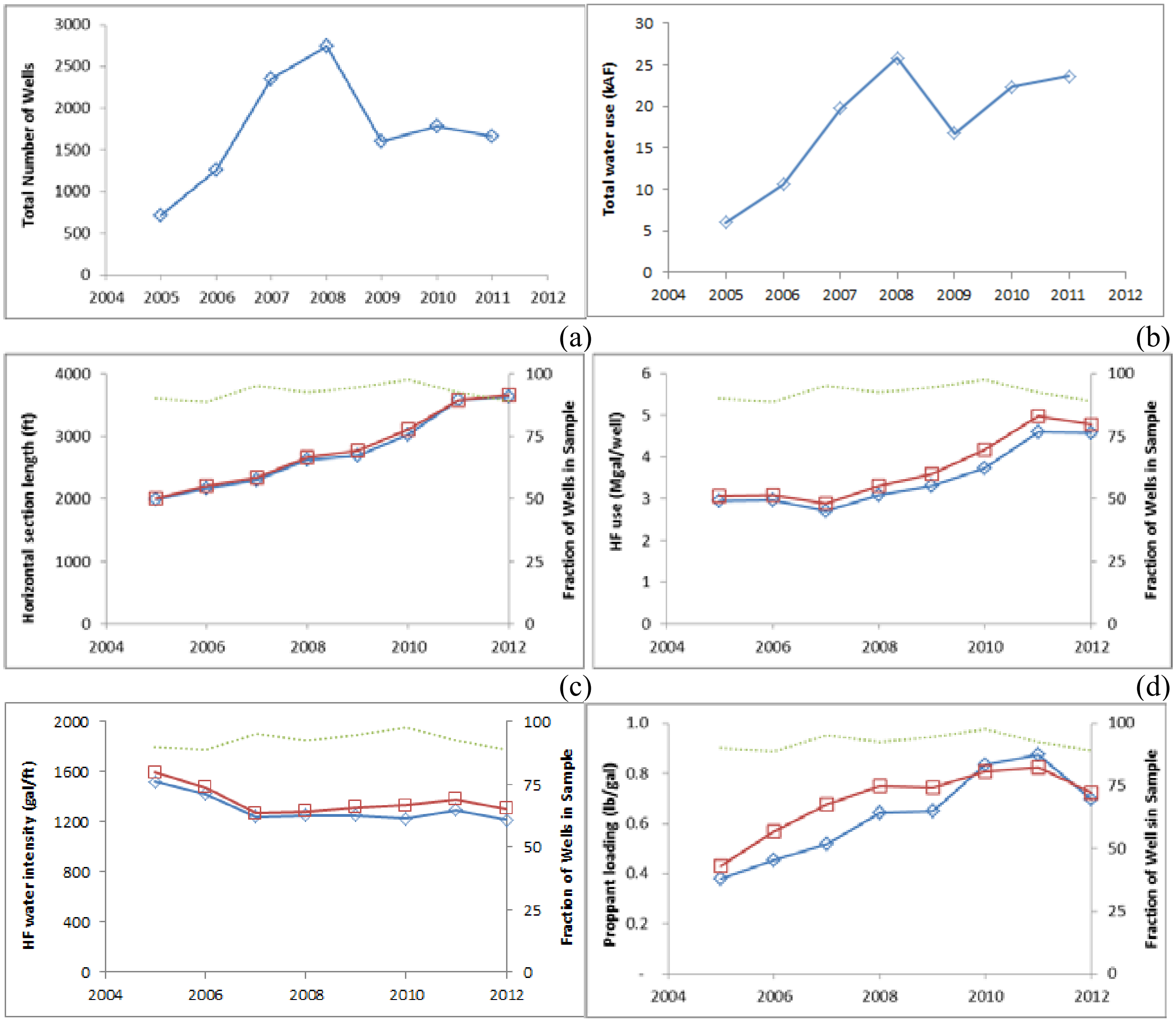
Similarly to the Permian Basin and the East Texas Basin, the Gulf Coast Basin, which includes many counties from the Mexican border to the Louisiana state line, contains several formations amenable to being hydraulically fractured. Each of these formations is not described here (for example, the Austin Chalk), but their water use is included in the total reported below. In this section, we document the Olmos Sands, where HF is taking place through horizontal wells. The annual number of completion is still low at 70 completions a year (Figure 43a) but growing and the total water use displays the same growth (~0.5 kAF in 2011, Figure 43b). Average lateral length has reached ~4,000 ft in 2011 (Figure 43c), and the average water use per well has increased to 4 million gal/well (Figure 43d). Although irregular through the years, water intensity has reached a value of ~1,000 gal/ft (Figure 43e) consistent with what has been observed elsewhere.

Table 2. Percentage of wells in each play or region that yielded a complete and consistent data set (water, proppant, length) from year 2011.

Play / Region	Percent
Barnett	92.7%
Eagle Ford	46.9%
Haynesville	31.8%
Cotton Valley	31.4%
Anadarko	69.4%
Permian Basin	84.9%

ResultsSummary_year2011.xlsx

Barnett Shale:



(a) (b) (c) (d) (e) (f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 4. Barnett Shale horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Barnett Shale:

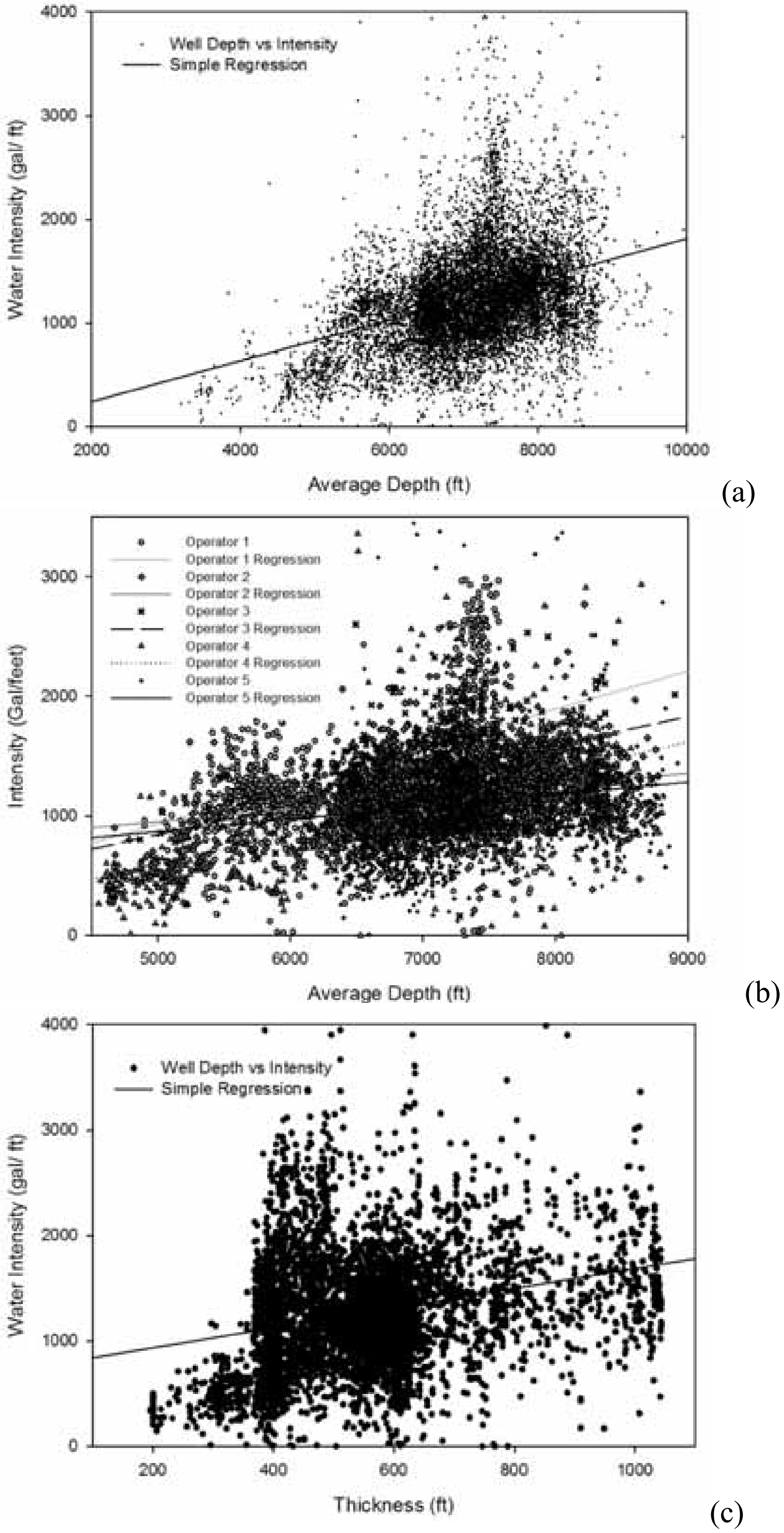
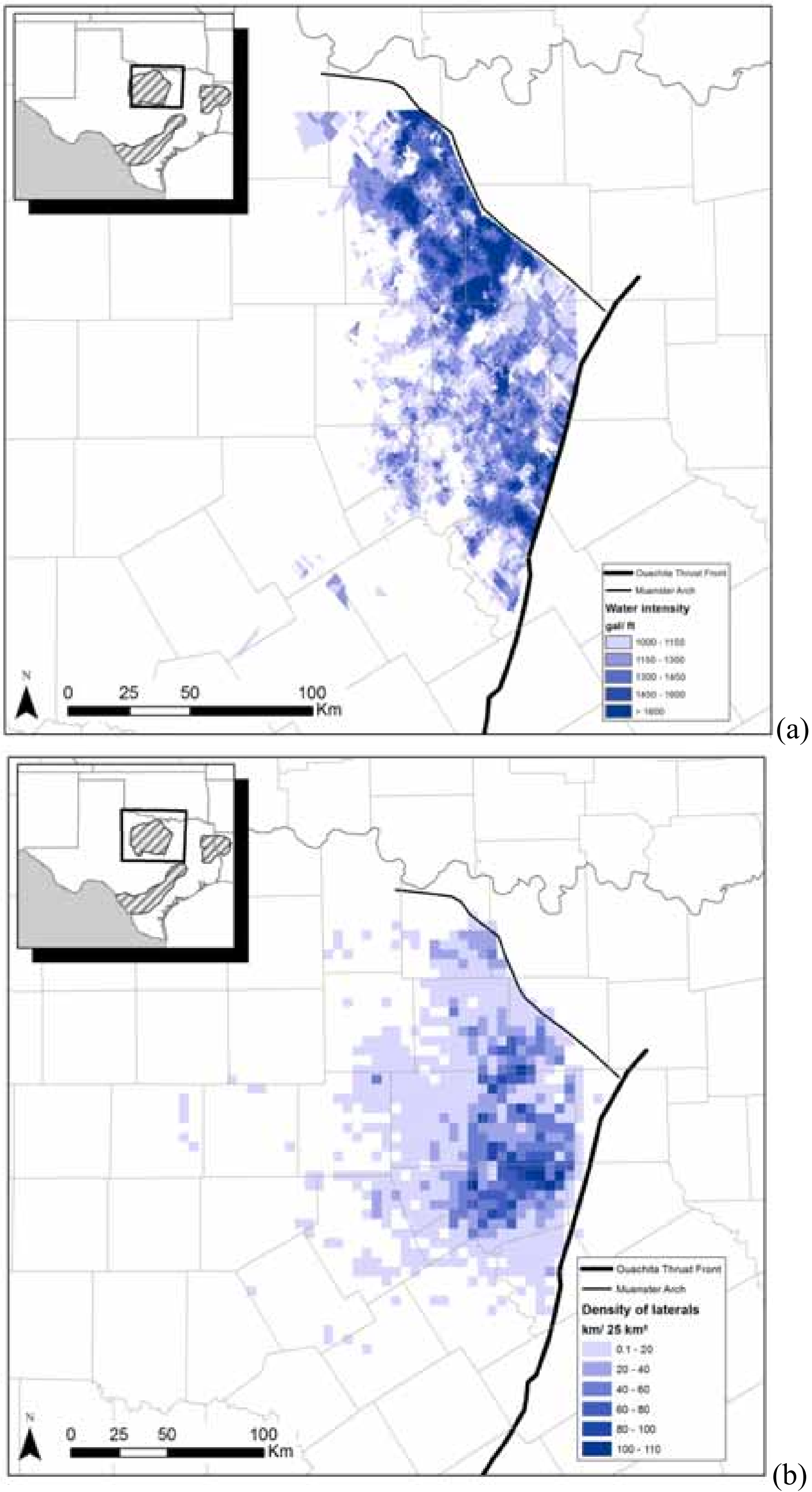


Figure 5. Barnett Shale horizontal water use intensity as a function of (a) depth; (b) operator and depth; and (c) formation thickness.

Barnett Shale:



Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 6. Barnett Shale spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

Barnett Shale:

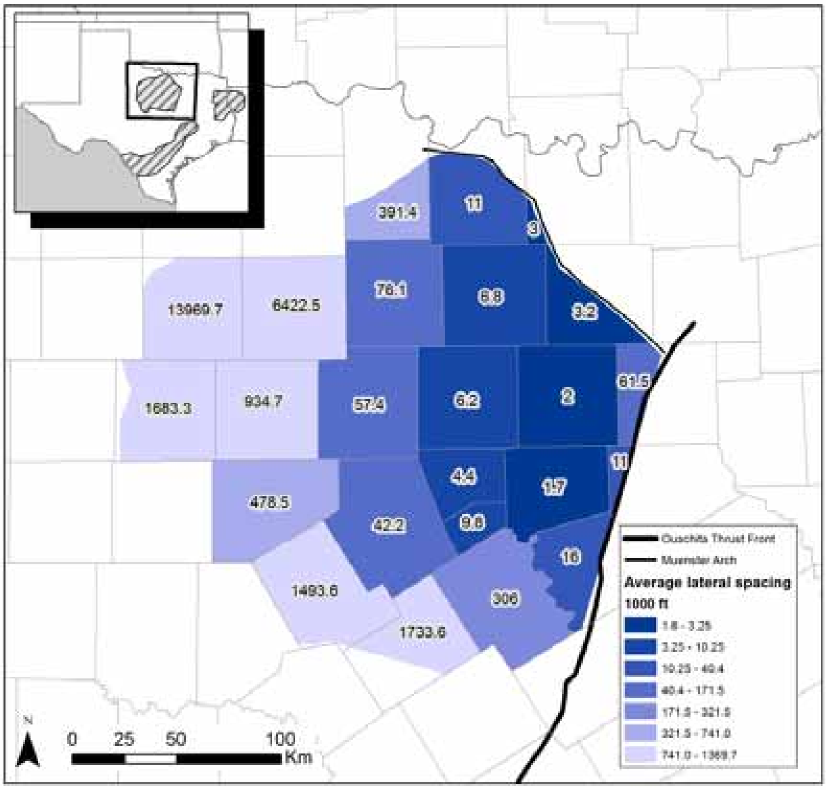


Figure 7. Barnett Shale county-level average lateral spacing.

Table 3. Barnett Shale county-level average lateral spacing for top producing counties.

County Name	Sum lateral length / county area (km/km^2)	Average Lateral Spacing (1000 ft)
Johnson	1.94	1.69
Tarrant	1.66	1.98
Hood	0.75	4.35
Parker	0.53	6.20
Wise	0.48	6.77
Denton	0.47	6.99
Somervell	0.34	9.76
Others		>10×10^3 ft

Note: Average spacing = 1/ (lateral length density);
Counties are sorted by decreasing lateral length density

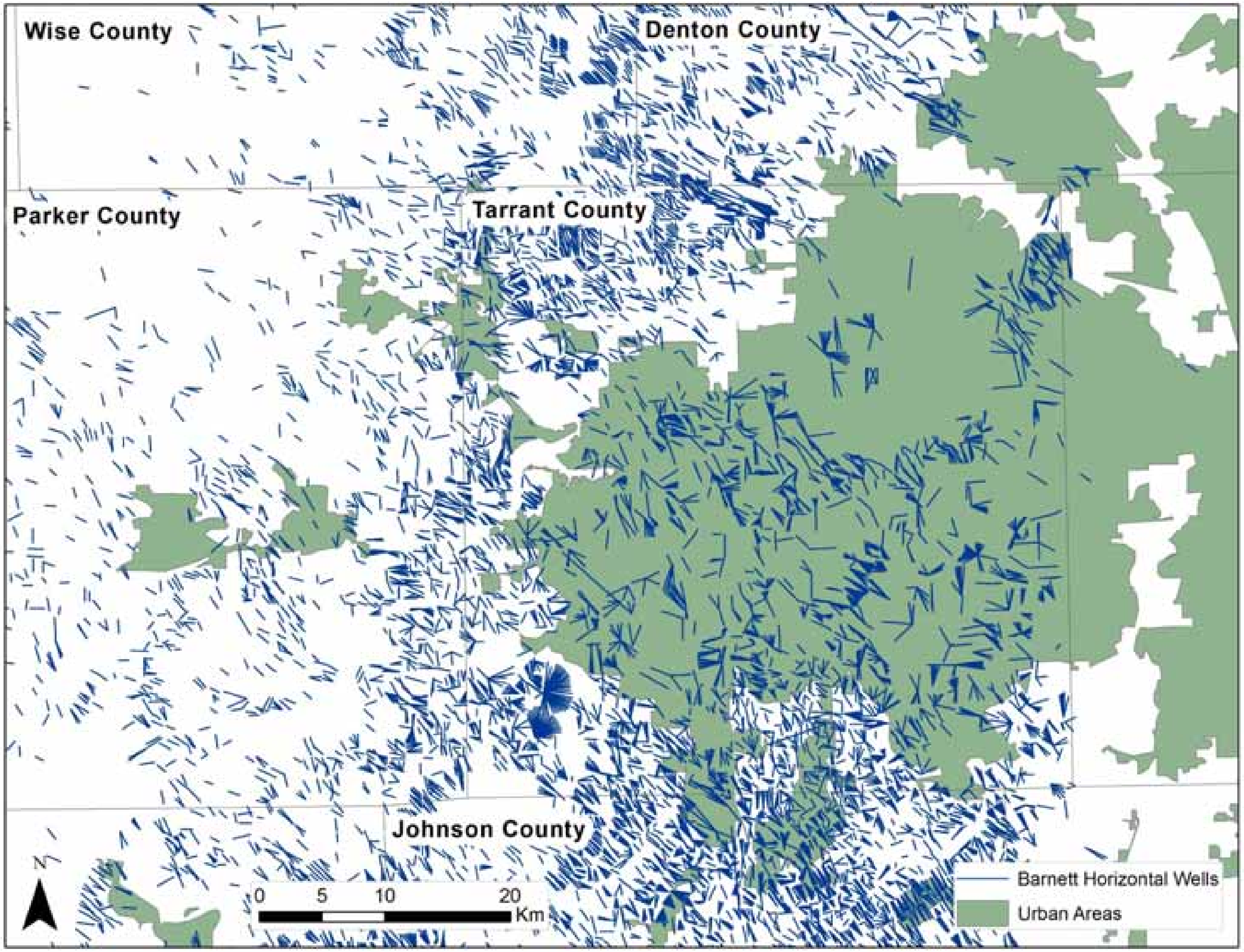
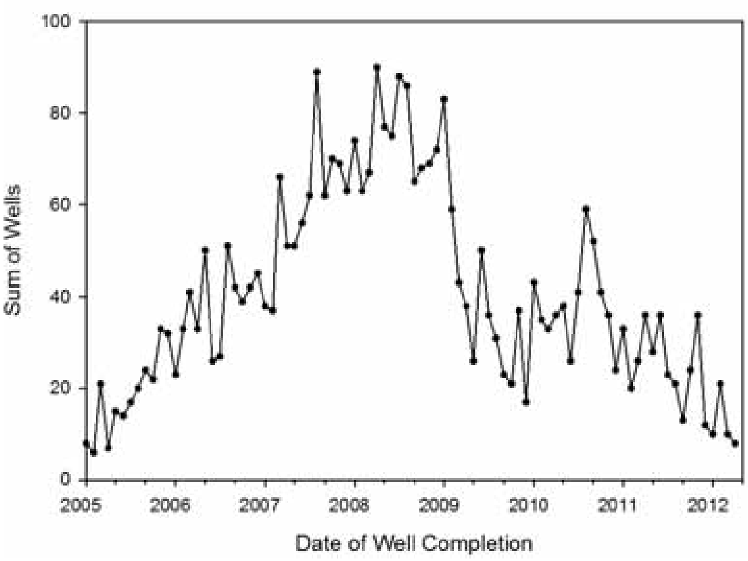
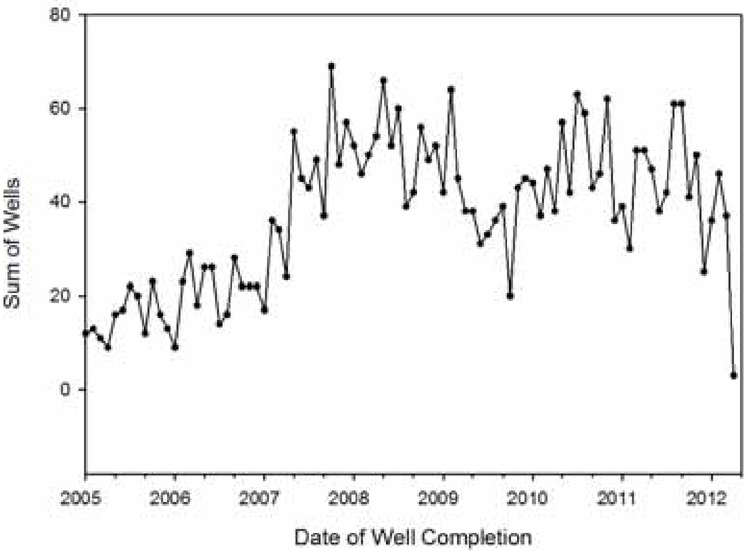


Figure 8. Map view of lateral expression of horizontal wells in the Barnett Shale centered on Tarrant County.



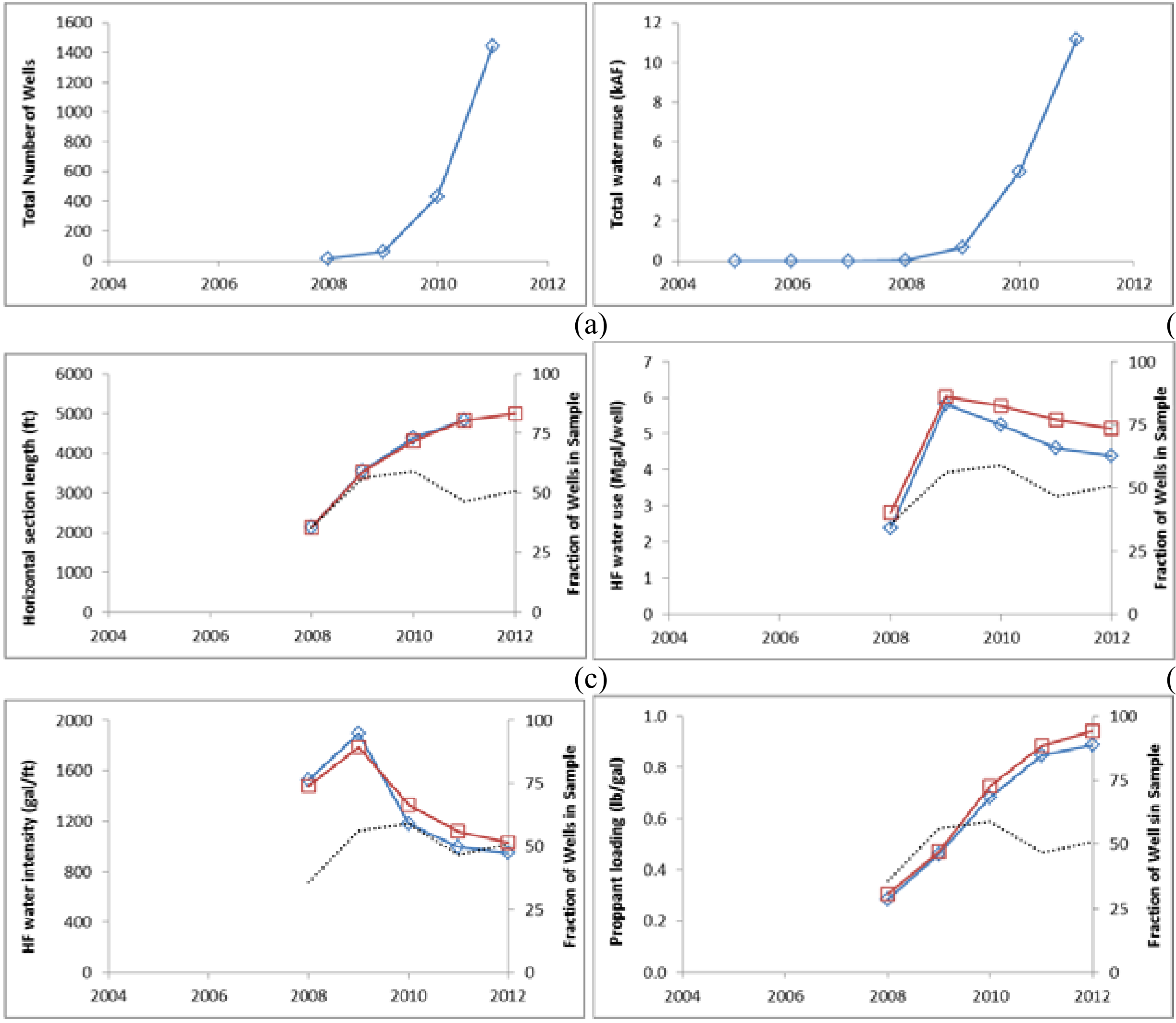
(a)



(b)

Figure 9. Annual well count in Johnson (a) and Tarrant (b) counties.

Eagle Ford Shale:



(a) (b) (c) (d) (e) (f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 10. Eagle Ford horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Eagle Ford Shale:

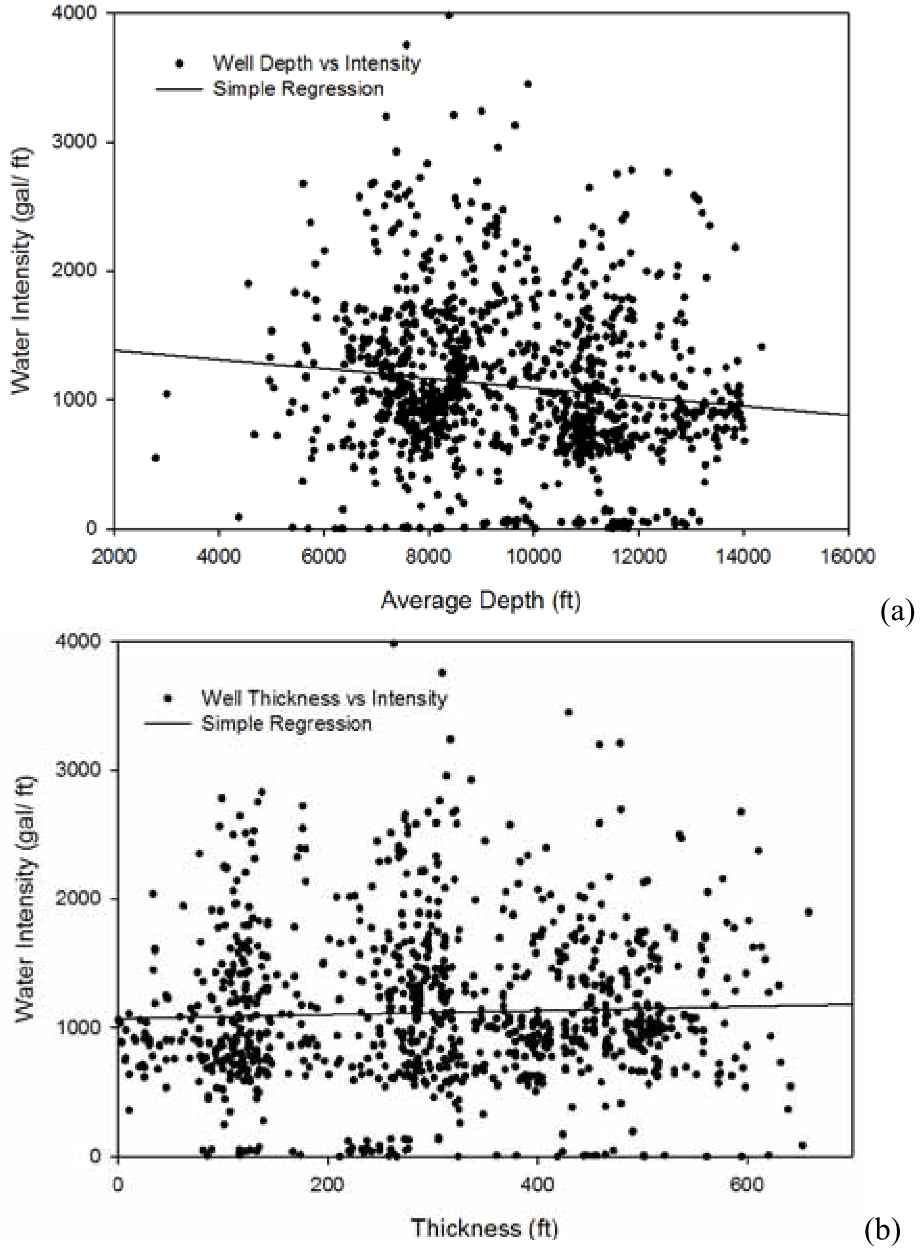
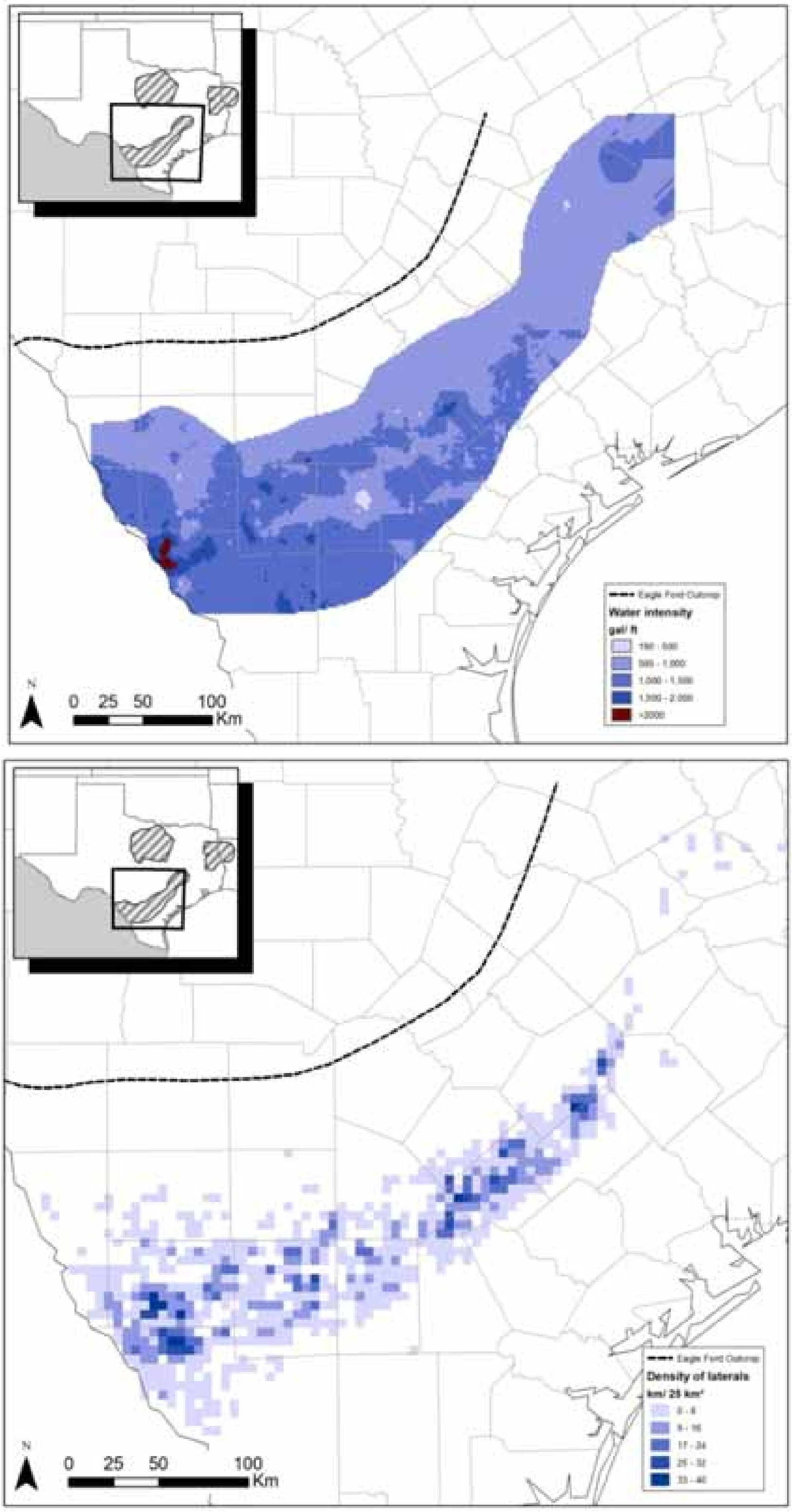


Figure 11. Eagle Ford Shale horizontal wells' water use intensity as a function of (a) depth; and (b) formation thickness.

Eagle Ford Shale:



(a)

(b)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 12. Eagle Ford Shale spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

Eagle Ford Shale:

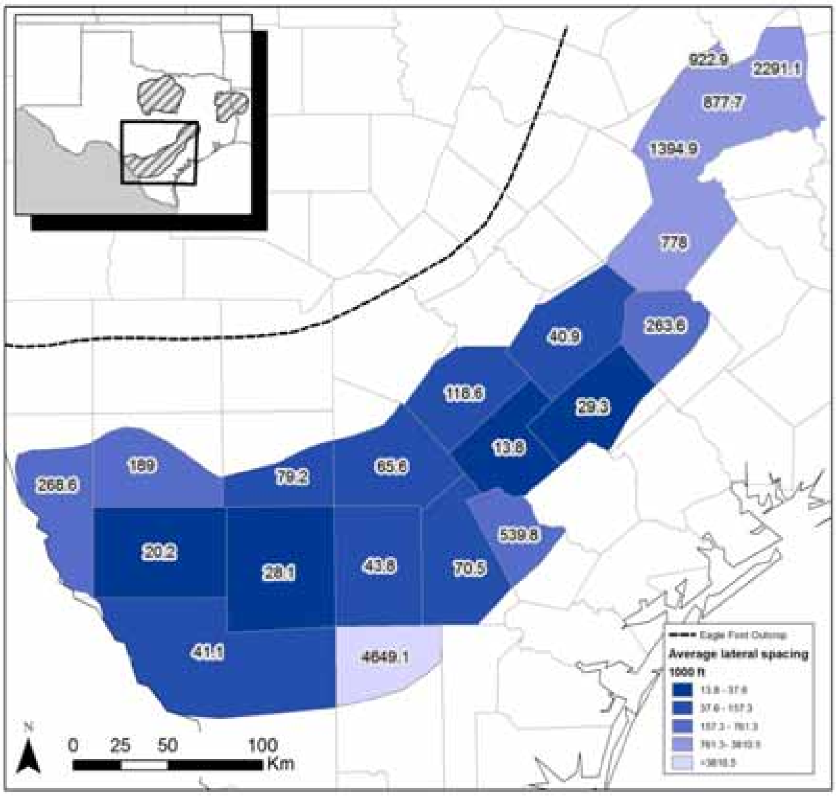
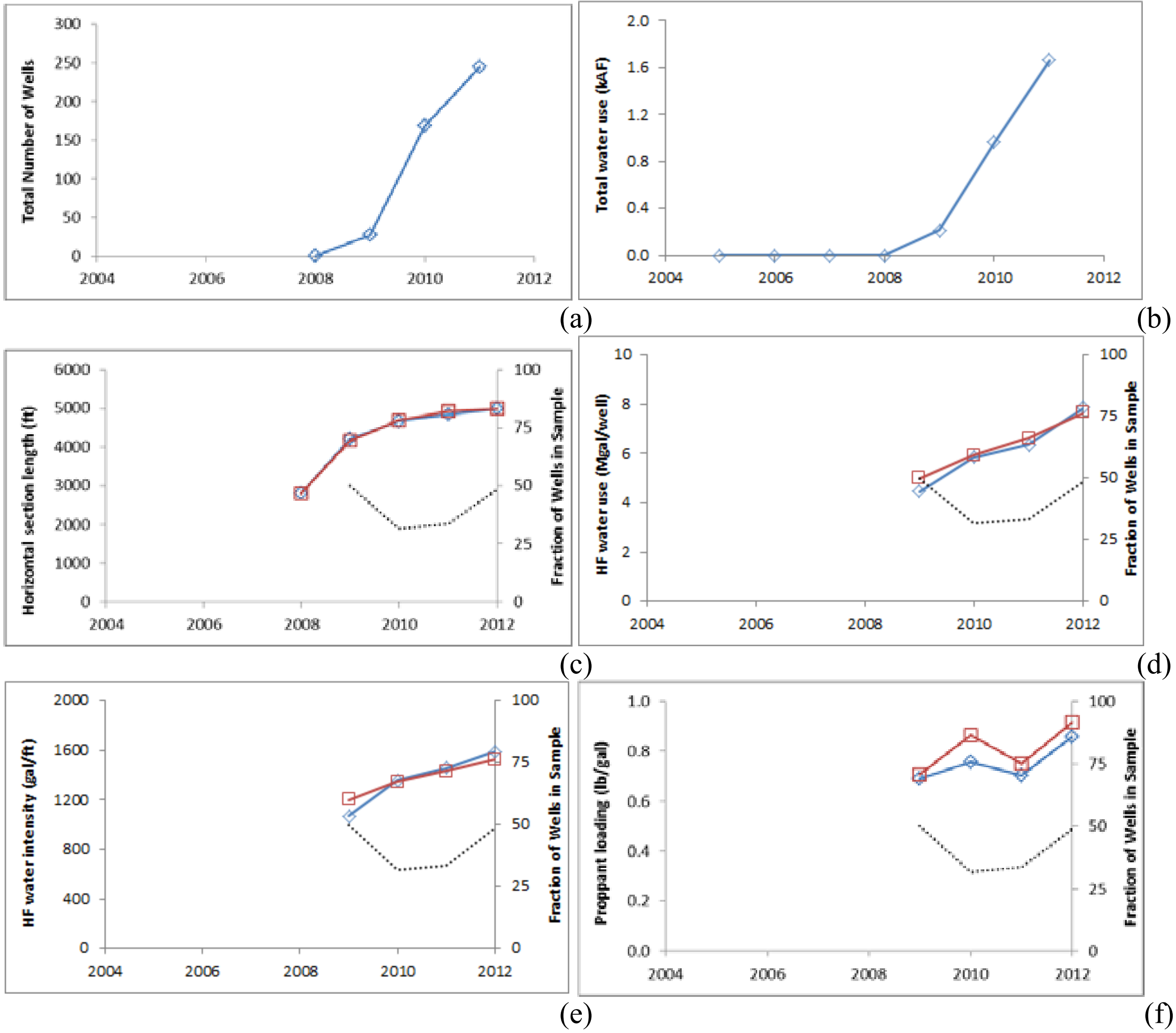


Figure 13. Eagle Ford Shale county-level average lateral spacing.

Table 4. Eagle Ford Shale county-level average lateral spacing for top producing counties.

County Name	Sum lateral length / county area (km/km^2)	Average Lateral Spacing (1000 ft)
Karnes	0.236	13.93
Dimmit	0.162	20.30
La Salle	0.116	28.20
De Witt	0.111	29.63
Gonzales	0.080	41.01
McMullen	0.075	43.79
Webb	0.080	41.11

TX-Haynesville Shale:



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 14. TX-Haynesville Shale horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

TX-Haynesville Shale:

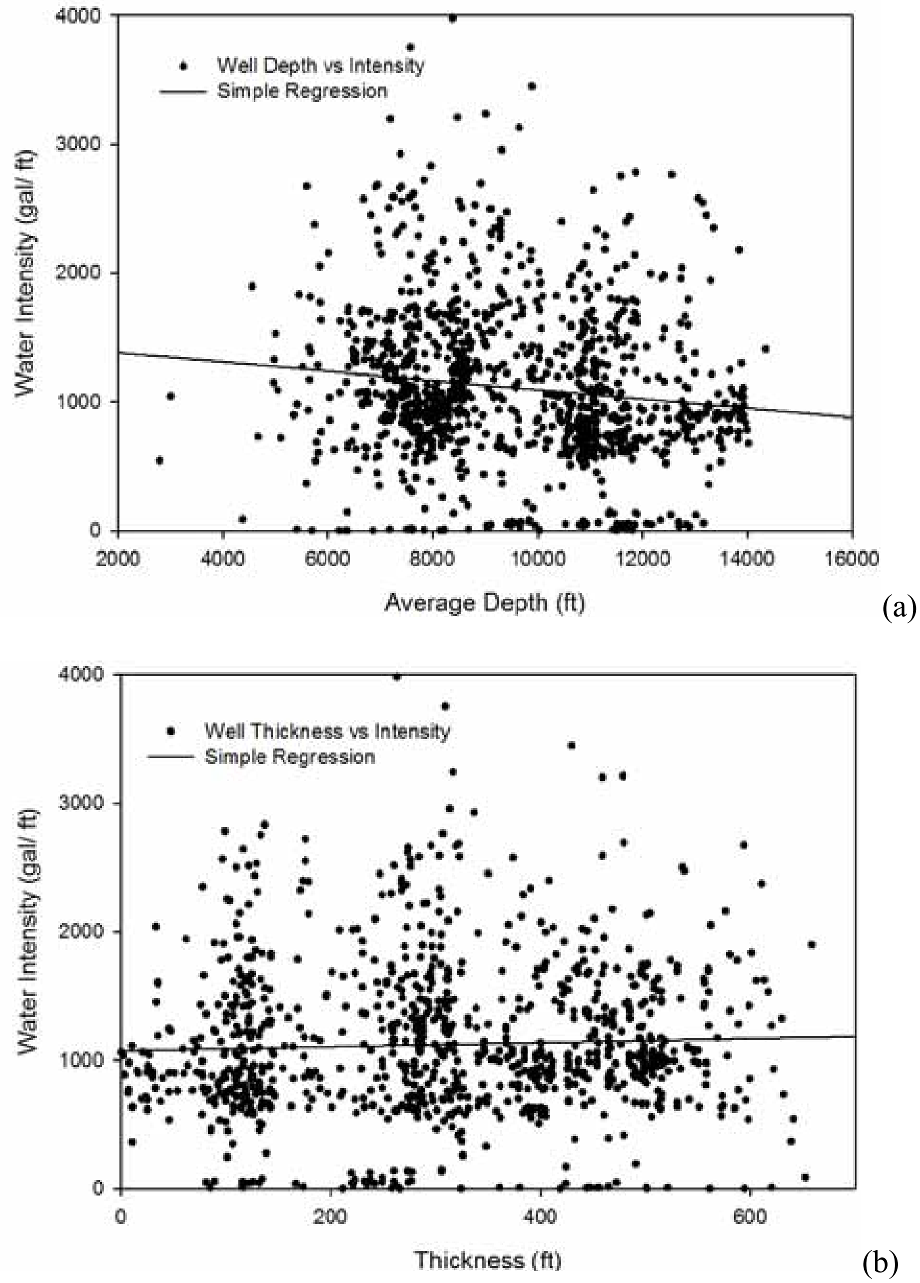
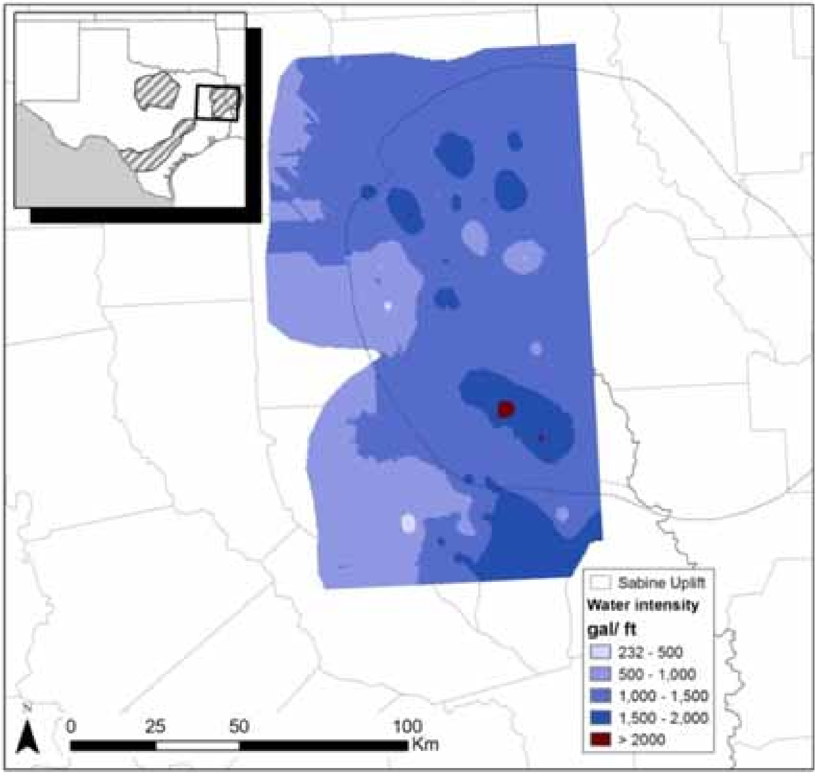
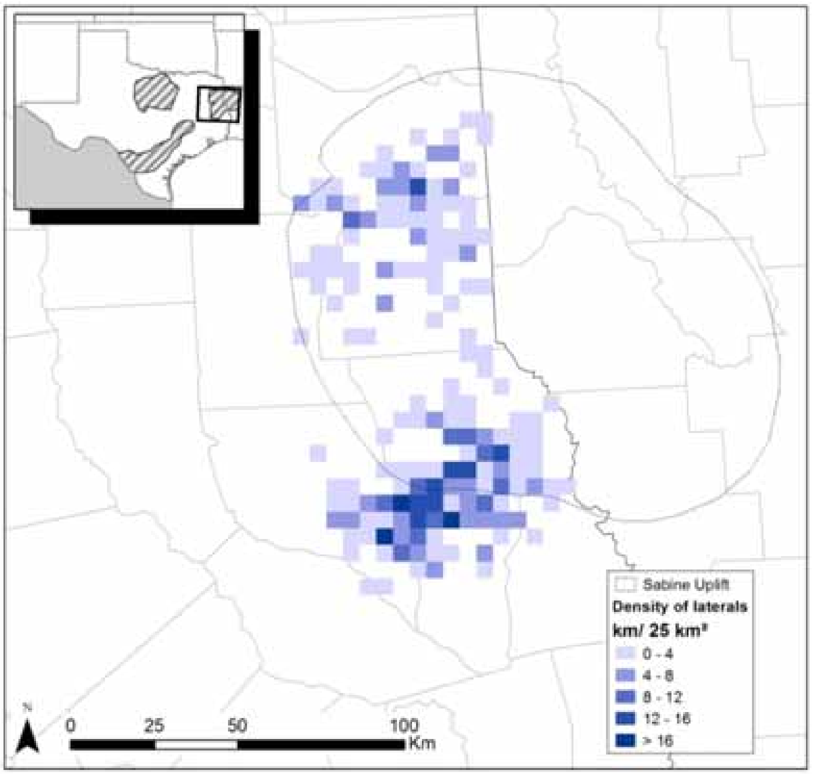


Figure 15. TX-Haynesville Shale horizontal water use intensity as a function of (a) depth; and (b) formation thickness.

TX-Haynesville Shale:



(a)



(b)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 16. TX-Haynesville Shale spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

TX-Haynesville Shale:

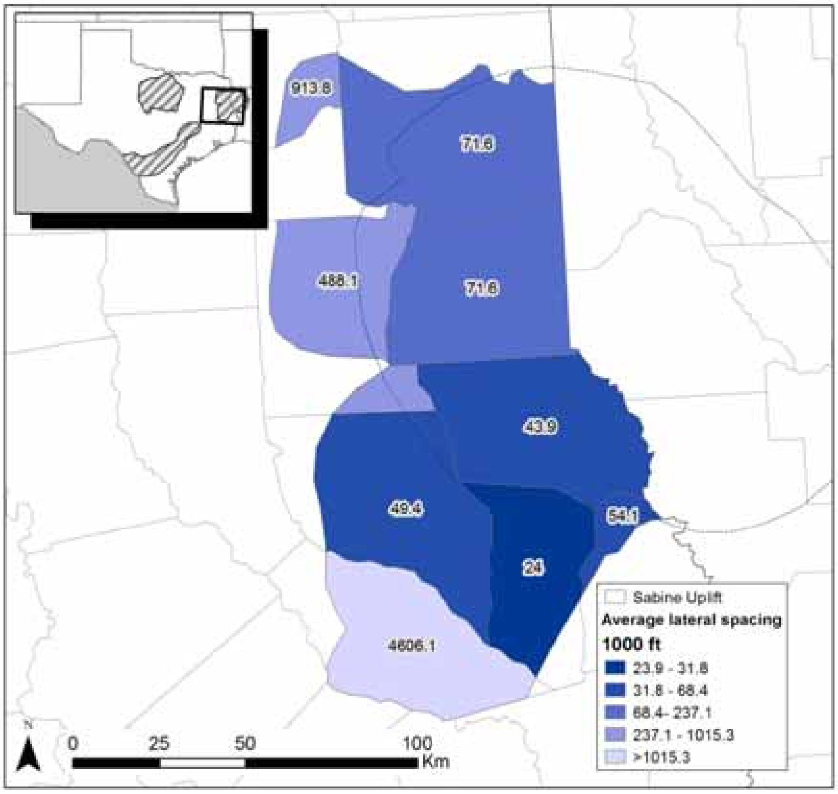
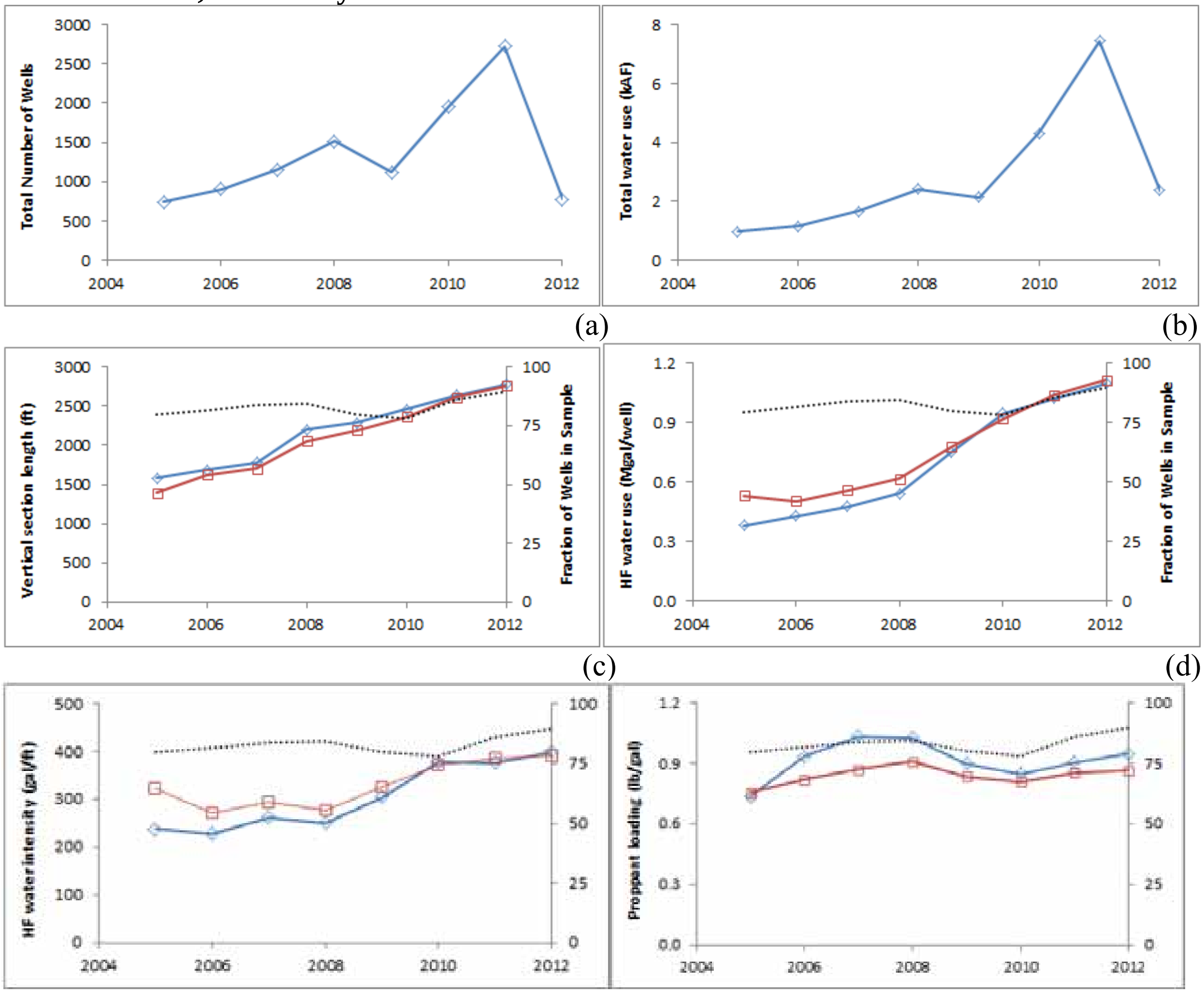


Figure 17. TX-Haynesville Shale county-level average lateral spacing.

Table 5. TX-Haynesville Shale county-level average lateral spacing for top producing counties.

County Name	Sum lateral length / county area (km/km^2)	Average Lateral Spacing (1000 ft)
San Augustine	0.137	23.97
Shelby	0.074	44.24
Nacogdoches	0.065	50.78
Sabine	0.061	54.11
Panola	0.046	72.03
Harrison	0.045	72.84

Permian Basin, Wolfberry Verticals:

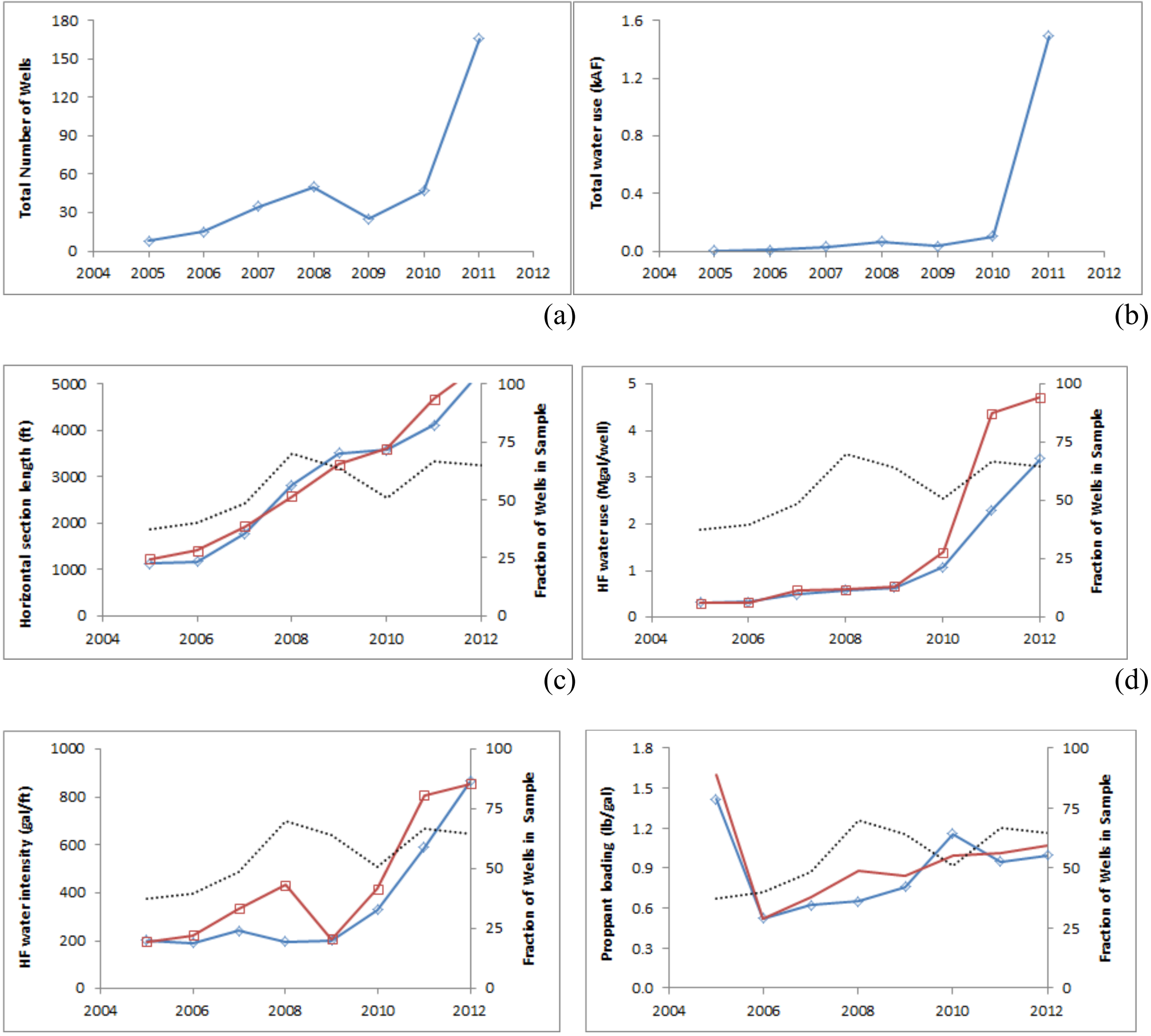


(a) (b) (c) (d) (e) (f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 18. Wolfberry verticals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median vertical productive section length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Permian Basin, Wolfcamp Horizontals:



(a) (b)

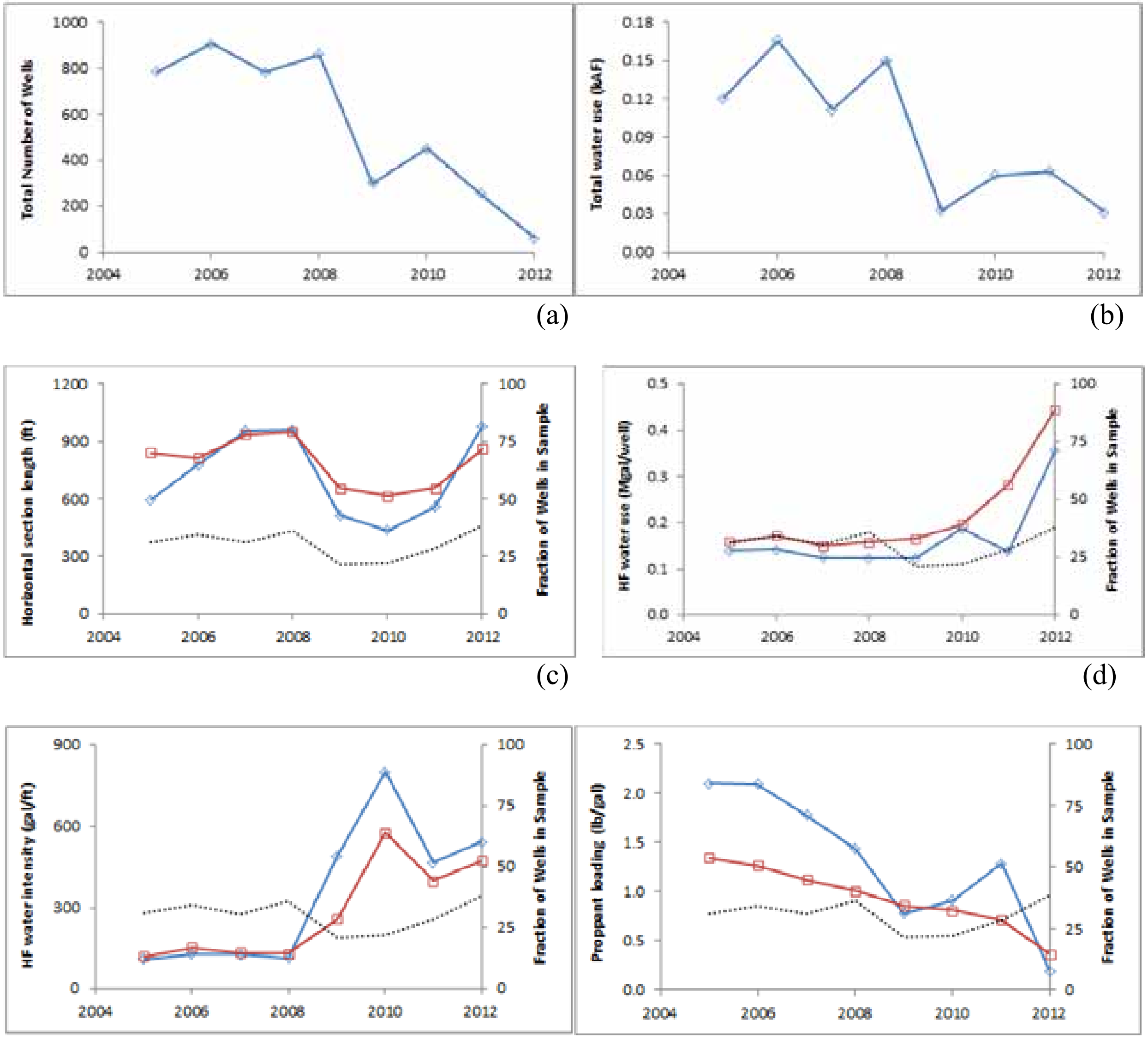
(c) (d)

(e) (f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 19. Wolfcamp horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Permian Basin, Canyon – Horizontals:



(a) (b)

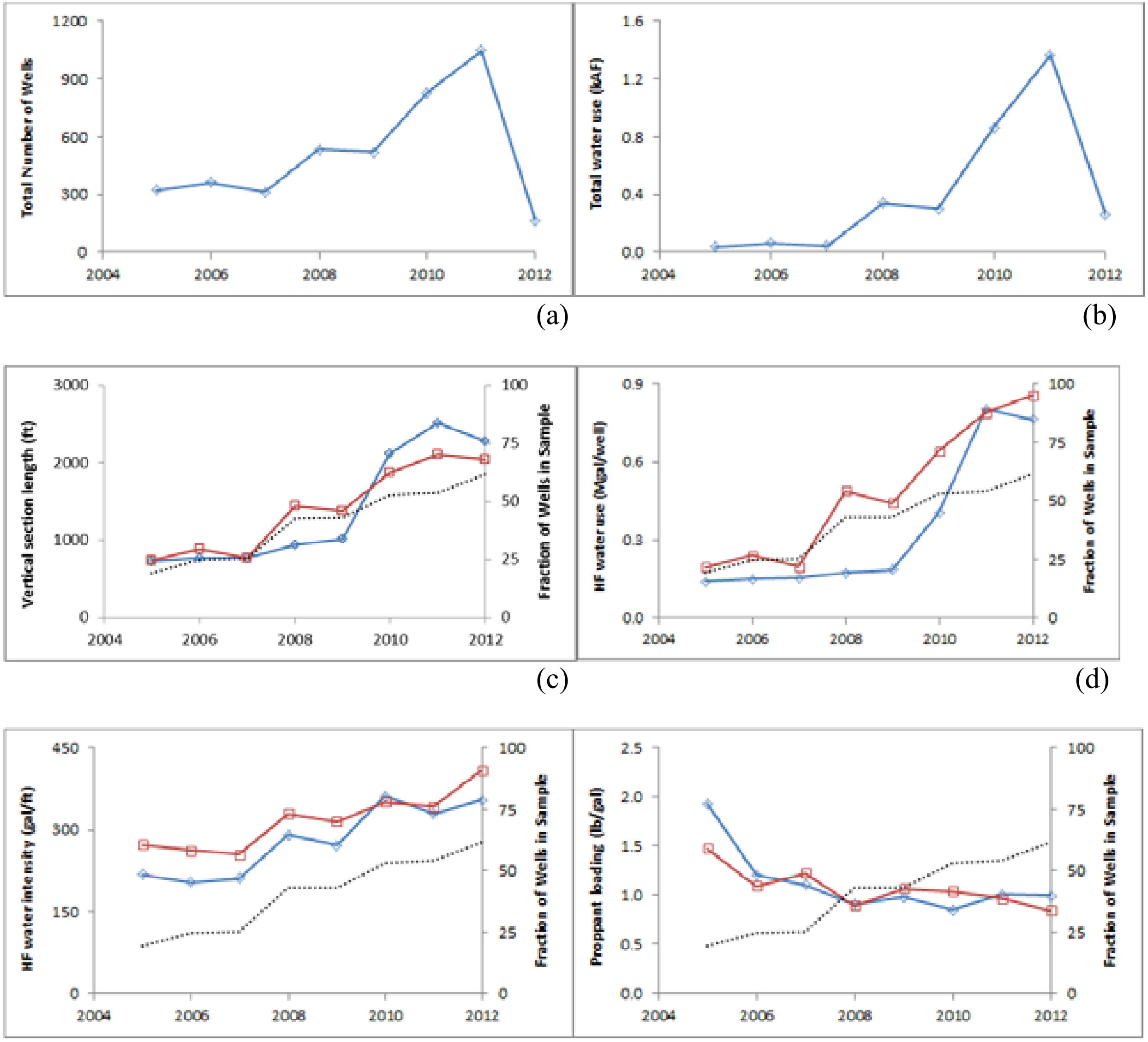
(c) (d)

(e) (f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 20. Canyon Sand horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Permian Basin, Clearfork - Verticals



(a) (b)

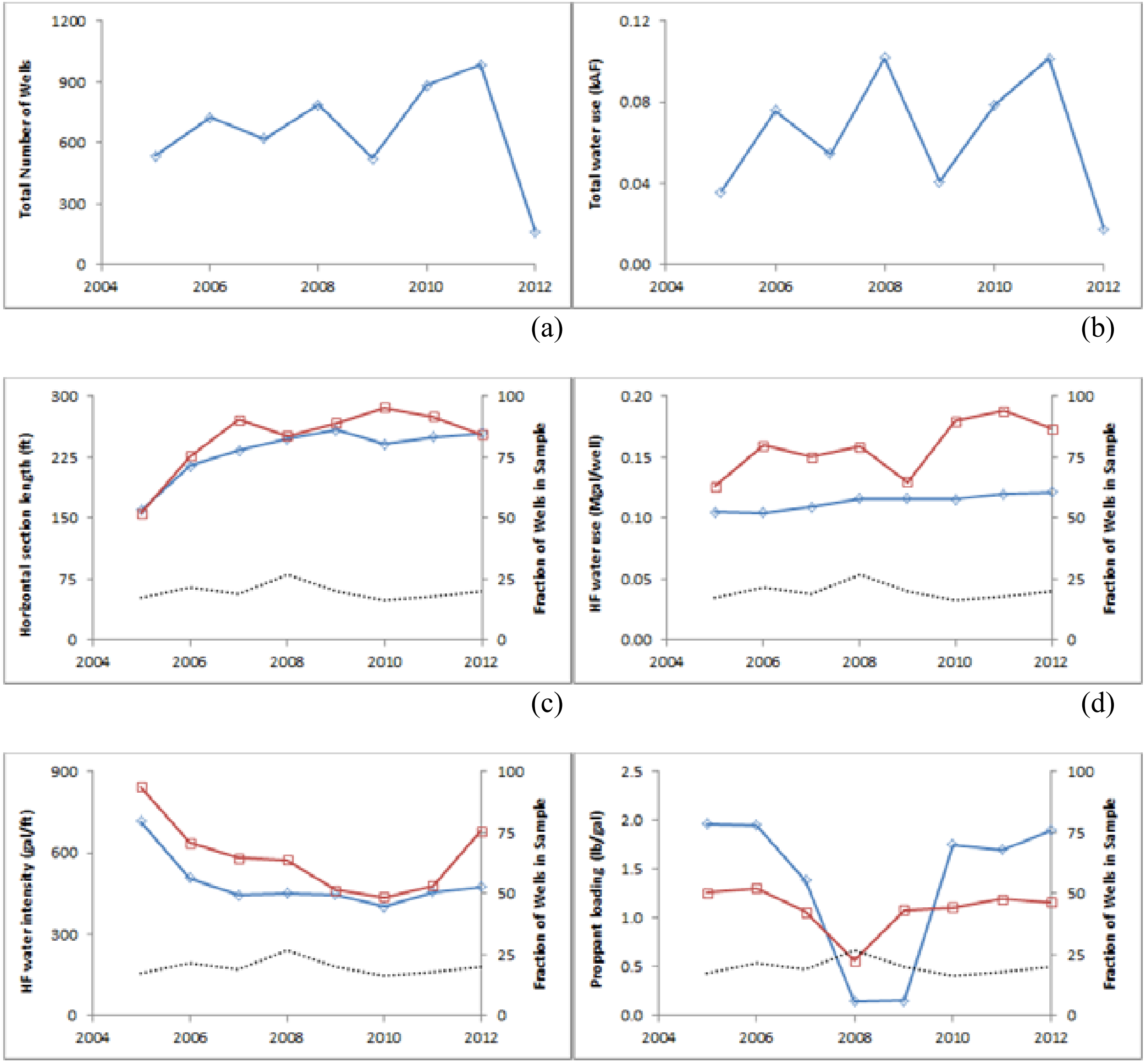
(c) (d)

(e) (f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 21. Clearfork verticals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median vertical productive section length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Permian Basin, San Andres-Grayburg -Verticals



(a) (b)

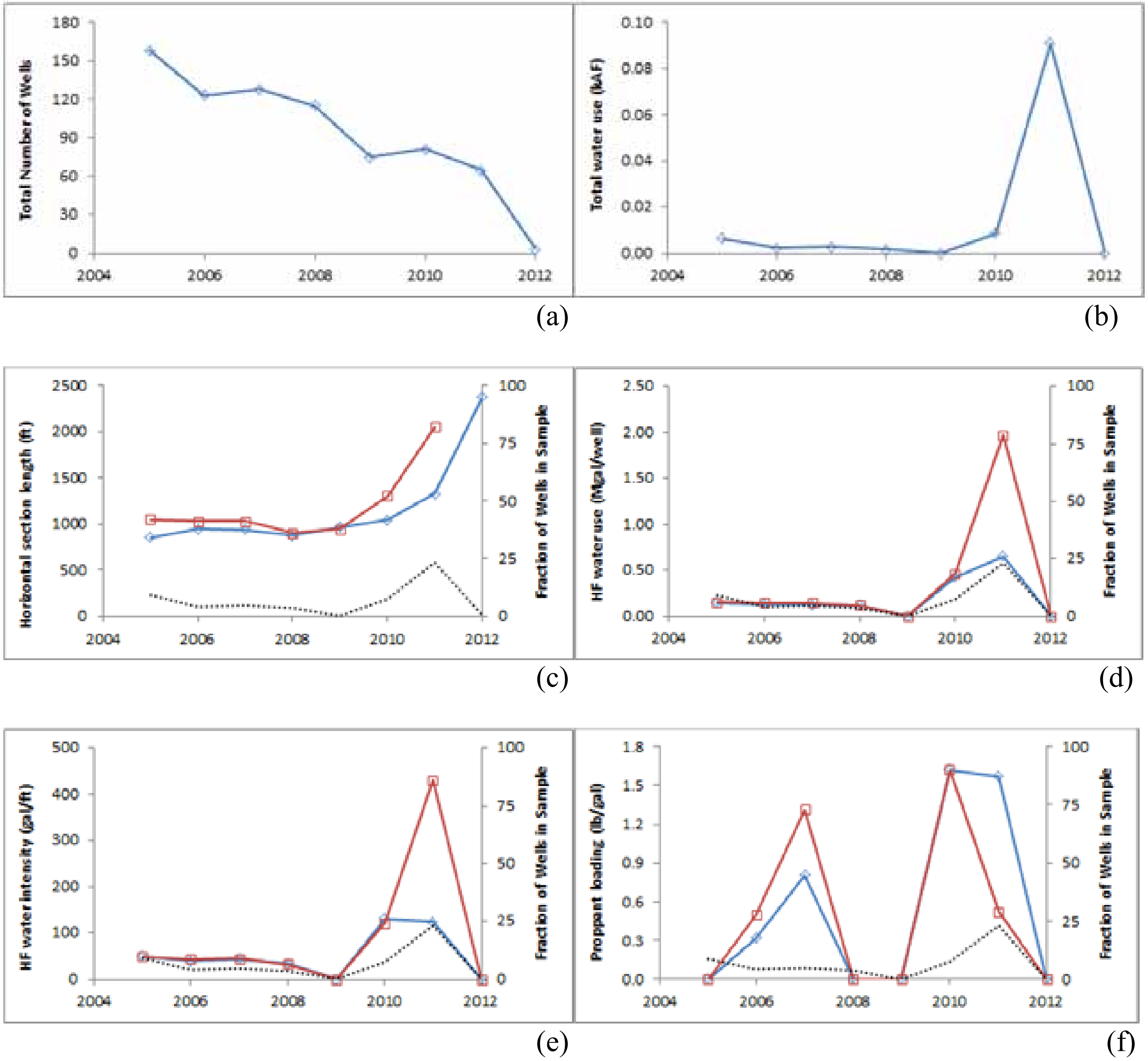
(c) (d)

(e) (f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 22. San Andres-Grayburg verticals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median vertical productive section length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Permian Basin, San Andres-Grayburg -Horizontals



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 23. San Andres-Grayburg horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Permian Basin:

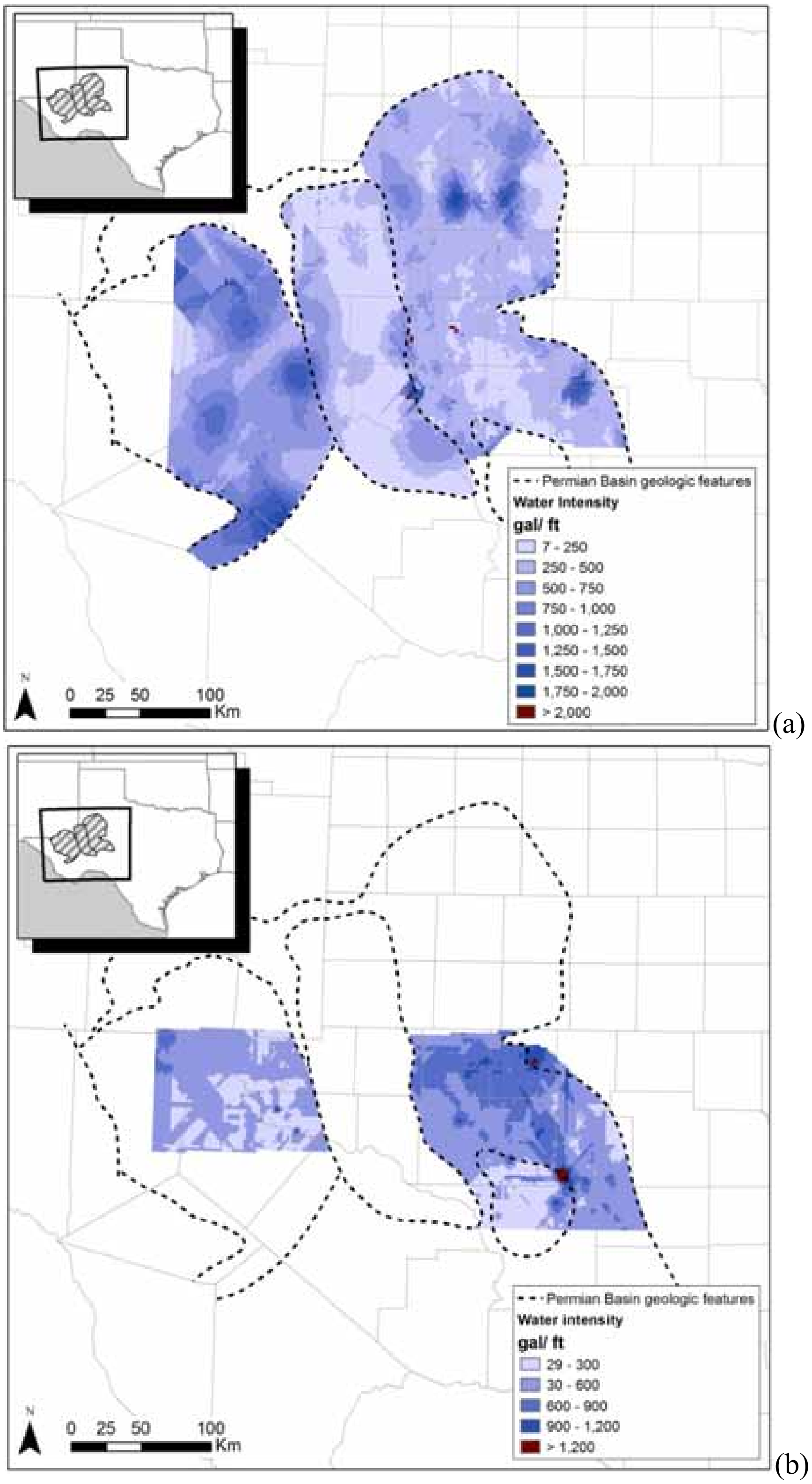
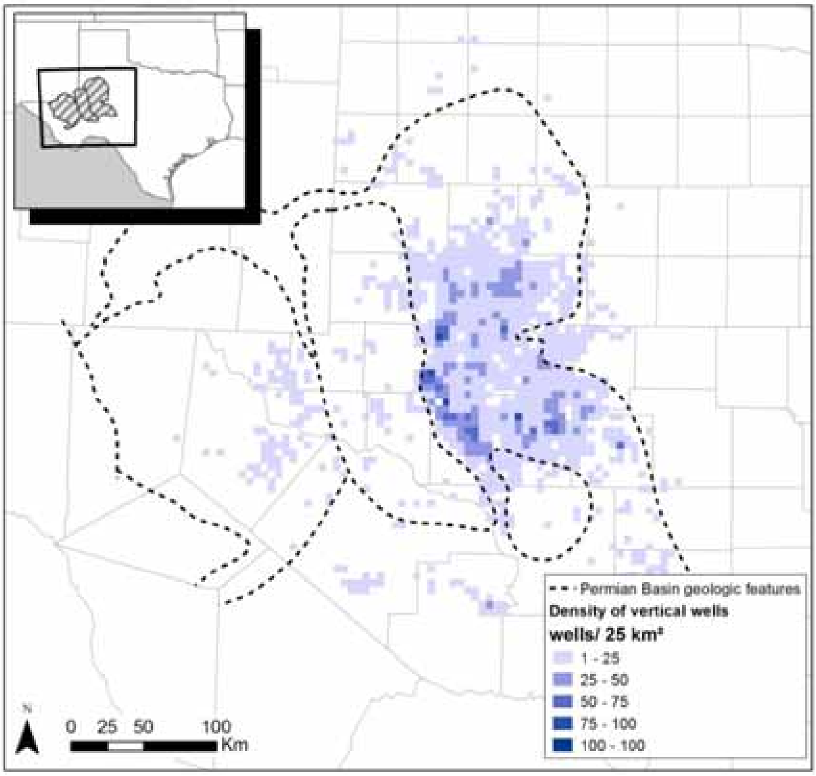


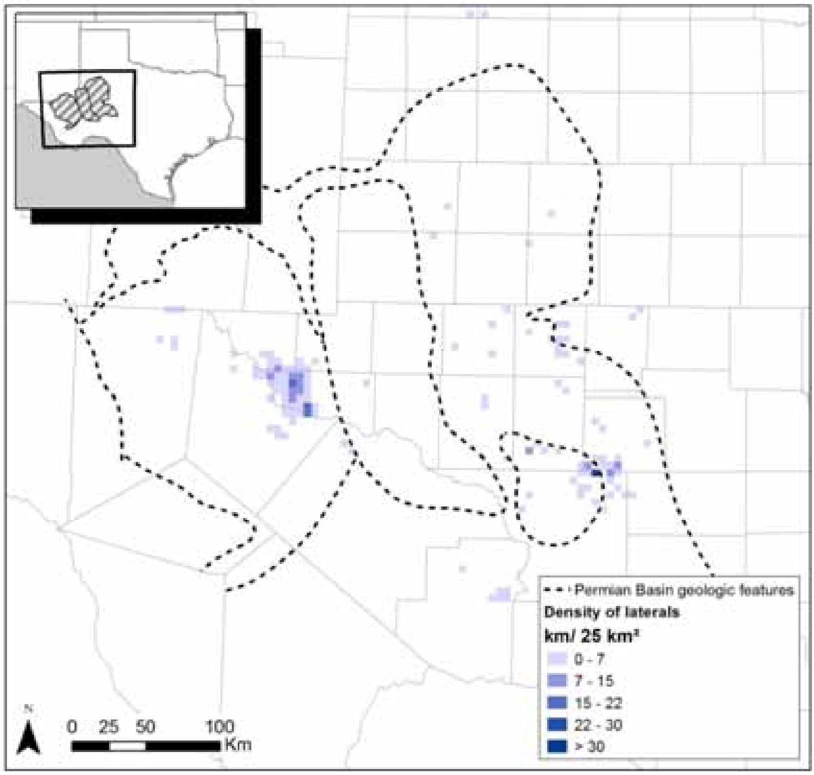
Figure 24. Permian Basin spatial distribution of water intensity for (a) vertical and (b) horizontal wells.

Permian Basin:



(a)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres



(b)

Figure 25. Permian Basin spatial distribution of (a) vertical well density and (b) density of lateral (cumulative length per area) for horizontal wells.

Permian Basin

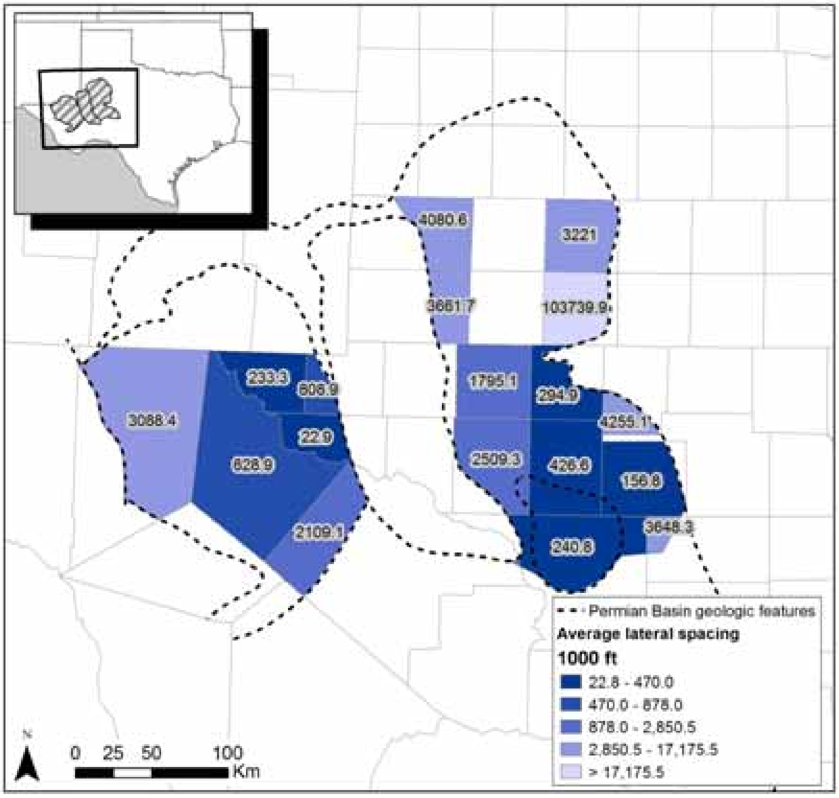
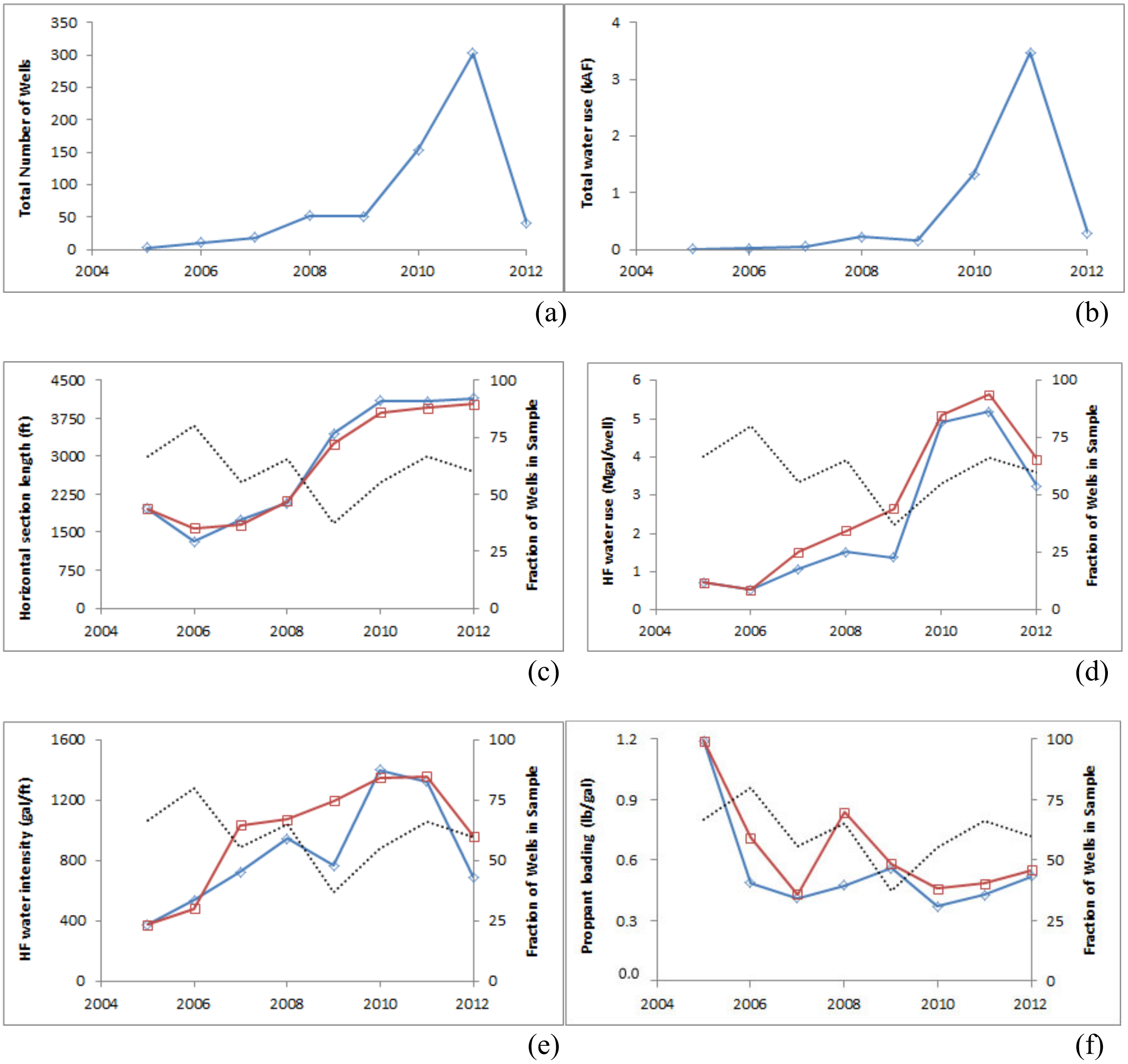


Figure 26. Permian Basin county-level average lateral spacing

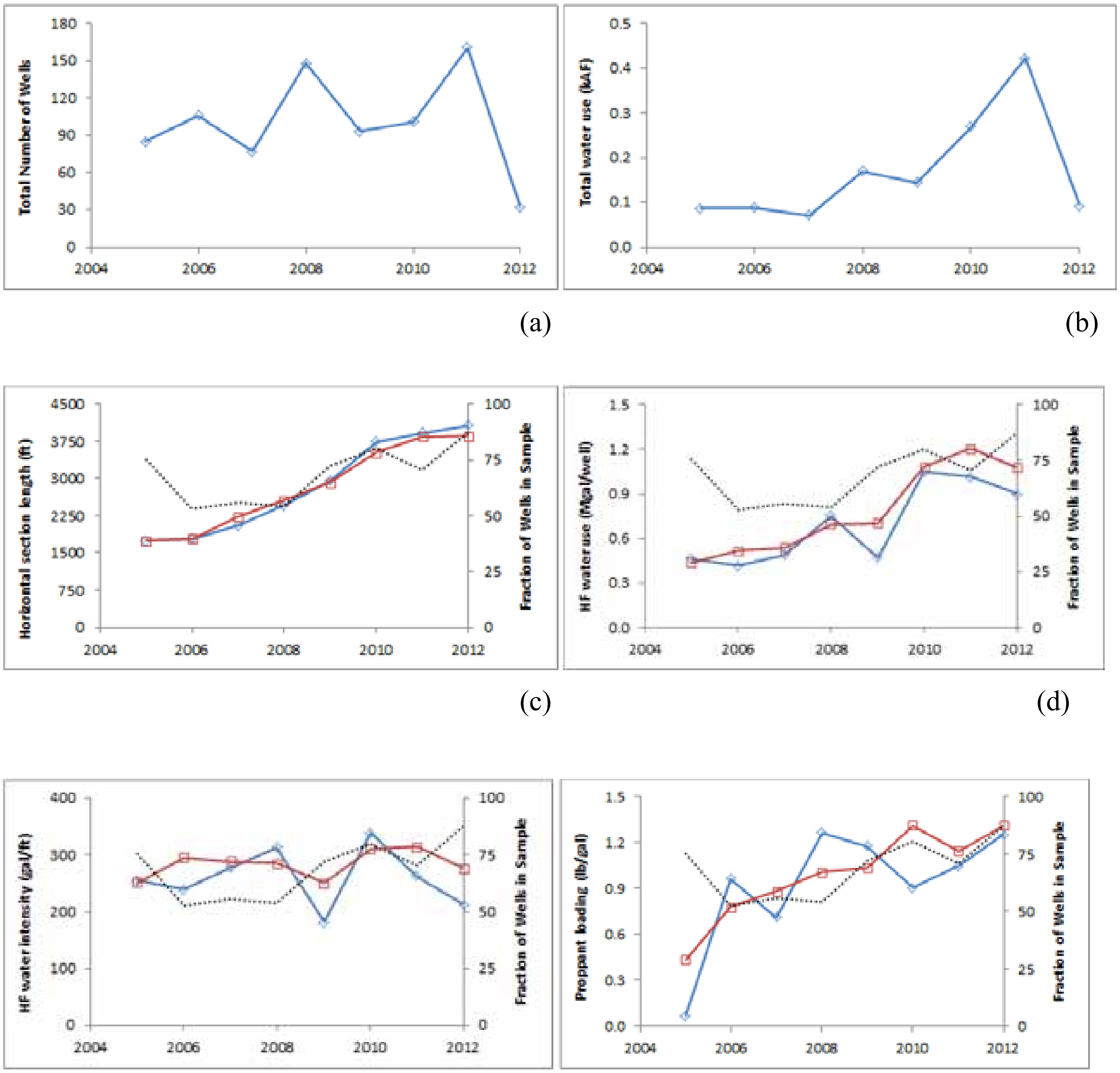
Anadarko Basin: Granite Wash Horizontals:



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 27. Granite Wash horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Anadarko Basin: Cleveland Horizontals:



(a) (b)

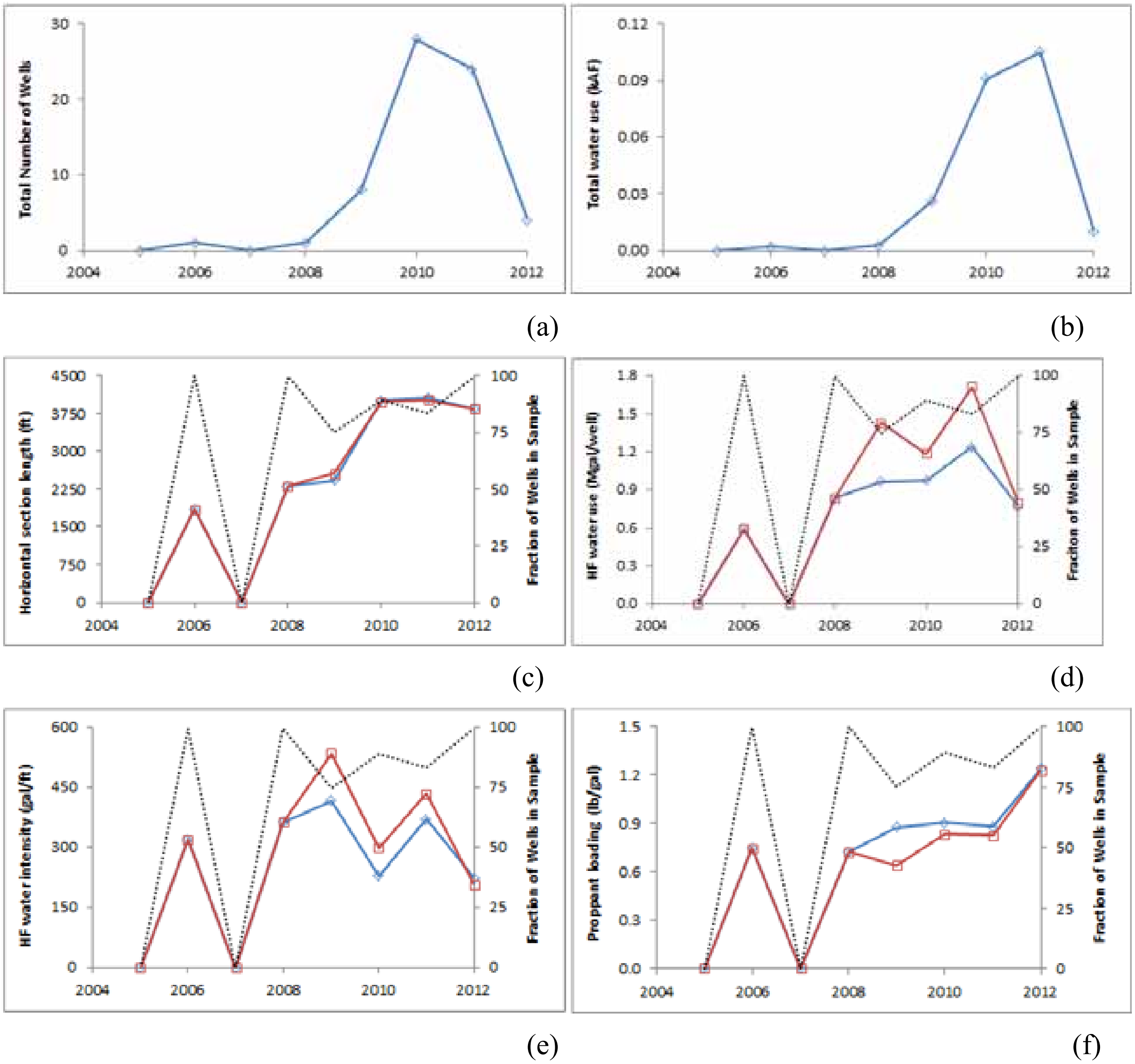
(c) (d)

(e) (f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 28. Cleveland horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Anadarko Basin: Marmaton Horizontals:



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 29. Marmaton horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Anadarko Basin: Granite Wash Horizontals:

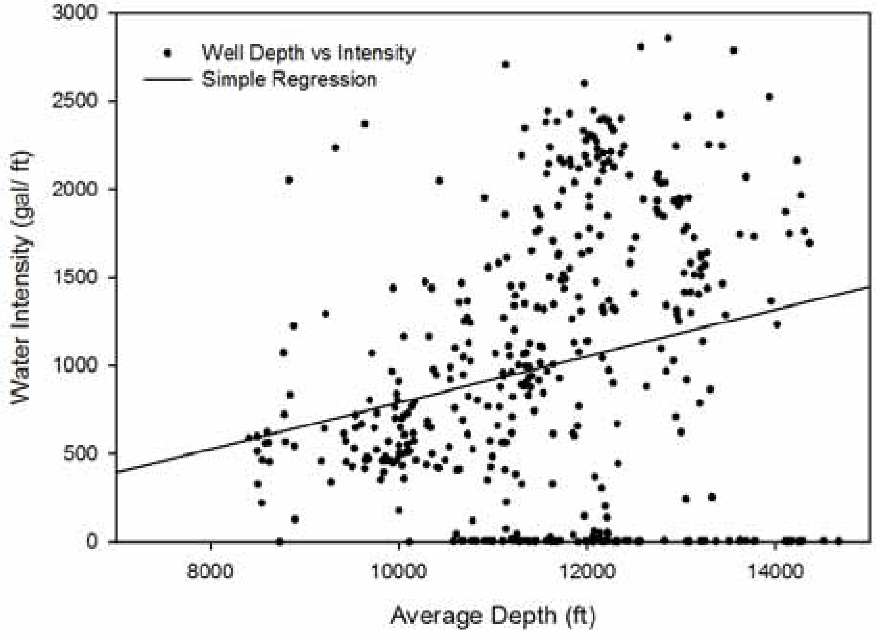


Figure 30. Granite Wash horizontal water use intensity as a function of depth.

Anadarko Basin: Cleveland Horizontals:

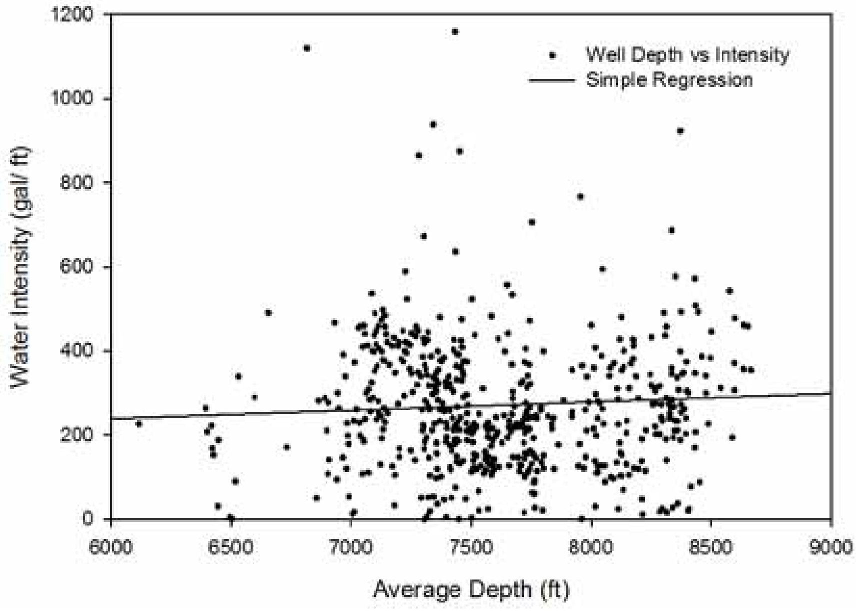
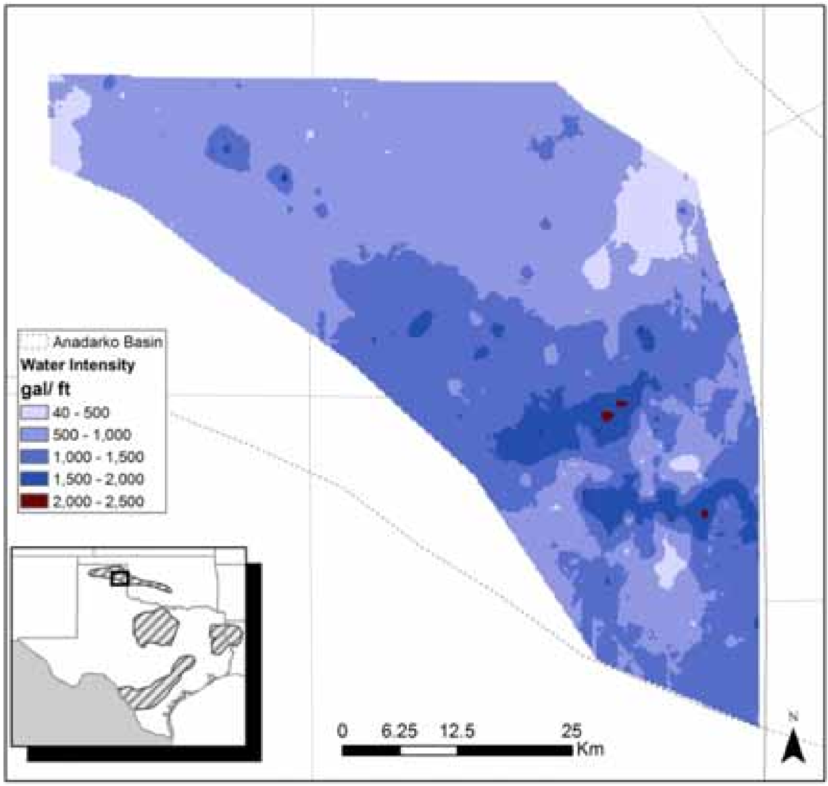
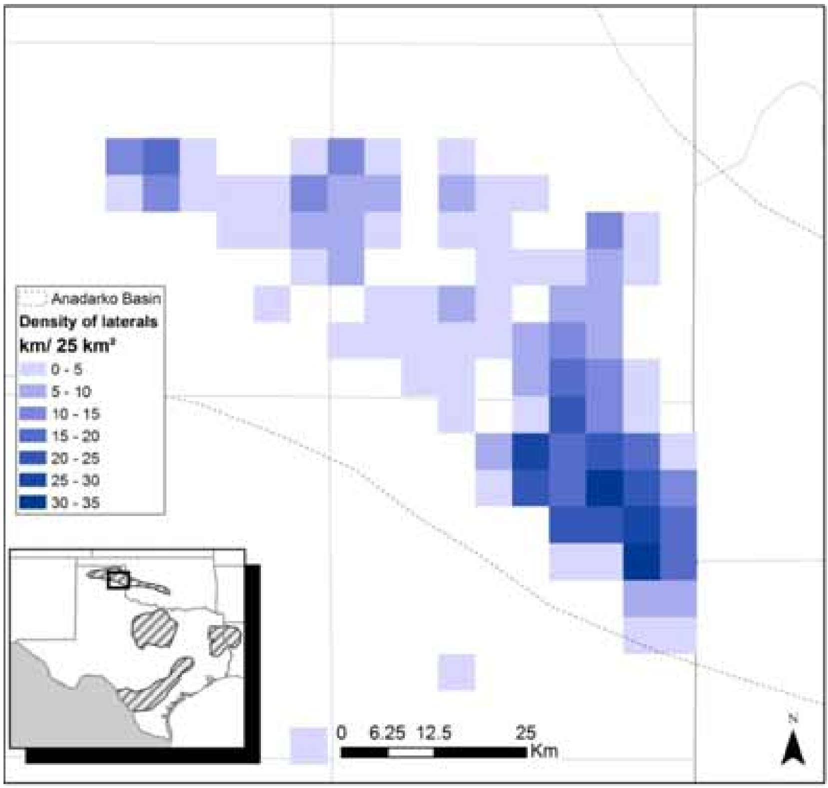


Figure 31. Cleveland horizontal water use intensity as a function of depth.

Anadarko Basin: Granite Wash Horizontals:



(a)



(b)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 32. Granite Wash spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

Anadarko Basin: Granite Wash Horizontals:

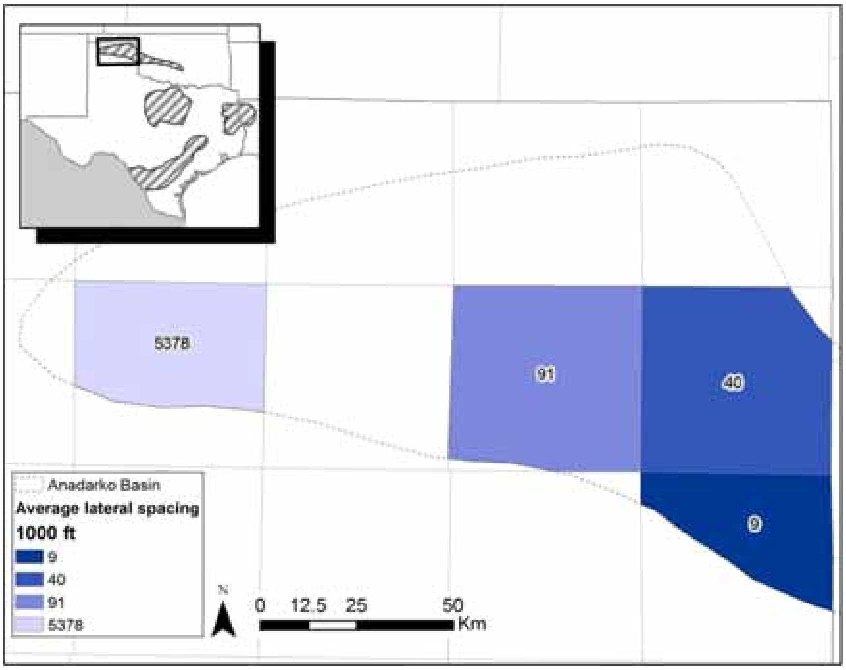
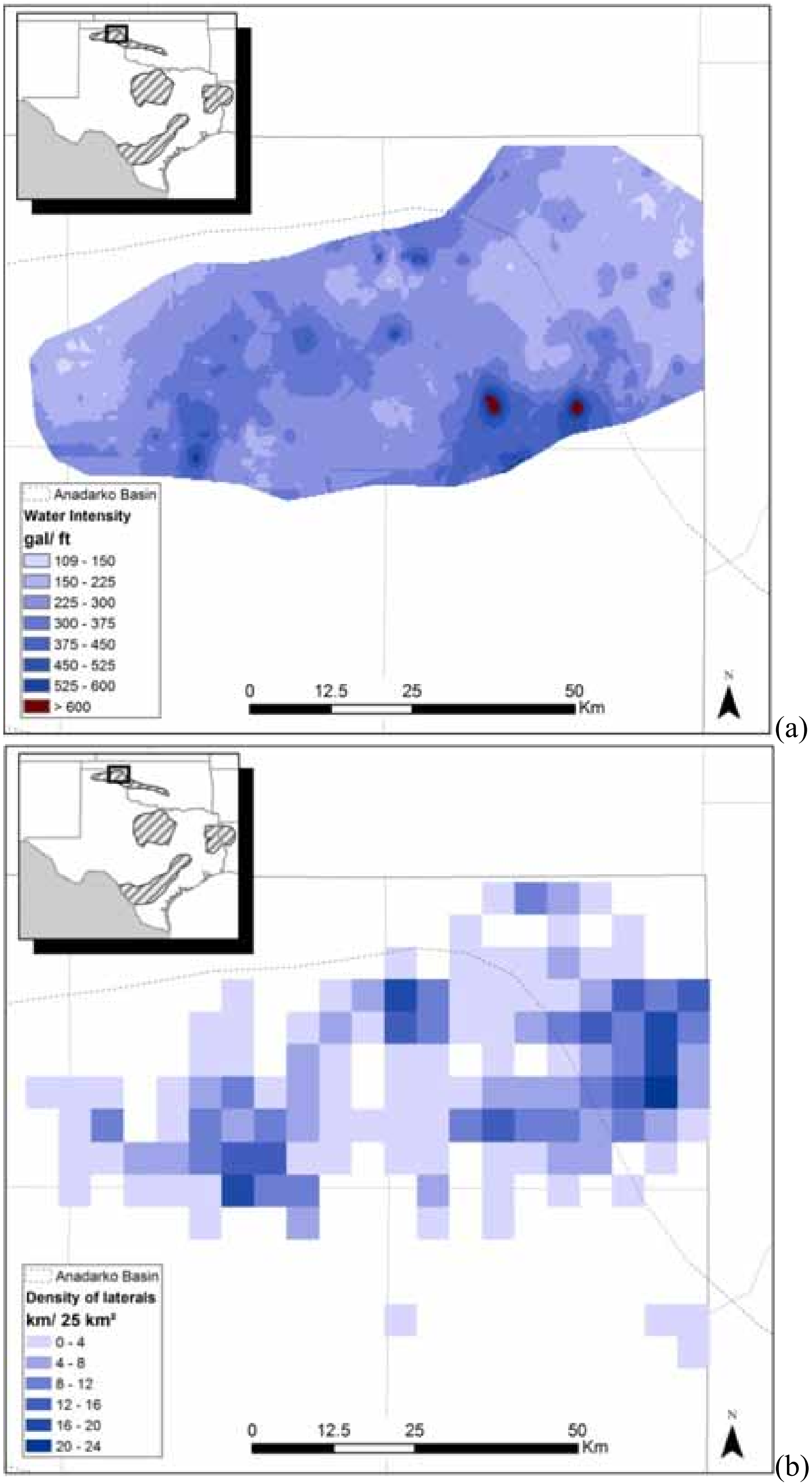


Figure 33. Granite Wash horizontals county-level average lateral spacing

Table 6. Granite Wash county-level average lateral spacing for top producing counties

County Name	Sum lateral length / county area (km/km^2)	Average Lateral Spacing (1000 ft)
Wheeler	0.351	9.34
Hemphill	0.082	39.74
Roberts	0.036	90.54

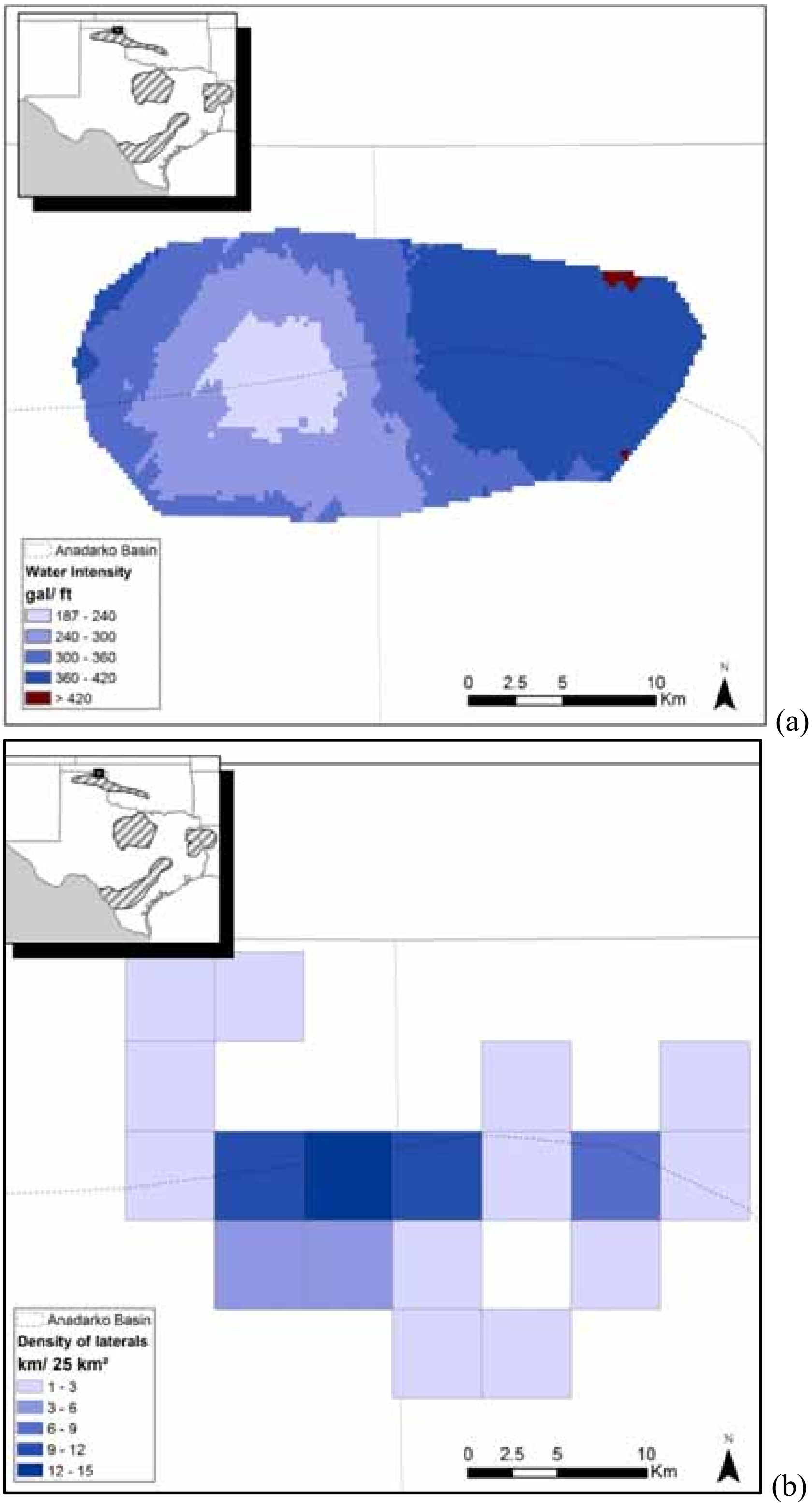
Anadarko Basin: Cleveland Horizontals:



Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 34. Cleveland spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

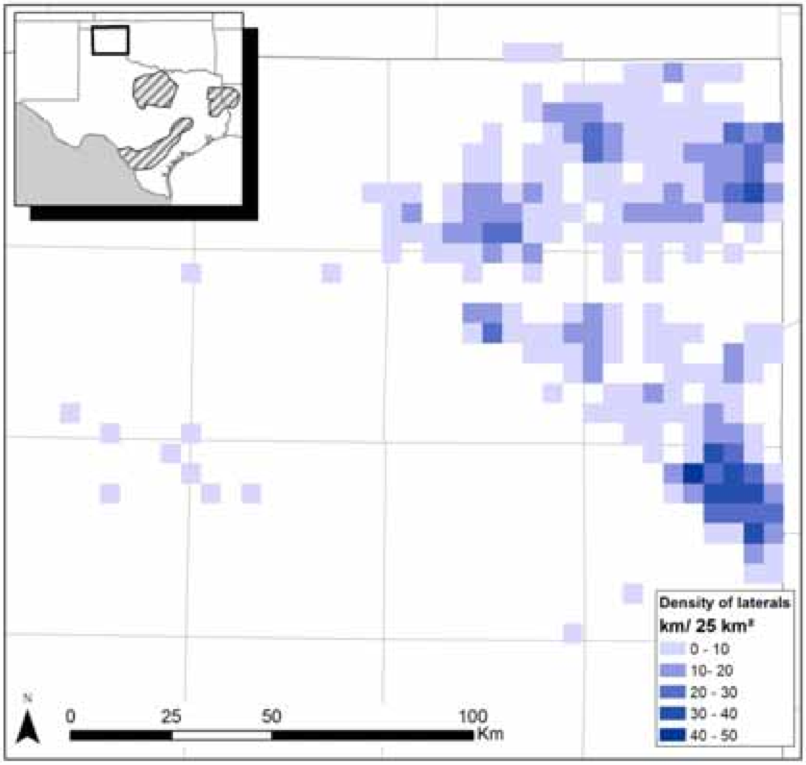
Anadarko Basin: Marmaton Horizontals:



Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

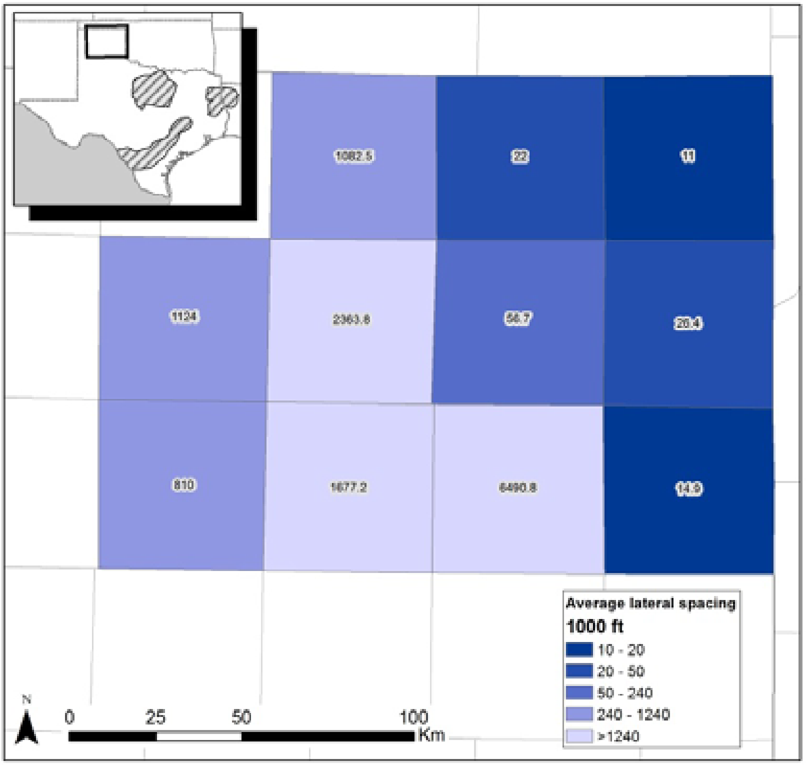
Figure 35. Marmaton spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

Anadarko Basin: Horizontals:



(a)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres



(b)

Figure 36. Anadarko spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

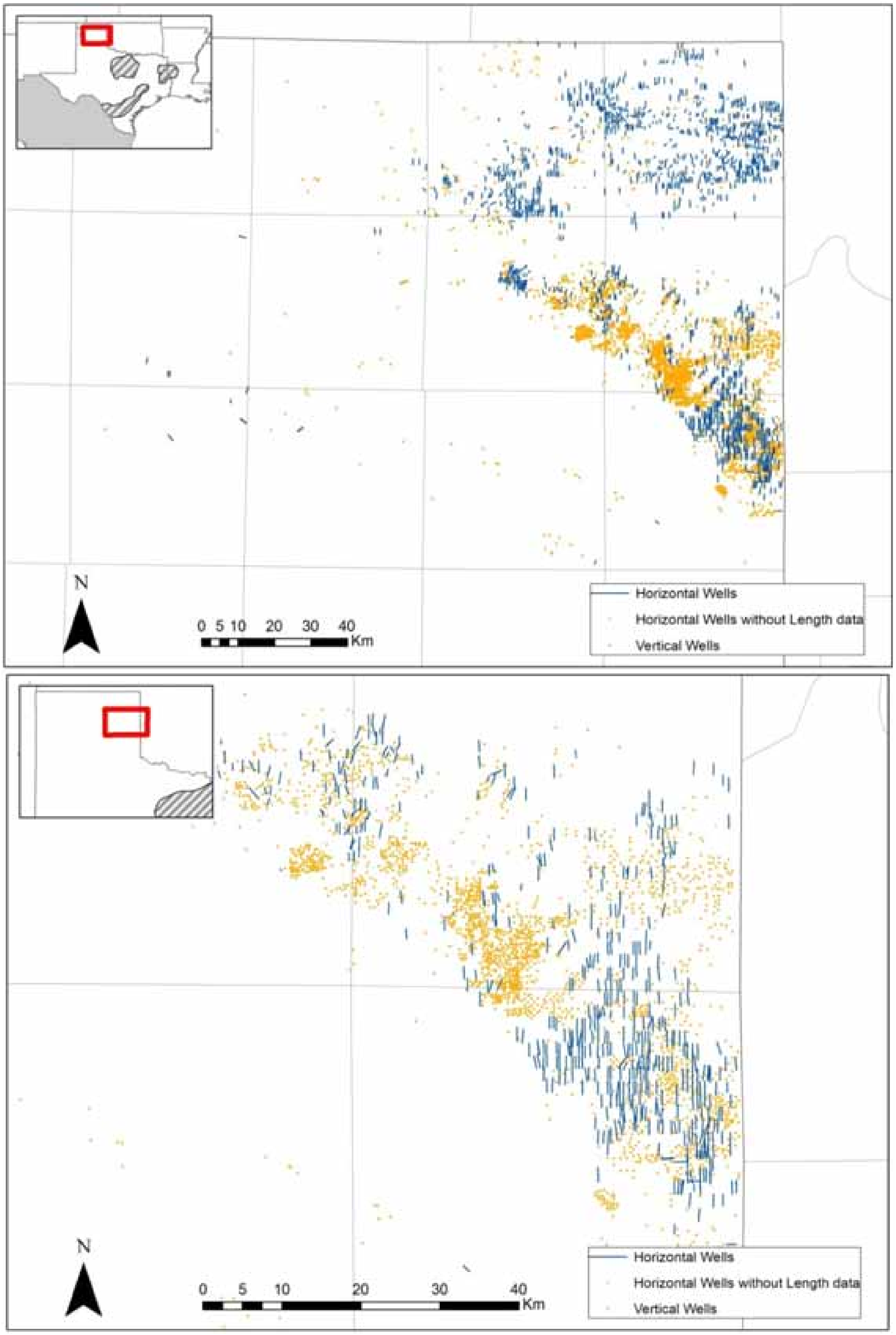
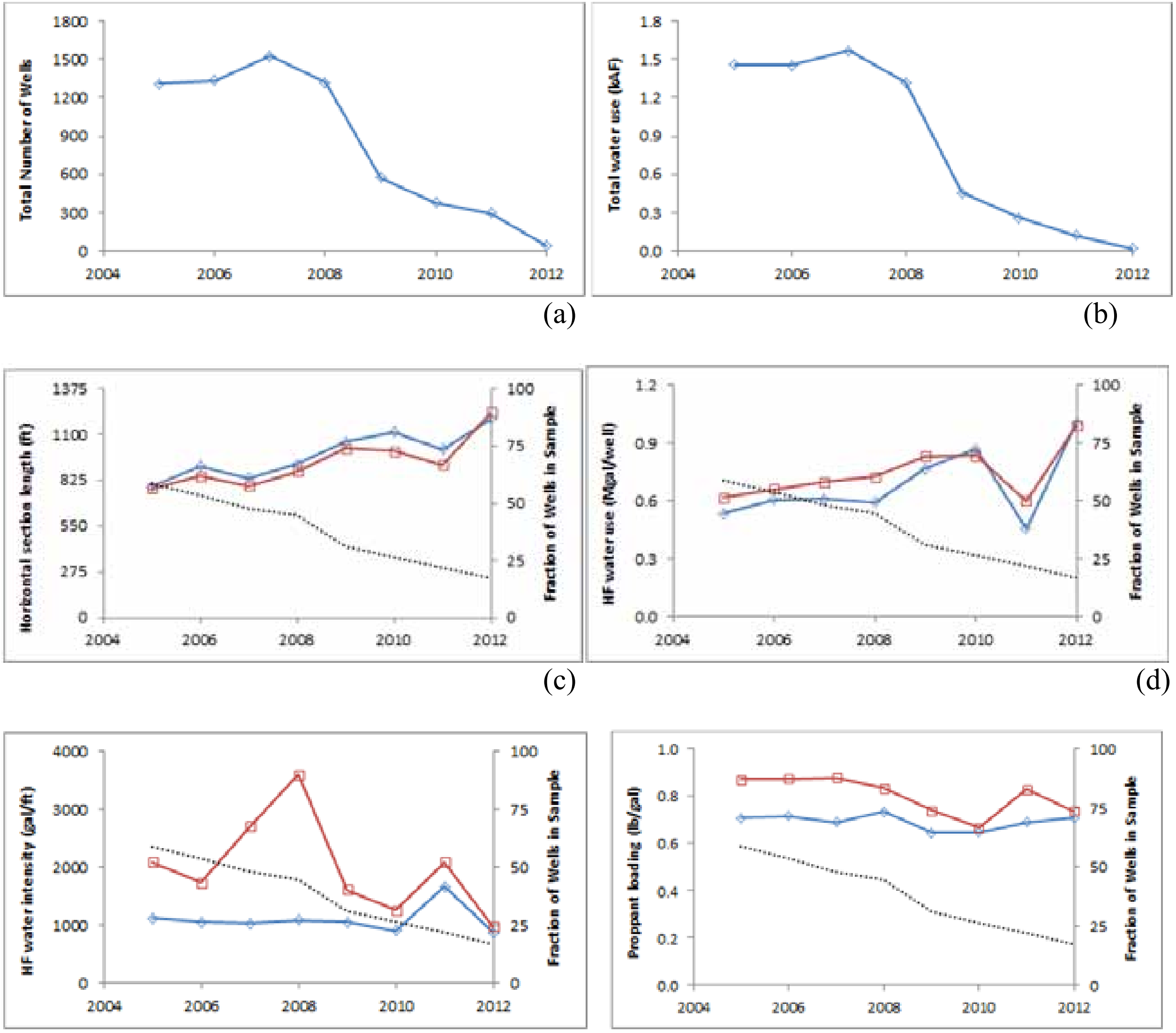


Figure 37. Map view of wells' lateral expression and vertical well location in the Anadarko Basin.

East Texas Basin: Cotton Valley Verticals



(a) (b)

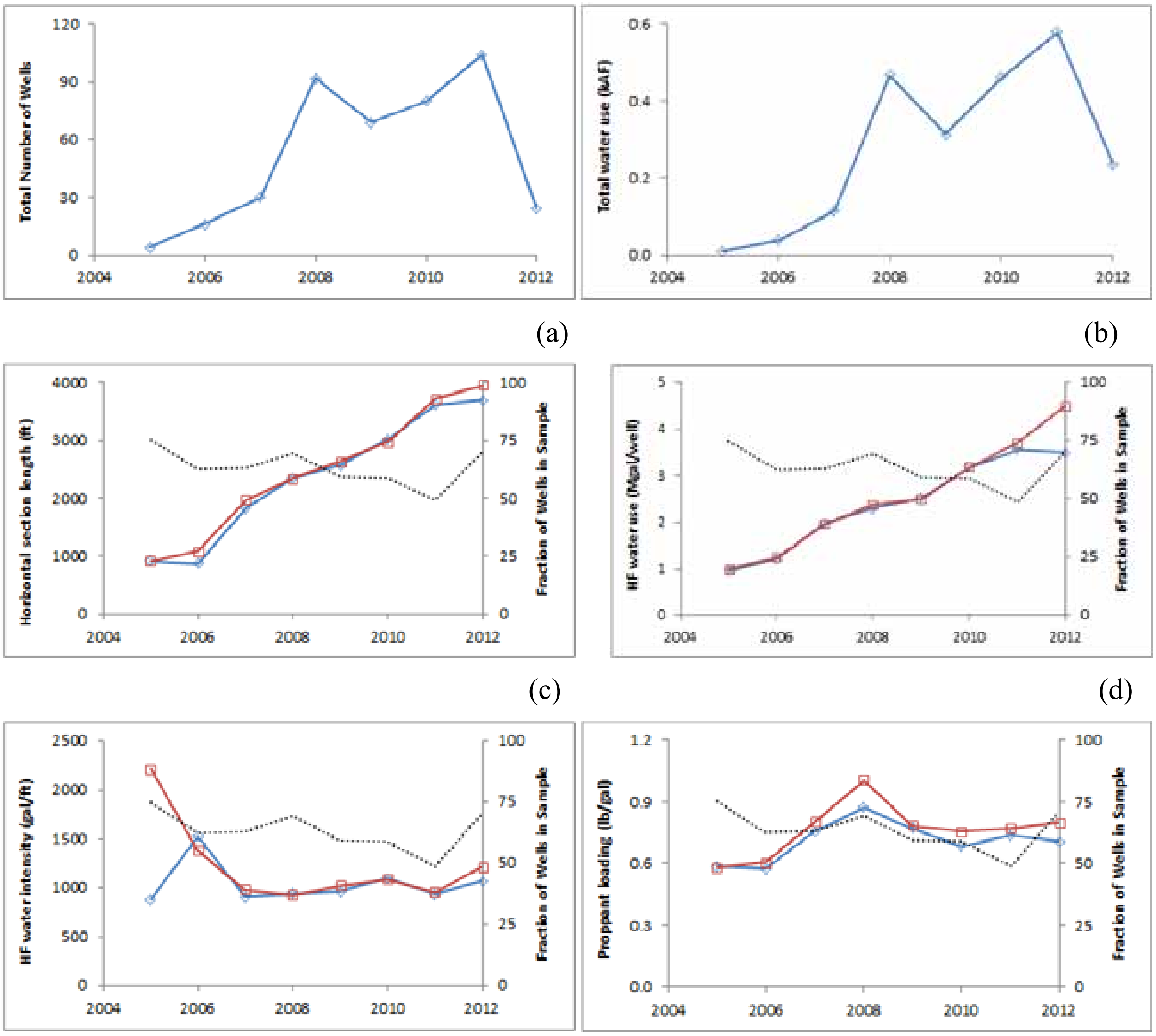
(c) (d)

(e) (f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 38. Cotton Valley verticals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median vertical productive section length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

East Texas Basin: Cotton Valley Horizontals



(a) (b)

(c) (d)

(e) (f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 39. Cotton Valley horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

East Texas Basin: Cotton Valley

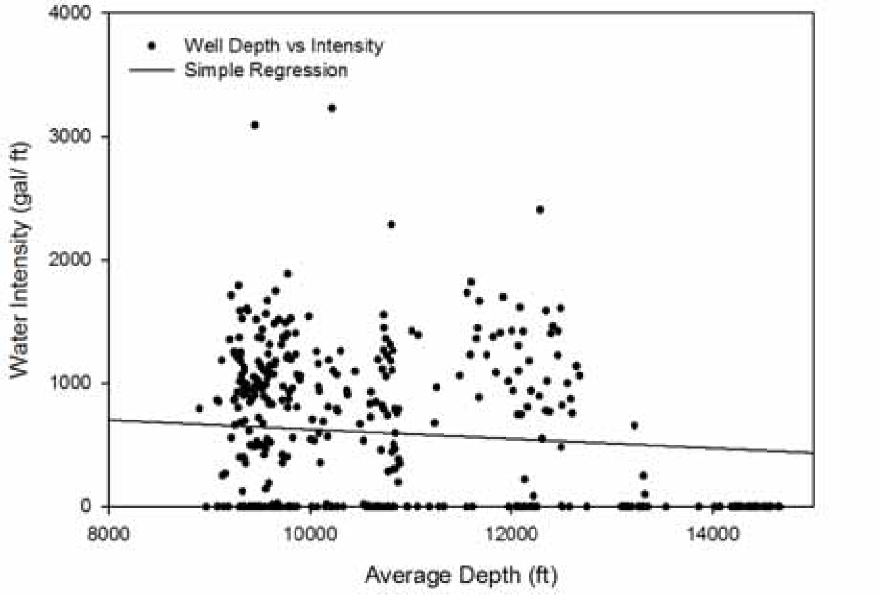
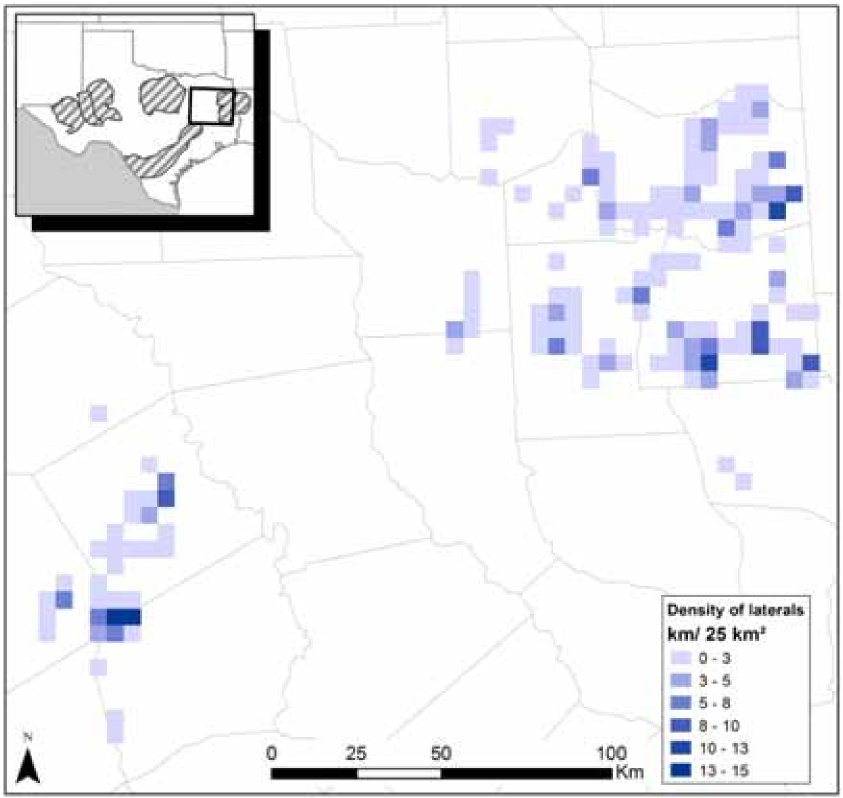


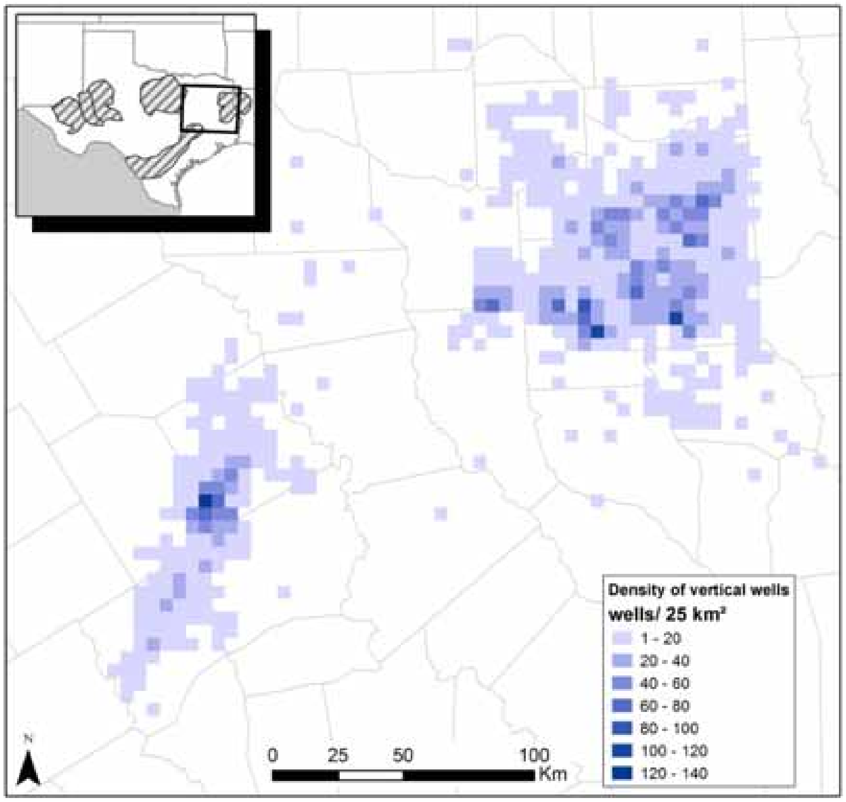
Figure 40. Cotton Valley horizontal water use intensity as a function of depth.



Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 41. Cotton Valley spatial distribution of density of lateral (cumulative length per area).

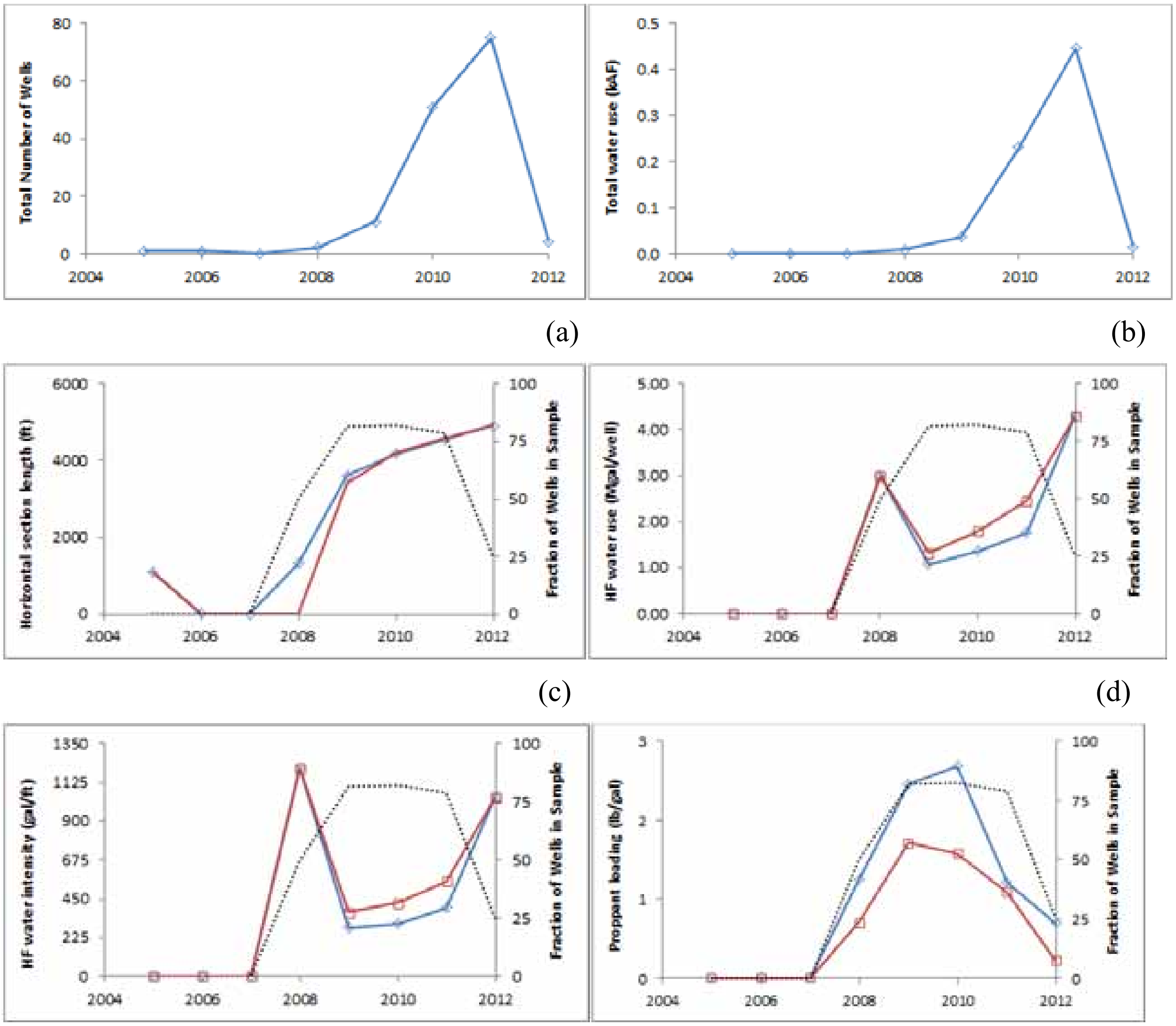
East Texas Basin: Cotton Valley



Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres
Note: Cotton Valley wells drilled before 2005 are not included (see Nicot et al., 2011 for details).

Figure 42. Cotton Valley spatial distribution of density of vertical wells (years 2005-2011).

Gulf Coast Basin, Olmos - Horizontal



(a) (b)

(c) (d)

(e) (f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 43. Olmos horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

III-2. Current Water Consumption and Sources

III-2-1 Information about Recycling/Reuse and Brackish Water Use

We collected information about recycling/reuse and brackish water use gathered during discussions with operators (Table 7). The amount of fresh water used is quite unequal across the different plays as a function of the local conditions. It can be as low as 20% in Far-West Texas or nearly 100% in East Texas. Collecting a sufficient amount of information concerning recycling/reuse and brackish water use is an improvement over the 2011 report which overall underestimated it. Reuse is limited by the amount of flow back that varies across plays. We could not document volumes of water recycled from wastewater treatment plants, but the TCEQ lists ~30 municipal and industrial facilities located in the Barnett Shale and Eagle Ford Shale plays that provide water to the industry (Figure 44). Groundwater/surface water could be extremely variable within a single play, but water data also reflect local conditions (Table 8): heavy surface water use towards the eastern part of the state and reliance on groundwater (sometimes brackish) elsewhere. The following short paragraphs discuss recycling/reuse and brackish water use and GS/SW split in major plays/regions.

Barnett Shale: For the most part, operators use fresh surface water in this play (estimated at 80% of "new" water). This is a change from the 50%+ groundwater use estimated in 2006 in Bené et al. (2007) and Nicot and Potter (2007). Some operators use brackish water, particularly in the combo play and on the western edges of the play. Some also use outfall from wastewater treatment plants. Overall, little recycling/reuse and brackish water use is currently occurring in this play as compared to other plays further west or south.

Eagle Ford Shale: Operators rely mostly on groundwater (estimated at 90% of "new" water) and there is a significant amount of brackish water being used (currently estimated at 20% but variable among operators). Several aquifers are brackish in the footprint of the play: the Gulf Coast aquifers and the Wilcox aquifers as well as the downdip section of the Carrizo aquifer.

Haynesville Shale and East Texas Basin: Water is generally plentiful in East Texas and no significant recycling/reuse and use for brackish water was documented during this study. We estimated it at 5%, mostly from treatment plants and produced water from Cotton Valley wells. We estimated that about 70% of the "new" water is groundwater.

Permian Basin: A significant percentage (30% or more) of the HF water used in both the Midland and Delaware basins is brackish. Nearly all of the water used is groundwater tapping aquifers such as the Ogallala (which is often brackish towards its southern domain, where the industry has many HF operations), and the Dockum, Trinity Edwards, Capitan, and other aquifers. The industry currently does little recycling/reuse, although several companies use produced water from conventional oil and gas operations. Such produced water has relatively low salinity at several places in the basin.

Anadarko Basin: This basin has hosted much recycling/reuse (estimated at 20%) and use of brackish water (estimated at 30%). Most of the "new" water is groundwater (estimated at 80%).

III-2-2 2011 HF Water Use and Consumption

Combining information collected from the IHS database, industry information, and selected information from the 2011 report results in an estimated water use for HF of ~81,500 AF across the state in 2011 (Table 9). The Barnett Shale and the Eagle Ford shale used a similar amount of water (~25 kAF), but less fresh water was used in the Eagle Ford. The Permian Basin is catching up (~15 kAF), but it uses relatively less fresh water than the two shale plays. Water use in the Texas section of the Haynesville Shale is becoming subordinate to other plays located in the same area (for example, Cotton Valley). County-level water use (Table 10) shows that many counties across the state have some HF water use (126 counties with >1AF in 2011 and 26 counties with >1kAF). The top 10 HF users consist of Tarrant County in the Barnett core (8.8 kAF), Webb County in the southern Eagle Ford (4.6 kAF), Johnson County in the core of the Barnett Shale (4.2 kAF), Karnes County in the Eagle Ford (3.9 kAF), Wheeler County in the Granite Wash of the Anadarko Basin (3.8 kAF), Dimmit County in the Eagle Ford (3.7 kAF), Denton County in the core of the Barnett Shale (3.2 kAF), Montague County in the combo play of the Barnett Shale (3.2 kAF), La Salle County in the Eagle Ford (2.9 kAF), and Wise County in the core of the Barnett Shale (2.3 kAF). The top ten counties total about half of the HF water use in the state. The top 10 counties stay the same when only water consumption is considered despite some reshuffling because of the variable impact of recycling/reuse and brackish water use.

In the next section we compare our current findings to the findings of the 2011 report (that projected a water use of 62 kAF in 2011, Table 9) and explain the discrepancies.

Table 7. Estimated percentages of recycling/ reused and brackish water use in main HF areas in 2011.

Play / Region	**Type**	**Current (2011) %**
Permian Far West	Recycled/reused	0%
	Brackish	80%
	Fresh	**20%**
Permian Midland	Recycled/reused	2%
	Brackish	30%
	Fresh	**68%**
Anadarko Basin	Recycled/reused	20%
	Brackish	30%
	Fresh	**50%**
Barnett Shale	Recycled/reused	5%
	Brackish	3%
	Fresh	**92%**
Eagle Ford Shale	Recycled/reused	0%
	Brackish	20%
	Fresh	**80%**
East Texas Basin	Recycled/reused	5%
	Brackish	0%
	Fresh	**95%**

Table 8. Estimated groundwater / surface water split (does not include recycling / reuse)

Play / Region	Groundwater	Surface Water
Barnett Shale	20%	80%
Eagle Ford Shale	90%	10%
East Texas Basin	70%	30%
Anadarko Basin	80%	20%
Permian Basin	100%	0%

Table 9. HF water use in 2008 and 2011compared to the 2011 projected water use from 2008.

Play / Region Unit: kAF	2011 Actual Water Use	Fraction Non-R/R Non-brackish	2011 Actual Water Consumption	2011 Projected Water Use
Barnett Shale	25.75	0.92	23.69	33.08
Eagle Ford Shale	23.76	0.8	18.81	10.07
East Texas Basin	7.54	0.95	7.06	8.46
Anadarko Basin	6.52	0.5	3.21	2.26
Permian Basin	14.44	0.68 / 0.2	8.55	7.26
Gulf Coast Basin	3.49	0.95 / 0.8	3.31	1.00
Statewide	81.51	0.79*	64.63	62.13

FrackingWaterUse2008&2011_Bob-JPComp_2.xls

*: computed from state consumption and use columns (sum of other rows)

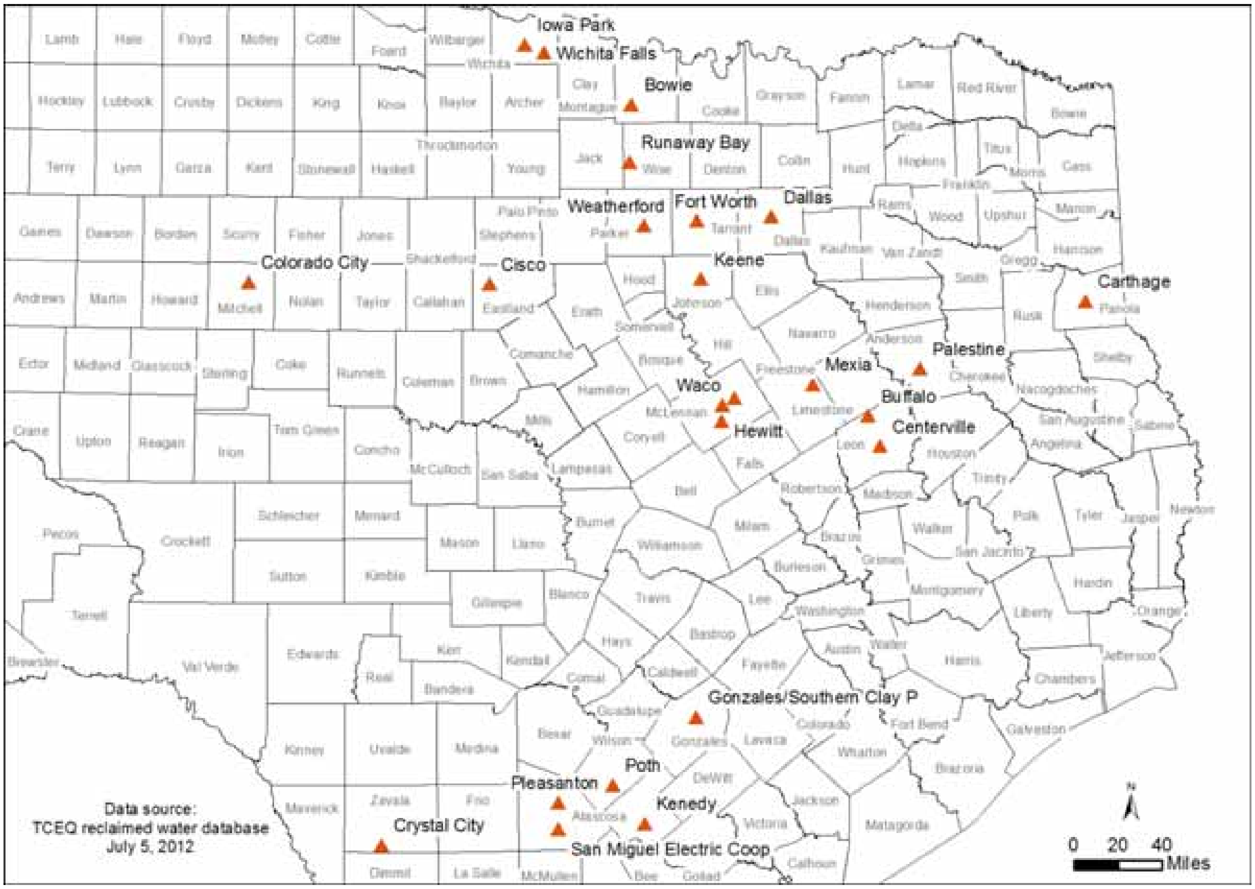
Table 10. County-level estimate of 2011 HF water use and water consumption (kAF).

County	HF Water Use (kAF)	HF Water Consumption (kAF)	County	HF Water Use (kAF)	HF Water Consumption (kAF)
Andrews	1.391	0.946	Limestone	0.268	0.214
Angelina	0.007	0.006	Lipscomb	0.382	0.191
Archer	0.017	0.016	Live Oak	0.972	0.777
Atascosa	1.009	0.807	Loving	0.189	0.038
Bee	0.066	0.053	McMullen	1.752	1.401
Borden	0.033	0.023	Madison	0.204	0.163
Brazos	0.238	0.191	Marion	0.010	0.010
Brooks	0.008	0.006	Martin	2.035	1.384
Burleson	0.247	0.197	Maverick	0.192	0.154
Caldwell	0.075	0.060	Midland	1.573	1.070
Carson	0.085	0.042	Milam	0.034	0.027
Cherokee	0.010	0.009	Mitchell	0.018	0.012
Clay	0.058	0.053	Montague	3.221	2.963
Cochran	0.031	0.021	Moore	0.076	0.038
Coke	0.001	n/a	Nacogdoches	1.128	1.072
Cooke	1.480	1.362	Newton	0.098	0.093
Crane	0.159	0.108	Nolan	0.011	0.008
Crockett	0.475	0.323	Nueces	0.016	0.013
Crosby	0.012	0.008	Ochiltree	0.273	0.136
Culberson	0.166	0.033	Orange	0.006	n/a
Dallas	0.079	0.073	Palo Pinto	0.041	0.038
Dawson	0.089	0.061	Panola	0.966	0.917
Denton	3.249	2.989	Parker	1.086	1.000
DeWitt	2.151	1.721	Pecos	0.110	0.022
Dimmit	3.706	2.965	Polk	0.133	0.126
Ector	0.756	0.514	Potter	0.044	0.022
Ellis	0.038	0.035	Reagan	1.240	0.843
Erath	0.012	0.011	Reeves	0.522	0.104
Fayette	0.132	0.106	Roberts	0.393	0.197
Franklin	0.014	0.014	Robertson	0.306	0.245
Freestone	0.424	0.339	Runnels	0.004	0.003
Frio	0.729	0.583	Rusk	0.158	0.150
Gaines	0.142	0.096	Sabine	0.147	0.139
Garza	0.001	n/a	San Augustine	1.622	1.541
Glasscock	1.434	0.975	Schleicher	0.090	0.061
Gonzales	2.224	1.779	Scurry	0.010	0.007
Grayson	0.021	0.020	Shackelford	0.002	0.002
Gregg	0.025	0.024	Shelby	1.419	1.348
Grimes	0.095	0.076	Sherman	0.002	0.001
Guadalupe	0.018	0.014	Smith	0.005	0.005
Hansford	0.011	0.005	Somervell	0.287	0.264
Hardeman	0.017	0.012	Starr	0.036	0.029
Harrison	0.893	0.849	Sterling	0.057	0.039
Hemphill	1.462	0.731	Stonewall	0.001	n/a
Henderson	0.012	0.012	Sutton	0.034	0.023
Hidalgo	0.059	0.047	Tarrant	8.805	8.101
Hill	0.131	0.120	Terrell	0.010	0.007
Hockley	0.005	0.003	Terry	0.003	0.002
Hood	0.645	0.593	Titus	0.003	0.003

County	HF Water Use (kAF)	HF Water Consumption (kAF)	County	HF Water Use (kAF)	HF Water Consumption (kAF)
Houston	0.178	0.142	Tyler	0.076	0.072
Howard	0.552	0.376	Upshur	0.004	0.004
Hutchinson	0.005	0.002	Upton	1.761	1.198
Irion	0.875	0.595	Ward	0.568	0.114
Jack	0.048	0.044	Washington	0.036	0.029
Jasper	0.087	0.083	Webb	4.596	3.677
Johnson	4.192	3.857	Wheeler	3.792	1.896
Karnes	3.869	3.095	Wilson	0.417	0.334
Kenedy	0.006	0.005	Winkler	0.062	0.012
Kleberg	0.034	0.028	Wise	2.314	2.129
La Salle	2.901	2.321	Yoakum	0.018	0.013
Lavaca	0.118	0.094	Young	0.008	0.007
Lee	0.131	0.105	Zapata	0.032	0.026
Leon	0.273	0.218	Zavala	0.407	0.127
			SUM	**81.50 kAF**	**64.63 kAF**

Note: filtered at 0.001 kAF

FrackingWaterUse2008&2011_Bob-JPComp_2.xls

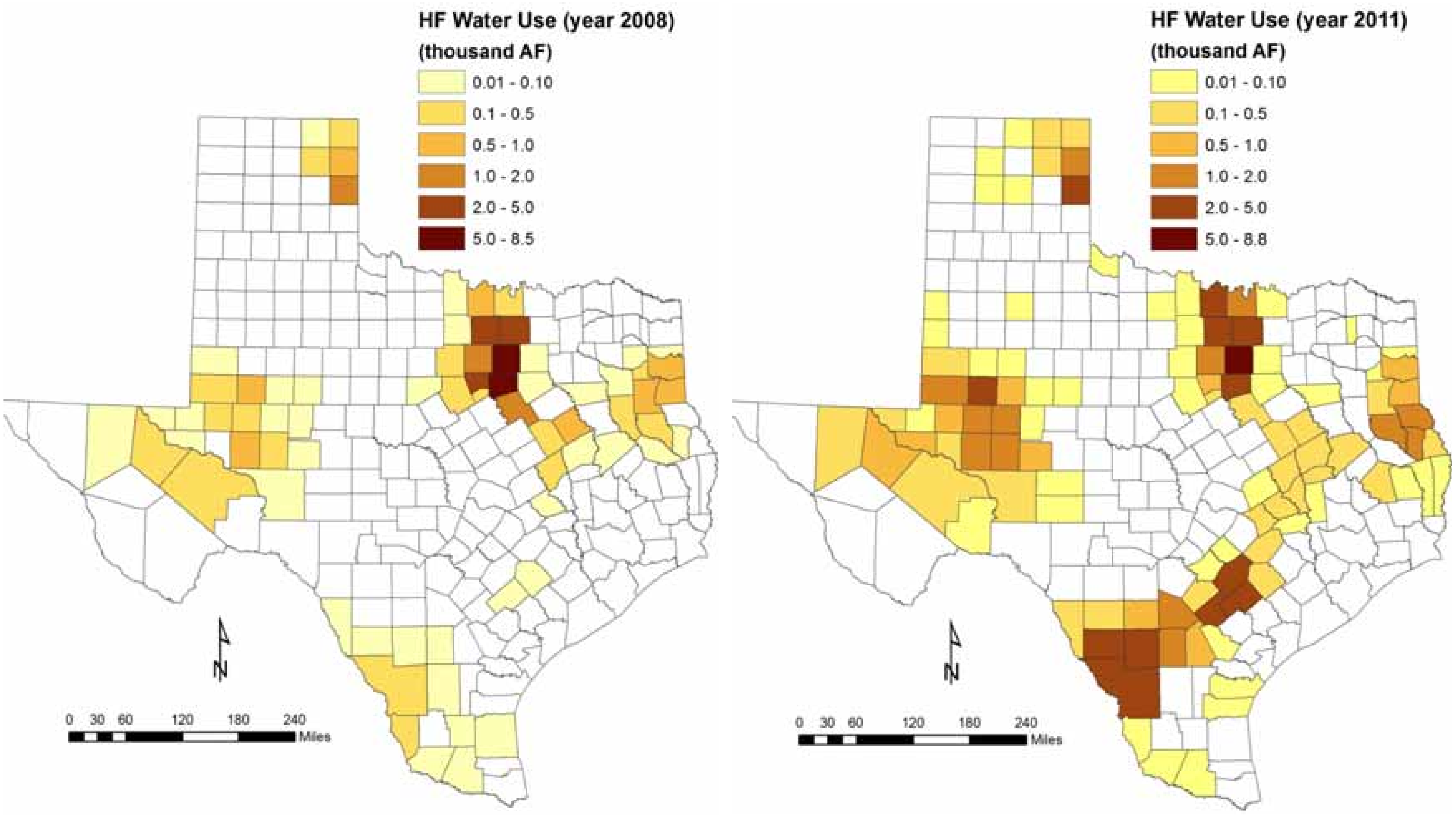


Source: TCEQ, 2012

Figure 44. Location of waste water treatment facilities that provide or have provided water to the industry for HF as of July 2012.

III-3. Comparison to Earlier Findings

Projections made in 2009 for 2011 in the 2011 report underestimated water use by about 30% (81.5 kAF compared to 62.1 kAF, Table 9). It is important to understand the underlying causes in order to develop better projections in this document. Comparing actual water use in 2008 and 2011 (Figure 45) shows (1) extension of HF across the state, Barnett Shale stays relatively steady, fracturing in the Haynesville Shale and Anadarko Basin expands, and the Eagle Ford becomes much more prominent as does the Permian Basin. A bar plot illustrates the county-by-county discrepancies between projections and actual numbers (Figure 46). A cross-plot is a different way of presenting the same information (Figure 47), and it is apparent that most counties with larger water use (dots in the upper right-hand side of the side) were correctly accounted (no dots on either the x- or y-axis), even if it was underestimated (dots mostly below the 1:1 line). Major discrepancies occurred because there was no Barnett extension outside of the core area (for example, Bosque, Comanche, Erath, and Palo Pinto counties in Figure 46), and because of more and faster development in the Eagle Ford Shale and Permian Basin. Both these factors are connected to the drop in gas price and increase in oil price in the past 2 or 3 years, parameters notoriously difficult to predict.



~36,000 AF
(Nicot el al., 2011)

~81,500 AF
including ~17,000 AF of recycling/reuse
and use of brackish water

Figure 45. Spatial distribution of HF water use in 2008 and 2011.

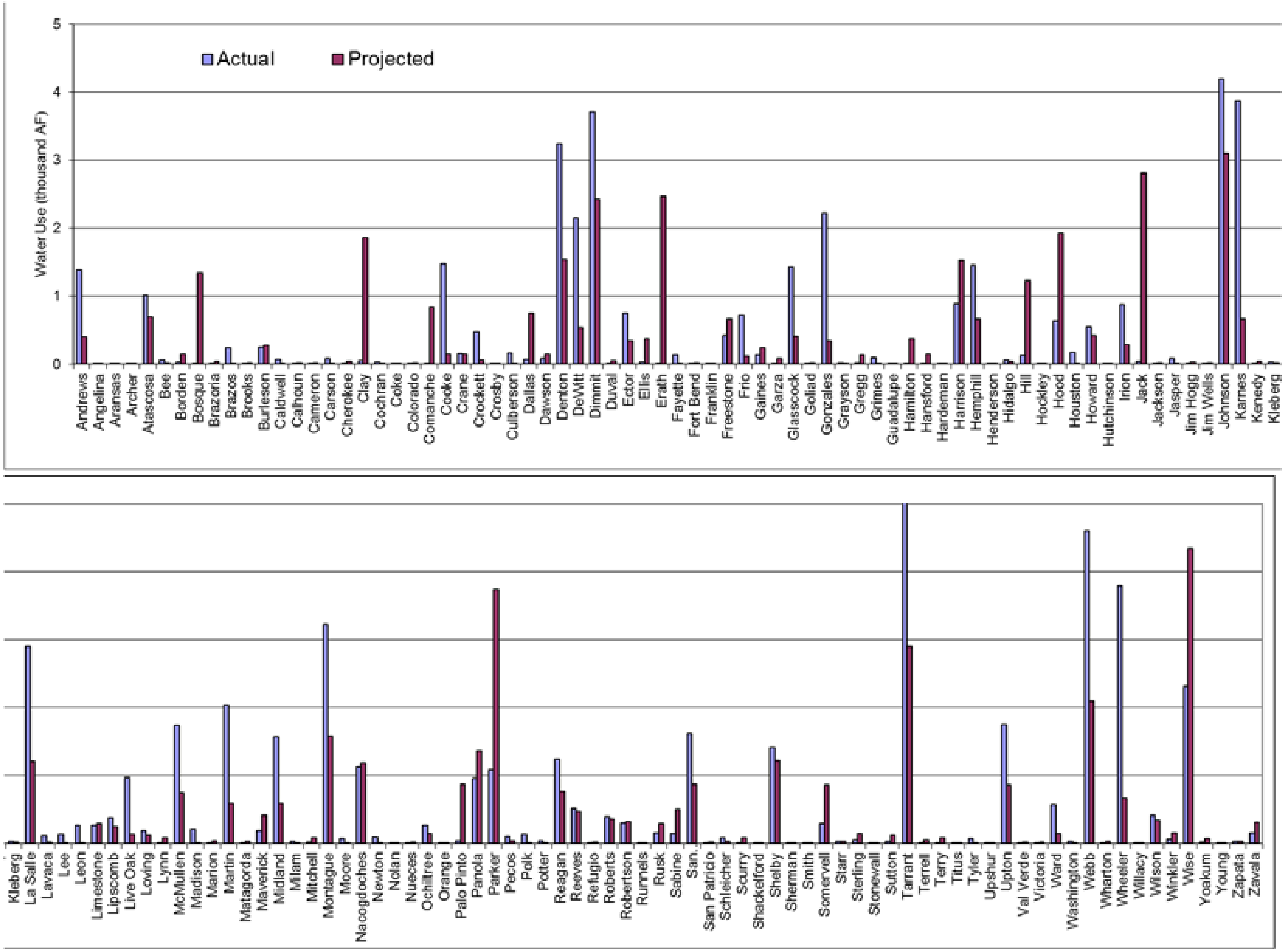
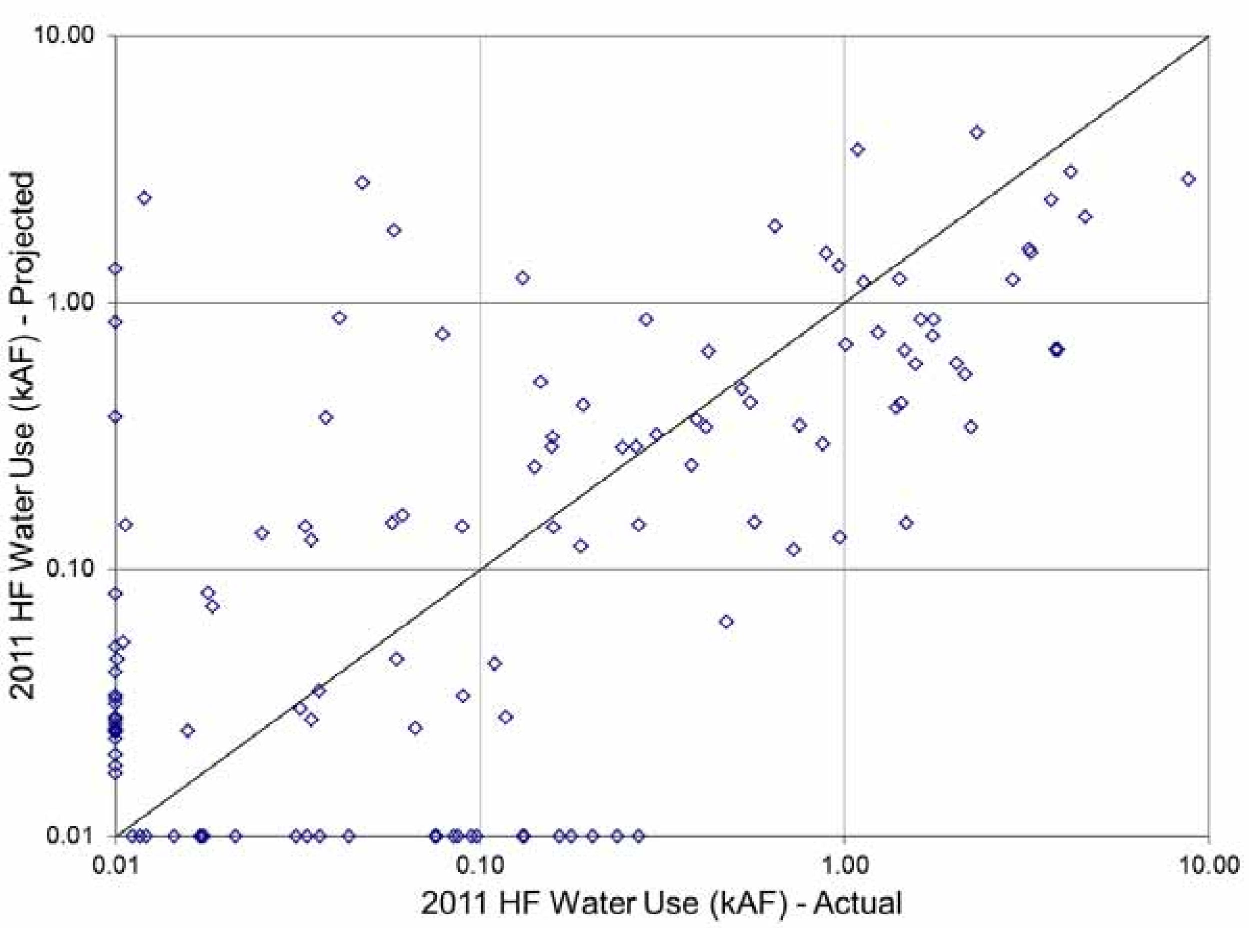


Figure 46. Bar plot comparison of 2011 actual water use to projections from 2009.



Note: Note the log-log scale.

Figure 47. County-level cross-plot comparison of 2011 actual water use to projections from 2008. Values on x- and y- axis represent counties whose actual (y-axis) / projected (x-axis) water use is 0. A total of 168 counties are represented.

III-4. Drilling Water Use

In the course of the study, we also collected information about drilling water use. Results are not sufficiently representative to change results presented in the 2011 report amounting to 8 kAF. The general observation, though, is that drilling requires water of better quality than HF although in smaller amounts (Table 11). The amount of water used depends on the length of the well and on operator preferences but also, more importantly, heavily on local factors. For example, in the Eagle Ford the drilling muds used in drilling through horizontal sections (for example, Fan et al., 2011) are oil-based.

Table 11. Drilling water use information

Play / Region in 1000's gal/well	Range provided by operators	Comments
Barnett Shale	250	N/A
	210-420	~Fresh
	168	~Fresh
	500	~Fresh
Eagle Ford Shale	125	N/A
	420	N/A
	160	~Fresh
	126	~Fresh
	252-420	~Fresh
East Texas Basin	600	N/A
	840-1,100	~Fresh
	420	~Fresh
Anadarko Basin	200	N/A
	420	~Fresh
Midland Basin (Permian Basin)	84	~Fresh
	100	N/A
	210	~Fresh
	210-420	~Fresh
Delaware Basin (Permian Basin)	100	N/A
	210-420	Brackish

Note: fresh is defined as TDS<3,000 mg/L

IV. Water Use Projections

This section describes projections for HF water use and fresh-water consumption in Texas to year 2060. As described in the 2011 report, all projections entail many uncertainties and those caveats are still valid in this update. In general, the life of the plays was extended beyond 2060, less prospectivity was given to the gas window, and steeper development to the oil window section of plays or tight oil plays. The overall results is that the HF water use will have a broad plateau at ~125 kAF/yr around the 2020-2030 decade and then slowly decrease with time to 2060 and beyond (Figure 48). However, the amount of fresh water consumed (that is, not recycled or reused or brackish water) will stay relatively constant at ~70 kAF despite the increase in water use and then slowly subside with the decrease in HF activities. Fresh-water use will decrease for two reasons: (1) the industry is getting better at reusing flow back (but sometimes limited by the small fraction coming back) and at finding alternate sources of recycling (treatment plants, produced water from conventional wells) and at using brackish water because of the technological advances in additives tolerating more saline water. And (2) the Permian Basin, which may become the focus of HF in Texas in the long run, offers great production potential. In the Permian Basin, fresh water is at a premium and brackish water is already used by the industry.

Total oil and gas water use and consumption (combining HF, waterflooding, and drilling) is presented in Figure 49. Oil and gas water use, consistent with the definition of make-up fresh water used in this document, was computed by summing HF water use (Figure 48), drilling water use –with no change from the 2011 report, and waterflood water use –computed from the 2011 report by adding fresh and brackish water use. Oil and gas water consumption was computed by summing HF water consumption (Figure 48), drilling water use –with no change from the 2011 report and the additional note that water use and consumption are identical. Waterflood water consumption is the same as water use in the 2011 report that represented fresh water use. Projected oil and gas water use and consumption are dominated by HF. By design, in the 2011 report, drilling technology was projected to move the industry away from the use of fresh water. Progress in waterflooding was also projected to decrease fresh water requirements but to increase brackish water use until the whole industry relies only on saline water (not showed). Under these assumptions, oil and gas industry water use is projected to peak with a broad plateau at 180 kAF in the 2020-2030 decade, slowly declining to ~60 kAF by 2060. Fresh water consumption in the oil and gas industry is projected to reach a maximum of ~100 kAF before the end of this decade and then to slowly decrease to a low level of a few tens of thousands AF by the middle of the century.

We did not account for many unknowns that could possibly impact the results as they did in the Eagle Ford Shale when the industry switched from slick-water fracs to gel fracs in the oil window that use less water. The Eagle Ford was the only play in which we observed such a trend, everywhere else the trend (based on 2 to 5 years of data) shows an increase or a steady value in water intensity (Table 12). Data about recycling/reuse and brackish water use were derived from industry information of these uses as of today and in 2020 (Table 13). The most likely values from 2011 and 2020 are essentially estimated directly from the various responses in a given play. Extrapolation to 2060 and translation to high and low scenarios for all years starting in 2012 are speculative and are based on industry trends and on the general knowledge of the authors about fresh and brackish water aquifers and of their yields around the state. The amount of reuse cannot be larger than the amount of flow back / produced water from recently fractured wells and at the play level reuse is likely less because of the operational issues of transporting water. Some plays, such as the Haynesville and Eagle Ford Shales, are at a disadvantage for this; they produce back less than 20% of the injected water (Table 14). They, and others, could however take advantage of produced water from other formations.

We did not deviate much from the overall water use of the 2011 report because of constraints accounted for the 2011 report and related to drilling rig count, labor force availability/staff shortage, infrastructure development, and other factors. National rig count seems steady at ~2,000 or slightly lower in the past year (~50% of them in Texas), but drillers are improving at operating them, which suggests that the projections presented in this update are consistent with the number of drilling rigs currently available.

Cumulative water use is related to the eventual well density or lateral spacing. Ultimate average spacing between laterals, or vertical well density, is the parameter driving water use along with water intensity. Typical vertical well spacing is 1 well per 40 acres; that ratio can decrease to 1 well per 20 or 10 acres in some instances. Typical lateral spacing can be computed from 1 horizontal well per 160 acres. If lateral length is 5,000 ft, the resulting spacing between laterals is 1,400 ft. If the horizontal well density declines to 1 well per 40 acres, lateral spacing is 350 ft. This update document assumes a lateral spacing of 1000 ft, perhaps smaller in oil windows (Figure 51).

County-level projections for HF water use and water consumption are listed in Table 15. The county coverage is essentially the same as in the 2011 report with the addition of four counties in East Texas (Polk, Tyler, Jasper, and Newton counties, Figure 50). Total oil and gas (combining HF, waterflooding, and drilling) county-level projections are presented in Table 16.

The following paragraphs address HF projection issues specific to each play and region. Each play is represented by two plots. One plot compares projections from the 2011 report to projections from this update. The second plot displays water use and fresh water consumption in the high, low, and most likely scenarios. Only the latter is displayed in the first plot and is retained as the preferred set of projections to be used by the TWDB. As explained in the Methodology Section (Section II), low and high scenarios were derived by varying two factors: (1) the prospectivity factor, which assesses the ultimate amount of HF in a play, varies on a county and play basis from 1 to 0, with 1 meaning the county is within the core area and highly prospective (for example, Tarrant County in the Barnett Shale) and near- zero values suggesting that little of the county will be developed (for example ,Shackelford County in the Barnett Shale); and (2) coefficients for recycling/reuse and brackish water use (Table 13). The prospectivity factor was changed according to a sliding linear scale: a value of 1 stays at 1 but a value of 0.2 either goes to zero (low water use scenario) or 0.4 (high water use scenario). The change was made systematically with no tentative exercise to tailor it to each county/play couple. In the case of tight oil/ tight gas plays, a third factor was varied. This factor varies from 0 to 1 and addresses the spatial coverage of the county that could ultimately undergo HF. In the case of resource plays such as shale plays, the factor is constant and close to one because the whole footprint of the play is potentially a target for drilling. The only unknown is the well density which is accounted for through the prospectivity factor. In tight oil/gas plays, it cannot be assumed that the whole footprint of the formation will experience HF because some parts of it can be properly produced through conventional wells. This third factor was used in the East

Texas (Cotton Valley), Anadarko (Granite Wash), Gulf Coast (Austin Chalk), and Permian basins.

Barnett Shale: In this play with the longest history, we considerably decreased the prospectivity factors outside of the core area in the most likely scenario. That is, instead of increasing water use because of the expansion of the productive Barnett Shale footprint, we assumed that most of the HF will stay confined to the core area and stay relatively stable for a few years before slowly decreasing (Figure 52a). The peak from earlier projections has disappeared and water use should stay below 30 kAF and decrease more slowly than projected in the 2011 report. The high water use scenario projection (Figure 52b) displays a small increase in water use (but not in water consumption) in the 2020 decade because the prospectivity factors are closer to those used in the 2011 report.

Eagle Ford Shale: Projections for this play display a decrease in water use compared to those projected values of the 2011 report (Figure 53a) because of the observed decrease in water intensity that we assumed will hold in the future. The projections suggest a slow increase in water for the next 10 years with a broad peak at ~35kAF and a slow decrease beyond 2060. Unlike the Barnett with a clearly delimited core, we assumed that most counties in the Eagle Ford are highly prospective and thus there is not much variation between high and low scenario projections except when recycling/reuse and use of brackish water are included (Figure 53b).

Pearsall Shale: This gas play was briefly hydraulically fractured in the mid-2000’s and has not received a lot of attention since then. However, initial production estimates suggest that the play will be produced in the future. We used the same water use parameters in the Pearsall as those in the Eagle Ford Shale because these plays are geographically close. Projections from the 2011 report were only slightly modified displacing the peak water use at ~10 kAF by about 5 years into the future (Figure 54a). As was the case for the Eagle Ford, the high and low scenarios are mostly impacted by the amount of recycling/reuse and brackish water use (Figure 54b).

TX-Haynesville and Bossier Shales: The Haynesville and Bossier Shales have declined in operator interest because of their relatively high operational cost and low gas prices. They are, however, still likely to produce significant amounts of gas in the future, albeit at a lower rate than anticipated in the 2011 report. Projections of this update document show a decreased and broader peak (Figure 55a), with annual water use slated to be no higher than ~12kAF. A minor player, the Haynesville-West play will possibly undergo some development on the western flank of the East Texas Basin and its water use projections stay similar to that of the 2011 report (Figure 56a), with a decrease peak as well. Low and high scenario projections stay relatively close together (Figure 55b), because there is little variability in terms of projected non-fresh water use (almost none).

Other East Texas Formations: This category includes all formations except the Haynesville and Bossier Shales, such as the Cotton Valley, James Lime, Bossier Sands, and others. The same water consumption data used in the Haynesville were used for this group of formations. Relative to the 2011 report projections, the projections derived in this update assumed a broader peak displaced toward the future by ~10 years (Figure 57a). Projected maximum water use is estimated at <5 kAF/yr. The small variance between water use and water consumption is explained by the location of the plays in East Texas where fresh water is relatively abundant and the large differences between the different scenario projections is due to the spread of the third factor, addressing spatial coverage of the formation of interest (Figure 57b).

Gulf Coast Formations: Amount of water use and consumption in the Gulf Coast Basin outside of the shale plays is very uncertain. The Gulf Coast Basin is the area in Texas that has experienced the least HF (Nicot et al., 2011) and explained the large range of projections between the different scenarios (Figure 58b). This category include formations such as the Olmos Sands and the Austin Chalk, and these projections assumed that water use will peak at ~8kAF in the 2020's (Figure 58a). Water consumption is assumed to be much lower because most of the plays are in South Texas, where there are some brackish water resources.

Anadarko Basin: Anadarko Basin consists mostly of the Granite Wash in Hemphill and Wheeler counties and the Marmaton/Cleveland in Ochiltree and Lipscomb counties. Current water use in this basin is much higher than anticipated in the 2011 report projections. We revisited prospectivity factors and the projected water use reaches a broad peak of ~9kAF in the 2020's (Figure 59a) with a smaller projected water consumption because of anticipated recycling/reuse and brackish water use. However, the uncertainty in final coverage put this basin in the same category as the Gulf Coast Basin and East Basin category, resulting in a large spread of potential outcomes (Figure 59b).

Permian Basin: As has the Anadarko Basin, the Permian Basin has grown much faster than anticipated and water use projections call for a plateau at ~40 kAF during the 2020-2040 period (Figure 60a) concomitant with a fairly stable fresh water consumption at 10-15 kAF. The large gap between water use and water consumption, much larger than presented in the 2011 report (Figure 60a), is due to the expectation of availability of significant amounts of brackish water and of their extensive use by the industry (as currently documented by anecdotal evidence). The large range in outcome from the different scenarios is related to the unknowns in spatial coverage of the non-shale plays (Figure 60b). We now turn to the description of the major components making up water use in the Permian Basin. Although the Barnett-Woodford system in the Permian Basin has received limited interest, we assume it will produce gas in the future (Figure 61a). The most likely scenario calls for a peak at ~5 kAF in 2035 but with the possibility of a high scenario with a much higher water use and a low scenario with no development. Development centered on the Wolfcamp is more certain and differences between high and low scenario projections were derived mostly from assumptions on the level of use of non-fresh water(Figure 61b). The other formations in the Permian Basin also display the same uncertainty related to the amount of spatial coverage ("third factor" as described above). The most likely scenario projection is estimated to have a broad peak in the 15-20 kAF range for many years with considerably less water consumption (Figure 61c).

Table 12. Recent trends in well completion and water use in hydraulic-fractured plays.

Play	Well Type	~# of Recent Wells/yr	Recent Trend (well/yr)	Water Use / well (Mgal)	Water Use Intensity (gal/ft)	Recent Trend (water use)
Barnett	H	1500	down / steady	n/a	1200	steady
Eagle Ford	H	1000	strongly up	n/a	850	down
TX-Haynesville	H	250	up	n/a	1400	steady
Granite Wash	H	250	strongly up	n/a	1200	steady / up
	V	60	strongly down	1500	800	steady
Cleveland	H	100	steady	n/a	250	steady
	V	20	down	1.7	2000	steady
Marmaton	H	30	strongly up	n/a	250	steady
	V	10	steady	1.0	2500	up
Cotton Valley	H	100	up	n/a	1000	steady
	V	300	strongly down	0.8	1200	steady
Olmos	H	50	up	n/a	1000	up
	V	100	strongly down	0.15	2500	steady
Wolfcamp	H	150	strongly up	n/a	900	strongly up
Wolfberry	V	2000	up	1.0	350	up
Canyon	V	300	down	0.4	500	up
Clear Fork	V	800	up	0.8	350	up
San Andres	H	50	strongly down	n/a	350	strongly up
	V	800	steady / up	0.15	500	steady

Table 13. Coefficients (%) to compute water consumption to be applied to total water use.

Play / Region		High Water Use	Most Likely	Low Water Use
Far West Permian Basin	**Recycling**			
	2011	0	0	0
	2020	0	50	40
	2060	0	40	40
	Brackish			
	2011	80	80	80
	2020	80	30	50
	2060	80	40	50
Permian Midland Basin	**Recycling**			
	2011	2	2	2
	2020	2	25	30
	2060	2	30	40
	Brackish			
	2011	30	30	30
	2020	30	40	40
	2060	30	40	50
Anadarko Basin	**Recycling**			
	2011	20	20	20
	2020	20	30	40
	2060	20	40	40
	Brackish			

Play / Region		High Water Use	Most Likely	Low Water Use
	2011	30	30	30
	2020	30	30	30
	2060	30	30	40
Barnett Shale	**Recycling**			
	2011	5	5	5
	2020	5	10	25
	2060	5	20	20
	Brackish			
	2011	3	3	3
	2020	3	15	20
	2060	3	25	25
Eagle Ford Shale	**Recycling**			
	2011	0	0	0
	2020	0	10	10
	2060	0	10	10
	Brackish			
	2011	20	20	20
	2020	20	40	50
	2060	20	50	50
South Texas	**Recycling**			
	2011	0	0	0
	2020	0	10	10
	2060	0	10	10
	Brackish			
	2011	20	20	20
	2020	20	40	50
	2060	20	50	50
East Texas	**Recycling**			
	2011	5	5	5
	2020	5	10	10
	2060	5	10	10
	Brackish			
	2011	0	0	0
	2020	0	0	10
	2060	0	10	10

Table 14. Estimated flow back/produced water volume relative to HF injected volume.

Play / Region	Comment
Delaware Basin (Permian Basin)	Close to 100% in year 1, 150% well life >200% well life
Midland Basin (Permian Basin)	50%-100% in year 1
Anadarko Basin	~50% in month 1, 90% at month 6
Barnett Shale	10-20% month 1, 20-60% well life 70% year1; 150% in 5 years
Eagle Ford Shale	20% over life; 20% over life
Haynesville Shale	20% over life; 15% over life
Cotton Valley Fm.	60% month 1, >100% well life; 40% or 100% over life

Table 15. County-level estimate of 2012-2060 projections for HF water use and water consumption (AF).

	Water Use (AF)											Water Consumption (AF)										
County	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**
Anderson	0	31	58	89	119	131	139	124	105	85	66	0	23	41	64	86	97	104	92	76	61	46
Andrews	1,391	1,617	2,140	2,053	1,965	1,878	1,654	1,431	1,207	983	806	946	862	749	690	634	580	501	425	351	279	224
Angelina	7	60	160	260	360	379	345	310	276	241	207	6	56	144	231	315	327	293	260	228	196	165
Aransas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Archer	17	81	183	284	385	354	321	289	257	225	193	16	68	137	206	270	239	209	181	154	129	106
Armstrong	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Atascosa	1,009	2,902	2,638	2,589	2,594	2,598	2,602	2,314	1,953	1,591	1,230	807	2,064	1,583	1,500	1,443	1,386	1,329	1,144	935	736	545
Austin	0	0	98	195	293	264	234	205	176	146	117	0	0	59	115	169	148	129	110	92	75	59
Bailey	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bandera	0	0	0	0	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0
Bastrop	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Baylor	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bee	66	80	101	108	94	81	67	54	40	27	13	53	60	64	67	57	48	39	31	23	15	7
Bell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bexar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Blanco	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Borden	33	228	638	892	899	906	764	622	480	338	230	23	122	223	307	303	300	248	198	150	104	69
Bosque	0	192	329	466	603	553	502	452	402	352	301	0	162	247	338	422	373	327	283	241	202	166
Bowie	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brazoria	0	41	60	79	97	91	79	67	55	43	31	0	31	38	49	59	54	46	38	31	24	17
Brazos	238	322	696	931	1,166	1,036	905	775	644	514	384	191	243	431	559	681	592	506	423	343	267	193
Brewster	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Briscoe	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brooks	8	37	49	62	62	54	46	38	30	22	14	6	28	31	38	38	32	27	22	17	12	8
Brown	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burleson	247	331	943	1,409	1,877	1,676	1,474	1,273	1,071	867	665	197	250	580	840	1,090	952	819	690	567	447	334
Burnet	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Caldwell	75	90	116	103	90	77	64	52	39	26	13	60	68	73	64	55	46	38	29	22	14	7
Calhoun	0	25	33	42	42	37	31	26	21	15	10	0	19	21	26	26	22	18	15	11	8	5
Callahan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cameron	0	37	50	62	62	54	46	38	30	22	14	0	28	31	38	38	32	27	22	17	12	8
Camp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carson	85	0	0	0	0	0	0	0	0	0	0	42	0	0	0	0	0	0	0	0	0	0
Cass	0	10	25	41	56	68	60	52	45	37	30	0	9	24	38	52	60	52	45	38	31	24
Castro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chambers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cherokee	10	70	128	186	244	284	253	221	190	158	126	9	66	122	173	223	254	221	189	159	129	101
Childress	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Clay	58	194	355	516	678	621	565	508	452	395	339	53	164	266	374	474	419	367	318	271	227	186
Cochran	31	94	121	149	176	203	180	158	135	113	90	21	50	42	51	59	67	59	50	42	35	27
Coke	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coleman	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Collin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Collingsworth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Colorado	0	38	517	996	1,462	1,314	1,166	1,018	870	722	574	0	29	312	587	843	741	643	548	458	371	287
Comal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Comanche	0	125	228	332	436	392	349	305	261	218	174	0	105	171	241	305	265	227	191	157	125	96
Concho	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cooke	1,480	1,653	1,294	934	575	215	0	0	0	0	0	1,362	1,396	970	677	402	145	0	0	0	0	0
Coryell	0	289	1,012	947	684	421	158	0	0	0	0	0	244	759	686	479	284	103	0	0	0	0

	Water Use (AF)											Water Consumption (AF)										
County	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**
Cottle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Crane	159	339	438	559	681	802	729	656	583	510	438	108	181	153	189	223	257	229	203	177	152	128
Crockett	475	996	1,636	1,946	1,760	1,475	1,190	905	620	335	149	323	531	573	669	594	489	387	288	194	103	45
Crosby	12	0	0	0	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0	0	0	0
Culberson	166	141	188	576	963	1,280	1,163	1,047	931	814	698	33	75	66	149	231	290	262	235	207	180	154
Dallam	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dallas	79	654	1,018	848	679	509	339	170	0	0	0	73	553	763	615	475	343	220	106	0	0	0
Dawson	89	476	724	918	954	990	844	699	553	408	294	61	254	253	308	308	308	257	208	160	115	80
Deaf Smith	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Delta	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Denton	3,249	3,159	2,106	1,053	0	0	0	0	0	0	0	2,989	2,667	1,579	763	0	0	0	0	0	0	0
DeWitt	2,151	1,977	1,773	1,569	1,354	1,130	907	684	460	237	14	1,721	1,407	1,065	924	780	638	500	369	243	122	7
Dickens	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dimmit	3,706	4,777	4,765	4,857	4,871	4,834	4,232	3,489	2,746	2,002	1,259	2,965	3,407	2,828	2,774	2,669	2,534	2,145	1,710	1,294	895	516
Donley	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Duval	0	70	94	117	118	103	87	72	57	42	27	0	53	59	73	72	61	51	41	32	23	14
Eastland	0	0	424	642	550	458	367	275	184	92	0	0	0	318	465	385	309	238	172	110	53	0
Ector	756	983	1,340	1,434	1,529	1,484	1,309	1,134	959	784	644	514	524	469	478	488	451	390	332	274	219	176
Edwards	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ellis	38	87	126	166	206	185	164	144	123	103	82	35	74	95	120	144	125	107	90	74	59	45
El Paso	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Erath	12	163	253	343	433	397	361	325	289	253	217	11	137	190	249	303	268	235	203	173	145	119
Falls	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fannin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fayette	132	1,081	2,329	2,093	1,822	1,526	1,229	932	636	340	43	106	773	1,402	1,236	1,054	864	681	505	337	176	23
Fisher	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Floyd	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Foard	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fort Bend	0	35	46	58	58	51	43	36	28	21	14	0	26	29	36	35	30	25	20	16	11	7
Franklin	14	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	0	0
Freestone	424	750	975	1,229	1,424	1,404	1,241	1,076	912	748	584	339	678	846	1,042	1,196	1,164	1,012	863	720	582	449
Frio	729	1,119	1,146	1,176	1,189	1,159	1,127	1,097	947	769	589	583	809	701	708	692	647	602	559	465	364	266
Gaines	142	830	1,273	1,709	1,881	1,841	1,582	1,323	1,064	805	599	96	443	445	563	588	542	456	372	290	212	152
Galveston	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Garza	1	237	315	394	473	426	379	331	284	237	189	0	126	110	136	160	141	123	106	89	72	57
Gillespie	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Glasscock	1,434	1,938	2,621	2,466	2,311	1,978	1,646	1,313	980	648	427	975	1,033	917	848	780	655	535	419	306	198	128
Goliad	0	34	45	56	56	49	42	35	27	20	13	0	25	28	35	34	29	24	20	15	11	7
Gonzales	2,224	1,746	1,552	1,358	1,164	970	776	582	388	194	0	1,779	1,241	931	798	669	545	427	313	204	99	0
Gray	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Grayson	21	0	0	0	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	0	0	0
Gregg	25	134	224	313	402	449	405	362	318	274	230	24	127	208	284	357	391	347	305	263	223	184
Grimes	95	125	287	448	569	506	443	380	317	254	191	76	94	178	270	334	291	249	209	170	133	97
Guadalupe	18	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	0	0
Hale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hamilton	0	251	304	253	203	152	101	51	0	0	0	0	212	228	184	142	103	66	32	0	0	0
Hansford	11	0	513	1,025	879	732	586	439	293	146	0	5	0	205	397	329	265	205	148	95	46	0
Hardeman	17	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0
Hardin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Harris	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Harrison	893	1,578	2,223	2,012	1,851	1,689	1,527	1,365	1,203	1,041	880	849	1,479	2,030	1,808	1,636	1,469	1,307	1,149	996	847	704

	Water Use (AF)											Water Consumption (AF)										
County	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**
Hartley	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Haskell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hays	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hemphill	1,462	2,484	2,231	1,978	1,724	1,470	1,217	963	710	456	203	731	1,132	892	766	646	533	426	325	231	143	61
Henderson	12	46	124	201	278	333	296	259	222	185	148	12	44	117	187	254	297	259	222	186	151	118
Hidalgo	59	63	83	104	105	91	78	64	51	37	24	47	47	53	65	64	54	45	37	28	20	13
Hill	131	1,429	1,225	1,021	816	612	408	204	0	0	0	120	1,207	919	740	571	413	265	128	0	0	0
Hockley	5	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0
Hood	645	409	580	751	921	829	737	645	553	461	369	593	346	435	544	645	560	479	403	332	265	203
Hopkins	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Houston	178	237	305	271	237	203	170	135	102	68	34	142	179	193	168	144	121	99	77	57	37	18
Howard	552	1,471	2,360	2,822	2,642	2,250	1,859	1,468	1,076	685	422	376	784	826	970	892	745	604	468	336	210	126
Hudspeth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hunt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hutchinson	5	0	90	180	154	128	103	77	51	26	0	2	0	36	70	58	47	36	26	17	8	0
Irion	875	1,478	2,429	2,889	2,613	2,190	1,766	1,343	920	497	221	595	788	850	993	882	725	574	428	287	152	66
Jack	48	242	363	485	605	545	485	424	363	303	242	44	204	273	351	424	368	315	265	218	174	133
Jackson	0	34	45	56	56	49	42	35	28	20	13	0	25	29	35	34	29	25	20	15	11	7
Jasper	87	105	135	120	105	90	75	60	45	30	15	83	79	86	75	64	54	44	34	25	16	8
Jeff Davis	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jefferson	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jim Hogg	0	45	60	75	75	65	56	46	37	27	17	0	34	38	46	46	39	32	26	20	15	9
Jim Wells	0	34	45	57	57	50	42	35	28	21	13	0	26	29	35	35	30	25	20	15	11	7
Johnson	4,192	4,038	3,365	2,692	2,019	1,346	673	0	0	0	0	3,857	3,410	2,524	1,952	1,413	909	437	0	0	0	0
Jones	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Karnes	3,869	2,749	2,457	2,165	1,863	1,554	1,245	937	629	320	11	3,095	1,956	1,475	1,273	1,073	876	686	505	331	165	6
Kaufman	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kendall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kenedy	6	57	76	95	95	83	71	58	46	34	22	5	43	48	59	58	49	41	33	26	19	12
Kent	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kerr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kimble	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
King	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kinney	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kleberg	34	37	49	62	62	54	46	38	30	22	14	28	28	31	38	38	32	27	22	17	12	8
Knox	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lampasas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
La Salle	2,901	4,432	4,425	4,532	4,621	4,698	4,147	3,440	2,732	2,025	1,318	2,321	3,154	2,612	2,563	2,499	2,427	2,070	1,659	1,265	889	530
Lavaca	118	913	1,522	1,388	1,241	1,086	930	775	620	464	309	94	651	915	818	716	613	513	418	326	239	155
Lee	131	203	392	508	624	553	484	414	345	274	204	105	152	243	305	365	316	270	226	184	142	103
Leon	273	663	1,289	1,800	2,309	2,192	1,934	1,674	1,416	1,155	898	218	487	831	1,166	1,487	1,415	1,225	1,041	864	693	529
Liberty	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limestone	268	307	347	388	410	376	332	287	242	197	153	214	281	307	333	346	312	270	229	190	153	116
Lipscomb	382	560	1,026	876	725	574	423	272	121	0	0	191	255	410	339	272	208	148	92	39	0	0
Live Oak	972	783	729	676	692	720	748	776	689	575	461	777	558	439	399	392	388	384	379	324	261	200
Llano	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Loving	189	313	418	561	704	690	627	565	502	439	376	38	167	146	187	227	213	191	169	147	127	107
Lubbock	0	0	0	51	103	154	140	126	112	98	84	0	0	0	10	21	31	28	25	22	20	17
Lynn	0	0	246	336	427	517	460	402	345	287	230	0	0	86	116	144	171	149	128	108	88	69
McCulloch	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

	Water Use (AF)											Water Consumption (AF)										
County	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**
McLennan	0	53	120	187	253	228	203	177	152	127	101	0	45	90	135	177	154	132	111	91	73	56
McMullen	1,752	2,545	2,762	3,067	3,329	3,562	3,306	2,930	2,553	2,177	1,801	1,401	1,815	1,627	1,729	1,797	1,840	1,658	1,430	1,211	1,001	801
Madison	204	261	561	750	940	832	727	622	518	413	308	163	197	348	451	549	475	406	339	275	214	155
Marion	10	121	270	420	569	579	522	466	408	351	295	10	114	249	380	506	506	449	393	339	286	236
Martin	2,035	2,446	3,071	2,824	2,577	2,267	1,892	1,516	1,141	765	512	1,384	1,305	1,075	963	855	731	597	468	344	224	145
Mason	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Matagorda	0	46	61	77	77	67	57	47	37	28	18	0	35	39	48	47	40	33	27	21	15	9
Maverick	192	1,574	1,857	2,241	2,626	3,010	2,843	2,538	2,234	1,928	1,623	154	1,119	1,074	1,226	1,368	1,501	1,376	1,195	1,022	856	698
Medina	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Menard	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Midland	1,573	2,640	3,265	3,034	2,803	2,465	2,045	1,625	1,205	785	488	1,070	1,408	1,143	1,034	928	791	643	499	361	227	136
Milam	34	0	0	0	0	0	0	0	0	0	0	27	0	0	0	0	0	0	0	0	0	0
Mills	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mitchell	18	238	317	397	476	428	381	333	286	238	190	12	127	111	136	161	142	124	106	89	73	57
Montague	3,221	3,496	2,997	2,497	1,998	1,498	999	499	0	0	0	2,963	2,952	2,248	1,810	1,398	1,011	649	312	0	0	0
Montgomery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Moore	76	0	0	0	0	0	0	0	0	0	0	38	0	0	0	0	0	0	0	0	0	0
Morris	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Motley	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nacogdoches	1,128	1,424	2,066	1,937	1,809	1,659	1,503	1,347	1,191	1,036	880	1,072	1,327	1,873	1,731	1,593	1,438	1,283	1,132	985	842	704
Navarro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Newton	98	125	161	143	125	108	89	71	54	36	18	93	94	102	89	76	64	52	41	30	20	9
Nolan	11	0	0	0	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0	0	0	0
Nueces	16	34	45	56	56	49	42	35	28	20	13	13	25	29	35	34	29	25	20	15	11	7
Ochiltree	273	408	748	985	815	646	476	306	136	0	0	136	186	299	382	306	234	166	103	44	0	0
Oldham	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Orange	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Palo Pinto	41	194	356	518	680	612	544	476	408	340	272	38	164	267	376	476	413	354	298	245	196	150
Panola	966	1,412	1,988	1,801	1,655	1,511	1,366	1,221	1,077	932	787	917	1,323	1,816	1,618	1,464	1,314	1,169	1,028	891	758	630
Parker	1,086	925	1,255	1,585	1,916	1,724	1,533	1,341	1,149	958	766	1,000	781	941	1,149	1,341	1,164	996	838	690	551	421
Parmer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pecos	110	130	173	387	601	746	674	601	528	456	383	22	69	60	108	156	180	161	142	123	105	87
Polk	133	180	232	206	180	155	129	103	77	52	26	126	136	147	128	110	92	75	59	43	28	14
Potter	44	0	0	0	0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	0	0
Presidio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Randall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reagan	1,240	3,207	4,019	3,627	3,236	2,844	2,332	1,820	1,308	796	444	843	1,710	1,407	1,247	1,092	942	758	580	409	244	133
Real	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Red River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reeves	522	866	1,155	1,744	2,333	2,509	2,304	2,098	1,893	1,687	1,481	104	462	404	556	705	713	646	581	518	456	395
Refugio	0	32	42	53	53	46	39	33	26	19	12	0	24	27	33	32	27	23	19	14	10	7
Roberts	393	1,628	1,419	1,210	1,002	793	584	376	167	0	0	197	742	568	469	376	287	205	127	54	0	0
Robertson	306	587	741	773	806	734	639	544	449	354	259	245	501	587	619	648	584	500	419	342	268	196
Rockwall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Runnels	4	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0
Rusk	158	477	930	1,384	1,838	1,707	1,542	1,378	1,213	1,048	884	150	446	850	1,245	1,627	1,487	1,322	1,161	1,005	853	707
Sabine	147	235	470	705	940	861	783	705	627	548	470	139	218	423	625	823	743	666	590	517	445	376
San Augustine	1,622	2,092	1,953	1,814	1,674	1,534	1,395	1,256	1,116	977	837	1,541	1,941	1,758	1,610	1,465	1,323	1,186	1,052	921	793	670
San Jacinto	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Patricio	0	28	37	46	46	40	34	28	22	17	11	0	21	23	28	28	24	20	16	13	9	6

	Water Use (AF)											Water Consumption (AF)										
County	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
San Saba	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Schleicher	90	312	468	568	584	507	430	354	277	200	140	61	166	164	195	197	168	140	113	87	61	42
Scurry	10	0	249	341	432	524	466	408	349	291	233	7	0	87	117	146	174	151	130	109	89	70
Shackelford	2	0	156	311	467	421	374	327	280	234	187	2	0	117	226	327	284	243	204	168	134	103
Shelby	1,419	1,658	3,073	2,929	2,785	2,621	2,377	2,133	1,889	1,645	1,400	1,348	1,539	2,771	2,607	2,446	2,270	2,027	1,790	1,561	1,337	1,120
Sherman	2	0	0	92	184	158	132	105	79	53	26	1	0	0	36	69	57	46	36	26	16	8
Smith	5	18	49	80	111	133	118	103	88	74	59	5	17	47	75	101	118	103	88	74	60	47
Somervell	287	184	260	336	413	372	330	289	248	207	165	264	155	195	244	289	251	215	181	149	119	91
Starr	36	48	64	79	79	69	59	49	39	29	18	29	36	40	49	48	41	35	28	22	16	10
Stephens	0	52	184	315	447	402	357	312	268	223	179	0	44	138	229	313	271	232	195	161	128	98
Sterling	57	265	707	881	893	905	765	625	484	344	236	39	141	248	303	302	300	249	199	151	105	71
Stonewall	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sutton	34	0	390	534	677	821	730	639	547	456	365	23	0	137	183	229	272	237	204	171	140	109
Swisher	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tarrant	8,805	6,836	5,469	4,101	2,734	1,367	0	0	0	0	0	8,101	5,773	4,102	2,974	1,914	923	0	0	0	0	0
Taylor	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Terrell	10	0	162	221	281	341	303	265	227	189	151	7	0	57	76	95	113	98	84	71	58	45
Terry	3	0	243	332	422	511	454	397	341	284	227	2	0	85	114	142	169	148	127	106	87	68
Throckmorton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Titus	3	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0
Tom Green	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Travis	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trinity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tyler	76	110	147	184	185	161	137	114	90	66	42	72	83	93	114	113	96	80	65	50	36	23
Upshur	4	57	247	437	627	764	690	617	543	469	396	4	54	226	393	555	665	591	519	449	382	316
Upton	1,761	2,955	3,728	3,442	3,156	2,870	2,398	1,927	1,455	983	664	1,198	1,576	1,305	1,171	1,041	916	749	588	433	283	185
Uvalde	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Val Verde	0	0	80	110	139	168	150	131	112	94	75	0	0	28	38	47	56	49	42	35	29	22
Van Zandt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Victoria	0	35	46	58	58	51	43	36	28	21	14	0	26	29	36	35	30	25	20	16	11	7
Walker	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Waller	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ward	568	568	683	888	871	855	764	672	581	489	398	114	568	239	297	278	260	228	197	167	138	110
Washington	36	0	497	878	798	718	638	559	479	399	319	29	0	298	516	459	404	351	300	251	204	160
Webb	4,596	3,661	3,476	3,052	2,626	2,244	1,872	1,501	1,128	699	255	3,677	2,627	2,109	1,814	1,529	1,274	1,033	803	580	344	113
Wharton	0	43	57	71	72	62	53	44	35	26	17	0	32	36	44	43	37	31	25	20	14	9
Wheeler	3,792	3,524	3,072	2,620	2,168	1,717	1,265	813	362	0	0	1,896	1,605	1,229	1,015	813	622	443	274	117	0	0
Wichita	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wilbarger	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Willacy	0	23	31	39	39	34	29	24	19	14	9	0	18	20	24	24	20	17	14	11	8	5
Williamson	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wilson	417	1,612	1,865	1,679	1,492	1,306	1,119	932	746	560	373	334	1,146	1,119	986	858	734	615	501	392	287	187
Winkler	62	464	618	821	1,024	979	873	767	661	556	450	12	247	216	275	332	305	267	231	195	160	127
Wise	2,314	2,757	2,450	2,144	1,838	1,531	1,225	919	613	306	0	2,129	2,328	1,838	1,555	1,287	1,034	796	574	368	176	0
Wood	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Yoakum	18	238	330	423	384	346	308	269	230	192	154	13	127	116	145	130	115	100	86	72	59	46
Young	8	0	78	157	235	211	188	164	141	118	94	7	0	59	113	164	143	122	103	85	68	52
Zapata	32	41	55	68	68	60	51	42	33	25	16	26	31	35	42	42	35	30	24	19	13	8
Zavala	407	2,065	2,427	2,280	2,167	2,035	1,904	1,773	1,502	1,197	891	326	1,477	1,465	1,351	1,247	1,132	1,020	912	747	575	410
SUM (kAF)	**81.5**	**110**	**132**	**135**	**134**	**122**	**104**	**87**	**70**	**53**	**39**	**64.8**	**78.2**	**76.9**	**76.0**	**72.8**	**64.2**	**53.2**	**43.4**	**34.4**	**26.3**	**19.1**

MiningWaterUse2010-2060_5.xls

Table 16. County-level estimate of 2012-2060 projections for oil and gas water use and water consumption (AF).

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
Anderson	39	129	140	157	177	181	185	169	147	126	105	67	87	88	98	109	115	121	109	93	78	63
Andrews	3,212	3,481	3,959	3,833	3,710	3,511	3,177	2,842	2,509	2,192	1,929	1,868	1,231	1,029	921	819	742	640	544	453	372	311
Angelina	0	116	220	316	412	427	389	351	312	274	237	32	112	203	286	366	374	336	299	263	228	195
Aransas	0	12	10	8	7	5	5	5	5	5	5	10	11	10	8	6	5	5	5	5	5	5
Archer	30	351	405	444	483	389	344	311	279	246	213	239	326	337	343	344	252	222	194	167	142	119
Armstrong	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Atascosa	1,012	2,993	2,770	2,713	2,706	2,700	2,693	2,393	2,021	1,649	1,279	867	2,155	1,711	1,618	1,551	1,484	1,415	1,219	1,000	790	590
Austin	0	28	127	224	320	288	257	226	194	163	132	20	29	88	143	195	173	151	130	110	91	73
Bailey	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bandera	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bastrop	0	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Baylor	1	14	14	14	14	14	13	13	13	13	13	12	12	12	12	12	12	12	12	12	13	13
Bee	66	111	127	129	112	95	80	67	53	40	26	92	90	89	87	74	62	52	44	36	28	20
Bell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bexar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Blanco	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Borden	27	272	679	926	927	929	784	639	494	352	244	72	165	263	339	331	323	267	214	164	117	82
Bosque	0	470	557	627	696	579	516	466	416	365	315	238	439	462	485	502	387	340	296	255	216	180
Bowie	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brazoria	0	91	102	113	125	114	100	88	76	64	52	42	80	78	82	86	76	67	59	52	45	38
Brazos	238	364	741	975	1,207	1,072	938	804	670	536	402	266	286	477	602	721	628	538	451	368	287	211
Brewster	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Briscoe	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brooks	27	70	77	84	80	69	60	52	44	36	28	50	60	58	60	55	47	41	36	31	26	22
Brown	23	35	34	34	33	32	31	30	29	28	27	17	16	14	14	14	14	14	14	14	14	14
Burleson	247	380	995	1,459	1,923	1,717	1,512	1,306	1,100	892	686	279	299	632	890	1,135	993	855	723	595	471	354
Burnet	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Caldwell	75	98	123	111	98	85	72	59	46	33	20	82	75	81	71	62	54	45	37	29	22	14
Calhoun	18	48	52	57	55	47	41	35	30	25	19	34	41	39	41	38	32	28	24	21	18	15
Callahan	84	93	88	88	87	83	79	74	70	66	62	29	24	18	17	16	15	15	15	15	15	15
Cameron	27	58	65	72	68	57	47	39	31	23	15	38	47	45	48	43	34	28	23	18	13	9
Camp	13	12	12	11	11	11	10	9	9	8	8	2	2	1	1	1	0	0	0	0	0	0
Carson	2	14	14	14	14	14	14	14	14	14	14	13	13	13	13	13	13	13	13	13	13	13
Cass	1	30	39	48	58	68	60	52	45	37	30	26	28	36	44	52	60	52	45	38	31	24
Castro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chambers	0	9	9	9	9	9	9	9	9	9	9	8	9	9	9	9	9	9	9	9	9	9
Cherokee	10	129	172	216	263	299	267	236	204	173	141	80	123	163	201	239	269	236	204	173	144	116
Childress	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Clay	63	508	613	699	786	655	584	527	471	414	357	318	472	506	538	563	435	382	333	286	243	202
Cochran	56	128	154	181	208	234	210	187	163	139	115	46	64	54	63	71	79	70	62	54	46	38
Coke	520	511	484	480	477	451	425	397	370	346	322	114	84	46	40	33	32	31	29	28	27	26
Coleman	100	113	108	107	107	102	97	91	86	82	77	37	31	24	23	22	21	21	21	21	21	20
Collin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Collingsworth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Colorado	28	129	608	1,078	1,534	1,376	1,221	1,067	913	759	605	86	120	402	667	913	802	697	596	499	406	317
Comal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Comanche	2	388	444	485	525	419	363	319	276	232	188	224	366	374	379	380	278	240	204	170	138	109
Concho	515	507	480	477	474	448	422	394	367	343	320	114	84	46	40	34	33	31	30	29	28	27
Cooke	1,493	1,708	1,343	978	612	246	28	27	26	25	24	1,391	1,434	1,001	702	421	158	13	13	13	13	13
Coryell	0	569	1,238	1,102	767	434	158	0	0	0	0	236	522	972	827	548	284	103	0	0	0	0

County	Water Use (AF)											Water Consumption (AF)										
	2011	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**
Cottle	32	43	41	41	41	39	38	36	34	33	31	18	16	14	14	13	13	13	13	13	13	13
Crane	280	508	617	728	840	947	861	776	692	610	531	227	246	225	249	273	299	265	232	201	174	149
Crockett	507	1,097	1,732	2,035	1,843	1,552	1,261	971	682	394	207	553	606	641	730	650	539	434	332	235	143	85
Crosby	1,083	1,050	994	987	980	926	871	814	757	706	656	224	161	82	69	55	53	50	47	45	43	40
Culberson	279	293	506	873	1,240	1,535	1,393	1,250	1,110	972	843	151	97	249	308	371	415	368	323	279	240	208
Dallam	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dallas	79	726	1,076	888	700	512	339	170	0	0	0	134	624	818	651	493	343	220	106	0	0	0
Dawson	268	695	954	1,137	1,164	1,184	1,023	862	703	546	423	165	323	328	371	360	353	296	241	189	140	104
Deaf Smith	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Delta	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Denton	3,249	3,297	2,220	1,136	51	19	13	13	13	13	13	3,108	2,805	1,688	840	44	13	13	13	13	13	13
DeWitt	2,177	2,061	1,858	1,646	1,421	1,188	958	729	500	271	42	1,801	1,493	1,149	999	846	694	550	413	281	155	35
Dickens	0	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	13
Dimmit	3,708	4,874	4,919	5,001	5,001	4,952	4,337	3,580	2,824	2,068	1,315	3,068	3,506	2,980	2,913	2,795	2,648	2,246	1,797	1,368	958	569
Donley	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Duval	52	133	147	160	153	131	114	99	84	69	54	96	114	110	114	105	89	77	68	58	50	41
Eastland	333	578	937	1,091	934	764	644	535	425	318	211	286	303	539	619	472	335	263	196	133	75	21
Ector	845	1,144	1,537	1,612	1,690	1,628	1,435	1,245	1,056	870	725	850	612	588	577	570	520	447	377	310	251	206
Edwards	0	28	29	29	29	29	29	29	29	29	29	28	28	29	29	29	29	29	29	29	29	29
Ellis	38	112	147	180	213	186	164	144	123	103	82	56	99	114	133	150	125	107	90	74	59	45
El Paso	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Erath	12	470	505	521	536	426	376	340	304	268	232	274	443	427	411	391	283	250	218	188	161	134
Falls	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fannin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fayette	132	1,149	2,403	2,164	1,887	1,585	1,282	979	677	375	72	166	844	1,476	1,306	1,118	922	733	551	377	210	51
Fisher	432	426	403	401	398	376	355	332	309	289	269	97	71	40	35	30	28	27	26	25	24	24
Floyd	148	156	148	147	146	139	131	123	116	109	102	42	34	23	21	19	19	19	18	18	18	17
Foard	3	12	12	12	12	12	12	12	12	12	11	10	10	10	10	10	10	10	10	10	10	10
Fort Bend	25	66	72	79	75	65	56	49	41	34	27	47	56	54	56	52	44	38	33	29	24	20
Franklin	5	5	5	5	5	5	4	4	4	3	3	1	1	0	0	0	0	0	0	0	0	0
Freestone	429	929	1,117	1,331	1,494	1,458	1,291	1,121	954	785	618	600	844	975	1,133	1,254	1,213	1,056	903	757	615	479
Frio	729	1,167	1,217	1,243	1,250	1,215	1,178	1,142	986	804	620	666	858	772	774	752	702	652	603	504	398	296
Gaines	124	914	1,429	1,846	2,000	1,945	1,671	1,398	1,127	859	651	190	517	590	686	694	635	533	436	344	259	197
Galveston	0	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Garza	53	321	395	469	544	491	438	386	334	284	234	44	166	144	164	184	162	142	122	104	87	71
Gillespie	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Glasscock	1,838	2,402	3,057	2,887	2,718	2,355	1,994	1,634	1,275	921	681	1,590	1,165	1,010	923	839	704	575	452	334	224	153
Goliad	25	64	70	77	73	63	54	47	40	33	26	46	55	53	55	50	42	37	32	28	24	20
Gonzales	2,164	1,791	1,600	1,405	1,207	1,010	813	616	418	221	24	1,764	1,288	980	844	712	585	463	346	233	126	23
Gray	68	78	75	74	74	70	67	63	60	57	53	26	22	17	16	15	15	15	15	15	15	15
Grayson	6	19	18	18	18	18	18	18	17	17	17	14	14	14	14	14	14	14	14	14	14	14
Gregg	25	191	274	353	433	476	429	383	337	292	246	71	182	256	322	387	418	371	326	282	240	199
Grimes	95	159	323	483	602	537	471	405	340	275	209	120	129	214	305	367	321	276	233	192	153	115
Guadalupe	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Hale	1,289	1,235	1,168	1,160	1,152	1,087	1,022	954	886	826	766	252	177	82	67	51	48	45	42	39	36	33
Hall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hamilton	0	361	393	314	236	157	101	51	0	0	0	93	321	312	239	169	103	66	32	0	0	0
Hansford	13	88	577	1,068	904	749	602	456	309	162	16	68	79	261	432	348	278	218	161	108	59	13
Hardeman	0	9	9	9	9	10	10	10	10	10	10	9	9	9	9	9	10	10	10	10	10	10
Hardin	0	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Harris	0	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Harrison	868	1,763	2,388	2,145	1,956	1,778	1,608	1,438	1,268	1,098	930	1,021	1,658	2,189	1,935	1,735	1,557	1,386	1,219	1,059	903	753

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
Hartley	7	7	7	7	7	6	6	6	5	5	4	1	1	0	0	0	0	0	0	0	0	0
Haskell	90	98	93	93	92	88	83	79	74	70	66	30	25	18	17	16	16	15	15	15	15	15
Hays	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hemphill	1,441	2,567	2,314	2,037	1,763	1,499	1,244	988	732	476	223	1,498	1,209	971	821	683	562	452	349	252	163	80
Henderson	3	120	176	235	296	346	308	272	235	198	161	91	113	166	218	269	310	272	235	199	164	131
Hidalgo	46	119	130	143	136	117	101	88	74	61	48	85	101	98	102	94	79	69	60	52	44	37
Hill	131	1,572	1,343	1,106	869	632	422	218	13	14	14	244	1,349	1,031	819	617	427	279	141	13	14	14
Hockley	6	18	18	18	18	17	17	17	17	16	16	13	13	13	13	13	13	13	13	13	13	13
Hood	645	529	678	820	961	841	743	651	559	467	375	695	465	528	608	679	566	485	409	338	271	209
Hopkins	42	41	38	38	38	36	34	31	29	27	25	8	6	3	2	2	2	1	1	1	1	1
Houston	178	254	322	287	254	220	187	152	119	85	51	195	196	210	185	161	138	116	94	74	54	35
Howard	619	1,611	2,491	2,939	2,747	2,343	1,940	1,538	1,138	742	476	643	870	898	1,028	938	782	633	490	354	226	142
Hudspeth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hunt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hutchinson	21	51	156	237	204	173	144	115	86	58	30	32	34	85	110	90	75	62	50	39	28	20
Irion	1,677	2,286	3,192	3,643	3,357	2,890	2,423	1,955	1,487	1,026	713	1,070	937	937	1,065	940	778	621	471	327	190	102
Jack	17	501	575	635	693	572	499	438	378	317	256	232	459	470	487	497	381	328	278	231	187	146
Jackson	25	64	70	77	73	63	55	47	40	33	26	46	55	53	55	51	43	37	32	28	24	20
Jasper	87	118	148	133	118	103	88	73	58	43	28	100	92	98	88	77	67	57	47	38	30	21
Jeff Davis	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jefferson	0	13	13	13	13	14	14	14	14	14	14	13	13	13	13	13	14	14	14	14	14	14
Jim Hogg	33	85	93	102	97	83	72	63	53	44	34	61	73	70	73	67	56	49	43	37	31	26
Jim Wells	25	65	71	78	74	64	55	48	40	33	26	46	55	53	55	51	43	37	33	28	24	20
Johnson	4,192	4,240	3,530	2,809	2,086	1,365	683	10	10	10	10	4,029	3,611	2,680	2,059	1,471	918	447	10	10	10	10
Jones	117	125	119	118	117	111	106	99	93	88	82	35	29	20	19	17	17	17	16	16	16	16
Karnes	3,882	2,820	2,528	2,229	1,919	1,603	1,288	975	662	349	35	3,155	2,028	1,545	1,336	1,127	923	728	542	363	192	29
Kaufman	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kendall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kenedy	42	108	118	130	123	106	92	80	68	55	43	78	92	89	92	85	72	62	55	47	40	33
Kent	29	39	38	38	38	36	35	33	32	31	29	18	16	14	14	13	13	13	13	13	13	13
Kerr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kimble	0	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
King	8,635	8,287	7,836	7,783	7,730	7,293	6,857	6,402	5,946	5,545	5,144	1,704	1,198	565	461	357	334	311	291	271	253	236
Kinney	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kleberg	27	70	77	84	80	69	60	52	44	36	28	51	60	58	60	55	47	41	36	31	26	22
Knox	3	15	15	15	15	14	14	14	14	14	14	12	12	12	12	12	12	12	12	12	12	12
Lamar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamb	647	620	586	582	579	546	513	479	445	415	385	127	89	41	34	26	24	22	21	19	18	17
Lampasas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
La Salle	2,889	4,569	4,617	4,705	4,772	4,830	4,263	3,541	2,819	2,098	1,380	2,408	3,293	2,801	2,731	2,647	2,556	2,183	1,757	1,349	959	590
Lavaca	145	1,003	1,613	1,470	1,313	1,148	985	824	662	501	340	179	742	1,005	898	786	673	567	465	368	274	184
Lee	132	230	421	536	650	577	506	435	363	290	218	151	179	272	333	390	340	292	246	201	158	117
Leon	327	847	1,482	1,983	2,481	2,349	2,077	1,802	1,530	1,256	985	361	629	977	1,301	1,611	1,527	1,325	1,129	941	758	584
Liberty	0	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Limestone	271	383	402	424	431	391	347	302	257	212	167	356	350	355	363	361	325	283	242	203	166	129
Lipscomb	387	656	1,098	926	758	597	446	294	142	21	21	434	335	467	375	290	221	161	105	52	13	13
Live Oak	1,002	851	814	751	757	776	798	820	729	610	492	853	627	523	473	455	443	433	422	363	294	230
Llano	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Loving	542	691	792	925	1,058	1,020	934	848	762	681	601	300	256	223	251	279	259	229	202	175	152	131
Lubbock	6,211	5,963	5,663	5,673	5,684	5,419	5,089	4,745	4,401	4,097	3,794	1,228	865	433	365	298	290	268	249	229	212	196
Lynn	981	974	1,166	1,246	1,327	1,365	1,255	1,144	1,033	929	826	226	168	179	192	205	227	200	175	150	128	107
McCulloch	42	40	38	38	38	35	33	31	29	27	25	8	6	3	2	2	2	1	1	1	1	1

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
McLennan	0	194	234	265	296	235	203	177	152	127	101	119	185	197	206	212	154	132	111	91	73	56
McMullen	1,720	2,653	2,912	3,203	3,448	3,666	3,398	3,010	2,622	2,235	1,850	1,465	1,924	1,775	1,860	1,911	1,941	1,746	1,507	1,276	1,056	848
Madison	204	295	597	785	972	861	754	646	538	430	323	227	231	384	485	581	504	432	362	295	231	169
Marion	5	208	348	483	619	622	561	501	440	379	319	73	196	322	438	552	546	485	425	368	312	258
Martin	2,435	2,906	3,527	3,262	2,998	2,657	2,251	1,845	1,441	1,043	771	2,190	1,435	1,191	1,059	933	796	651	513	380	257	177
Mason	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Matagorda	34	87	96	105	100	86	75	64	55	45	35	63	75	72	75	69	58	51	44	38	32	27
Maverick	174	1,652	1,988	2,364	2,737	3,111	2,933	2,617	2,302	1,986	1,674	188	1,196	1,201	1,342	1,474	1,597	1,461	1,269	1,085	910	744
Medina	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Menard	1,185	1,148	1,086	1,079	1,071	1,012	952	889	827	772	717	244	175	88	74	59	56	53	50	48	45	43
Midland	1,719	2,876	3,522	3,272	3,025	2,666	2,227	1,788	1,350	918	612	1,661	1,506	1,256	1,127	1,005	855	695	542	395	257	164
Milam	0	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Mills	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mitchell	27	284	361	435	511	460	409	358	309	259	211	50	162	142	163	184	162	141	122	103	86	70
Montague	3,233	3,776	3,228	2,665	2,102	1,538	1,026	525	25	24	24	3,186	3,216	2,452	1,950	1,474	1,025	663	326	14	14	14
Montgomery	0	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Moore	4	16	16	16	16	16	16	15	15	15	15	13	13	13	12	12	12	13	13	13	13	13
Morris	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Motley	130	138	132	131	130	123	117	110	103	97	91	39	31	22	20	19	18	18	18	18	17	17
Nacogdoches	1,073	1,642	2,299	2,141	1,986	1,815	1,643	1,471	1,299	1,128	958	1,220	1,550	2,101	1,930	1,764	1,591	1,420	1,251	1,089	932	779
Navarro	11	25	24	24	24	24	23	23	22	22	21	17	16	15	15	15	15	15	15	15	15	15
Newton	98	138	173	156	138	120	102	84	67	49	31	111	107	115	102	89	77	65	54	43	33	23
Nolan	214	218	207	205	204	193	182	171	160	150	140	54	42	26	24	21	21	20	20	19	19	18
Nueces	25	64	70	77	73	63	55	47	40	33	26	46	55	53	55	51	43	37	32	28	24	20
Ochiltree	286	508	824	1,040	853	674	503	332	161	24	23	329	266	355	418	325	247	180	116	57	13	13
Oldham	15	14	13	13	13	12	12	11	10	9	9	3	2	1	1	1	1	1	0	0	0	0
Orange	0	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Palo Pinto	120	547	656	752	847	709	625	552	480	408	336	281	446	483	524	557	430	370	314	261	212	165
Panola	958	1,578	2,136	1,919	1,749	1,590	1,438	1,286	1,134	983	832	1,095	1,484	1,959	1,731	1,552	1,392	1,240	1,091	948	808	674
Parker	1,083	1,180	1,464	1,733	2,001	1,748	1,545	1,353	1,162	970	779	1,215	1,035	1,139	1,284	1,414	1,176	1,009	851	702	563	434
Parmer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pecos	409	543	690	878	1,068	1,180	1,072	966	861	762	672	274	227	313	331	353	359	320	283	249	220	198
Polk	133	195	247	221	195	170	144	118	92	67	41	148	151	162	143	125	107	90	74	58	43	29
Potter	2	14	14	14	14	14	14	14	14	14	14	13	13	13	13	13	13	13	13	13	13	13
Presidio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Randall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reagan	1,350	3,414	4,211	3,802	3,395	2,985	2,457	1,931	1,406	886	529	1,361	1,825	1,501	1,323	1,153	991	796	610	432	265	155
Real	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Red River	4	4	4	4	4	4	3	3	3	3	3	1	1	0	0	0	0	0	0	0	0	0
Reeves	611	1,111	1,520	2,067	2,619	2,761	2,522	2,285	2,052	1,827	1,614	701	632	688	796	908	888	791	700	615	541	477
Refugio	23	60	66	72	69	59	51	44	38	31	24	43	51	49	51	47	40	35	30	26	22	18
Roberts	365	1,711	1,502	1,270	1,041	822	611	400	189	20	20	423	819	647	524	412	316	231	151	76	20	20
Robertson	305	691	813	817	826	746	651	556	461	366	271	431	599	654	657	664	595	512	431	354	279	208
Rockwall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Runnels	285	287	272	271	269	255	240	225	210	197	184	70	53	32	29	26	25	24	24	23	22	22
Rusk	210	719	1,149	1,569	1,994	1,844	1,668	1,492	1,316	1,141	967	323	637	1,017	1,377	1,730	1,578	1,404	1,234	1,070	912	759
Sabine	147	331	584	809	1,035	946	858	770	682	595	508	196	319	536	728	915	826	739	653	571	491	413
San Augustine	1,584	2,198	2,077	1,928	1,779	1,628	1,479	1,330	1,180	1,032	884	1,642	2,052	1,880	1,722	1,567	1,415	1,268	1,124	983	847	715
San Jacinto	0	8	8	8	8	9	9	9	9	9	9	8	8	8	8	8	9	9	9	9	9	9
San Patricio	20	52	57	63	60	51	44	39	33	27	21	38	45	43	45	41	35	30	26	23	19	16

County	**Water Use (AF)**											**Water Consumption (AF)**										
	2011	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**
San Saba	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Schleicher	230	473	621	718	732	647	562	477	392	308	241	144	213	199	226	225	194	165	136	109	84	64
Scurry	3	34	280	368	456	544	483	423	363	304	246	37	33	118	143	169	193	168	145	123	102	83
Shackelford	219	464	562	655	747	628	558	500	442	385	328	264	285	329	373	409	305	263	224	187	153	121
Shelby	1,388	1,861	3,283	3,109	2,938	2,754	2,496	2,238	1,980	1,723	1,467	1,536	1,745	2,976	2,781	2,593	2,400	2,143	1,892	1,650	1,414	1,185
Sherman	9	42	35	121	207	178	151	124	98	71	44	28	33	26	55	84	70	59	48	39	29	21
Smith	20	91	107	125	145	163	147	131	115	100	84	67	71	85	100	117	132	117	102	88	74	61
Somervell	287	237	304	367	431	377	333	292	250	209	168	309	208	236	272	304	253	217	183	151	121	93
Starr	35	90	99	108	103	89	77	67	57	46	36	65	77	75	77	71	60	52	46	39	34	28
Stephens	5,158	5,248	5,064	5,103	5,141	4,775	4,458	4,141	3,825	3,541	3,257	1,226	1,004	663	630	591	476	423	374	328	285	244
Sterling	89	343	780	947	953	958	812	667	522	380	270	107	191	290	338	331	325	270	217	166	120	85
Stonewall	629	615	583	579	575	543	511	478	445	416	387	136	99	53	45	38	36	34	33	31	30	29
Sutton	33	59	446	582	720	858	763	668	573	481	389	81	53	185	225	264	303	264	227	192	160	130
Swisher	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tarrant	8,805	7,084	5,672	4,245	2,817	1,391	12	12	12	12	12	8,313	6,020	4,294	3,105	1,985	935	12	12	12	12	12
Taylor	71	81	77	77	76	73	69	65	62	58	55	26	22	17	16	15	15	15	15	15	15	14
Terrell	502	540	673	724	776	806	740	672	606	544	483	158	128	145	152	160	173	154	136	120	105	92
Terry	90	119	355	439	525	606	543	479	416	354	293	51	45	121	144	168	192	167	144	122	102	83
Throckmorton	200	204	194	193	191	181	171	161	150	141	132	52	40	25	23	20	20	19	19	19	18	18
Titus	8	8	7	7	7	7	6	6	5	5	5	2	1	1	0	0	0	0	0	0	0	0
Tom Green	53	72	69	69	68	66	63	60	58	55	53	31	28	24	24	23	23	23	23	23	23	23
Travis	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trinity	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Tyler	78	123	160	197	198	174	150	127	103	79	55	91	96	106	127	125	109	93	78	63	49	36
Upshur	39	199	379	551	726	851	771	690	609	529	450	95	164	325	474	620	723	644	566	491	419	349
Upton	1,744	3,075	3,887	3,575	3,265	2,960	2,470	1,984	1,499	1,020	699	1,863	1,694	1,458	1,296	1,144	1,001	817	641	473	318	219
Uvalde	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Val Verde	0	66	144	169	195	221	199	179	158	139	120	67	66	91	97	102	108	98	89	81	74	68
Van Zandt	56	65	62	62	61	59	56	53	50	47	45	22	19	15	15	14	14	14	14	13	13	13
Victoria	25	66	72	79	75	65	56	49	41	34	27	47	56	54	56	52	44	38	33	29	24	20
Walker	0	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Waller	0	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Ward	582	632	775	968	941	915	815	716	617	521	429	622	620	317	362	333	307	267	229	193	161	132
Washington	0	44	545	924	840	757	673	589	506	422	338	30	46	346	561	500	442	385	330	277	227	178
Webb	4,599	3,878	3,708	3,257	2,804	2,397	2,007	1,623	1,238	796	341	3,948	2,844	2,337	2,014	1,701	1,422	1,166	922	687	439	196
Wharton	31	81	89	97	93	80	69	60	51	42	33	58	69	67	69	64	54	47	41	36	30	25
Wheeler	3,794	3,609	3,157	2,682	2,210	1,748	1,293	839	385	22	21	3,850	1,683	1,308	1,071	850	651	469	298	139	20	20
Wichita	59	65	62	62	61	58	55	52	49	46	44	20	17	12	12	11	11	11	11	10	10	10
Wilbarger	7	20	20	20	20	20	19	19	19	18	18	15	14	14	14	14	14	14	14	14	14	14
Willacy	17	44	49	53	51	44	38	33	28	23	18	32	38	37	38	35	29	26	22	19	17	14
Williamson	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wilson	418	1,671	1,929	1,740	1,548	1,357	1,165	973	782	590	399	373	1,206	1,182	1,045	912	783	659	540	426	315	210
Winkler	152	621	787	977	1,169	1,110	991	873	756	642	531	125	318	295	341	387	351	305	261	220	183	149
Wise	2,313	3,014	2,661	2,293	1,924	1,556	1,238	932	625	319	13	2,348	2,584	2,037	1,691	1,360	1,046	809	587	380	189	13
Wood	17	26	25	25	25	24	23	22	21	21	20	13	12	11	10	10	10	10	10	10	10	10
Yoakum	1,052	1,264	1,300	1,382	1,334	1,240	1,147	1,052	957	870	783	246	299	209	222	191	171	151	132	115	99	84
Young	15	142	197	244	291	236	206	183	159	135	111	125	136	165	188	208	156	135	116	97	81	65
Zapata	30	78	85	93	89	76	66	57	49	40	31	56	66	64	66	61	51	45	39	34	29	24
Zavala	407	2,140	2,531	2,379	2,257	2,118	1,977	1,838	1,559	1,245	932	409	1,555	1,570	1,448	1,336	1,212	1,092	975	802	622	450
SUM (kAF)	**118.4**	**159.3**	**178.4**	**179.6**	**175.1**	**159.9**	**139.0**	**119.1**	**99.6**	**81.4**	**65.4**	**92.7**	**96.4**	**91.8**	**88.0**	**82.0**	**71.3**	**59.7**	**49.4**	**39.8**	**31.3**	**23.8**

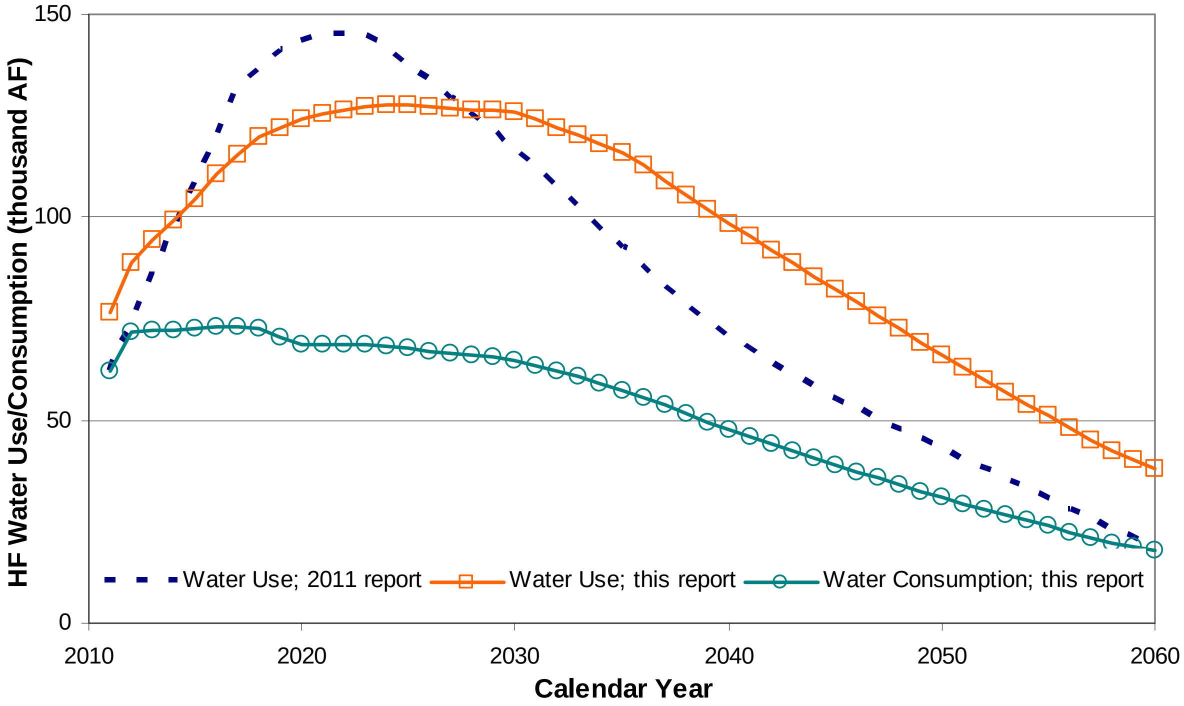
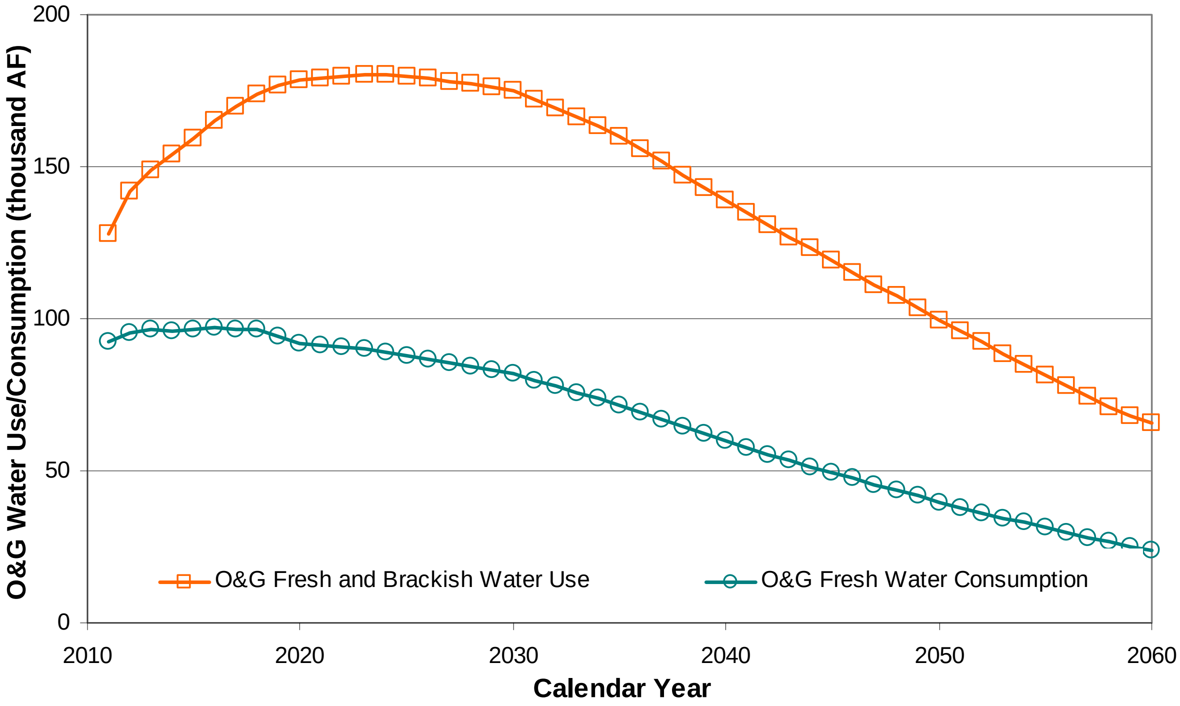


Figure 48. State-level projections to 2060 of HF water use and fresh-water consumption and comparison to earlier water projections.



O&G WaterUse&Consumption_2.xls

Figure 49. State-level projections to 2060 of oil and gas industry water use and fresh-water consumption.

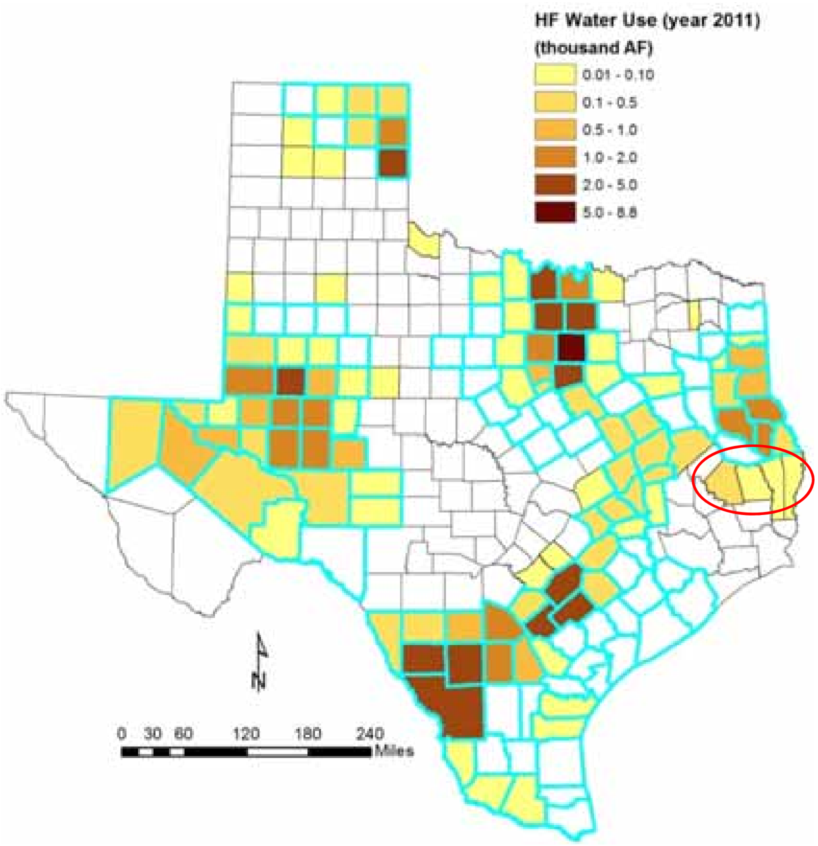
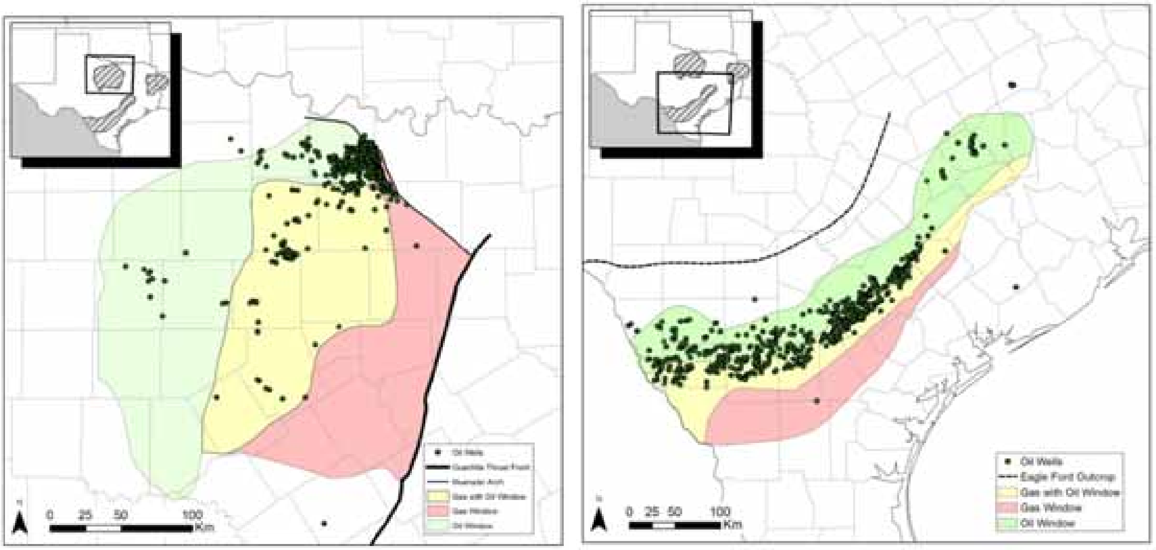


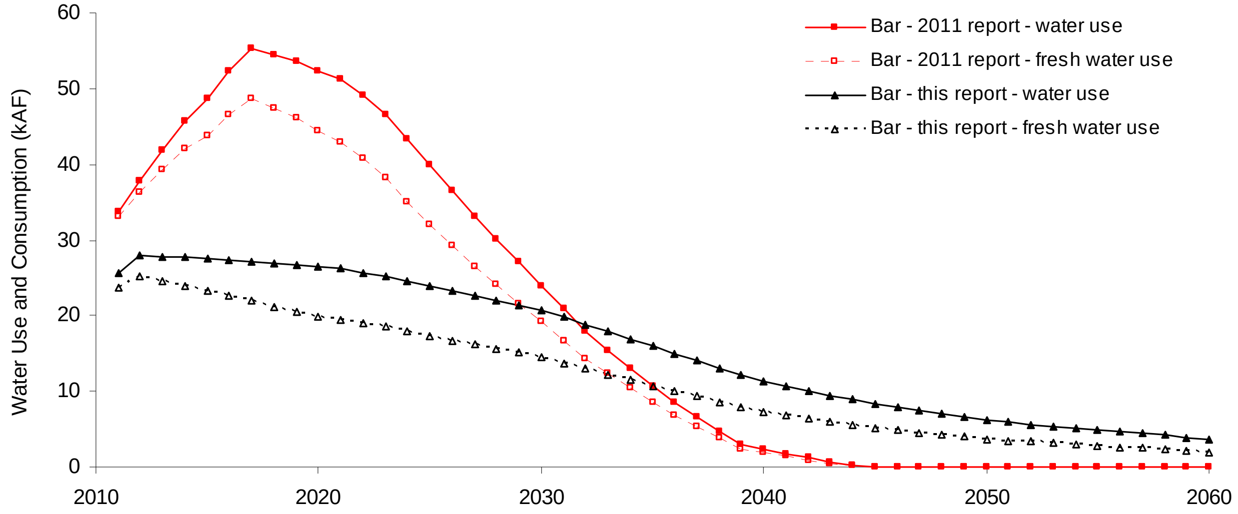
Figure 50. Counties with non-zero projected water use. Same coverage as in the 2011 report (thick blue lines) with the addition of Polk, Tyler, Jasper, and Newton counties in East Texas (red circle).



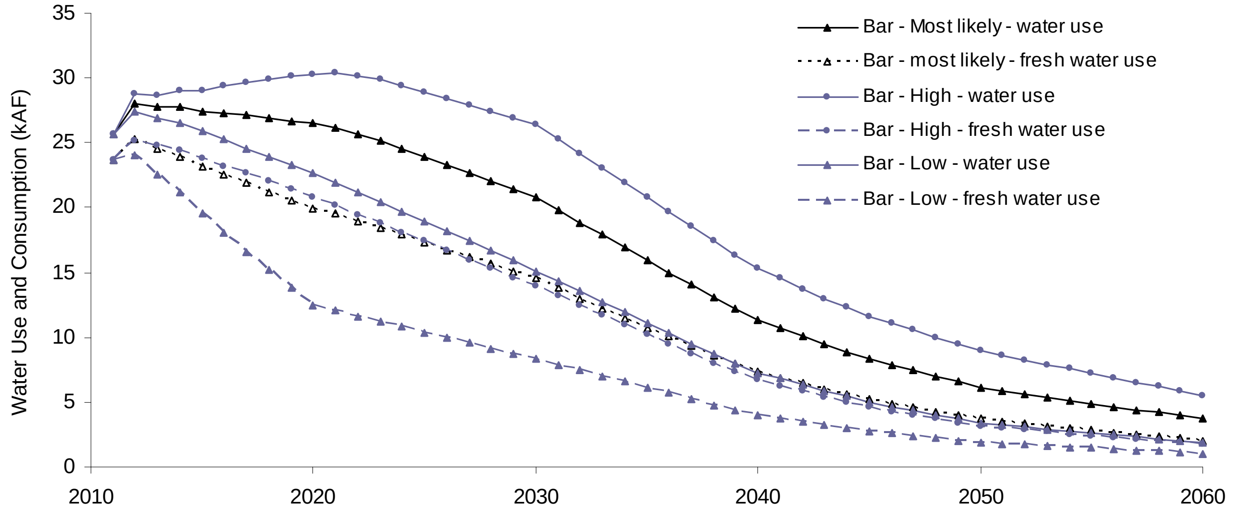
Source: Montgomery et al. (2005)

Source: McMahon and Vaden (2011)

Figure 51. Spatial location of the oil and gas windows in the (a) Barnett Shale and (b) Eagle Ford Shale.



(a)



TrackChanges 1.xls

(b)

Figure 52. Barnett Shale water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

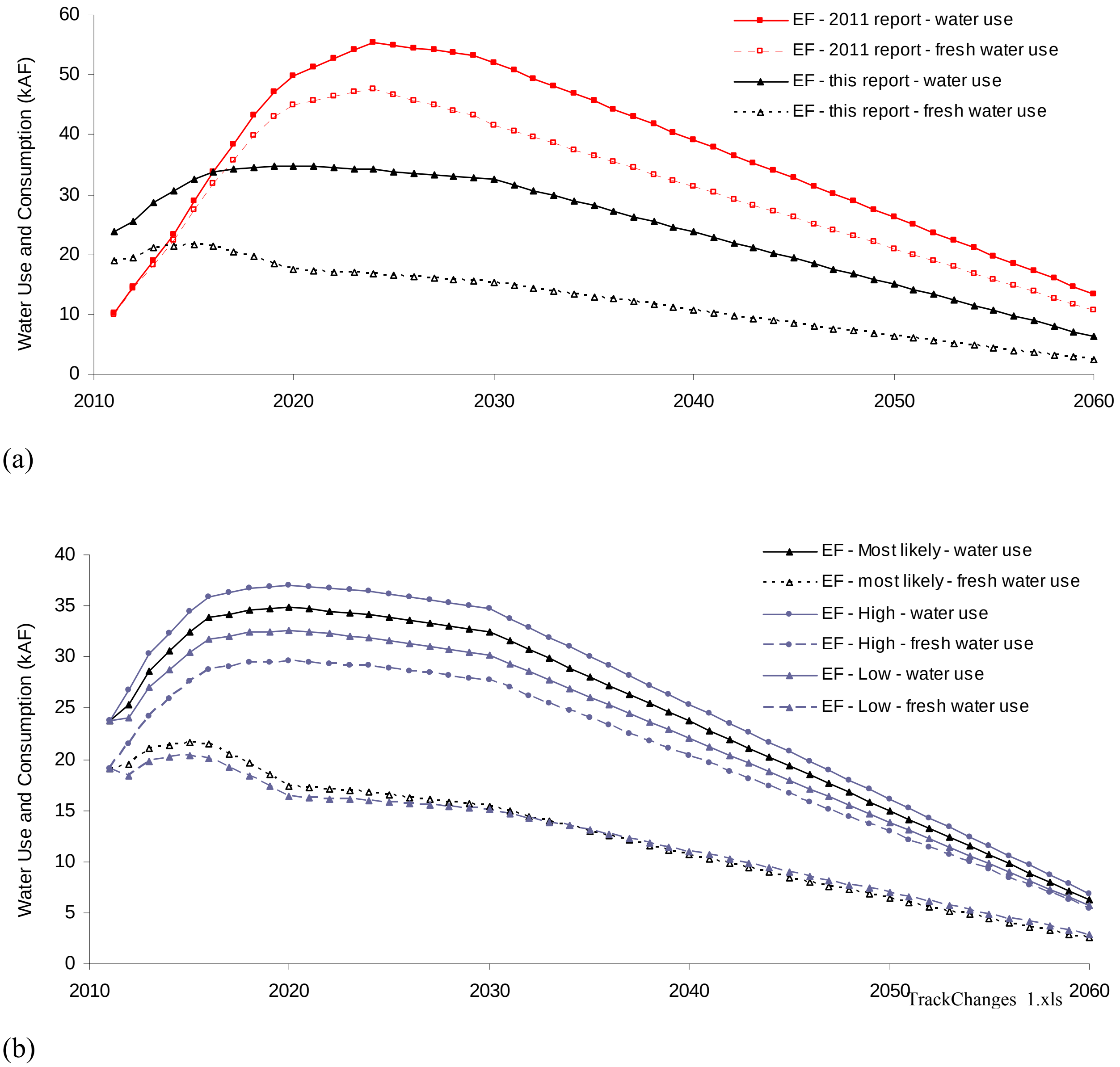


Figure 53. Eagle Ford Shale water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

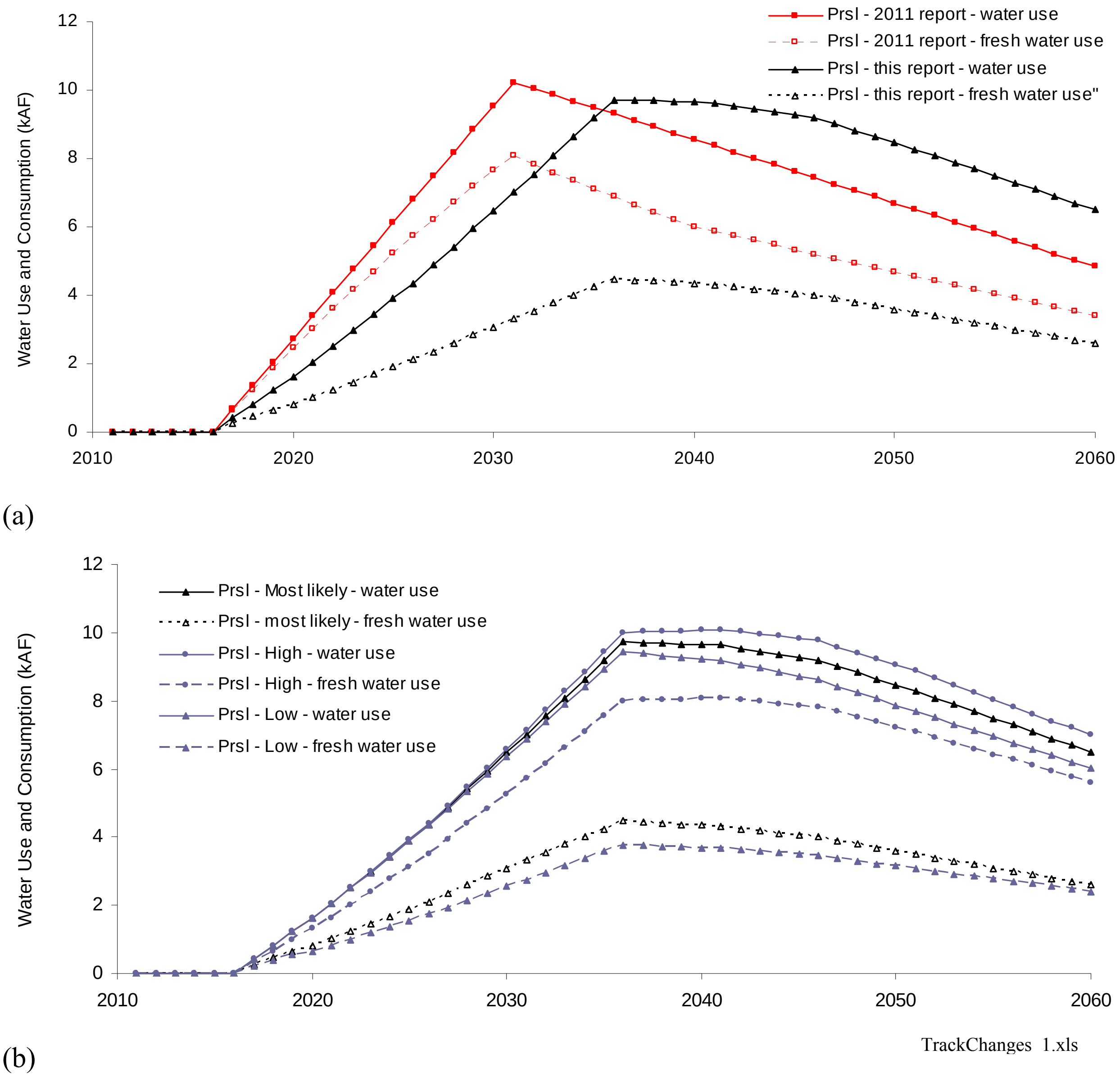


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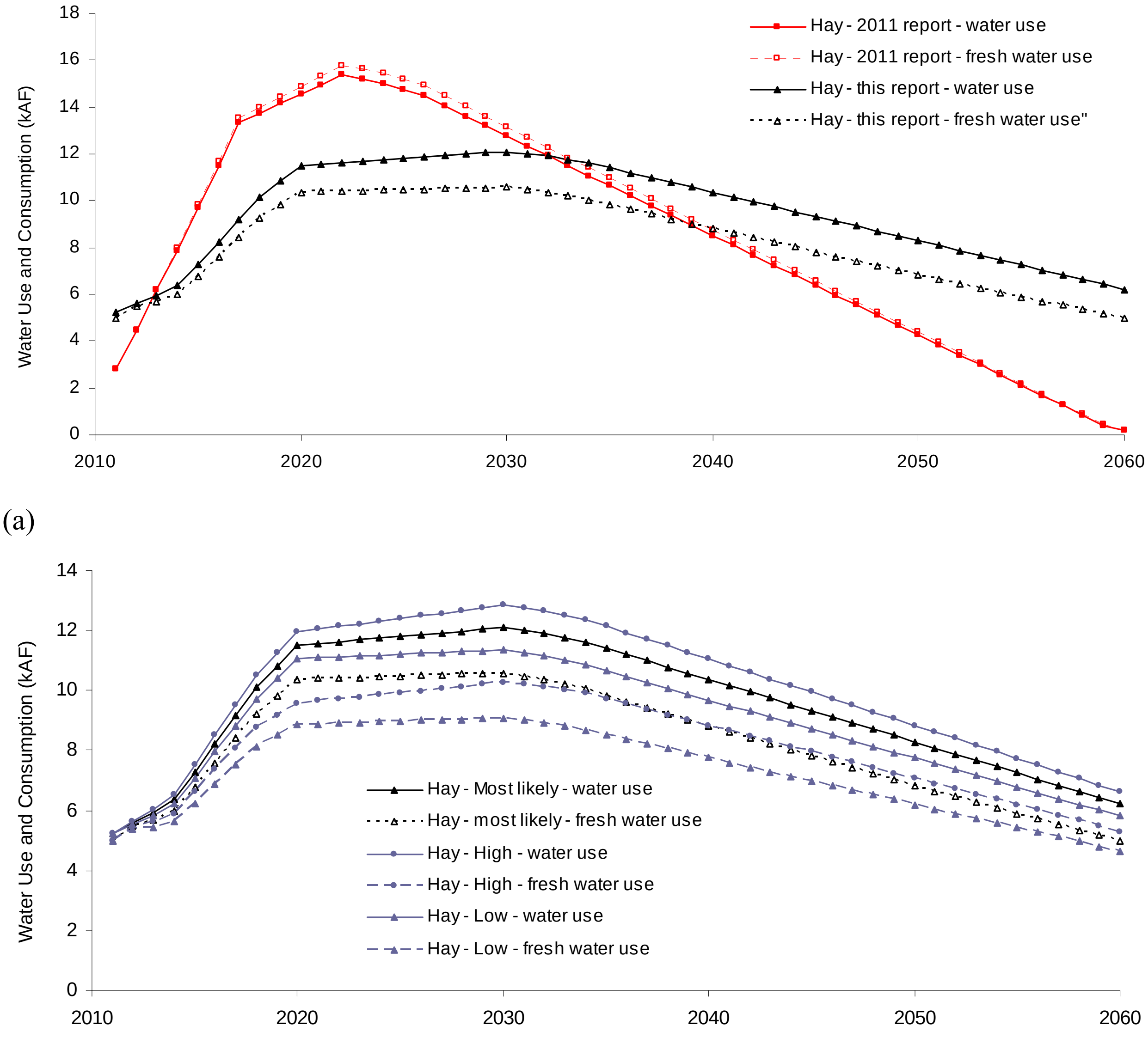
Figure 54. Pearsall Shale water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.



(a)

TrackChanges 1.xls

(b)

Figure 55. Haynesville and Bossier Shales water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

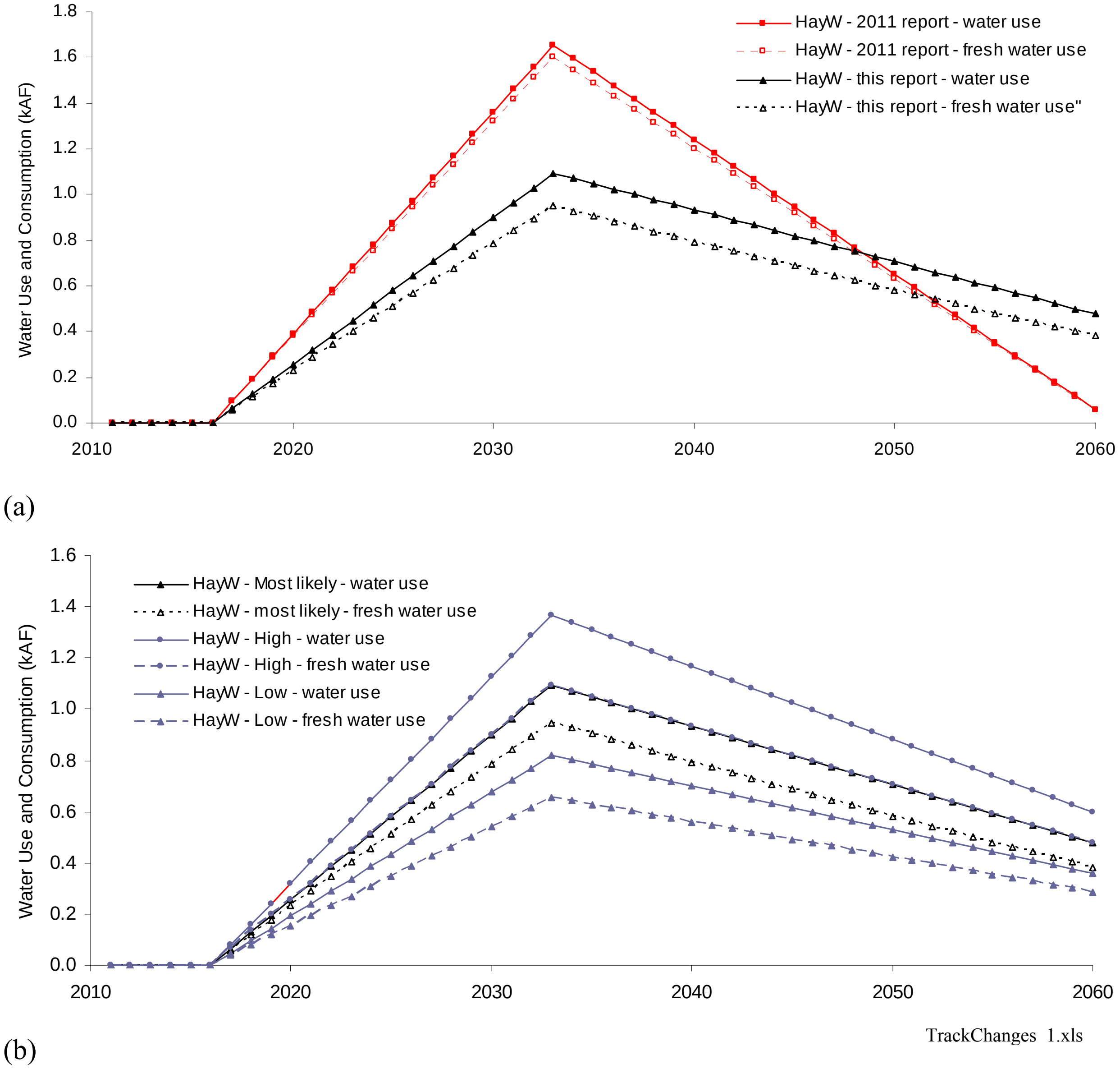


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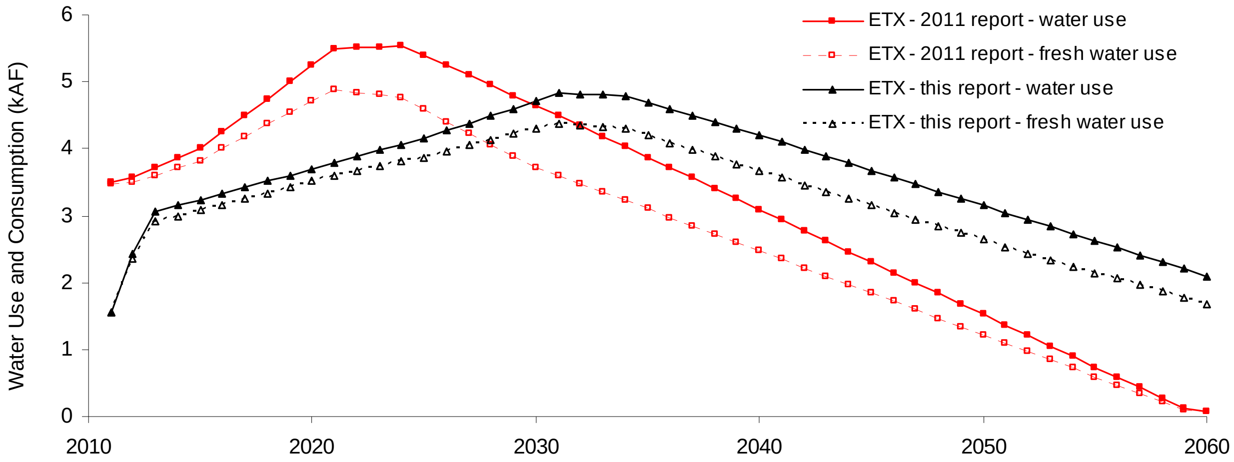
Figure 56. Haynesville-West Shale water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.



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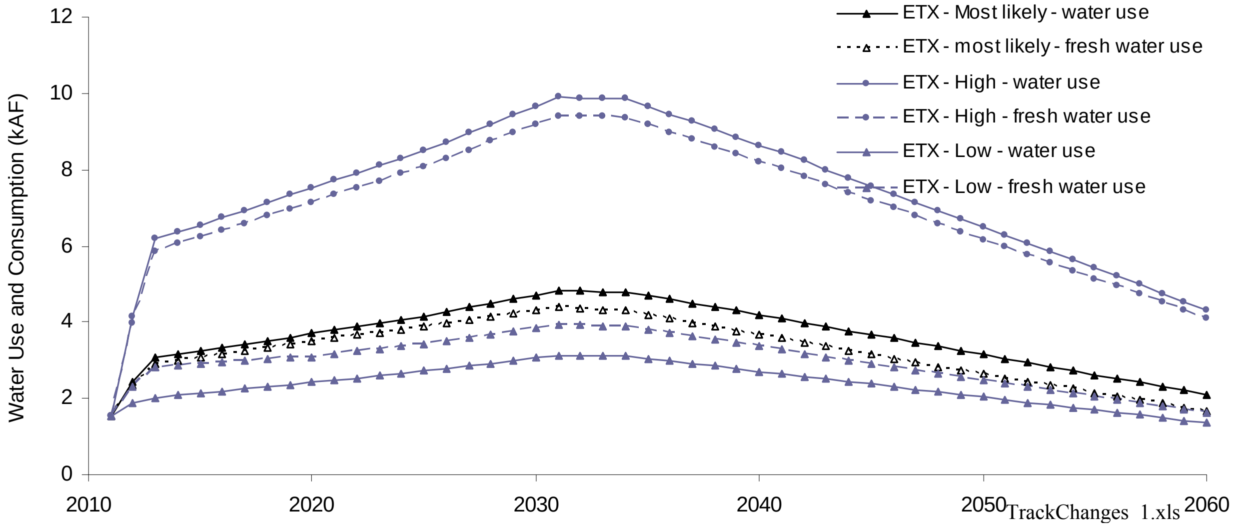
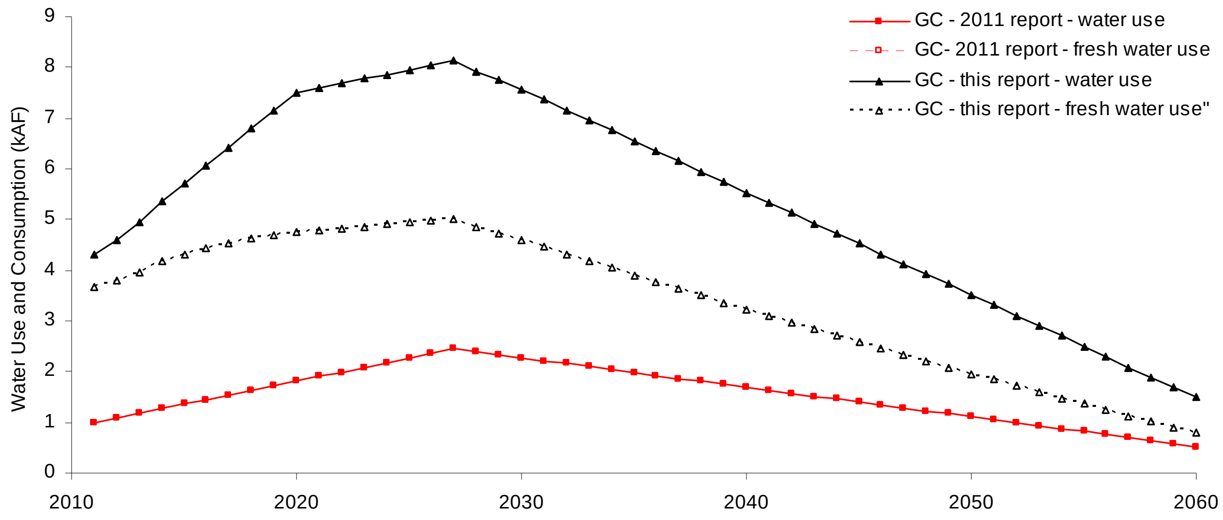


(b)

Figure 57. East Texas (not including Haynesville and Bossier Shales) water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.



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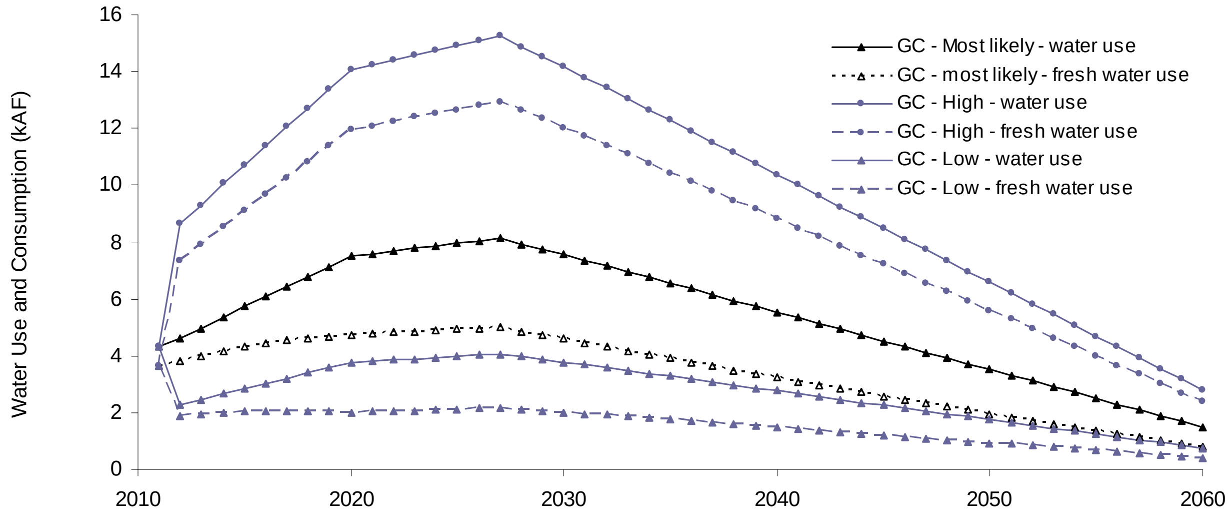

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(b)

Figure 58. Gulf Coast (not including shales) water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

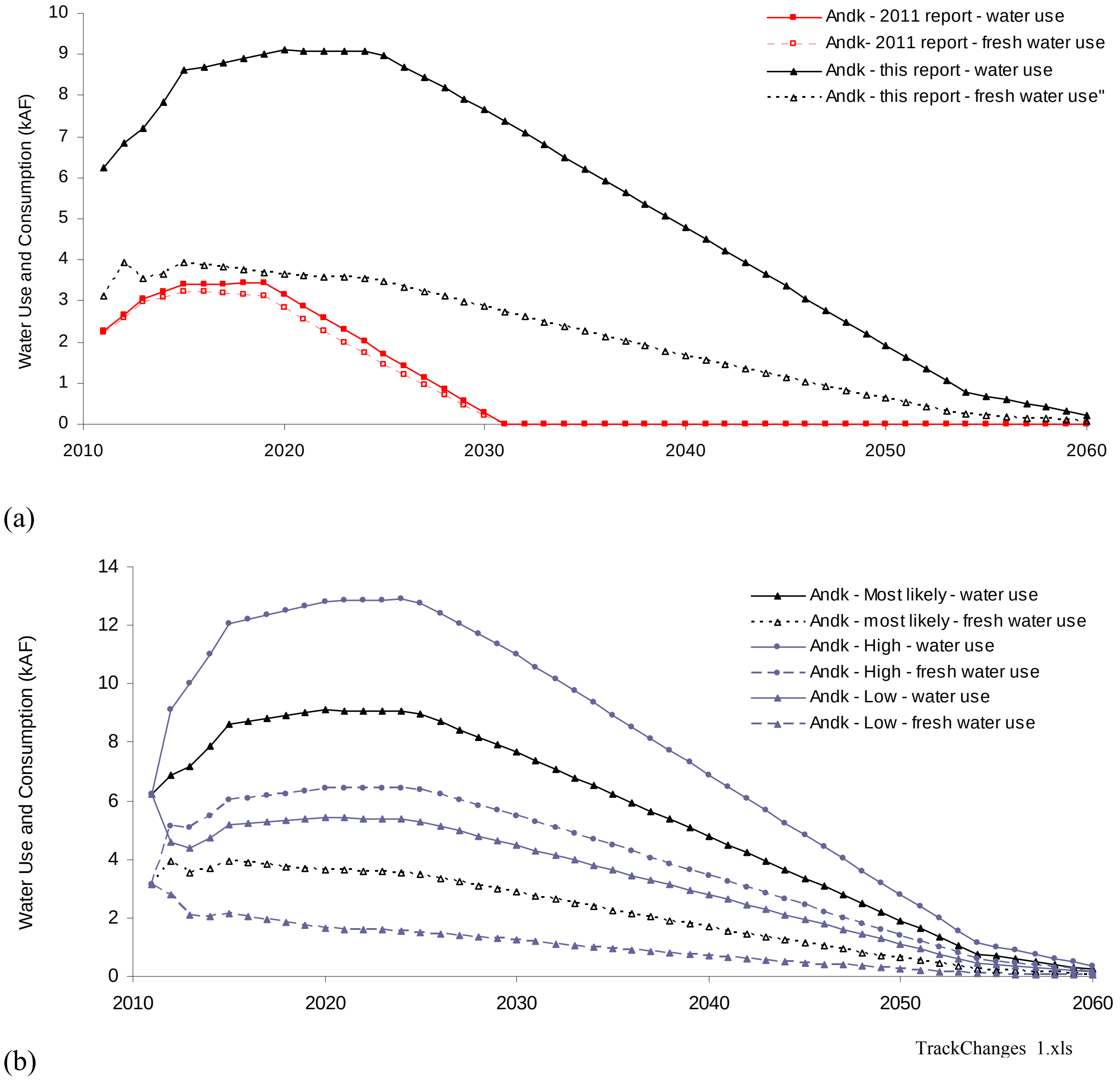

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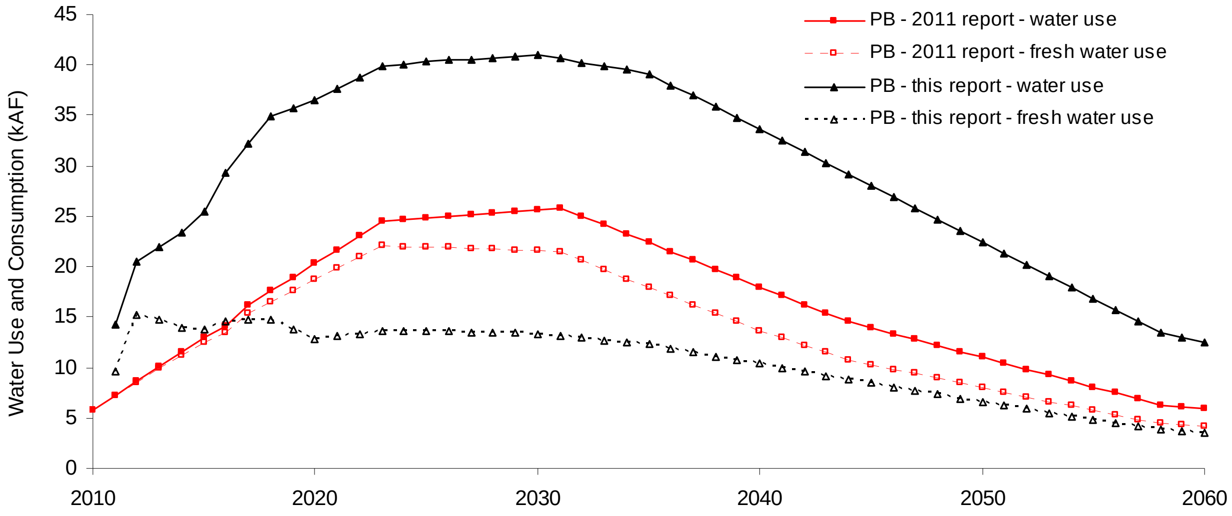
Figure 59. Anadarko Basin water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.



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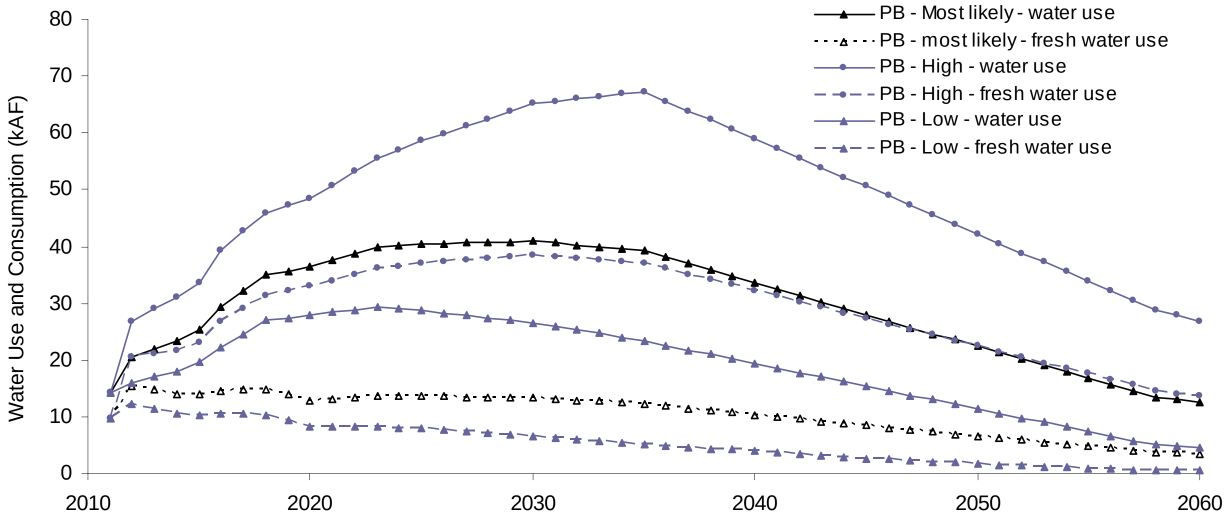


(b)

TrackChanges 1.xls

Figure 60. Permian Basin water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

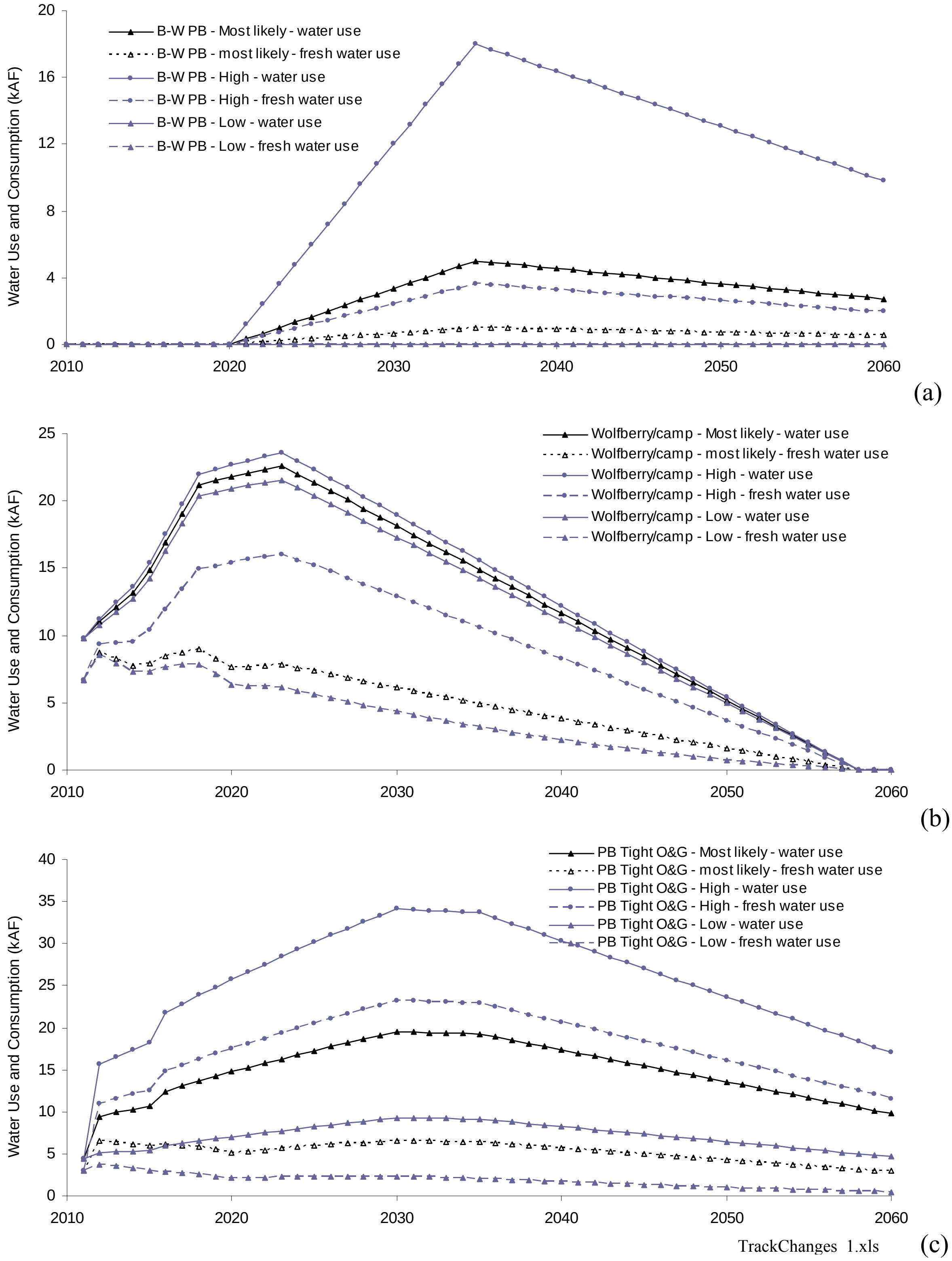
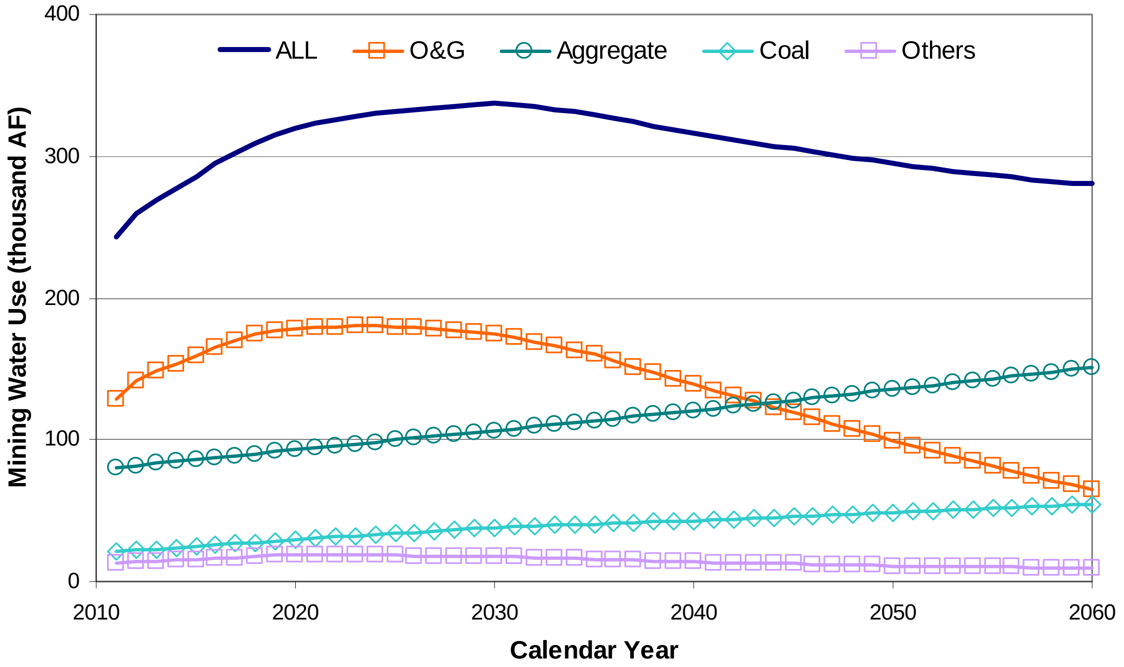


Figure 61. Permian Basin water use and consumption projections under the three scenarios: (a) Barnett and Woodford Shales; (b) Wolfcamp Shale and Wolfberry play; and (c) other Permian Basin formations.

V. Conclusions

This update to the 2011 report (whose conclusions were partly summarized in Nicot and Scanlon, 2012) does not fundamentally change the water use projections put forward originally. Both documents outline a water use that is likely to stay in the vicinity of 100±50 kAF/yr for many years. The new projections lower and broaden the expected peak water use and displace the center of gravity of HF water use toward West Texas, an area of the state that has less fresh water. This mechanically translates into a higher brackish water use which when allied with improvement in reuse technologies results in a much lower fresh water consumption than was projected in the 2011 report. The eventual solution in West Texas, after the initial step of using slightly brackish groundwater, is to use more saline brackish water or the abundant produced water from conventional wells to avoid competition with other users who will also rely more and more on brackish water as their water needs increase. In addition to this expected recycling from other uses, the industry itself is making rapidly maturing technological advances that will improve reuse. Fortunately flow back is abundant in most places where fresh water is not (such as in West Texas). However, as in all predictive work, unexpected events can generate large deviations from the projections (as the shale gas revolution did for domestic oil production). The simple discovery of an additional major play (deeper play?) beyond those described in this document could change the state-level water projections. They, however, are unlikely to deviate much in order of magnitude from those outlined here.

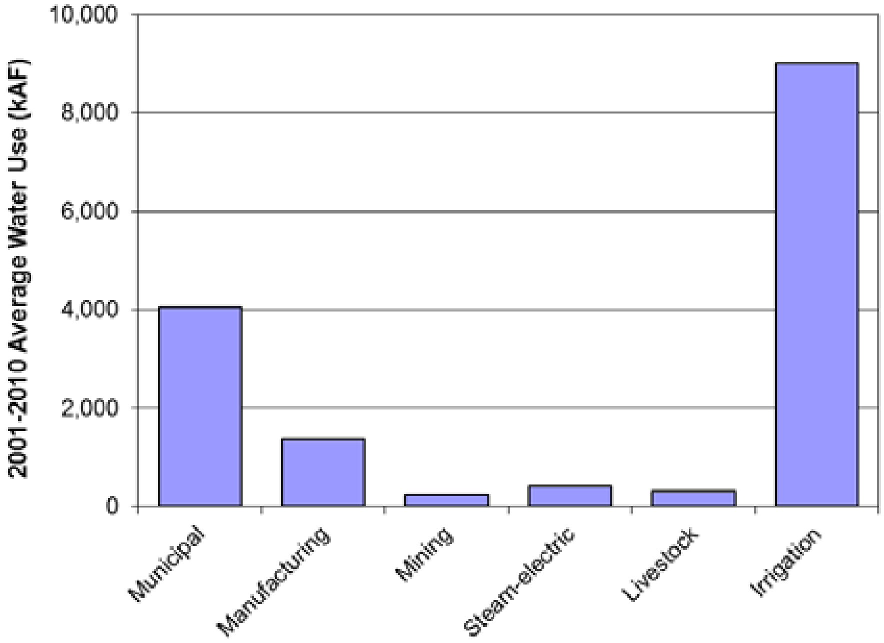
It follows that oil and gas water use projections remain a reasonable fraction of mining water use projections, no more than 54% (Figure 62) and a smaller fraction still of the total amount on water use in Texas every year: <0.1 million AF (81.5 kAF in 2011) compared to 15+ million AF (Figure 63).



MiningWaterUse2010-2060_4_TWDB_just.xls

Note: modified from the 2011 report (Nicot et al., 2011, Fig. 135)

Figure 62. Summary of projected water use by mining industry in Texas (2012-2060).



BarPlots_WaterUse_6.xls

Source: TWDB historical water use surveys, http://www.twdb.state.tx.us/waterplanning/waterusesurvey/estimates/

Note: value displayed for mining water use is the 230 kAF from Nicot et al. (2011) rather than the projected 296 kAF listed in TWDB (2012, p.137) or the 2001-2010 average of 184.4 kAF computed with limited information.

Figure 63. Average state level water use (all categories) in 2001-2010.

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Appendix 1: Revision to 2011 Report

Although the material below is now obsolete (Table 17), we thought it was important to correct Table 52 of the 2011 report (“Projected water use in the Barnett Shale (Fort Worth Basin)”). Although correct values were used in tables of higher order (state level or cumulative across water uses) in the 2011 report, its table 52 was not updated between the draft version and the final version.

Table 17. Update to Table 52 of 2011 report (now obsolete and superseded by this report)

County	2010*	2020	2030	2040	2050	2060
	AF					
Archer	0	1,618	1,292	369	0	0
Bosque	913	2,547	1,065	0	0	0
Clay	~~634~~ 951	~~3,731~~ 5,596	~~1,663~~ 2,495	0	0	0
Comanche	429	2,524	1,125	0	0	0
Cooke	101	282	118	0	0	0
Coryell	0	1,793	1,140	263	0	0
Dallas	620	769	271	0	0	0
Denton	1,674	587	0	0	0	0
Eastland	0	1,127	1,157	386	0	0
Ellis	325	235	63	0	0	0
Erath	2,017	2,500	882	0	0	0
Hamilton	190	1,118	498	0	0	0
Hill	1,008	1,249	441	0	0	0
Hood	1,720	990	215	0	0	0
Jack	~~1,835~~ 2,386	~~1,706~~ 2,218	~~535~~ 696	0	0	0
Johnson	3,308	1,537	241	0	0	0
McLennan	0	1,380	680	62	0	0
Montague	~~539~~ 809	~~3,174~~ 4.760	~~1,415~~ 2,122	0	0	0
Palo Pinto	446	2,627	1,171	0	0	0
Parker	4,003	1,787	153	0	0	0
Shackelford	0	1,121	1,151	384	0	0
Somervell	771	443	96	0	0	0
Stephens	0	1,854	1,178	272	0	0
Tarrant	3,147	1,104	0	0	0	0
Wise	~~4,220~~ 4.642	~~1,961~~ 2,157	~~308~~ 338	0	0	0
Young	0	563	578	193	0	0
Total (Th. AF)	**~~27.9~~** **29.5**	**~~40.3~~** **44.5**	**~~17.4~~** **19.2**	**1.9**	**0.0**	**0.0**

Note: double strikethrough on the incorrect values replaced by the correct but obsolete values.

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Pushing the Limits:
Using VIE to Identify Small Fish

Most tags just don't fit in small-bodied and early life stages of fish, but we still need to identify them, preferably without biasing our data. The options are further limited when many batches or individual identification is required. Visible Implant Elastomer™ (VIE) is internally injected but remains externally visible, and because the size of a tag is controlled by the tagger, it is easily adapted to very small fish. Colors and tag locations can be combined to create a coding scheme.

VIE has been used to tag newly settled coral reef fishes as small as 8—10 mm (1,2) with high tag visibility and little mortality. Marking success was influenced by depth of subcutaneous tag injection, anatomical location of the tag, pigmentation of the skin, and investigator's experience with the technique. Long-bodied fish like eels and lamprey as small as 1 g are easily tagged with VIE (3, 4).

Techniques for tagging very small salmonids have been developed for VIE. Brown trout ≤26 mm can be tagged at the base of the fins and have been recovered during stream surveys up to 83 days later[5]. This technique worked well with Atlantic Salmon ≤30 mm, and has been used for monitoring in-stream movements through snorkel surveys[6]. The minimum size for tagging juvenile salmonids has been pushed down to 22 mm FL, and is possible to tag alevins in the yolk sac[7], and fry in the fins[8].

VIE is well-suited for tagging juveniles of many other species and is used world wide. Please contact us if we can help with your project.

Photos: A syringe is used to inject VIE into the fin of a juvenile salmonid (top). VIE is available in 10 colors (left), of which six fluoresce under a VI Light for improved visibility and tag detection (center). Tagging rainbow trout fry as small as 22 mm is possible with VIE (below). Leblanc & Noakes[7] used this to identify fish originating from larger eggs (top) or smaller eggs (bottom).

[1] Frederick (1997) Bull. Marine Sci.; [2] Hoey & McCormick (2006) Proc. 10th Intern. Coral Reef Symp.; [3] Stone et al. (2006) N. Am. J. Fish. Manage.; [4] Simon & Dorner (2011) J. Appl. Ichthyology; [5] Olson &Vollestad (2001) N. Am. J. Fish. Manage.; [6] Steingrimsson & Grant (2003) Can. J. Fish. Aquat. Sci.; [7] Jensen et al. (2008) Fish. Manage. Ecol.; [8] Leblanc & Noakes (2012) N. Am. J. Fish. Manage.

Photo courtesy C. Leblanc.

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Cover: Brook Trout in front of a Hydraulic Fracturing Pad.
Photo Credits: foreground: Miles Luo; background: Alessandro Farsi

36 SIUC IL-AFS member Jake Norman instructs beginning anglers on how to properly cast a rod and reel during the 2012 Illinois Department of Natural Resources' Urban Fishing program. Through this vital community resource, many children had the opportunity to catch their first fish, thus generating a newfound enthusiasm for fishing within the youngest members of the Southern Illinois community.

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Teach Your Children Well

John Boreman, President

AFS President Boreman may be contacted at: John.Boreman@ncsu.edu

This is an exciting time to be a member of the American Fisheries Society (AFS). Conservation laws, technology, and the questions being asked of fisheries professionals are changing rapidly, as well the nature of the fisheries discipline itself. In the past 20 years we have witnessed increased accountability requirements for those managing our fisheries resources, not only in the United States but also globally, putting more responsibility on the shoulders of fisheries professionals. We have seen the Internet and associated social media become a mainstay in communications among fisheries professionals and for keeping us in touch with decision makers and the public in general. We have seen computational power and associated data storage requirements increase by orders of magnitude, along with the development and use of sensors to measure the environment and its biota. Today's students (and many of today's faculty) were not yet born when our astronauts walked on the moon, when we used transistors in our radios, and spun 45s on our record players. I was shocked when none of the students in my class ever heard of FORTRAN. What's in store for fisheries professionals the next 20 years? Will we be able to adapt to changes in everything affecting our lives and livelihoods? Will we be adequately prepared to do so?

As a professional society, the AFS has a role to play in ensuring that people entering the future workforce will be prepared to tackle the issues that fisheries professionals will then be facing. This role is codified in the AFS Strategic Plan for 2010–2014:

> *Guide colleges and universities to maintain, modify, or develop curricula of the highest quality for both undergraduate and graduate students that provide an array of courses and experiences needed to effectively manage and conserve fisheries resources and meet the needs of employers.*

In keeping with my theme "Preparing for the Challenges Ahead," I have established an AFS Special Committee on Educational Requirements, chaired by AFS Second Vice President Ron Essig, to accomplish several tasks. First, the committee will assemble a list of North American colleges and universities currently offering undergraduate and graduate degrees in fisheries-related disciplines (e.g., fisheries science, fisheries biology, fisheries ecology, fisheries management, fisheries policy, and fisheries economics) and publish the list on the AFS website. Concurrently, the committee will oversee a survey of major employers that will be hiring graduates with degrees in fisheries-related disciplines in the next 5–10 years to determine what coursework those graduates will be expected to have taken that would be most germane to the positions being filled. The survey results, and an evaluation of their implications, should be published in *Fisheries*. When the list and survey are completed, the committee will compare the coursework expectations of the employers with the current coursework requirements of a selected subset of colleges and universities offering fisheries degrees. If the comparison indicates a misalignment, the committee will recommend ways in which an alignment can be made, which could range from giving simple advice to the colleges and universities to instituting an accreditation program administered by the AFS (or something in between). The recommendations could serve as the basis for discussion at an upcoming AFS Governing Board retreat.

I have also asked the special committee to compare coursework expectations resulting from the survey to degree requirements for certification as a fisheries professional, working with the Education Subcommittee of the AFS Board of Professional Certification, as well as to the U.S. Office of Personnel Management's educational requirements in the grade-level qualification standards for the 482 (Fish Biology) series. Based on the comparisons, the committee could recommend changes that would bring the degree requirements for certification and federal employment into alignment with employer expectations. The committee might also look at analogous requirements for federal employment of fisheries professionals in Mexico and Canada. These comparisons can be published as a series of articles in *Fisheries*.

Continuing education, which helps fisheries professionals shore up their level of skill, knowledge, and expertise as employment demands evolve, is also important in preparing the future workforce. To this end, I have charged the AFS Continuing Education Committee to assist AFS staff in expanding opportunities for distance education (i.e., education via the Internet) beyond virtual attendance at continuing education courses offered at the annual meeting. One option the Continuing Education Committee will be tackling through the AFS will be to pilot at least one half-day short course in the coming year to be offered via a webinar. The pilot short course could be offered for free to alleviate complications with registration and fees and allow the committee to focus evaluation of the pilot solely on the quality of the learning experience. Given successful delivery of the pilot course, the AFS could pursue, for example, a quarterly distance education webinar series that may or may not require

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Hydraulic Fracturing and Brook Trout Habitat in the Marcellus Shale Region: Potential Impacts and Research Needs

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ABSTRACT: *Expansion of natural gas drilling into the Marcellus Shale formation is an emerging threat to the conservation and restoration of native brook trout (*Salvelinus fontinalis*) populations. Improved drilling and extraction technologies (horizontal drilling and hydraulic fracturing) have led to rapid and extensive natural gas development in areas overlying the Marcellus Shale. The expansion of hydraulic fracturing poses multiple threats to surface waters, which can be tied to key ecological attributes that limit brook trout populations. Here, we expand current conceptual models to identify three potential pathways of risk between surface water threats associated with increased natural gas development and life history attributes of brook trout: hydrological, physical, and chemical. Our goal is to highlight research needs for fisheries scientists and work in conjunction with resource managers to influence the development of strategies that will preserve brook trout habitat and address Marcellus Shale gas development threats to eastern North America's only native stream salmonid.*

Ruptura hidráulica y el hábitat de la trucha de arrollo en la región de Marcellus Shale: impactos potenciales y necesidades de investigación

RESUMEN: El crecimiento de las actividades de perforación de gas natural en la formación Marcellus Shale es una amenaza emergente para la conservación y restauración de las poblaciones nativas de la trucha de arroyo (*Salvelinus fontinalis*). La perforación más eficiente y las tecnologías de extracción (perforación horizontal y ruptura hidráulica) han facilitado el rápido y extensivo desarrollo de esta industria a las áreas que comprende la región Marcellus Shale. La expansión de las rupturas hidráulicas representa múltiples amenazas a las aguas superficiales, que pueden estar asociadas a atributos ecológicos clave que limitan las poblaciones de la trucha de arroyo. En la presente contribución se expanden los modelos conceptuales actuales que sirven para identificar tres fuentes potenciales de riesgo entre las amenazas a las aguas superficiales asociadas al creciente desarrollo del gas natural y los atributos de la historia de vida de la trucha de arroyo; atributos hidrológicos, físicos y químicos. El objetivo de este trabajo es hacer notar las necesidades de investigación para los científicos pesqueros y trabajar junto con los manejadores de recursos para influir en el desarrollo de estrategias tendientes a preservar el hábitat de la trucha de arroyo; así mismo se atienden las amenazas que representa el desarrollo de la industria del gas natural para el único salmónido nativo de América del norte.

INTRODUCTION

Hydraulic Fracturing in the Marcellus Shale

Natural gas extraction from subterranean gas-rich shale deposits has been underway in the northeastern United States for almost 200 years but has expanded rapidly over the past decade within the Devonian Marcellus Shale formation (P. Williams 2008). This expansion has largely been driven by the development and refinement of the horizontal hydraulic fracturing process (United States Energy Information Administration 2011a). Horizontal gas drilling differs from the more traditional vertical drilling process because the well is drilled to the depth of the shale stratum and then redirected laterally, allowing for access to a larger area of subterranean shale (Figure 1). Drilling is followed by the hydraulic fracturing process, which involves injecting a chemically treated water-based fluid into the rock formation at high pressure to cause fissures in the shale and permit the retrieval of gas held within the pore space of the shale. The fissures are kept open by sand and other proppants, which allow gas to be extracted (Soeder and Kappel 2009; Kargbo et al. 2010). The hydraulic fracturing process was granted exemptions to the Clean Water and the Safe Drinking Water Acts under the Energy Policy Act of 2005. Drilling has since expanded rapidly in the Marcellus Shale deposit in portions of West Virginia and Pennsylvania (Figure 2), is expected to continue into Ohio and New York, and will likely continue to expand within these states to include the gas-bearing Utica Shale formation.

Brook Trout Status within the Marcellus Shale

Eastern brook trout are native to the Eastern United States, with a historic range extending from the southern Appalachians in Georgia north to Maine (MacCrimmon and Campbell 1969; Figure 2). Brook trout require clean, cold water (optimal tem-

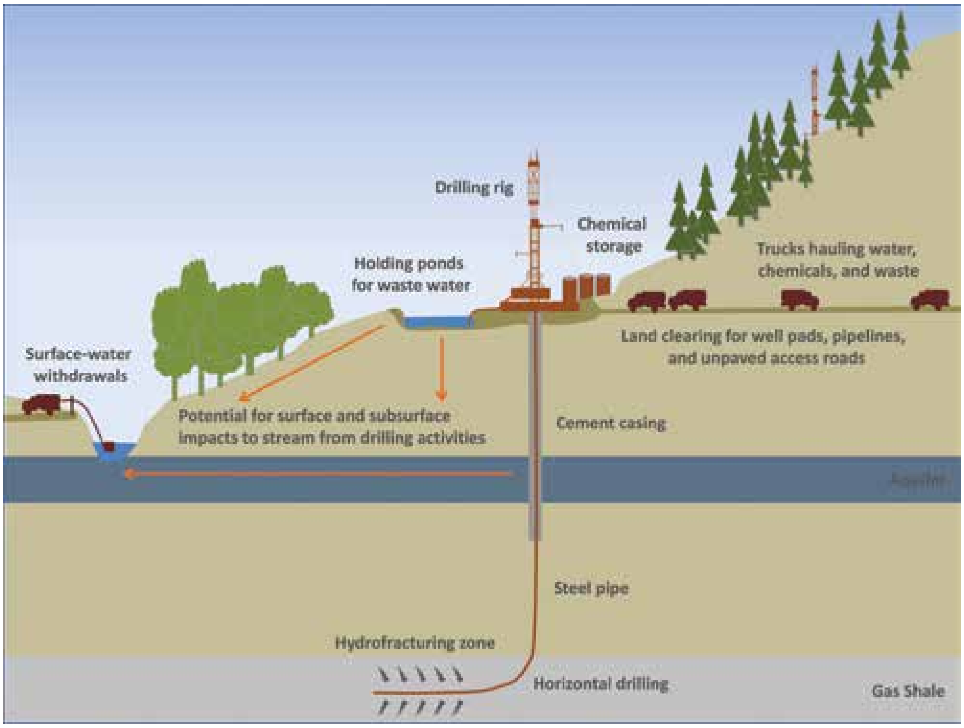

Figure 1. Conceptual diagram depicting the hydraulic fracturing process. A rig drills down into the gas-bearing rock and the well is lined with steel pipe. The well is sealed with cement to a depth of 1,000 ft. to prevent groundwater contamination. The well is extended horizontally 1,000 ft. or more into the gas-bearing shale where holes are blasted through the steel casing and into the surrounding rock. Sand, water, and chemicals are pumped into the shale to further fracture the rock and gas escapes through fissures propped open by sand particles and back through the well up to the surface. Supporting activities include land clearing for well pads and supporting infrastructure, including pipelines and access roads. Trucks use roads to haul in water extracted from local surface waters, chemicals, and sand. Recovered water is stored in shallow holding ponds until it can be transported by truck to treatment facilities or recycled to fracture another well. These activities may impact nearby streams through surface and subsurface pathways.

perature = 10–19°C), intact habitat, and supporting food webs to maintain healthy populations, making them excellent indictors of anthropogenic disturbance (Hokanson et al. 1973; Lyons et al. 1996; Marschall and Crowder 1996). Only 31% of subwatersheds (sixth level, 12-digit hydrological units [HUC12], as defined by the Watershed Boundary Dataset; U.S. Department of Agriculture, Natural Resources Conservation Service 2012) within the historic range of brook trout are currently expected to support intact populations (self-sustaining populations greater than 50% of the historical population; Hudy et al. 2008). Substantial loss of brook trout populations within their native range is due to anthropogenic impacts that have resulted in habitat fragmentation and reduction, water quality and temperature changes, and alteration of the biological environment through introduction and removal of interacting species (Hudy et al. 2008). Conservation efforts, including formation of the Eastern Brook Trout Venture (Eastern Brook Trout Joint Venture [EBTJV] 2007, 2011) and a shift by organizations such as Trout Unlimited (TU) to policies that oppose the stocking of nonnative hatchery-produced salmonids in native trout streams (TU 2011), are focused on maintaining and restoring brook trout populations in their native range. With these growing concerns about the future of native brook trout populations, natural gas well development within the Marcellus Shale region presents another potential threat to native brook trout populations.

Twenty-six percent of the historic distribution of brook trout habitat overlaps with the Marcellus Shale (Figure 2). The Pennsylvania portion of the Marcellus Shale has experienced the largest increase in natural gas development (Figure 2). Between January 1, 2005, and May 31, 2012, the cumulative number of Marcellus Shale well permits issued in Pennsylvania increased from 17 to 11,784 (Pennsylvania Department of Environmental Protection [PADEP] 2012a). Of these permitted wells, 5,514 were drilled during the same time period (PADEP 2012b; Figure 3A). Trends in drilled well densities among subwatersheds during the rapid expansion of drilling activity suggest that there have not been any extra protections granted during the well permitting process for subwatersheds that are expected to support intact brook trout populations (Figure 3B). Fifty-four of the 134 subwatersheds categorized as having intact brook trout populations within the Marcellus Shale region have already experienced drilling activity (Hudy et al. 2008). Overall, Marcellus drilling activity has expanded to 377 subwatersheds (mean area = 94.8 ± 1.9 km^2) in Pennsylvania (Figure 4).Within these 377 subwatersheds, patterns in well density over time show similar trends among subwatersheds varying in their current brook trout population status (Figure 3B). Though there is a significant difference in current well densities among the three subwatershed types (one-way analysis of variance [Type II], $F_{2,\,292} = 4.14$, $P = 0.02$), mean well density does not differ between subwatersheds where brook trout are extirpated/unknown and those with intact brook trout populations (Tukey's multiple comparison test, $\alpha = 0.05$; Figure 3B). In fact, the two highest drilling densities include an extirpated/unknown subwatershed (16.7 wells/10 km^2) and a subwatershed expected to support intact brook trout populations (15.1 wells/10 km^2; Figure 4). These trends highlight that increasing hydraulic fracturing development is occurring not only in degraded subwatersheds but also in those that support an already vulnerable native species and valuable sport fish. This trend should be of concern to fisheries scientists, managers, and conservationists who work to maintain and improve the current status of this natural heritage species.

Linking Marcellus Shale Drilling Impacts to Brook Trout Population Health

Recent efforts to conceptualize horizontal hydraulic fracturing impacts have focused on stream ecosystems and regional

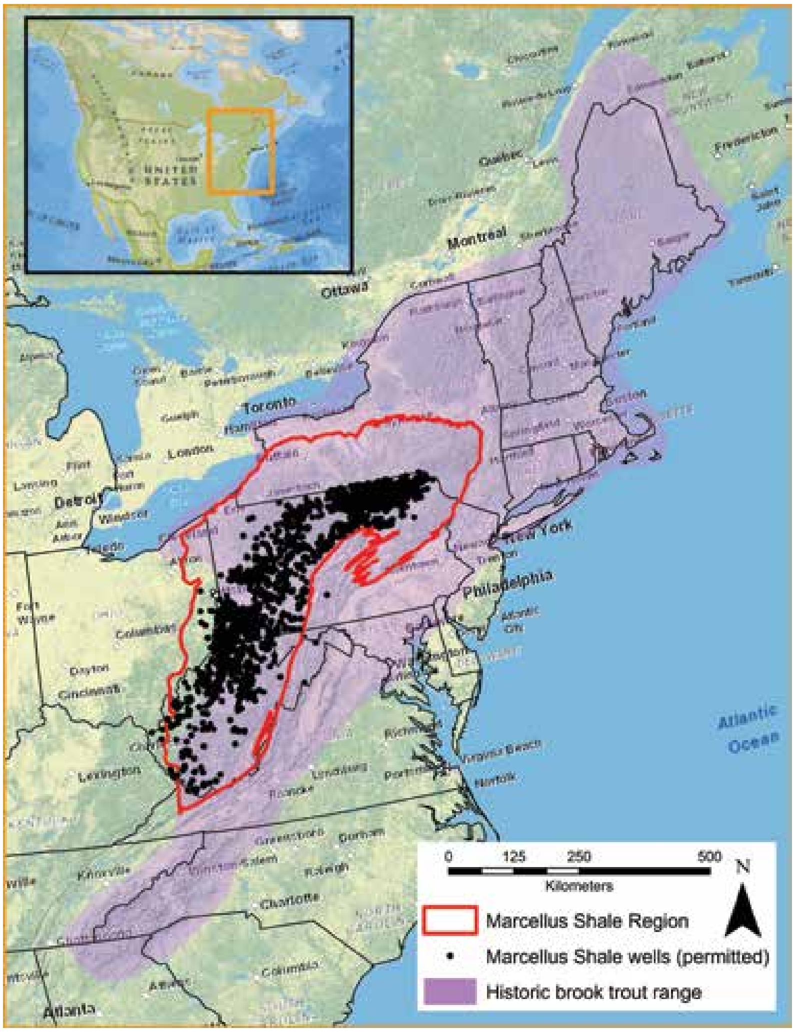

Figure 2. Overlay of the Marcellus Shale region of the Eastern United States (U.S. Geological Survey [USGS] 2011) and the historic distribution of eastern brook trout (Hudy et al. 2008) with permitted Marcellus Shale well locations, 2001–2011 (Ohio Department of Natural Resources 2011; West Virginia Geological and Economic Survey 2011; PADEP 2012a).

water supplies but not on potential pathways to particular target organisms. Herein, we integrate two existing conceptual models of potential natural gas development impacts to surface waters and link them to different brook trout life history attributes (Entrekin et al. 2011; Rahm and Riha 2012). Entrekin et al.'s (2011) conceptual model establishes connections between hydraulic fracturing activities and the ecological endpoint of stream ecosystem structure and function by way of potential environmental stressors from drilling activity sources. These stressors to stream ecosystems can be planned activities that must necessarily occur in the hydraulic fracturing process (deterministic events) or those that may occur unexpectedly (probabilistic events; Rahm and Riha 2012). Brook trout have different environmental requirements at the various stages of their life cycle and may be sensitive to potential impacts associated with the current expansion of hydraulic fracturing; thus, understanding the environmental stressors associated with hydraulic fracturing has implications for fisheries conservation, including maintenance and/or enhancement of native brook trout populations.

We delineated relationships between various stream ecosystem attributes that are potentially impacted by increased drilling activities and different aspects of the brook trout life cycle (Figure 5). A review of extant literature on the activities associated with natural gas drilling and other extractive industries and of the environmental changes known to directly influence brook trout at one or more of their life stages identified three primary pathways by which increased drilling will likely impact brook trout populations. The primary pathways include (1) changes in hydrology associated with water withdrawals; (2) elevated sediment inputs and loss of connectivity associated with supporting infrastructure; and (3) water contamination from introduced chemicals or wastewater (Entrekin et al. 2011; Rahm and Riha 2012). These three pathways may be considered natural gas drilling threats to brook trout populations that require study and monitoring to fully understand, minimize, and abate potential impacts.

PATHWAY #1: WITHDRAWALS → HYDROLOGY → BROOK TROUT

Two to seven million gallons of water are needed per hydraulic fracturing stimulation event; a single natural gas well can be fractured several times over its lifespan, and a well pad site can host multiple wells (Soeder and Kappel 2009; Kargbo et al. 2010). This large volume of water needed per well, multiplied by the distributed nature of development across the region, suggests that hydraulic fracturing techniques for natural gas development can put substantial strain on regional water supplies. This level of water consumption has sparked concern among hydrologists and aquatic biologists about the sourcing of the water, as well as the implications for available habitat and other hydrologically influenced processes in adjacent freshwater ecosystems (Entrekin et al. 2011; Gregory et al. 2011; Baccante 2012; Rahm and Riha 2012; Figure 5). Surface water is the primary source for hydraulic fracturing–related water withdrawals in at least one major basin intersecting the Marcellus Shale region (Susquehanna River Basin Commission [SRBC] 2010), but groundwater has been a major water source in other natural gas deposits such as the Barnett Shale region in Texas (Soeder and Kappel 2009). The cumulative effects of multiple surface and/or groundwater withdrawals throughout a watershed have the potential to effect downstream hydrology and connectivity of brook trout habitats (Rahm and Riha 2012; Petty et al. 2012).

Aquatic habitat is particularly limited by low-flow periods during the summer for fish and other aquatic organisms (Figure 6). Changes in temperature and habitat volume during summer low-flow periods are primary factors limiting brook trout populations (Barton et al. 1985; Wehrly et al. 2007; Xu et al. 2010). Brook trout rely on localized groundwater discharge areas within pools and tributary confluences to lower body temperature below that of the ambient stream temperature during warm periods, and groundwater withdrawals can alter these temperature refugia. Additionally, access to thermal refugia may be limited by loss of connectivity associated with reduced flows between temperature refugia (headwater streams, seeps, tributary confluences, groundwater upwellings) and larger stream habitats (Petty et al. 2012). Reduced flows, particularly coldwater inputs, may inhibit growth rates by reducing feeding activity of both juveniles and adults or inducing sublethal heat shock at temperatures above 23°C and lethal effects at 24–25°C (7-day upper lethal temperature limit; Cherry et al. 1977; Tangiguchi et al. 1998; Baird and Krueger 2003; Lund et al. 2003; Wehrly et al. 2007). Recovery from thermal stress responses (heat shock) can be prolonged (24–48 h) even if exposure to high stream temperatures is relatively short (1 h) but may be more than 144 h when exposed to high temperatures for multiple days (Lund et al. 2003). Adult abundance and biomass of brook trout in run habitats declines with flow reduction and carrying capacity is likely limited by available pool area during low-flow periods (Kraft 1972; Hakala and Hartman 2004; Walters and Post 2008).

Reduction in surface water discharge during summer months may also indirectly impact brook trout growth by decreasing macroinvertebrate prey densities (Walters and Post 2011) in small streams and lowering macroinvertebrate drift encounter rates for drift-feeding salmonids (Cada et al. 1987; Nislow et al. 2004; Sotiropoulos et al. 2006; Figure 5). Other indirect effects may include increasing interspecific competition through habitat crowding, especially with more tolerant competitor species such as brown trout (*Salmo trutta*) and rainbow trout (*Oncorhynchus mykiss*), due to decreased habitat availability and increased temperature during low-flow periods. Introduced brown trout tend to out-compete brook trout for resources and have higher growth rates in all but the smallest, coldest headwater streams (Carlson et al. 2007; Öhlund et al. 2008; Figure 5). Additionally, salmonids may be more susceptible to disease or infestation of parasites when the temperature of their environment is not consistent and adequately cool (Cairns et al. 2005), a problem that could be exacerbated by the crowding in pool habitats that can occur as a result of flow reductions (Figure 5). Sediment accrual in redds can limit recruitment (Alexander and Hansen 1986; Argent and Flebbe 1999), and adequate summer base flows coupled with occasional high flow pulses are important for preparing sediment free spawning redds (Hakala and Hartman 2004). DePhilip and Moberg (2010) demonstrated that the magnitude of withdrawals proposed by drilling companies in the Susquehanna River basin has the potential to impact summer and fall low flows, and in some cases, high-flow events (Q_{10}) in small streams.

Water withdrawals may also impact brook trout spawning activities and recruitment during higher flow periods (Figures 5 and 6). Brook trout peak spawning activity typically occurs at the beginning of November in gravel substrates immediately downstream from springs or in places where groundwater seepage enters through the gravel (Hazzard 1932). Withdrawals during the fall may dewater and reduce available spawning habitat, particularly during low-flow years. Additionally, stable base flows after spawning are necessary for maintaining redds during egg incubation throughout winter (Figure 6). Maintaining base flow in trout spawning habitats throughout the incubation period maintains shallow groundwater pathways, chemistry, and flow potentials in redds (Curry et al. 1994, 1995), which protect developing eggs from sedimentation (Waters 1995; Curry and MacNeill 2004) and freezing (Curry et al. 1995; J. S. Baxter and McPhail 1999). Thus, insuring that water withdrawals required for hydraulic fracturing do not interrupt stable winter base flows in small coldwater streams is an important consideration in protecting brook trout recruitment in the Marcellus Shale region (Figures 5 and 6).

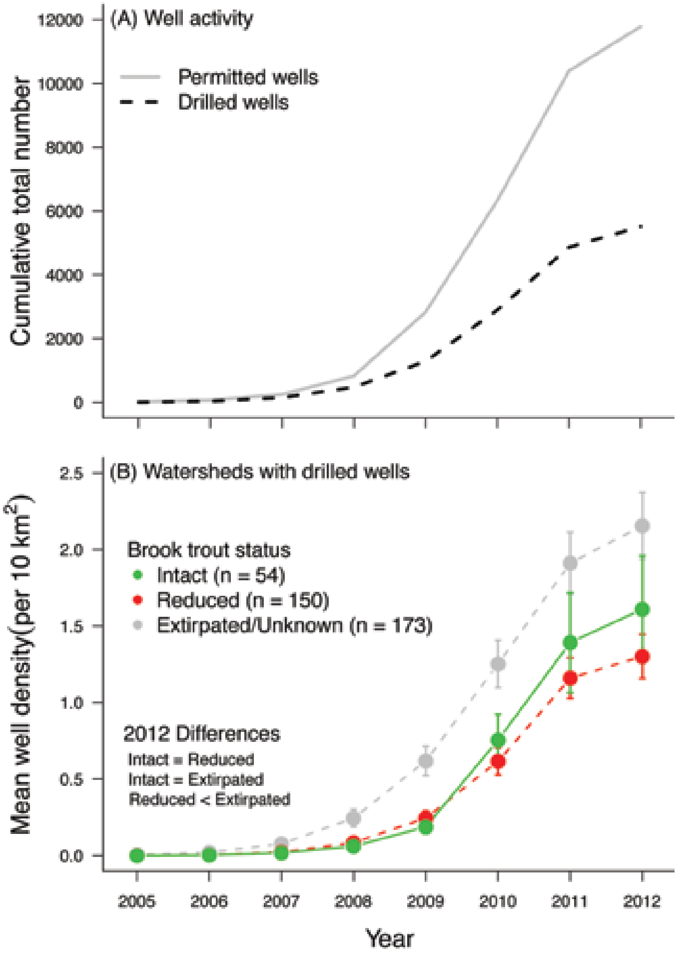

Figure 3. Well permitting and drilling in the Pennsylvania portion of Marcellus Shale from January 1, 2005, through May 31, 2012. (A) Cumulative number of permitted and drilled wells over time. (B) Mean well density (wells per 10 km^2) over time for 377 actively drilled HUC12 subwatersheds, grouped by status of brook trout population (Hudy et al. 2008). Permitted and drilled Marcellus well data are from PADEP (2012a, 2012b), respectively.

PATHWAY #2: INFRASTRUCTURE → PHYSICAL HABITAT → BROOK TROUT

Natural gas extraction requires development of well pad sites and infrastructure for transportation and gas conveyance, which involves a set of activities that will likely have impacts on water quality and habitat quality for brook trout unless proper precautions and planning are implemented. These activities

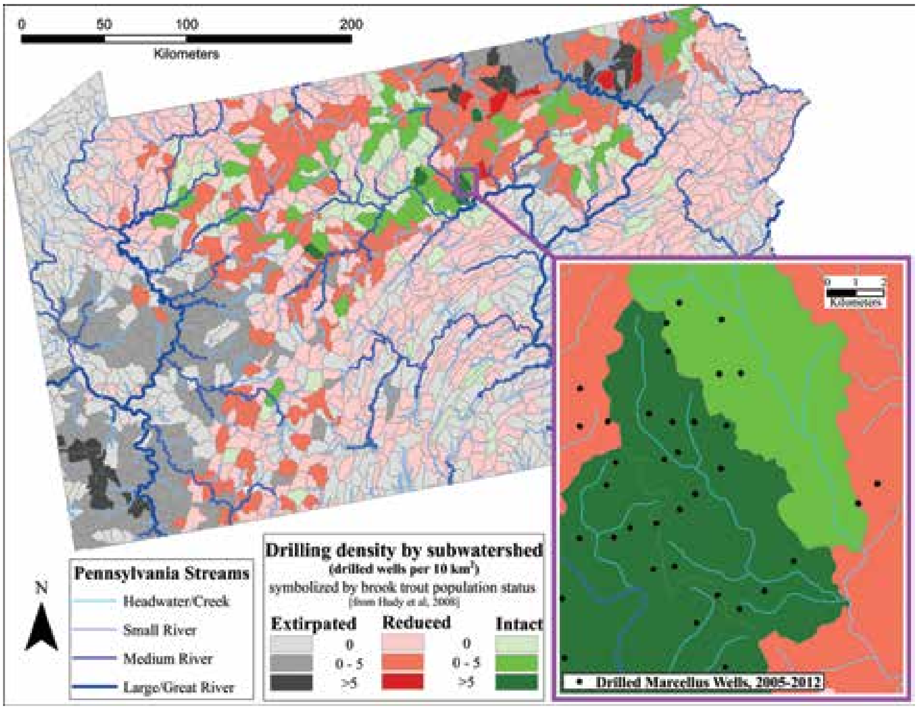

Figure 4. Density of wells drilled in the Pennsylvania portion of the Marcellus Shale by HUC12 subwatershed (well drilling locations from PADEP 2012b; 12-digit HUC subwatershed boundaries and areas from USGS Watershed Boundary Dataset; U.S. Department of Agriculture, Natural Resources Conservation Service 2012), symbolized by status of current brook trout population (Hudy et al. 2008). Inset: A subwatershed expected to support an intact brook trout population that currently has the second highest well density (15.1 wells/10 km2) of all drilled subwatersheds.

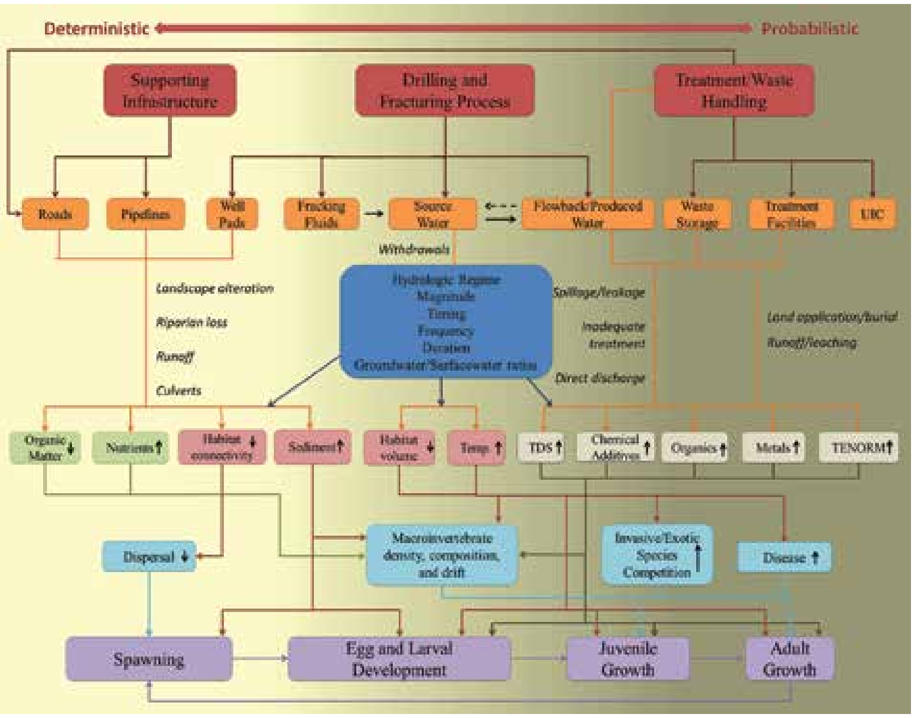

Figure 5. Conceptual model of relationships between hydraulic fracturing drilling activities and the life cycle of eastern brook trout (modified from conceptual models based on Entrekin et al. [2011] and Rahm and Riha [2012]).

include, but are not limited to, construction of well pads, roadways, stream crossings, and pipelines; increased use of existing rural roadways for transportation of equipment, source water, recycled flow-back, and wastes associated with hydraulic fracturing activities; and storage of these same materials (Figure 1). Increased sediment loads and loss of stream connectivity are some of the stream impacts associated with these deterministic activities, which could reduce habitat quality and quantity needed for brook trout spawning success, egg development, larval emergence, and juvenile and adult growth and survival (Figure 5).

Brook trout are particularly sensitive to the size and amount of sediment in streams, with coarse gravel providing a more suitable substrate than fine particles (Witzel and MacCrimmon 1983; Marschall and Crowder 1996). Well pad site, access road, and pipeline corridor construction require land clearing, which can mobilize from tens to hundreds of metric tons of soil per hectare (H. Williams et al. 2008; Adams et al. 2011). Pipeline construction (Reid et al. 2004) and unpaved rural roadways (Witmer et al. 2009) crossing streams can trigger additional sediment inputs to streams. Road and well pad densities have been found to be positively correlated with fine sediment accumulation in streams (Opperman et al. 2005; Entrekin et al. 2011), which disrupts fish reproduction and can lead to mortality (Taylor et al. 2006). Overall, trout populations have been found to decline in abundance, even with small increases in stream sediment loads (Alexander and Hansen 1983, 1986). Sediment can impact all stages of trout life cycles, because turbidity reduces foraging success for adults and juveniles (Sweka and Hartman 2001), and sediment accumulation can cause oxygen deprivation in salmonid redds and reduce successful emergence of larvae from eggs (Witzel and MacCrimmon 1983; Waters 1995; Argent and Flebbe 1999; Curry and MacNeill 2004; Figure 5).

The spatial and temporal extent of sediment impacts to streams is linked to the scale and persistence of mobilizing activities. For example, localized events, such as construction of culverts

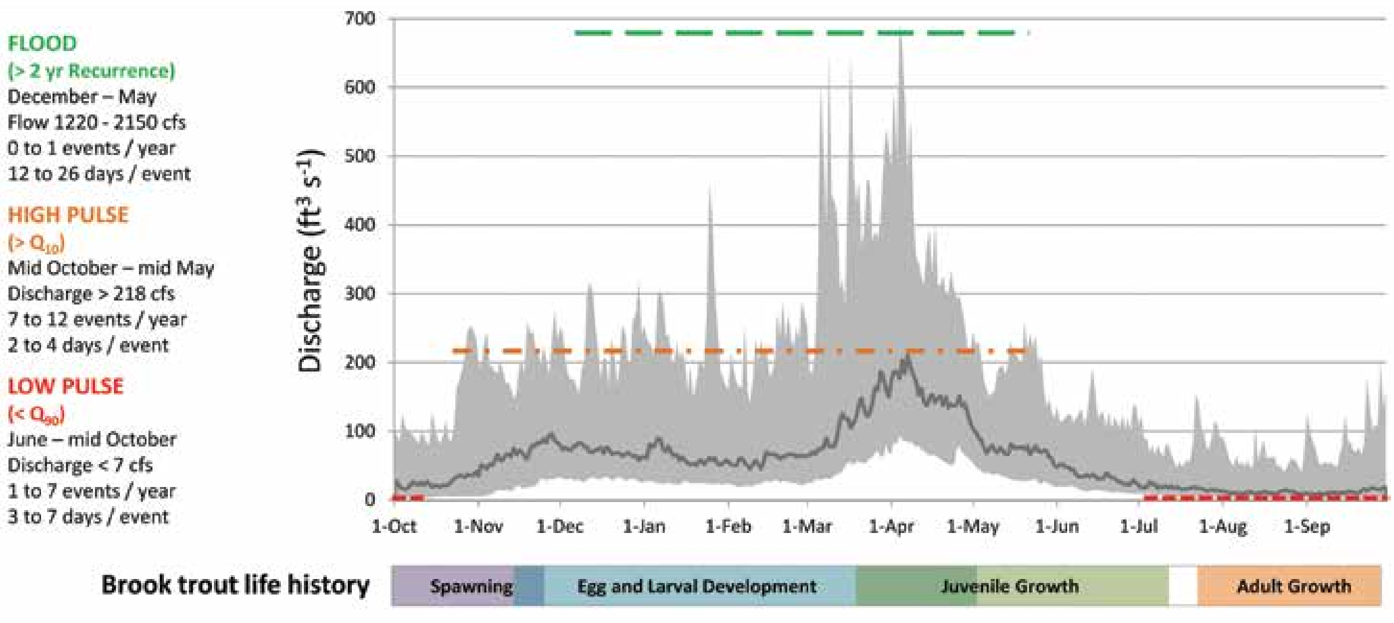

Figure 6. Hydrologic patterns for a trout supporting stream with relatively unaltered hydrology (Little Delaware River, USGS Gage 01422500, watershed area = 129 km2) in relation to timing of brook trout life history periods. Median (dark line), bounded by 10th and 90th percentile daily flows (grey) for 47 years of discharge data. Important flood, high-, and low-flow components were computed and described using Indicators of Hydrologic Alteration (The Nature Conservancy 2009).

at stream road crossings can increase sediment loads for up to 200 m downstream of the culvert over a 2- to 3-year period (Lachance et al. 2008). Conversely, the sediment loads associated with more diffuse land clearing activities and frequent and sustained access into rural areas by large vehicles can contribute to reductions in brook trout biomass and densities and shifts in macroinvertebrate communities that last approximately 10 years (VanDusen et al. 2005).

Sedimentation from drilling infrastructure development can further impact brook trout indirectly by reducing the availability of prey (Figure 5): high sediment levels reduce species richness and abundance of some aquatic macroinvertebrates (Waters 1995; Wohl and Carline 1996; VanDusen et al. 2005; Larsen et al. 2009), with high sediment environments generally experiencing a shift from communities rich in mayflies (Ephemoptera), stoneflies (Plectoptera), and caddisflies (Trichoptera) to those dominated by segmented worms (Oligochaeta) and burrowing midges (Diptera: Chironmidae; Waters 1995). Riparian clearing can also diminish food sources for brook trout populations, which tend to depend heavily on terrestrial macroinvertebrates (Allan 1981; Utz and Hartman 2007). However, shifts in the prey base from shredder-dominated communities that support higher brook trout abundance to grazer-dominated communities have been observed in recently logged watersheds due to higher primary productivity associated with increased sunlight from sparser canopy cover (Nislow and Lowe 2006). Consequently, land clearing and infrastructure development will likely increase sediment loads, culminating in changes in composition and productivity of the invertebrate prey base for brook trout, although not all of these changes will necessarily be negative for brook trout (Figure 5).

Conveyance of hydraulic fracturing equipment and fluids, and the extracted natural gas, into and out of well pad sites often necessitates crossing streams with trucks and pipelines. Culvert construction for roadway and pipeline stream crossings, if not properly designed, can create physical barriers that fragment brook trout habitat and disrupt their life cycle by preventing movement of adult fish into upstream tributaries for spawning and repopulation of downstream habitat by new juveniles (Wofford et al. 2005; Letcher et al. 2007; Poplar-Jeffers et al. 2009; Figure 5). Barriers to connectivity negatively impact fish species richness (Nislow et al. 2011), and habitat fragmentation without repopulation can cause local population extinction (Wofford et al. 2005; Letcher et al. 2007). Additionally, connectivity between larger stream reaches that provide food resources during growth periods and small headwater streams that may serve as temperature refugia during warmer months is important for overall population health (Utz and Hartman 2006; Petty et al. 2012). For these reasons, land clearing activities, road densities, and culvert densities can have a negative impact on trout reproductive activity and overall population size (Eaglin and Hubert 1993; C. V. Baxter et al. 1999).

PATHWAY #3: CHEMICAL WASTE → WATER QUALITY→ BROOK TROUT

Probabilistic events during the drilling process such as runoff from well pads, leaching of wastewater from holding ponds, or spills of hydraulic fracturing fluids during transportation to processing sites can affect the chemical composition of streams (Rahm and Riha 2012). Although the specific chemical composition of fracturing fluids is typically proprietary information, voluntary reporting of the content of fracturing fluids to the FracFocus Chemical Disclosure Registry (a partnership between the Ground Water Protection Council [GWPC] and Interstate Oil and Gas Compact Commission [IOGCC], supported the U.S. Department of Energy [USDOE]) has become more common (USDOE 2011). Fracturing fluids are generally a mix of water and sand, with a range of additives that perform particular roles in the fracturing process, including friction reducers, acids, biocides, corrosion inhibitors, iron controls, cross-linkers, breakers, pH-adjusting agents, scale inhibitors, gelling agents, and surfactants (GWPC and IOGCC 2012). The wastewater resulting from the hydraulic fracturing process is high in total dissolved solids (TDS), metals, technologically enhanced naturally occurring radioactive materials (TENORM), and fracturing fluid additives (U.S. Environmental Protection Agency [USEPA] 2012). Increased metals and elevated TDS from probabilistic spill events, or deterministic events including direct discharge of treated flow-back water into streams, will likely have negative effects on stream ecosystems that support brook trout populations (Figure 5).

Elevated concentration of metals causes decreased growth, fecundity, and survival in brook trout. In particular, aluminum has been shown to cause growth retardation and persistent mortality across life stages (Cleveland et al. 1991; Gagen et al. 1993; Baldigo et al. 2007), chromium reduces successful emergence of larvae and growth of juveniles (Benoit 1976), and cadmium can diminish reproductive success by causing death of adult trout prior to successful spawning (Benoit et al. 1976; Harper et al. 2008). Trout normally exhibit avoidance behaviors to escape stream reaches that are overly contaminated with heavy metals; however, because brook trout are so heavily reliant on low-temperature environs, they seek out refugia of cold groundwater outflow even if the water quality is prohibitively low (Harper et al. 2009). Thus, if groundwater is contaminated and the groundwater-fed portions of a stream are receiving a significant contaminant load, brook trout might be recipients of high concentrations of those contaminants.

Total dissolved solids represent an integrative measure of common ions or inorganic salts (sodium, potassium, calcium, magnesium, chloride, sulfate, and bicarbonate) that are common components of effluent in freshwaters (Chapman et al. 2000). Elevated TDS and salinity may have negative effects on spawning and recruitment of salmonids by decreasing egg fertilization rates and embryo water absorption, altering osmoregulation capacity, and increasing posthatch mortality (Shen and Leatherland 1978; Li et al. 1989; Morgan et al. 1992; Stekoll et al. 2009; Brix et al. 2010). There is also evidence from western U.S. lakes with increasing TDS concentrations that growth and survival of later life stages may be negatively impacted as well (Dickerson and Vinyard 1999). Elevated salinities can lower salmonid resistance to thermal stress (Craigie 1963; Vigg and Koch 1980), which may influence competition between brook trout and more tolerant brown trout (Öhlund et al. 2008). There is a growing body of evidence supporting associations between declines in macroinvertebrate abundance, particularly mayflies, and increased TDS or surrogate specific conductivity related to mining activities within the Marcellus Shale region (Kennedy et al. 2004; Hartman et al. 2005; Pond et al. 2008; Pond 2010; Bernhardt and Palmer 2011). Overall, changes in TDS associated with improper handling or discharge of flow-back water will likely impact brook trout through direct and indirect pathways including changes in macroinvertebrate communities that serve as the prey base and/or the alteration of environmental conditions to those more favorable for harmful invasive species (i.e., Golden algae; Renner 2009; Figure 5).

A FRAMEWORK FOR ADDRESSING RESEARCH NEEDS

Our examination of potential impacts of hydraulic fracturing for natural gas extraction in the Marcellus Shale on brook trout populations reveals three key pathways of influence: hydrological, physical, and chemical. These pathways originate from the various activities associated with the hydraulic fracturing method of natural gas extraction and may affect brook trout at one or more stages of their life cycle through direct and indirect mechanisms (Figure 5). The hydrological pathway is the broadest in that it is influenced by events at both the surface and groundwater levels and, subsequently, it influences brook trout both directly through flow regimes and indirectly by also influencing physical and chemical pathways. The primary drilling activity driving the hydrological pathway is the need for source water for the hydraulic fracturing process. The physical habitat pathway originates from the infrastructural requirements of the natural gas extraction industry, which can be expected to increase stream sedimentation and impede brook trout at all life phases. The consequences of infrastructural development further impact brook trout populations if road-building activities and poorly designed road-crossing culverts reduce connectivity between spawning areas, temperature refugia, and downstream habitats. Finally, the chemical pathway addresses the potential for contamination of streams by the hydraulic fracturing fluids and wastewater. This contamination can have direct consequences for brook trout and their food resources. The hydrological and physical pathways are expected to result from planned (deterministic) hydraulic fracturing activities, and the chemical pathway may be triggered by both unplanned spill and leak (probabilistic) events, as well as planned discharge of treated wastewater into streams or spreading of brines on roadways.

The delineation of these pathways identifies an array of immediate research priorities. The potential relationships identified in the conceptual model (Figure 5) provide a framework of empirical relationships between Marcellus Shale drilling activities, deterministic pathways, and brook trout populations that need to be tested and verified. There is currently variation in hydraulic fracturing density within the Marcellus Shale, ranging from extensive operations in Pennsylvania and West Virginia to a moratorium on the process in New York. Opportunities exist for researchers to develop studies that verify potential relationships between drilling activities and brook trout populations, such as examining sediment impacts and brook trout responses across watersheds representing a range of well densities (Entrekin et al. 2011) or over time in watersheds with increasing levels of drilling activity. Correlative studies should also be confirmed through experimental approaches that take advantage of paired watershed or before–after control-impact (Downes et al. 2002) designs. Tiered spatial analysis techniques can be used to assess the cumulative impacts of persistent drilling activity within nested drainage areas at a range of spatial scales (Bolstad and Swank 1997; MacDonald 2000; Strager et al. 2009). Additionally, risk assessment analyses based on biological endpoints are needed to characterize impacts of probabilistic events such as chemical spills and leaks (USEPA 1998; Karr and Chu 1997).

MOVING FROM RESEARCH TO MANAGEMENT AND CONSERVATION POLICY

Management of hydraulic fracturing activities in the Marcellus Shale is the responsibility of various permitting regulatory agencies with various scales of influence, including statewide (departments of environmental conservation/protection, departments of transportation, fish and game commissions, etc.) and regional (conservation districts, river basin commissions, etc.) entities. Though the individual policies are too numerous to describe in depth here, it is apparent that policies can be developed and refined with the support of research and monitoring programs that provide crucial data, such as a geographically finer scale understanding of brook trout distribution and population status, seasonal flow requirements for brook trout at their various life stages (Figure 6), identification and prioritization of high-quality habitat, and verification of the potential drilling impacts within the Marcellus Shale. These types of data are necessary for revising existing policies and developing new policies that are protective of brook trout populations and the stream ecosystems that support them in the face of increased Marcellus Shale drilling activities.

An example of science influencing policy that is protective of brook trout habitat is the current and proposed water withdrawal policies for the Susquehanna River Basin. The SRBC governs water withdrawal permitting for the Susquehanna River Basin region, and its policies have the potential to influence the degree to which hydrologic impacts of Marcellus Shale drilling may influence brook trout populations (SRBC 2002). The SRBC currently enforces minimum flow criteria for water withdrawals for hydraulic fracturing in coldwater trout streams to prevent low-flow impacts (Rahm and Riha 2012). The SRBC requires that water withdrawals must stop when stream flow at withdrawal sites falls below predetermined passby flows and cease until acceptable flow returns for 48 h. For small streams (<100 mile^2), passby flows are determined based on instream flow models (Denslinger et al. 1998) and are designed to prevent more than 5% to 15% change in trout habitat, depending on the amount of trout biomass the stream supports. A more general 25% average daily flow requirement is used as the passby flow for larger coldwater trout streams (SRBC 2002). This policy is expected to prevent water withdrawals from impacting habitats during low flows in summer. However, analyses of hypothetical withdrawals within the range of proposed water withdrawal permits suggest that water needs associated with Marcellus Shale drilling will impact seasonal flow needs (not just summer low flow) of small streams likely to support brook trout (DePhilip and Moberg 2010; Rahm and Riha 2012). Additionally, multiple upstream withdrawal events occurring on the same day within the same catchment may culminate in stream flows falling below the passby flow requirement. Though there is considerable uncertainty around water withdrawal estimates, accounting for cumulative withdrawal-induced low-flow effects can increase the number of days that are expected to fall below passby requirements for smaller streams by as much as approximately 100 days within an average year (Rahm and Riha 2012). Consequently, the SRBC has released new proposed low-flow protection regulations for public comment (SRBC 2012b, 2012c), based primarily on recommendations from a cooperative project between The Nature Conservancy, staff from the SRBC, and its member jurisdictions (DePhillip and Moberg 2010). The proposed SRBC flow policy uses a tiered approach to flow protection that prevents withdrawals or puts more stringent requirements in extremely sensitive or exceptional quality streams such as small headwater streams that support reproducing brook trout populations (SRBC 2012b, 2012c). This proposed policy would also provide significant flow protection for trout streams by incorporating seasonal or monthly flow variability into passby flow criteria rather than based on a single average daily flow criterion (Richter et al. 2011; Figure 6) and assessing proposed withdrawal impacts within the context of cumulative flow reductions associated with existing upstream withdrawals (Rahm and Riha 2012). However, the SRBC's proposed policy has received considerable critique from stakeholders, including the natural gas industry (SRBC 2012a). It is unclear what protections a revised water withdrawal policy will provide to streams that support brook trout habitat.

The SRBC policy is only one example of a regulatory body using scientific data to improve and refine a management policy that directly relates to potential drilling impacts on trout populations. It is crucial that policies governing hydraulic fracturing activities be likewise dynamic and subject to adaptation based on updated scientific knowledge. For example, the Pennsylvania *Oil and Gas Operators Manual* provides technical guidance for infrastructure development by identifying best management practices for sediment and erosion control and well pad, road, pipeline, and stream-crossing designs and delineates preventative waste-handling procedures to avoid unexpected probabilistic events like spills and runoff (PADEP 2001). These practices should be amended and updated as new studies refine methods to minimize impacts (e.g., Reid et al. 2004) and strategically protect or restore habitat quality or connectivity (e.g., Poplar-Jeffers et al. 2009). Furthermore, water quality data from monitoring efforts, like TU's Coldwater Conservation Corps (one of many stream survey programs that train and equip volunteers to conduct water quality testing in local streams; TU 2012) can alert regulatory agencies to failures in the probabilistic event prevention strategies that may help better characterize risks and improve waste transport and disposal procedures. For expansion of drilling in new areas, such as into New York State, regulatory agencies including the New York State Department of Environmental Conservation (NYSDEC), which is currently evaluating potential impacts of hydrologic fracturing activities and developing a corresponding set of proposed regulations (NYSDEC 2011), should utilize the most up-to-date and complete scientific data possible from active monitoring efforts to develop best management practices that are optimally protective of natural flow regimes, habitat conditions, and water quality in high-quality streams.

Spatial analysis and visualization of well density (Figure 4) can be combined with refined understanding of brook trout habitat and population status from stream surveys and ground-truthing to prioritize and geographically focus conservation efforts. Currently the Pennsylvania Fish and Boat Commission's Unassessed Waters Program in conjunction with Trout Unlimited and other partner organizations is conducting intensive assessments of streams with unknown brook trout status: to date, this program has identified an additional 99 streams that support wild populations (Weisberg 2011). Similar efforts are being spearheaded in New York by the NYSDEC and TU (2011). Furthermore, the efficacy of regulatory policy can be bolstered by data from monitoring and research efforts that define highest priority watersheds for conservation of brook trout. Various trout-focused organizations have identified key watersheds for protection and restoration. Trout Unlimited has updated their existing Conservation Success Index (J. E. Williams et al. 2007) with a targeted analysis for Pennsylvania to integrate new data on brook trout streams and natural gas drilling threats (TU 2011b). Likewise, the EBTJV has identified an extensive set of action strategies that identify priorities on a state-by-state basis (EBTJV 2011). Results from these types of analyses can be used to identify and direct conservation efforts to key areas where Marcellus Shale drilling activities are likely to have the greatest impacts by disturbing habitat for the highest quality remaining brook trout populations.

In summary, expedient efforts to develop strategies that minimize negative impacts of Marcellus Shale drilling activities on brook trout habitat are needed. Horizontal drilling and hydraulic fracturing for natural gas extraction is likely to increase and expand from Pennsylvania and West Virginia into unexploited areas with growing pressure related to economic incentives from the oil and gas industry and the need for cheap domestic energy sources. Natural gas drilling is expected to persist in the region for several decades due to the extent of the Marcellus Shale natural gas resource and the presence of the gas-rich Utica Shale below it (P. Williams 2008). Consequently, development of adequate management and conservation strategies based on science and enforcement of policies that conserve and protect stream ecosystems supporting brook trout populations and other aquatic organisms are needed to balance energy needs and economic incentives with environmental and brook trout conservation concerns.

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Adaptive Forgetting: Why Predator Recognition Training Might Not Enhance Poststocking Survival

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ABSTRACT: *The success of current fish restocking efforts is often hampered by poor poststocking survival of hatchery-reared juveniles. As a result of hatchery selection, combined with a lack of ecologically relevant experience, hatchery-reared fishes often fail to recognize and respond to potential predators following stocking into natural waterways. One commonly proposed method to enhance potential poststocking survival is to condition hatchery-reared fishes to recognize predators prior to stocking. However, despite a wealth of laboratory and field studies demonstrating predator recognition learning in fishes, only a handful of studies have attempted to assess potential poststocking benefits, and these suggest mixed results. Our goal is to highlight possible causes of this apparent contradiction. A survey of the behavioral ecology literature highlights the exceptional degree of sophistication of predator recognition learning among prey fishes. Moreover, an emerging body of literature suggests that how long prey retain learned predator recognition is as important as what prey learn. This highly plastic retention (memory window) may confer adaptive benefits under variable conditions. Hatchery selection may result in phenotypes leading to reduced learning and/or retention of learned information. We conclude by proposing several avenues of investigation aimed at improving the success of prestocking conditioning paradigms.*

Olvido adaptativo: por qué el entrenamiento para reconocer depredadores puede no incrementar la supervivencia después del repoblamiento

RESUMEN: El éxito de los esfuerzos de repoblamiento de peces suele disminuir debido a condiciones desfavorables para la supervivencia de juveniles, provenientes de cultivo, tras prácticas de repoblamiento. Como resultado de la selección en cultivo, en combinación con la falta de experiencia en temas de ecología, los peces de cultivo a veces fallan en reconocer y responder potenciales depredadores después de haber sido introducidos, con fines de repoblamiento, a cuerpos de agua. Un método comúnmente propuesto para aumentar la supervivencia post-repoblamiento es condicionar a los juveniles de peces cultivados a que reconozcan a sus depredadores antes de la translocación. Sin embargo, pese al buen equipamiento de los laboratorios y a los trabajos en campo que demuestran la capacidad de aprendizaje de los peces para reconocer depredadores, solo unos pocos estudios se han enfocado en evaluar los beneficios potenciales post-repoblamiento y dichos estudios muestran resultados encontrados. Nuestro objetivo es subrayar las posibles causas de esta aparente contradicción. Un sondeo bibliográfico acerca de ecología conductual destaca la extraordinaria sofisticación del proceso de aprendizaje en peces para reconocer a sus depredadores. No obstante, otra parte de la literatura reciente sugiere que el tiempo que los peces retienen el patrón de reconocimiento del depredador es igualmente importante que lo aprendido por el individuo. Esta retención altamente flexible (ventana de memoria) puede conferir beneficios adaptativos ante condiciones variables. La selección mediante el cultivo puede resultar en fenotipos caracterizados por una reducida capacidad y/o poca retención de la información aprendida. Concluimos proponiendo distintas líneas de investigación cuyo propósito es aumentar el éxito del acondicionamiento previo al repoblamiento.

Hatchery-reared (HR) fishes, especially salmonids, are routinely stocked into natural waterways as part of population enhancement, recovery programs, and conservation efforts (C. Brown and Laland 2001; Salvanes and Braithwaite 2006; Fraser 2008). These recovery programs, however, are often met with limited success. Though some studies have shown that HR fish have similar poststocking survival rates as do their wild counterparts (e.g., Johnson et al. 2010), many studies point toward reduced survival among HR populations (e.g., Olla et al. 1994; Shively et al. 1996; Salvanes and Braithwaite 2006). A reduced survival may be due, in part, to the maladaptive behavioral phenotypes of HR fish, compared to their wild counterparts (C. Brown and Day 2002; Fraser 2008; Fernö et al. 2011). A growing body of research shows that hatchery-rearing, even over a little as one to two generations, is sufficient to induce significant differences in foraging (Fernö et al. 2011), growth rates (Tymchuck et al. 2007), risk-taking behavioral tactics (Sundström et al. 2004), and predator avoidance behaviors (Shively et al. 1996; Houde et al. 2010; Jackson and Brown 2011) between HR salmonids and their wild counterparts. Such differences in behavioral phenotypes may lead to stocked fish having reduced growth rates, increased predation risk, and/or reduced fitness (Huntingford 2004; Fernö et al. 2011).

Maladaptive behavioral phenotypes may arise from one of two possible mechanisms or, more likely, a combination of the two. Initially, under hatchery conditions, juvenile HR fishes lack experience with natural foraging conditions, microhabitat variability, and predation threats (Olla et al. 1998; C. Brown and Day 2002; Fernö et al. 2011). As a result of the unnatural hatchery environment, juvenile HR fishes might suffer from a lack of opportunity to learn through direct or indirect experience (Fernö et al. 2011), resulting in poorly developed or context-inappropriate behavioral phenotypes (C. Brown and Day 2002). Secondly, behavioral differences between hatchery and wild populations may be the result of genetic divergence resulting from either inadvertent selection for traits that are beneficial under hatchery conditions or the relaxation of natural selection pressures under hatchery conditions (Huntingford 2004; Fraser 2008). Jackson and Brown (2011) directly tested this hypothesis under natural conditions with juvenile Atlantic salmon (Salmo salar) originating from the same population. They compared the predator avoidance behavior of wild-caught juvenile Atlantic salmon with that of the offspring of wild-caught parents (F_1) and the offspring of parents that had spent one full generation under hatchery conditions (F_2). Jackson and Brown (2011) found the strongest predator avoidance response to a standardized predation cue among wild-caught salmon and the weakest response among F_2 salmon. Curiously, the response of the F_1 group was intermediate, suggesting that both hatchery selection and a lack of ecologically relevant experience contribute to the maladaptive behavior patterns among HR salmon.

A commonly advocated solution in a wide range of taxonomically diverse prey populations reared under artificial conditions is "life skills training" (Suboski and Templeton 1989; G. E. Brown and Smith 1998; C. Brown and Laland 2001). The idea that HR fish can be taught to recognize potential predators prior to stocking is attractive because it could allow for increased poststocking survival. Such enhanced survival would reduce the costs associated with stocking programs and potentially increase the effectiveness of population recovery efforts (Salvanes and Braithwaite 2006). However, despite considerable effort to demonstrate learning under laboratory conditions (reviewed in G. E. Brown et al. 2011a), only a few studies have attempted to demonstrate the potential benefits of prestocking predator recognition training efforts on the poststocking survival of commercially important species. These studies have provided, at best, mixed results. For example, Berejikian et al. (1999) found that though Chinook salmon (*Oncorhynchus tshawytscha*) could be conditioned to avoid the odor of an ecologically relevant predator (adult cutthroat trout, *Oncorhynchus clarki*) under laboratory conditions, this did not result in enhanced poststocking survival. Likewise, Hawkins et al. (2007) conditioned 1+ Atlantic salmon (*Salmo salar*) to recognize northern pike (*Esox lucius*) as a potential predator. Conditioned salmon survived no better when stocked into lakes where pike were the dominant predator. Conversely, D'Anna et al. (2012) conditioned white seabream (*Diplodus sargus*) prior to release and found a near doubling of poststocking survival. Likewise, Hutchinson et al. (2012) demonstrated two- to fourfold increases in poststocking survival of juvenile Murray cod (*Maccullochella peelii*) but not for juvenile silver perch (*Bidyanus bidyanus*). Thus, we are left with the question of why this type of learning may not translate to enhanced survival.

Here, we provide an overview of recent work examining chemically mediated predator recognition mechanisms in aquatic prey species and highlight the incredible degree of sophistication involved in these learning mechanisms. In addition, we examine the poorly understood aspect of retention of learned information. Finally, we conclude with some potential avenues to address the question of why prestocking training might not work to increase poststocking survival. The extent to which hatchery effects (selection + differential experience) will impact the poststocking survival and learning ability of fishes clearly depends upon the holding and breeding practices employed within hatcheries. For example, Beckman et al. (1999) found that differences in prestocking growth rate of hatchery-reared Chinook salmon was related to the likelihood of stocked smolts returning as adults. Likewise, habitat enrichment within hatchery-rearing tanks is known to enhance natural foraging patterns, possibly increasing poststocking survival (Roberts et al. 2011). For simplicity, we refer to the dichotomy of hatchery-reared vs. wild-stock fishes within the context of predator-recognition learning. Our goal here is to bring to light recent advances in the study of ecologically relevant learning mechanisms and to bridge the gap between the behavioral ecological literature and possible fisheries applications.

THE SOPHISTICATION OF PREDATOR RECOGNITION LEARNING IN FISHES

Learning, in the broadest sense, can be defined as the ability to modify behavioral response patterns based on experience (G. E. Brown and Chivers 2005). The ability to reliably assess local predation threats allows prey (including juvenile salmonids) to balance the often conflicting demands of predator avoidance and a suite of behavioral activities such as foraging and territorial defense (Lima and Dill 1990; Kim et al. 2011). This is especially difficult under conditions of variable predation risk and/or foraging opportunity (Sih 1992; Dall et al. 2005). Learning to recognize potential predators allows prey to respond only to ecologically relevant threats and to avoid expending time and energy responding to irrelevant cues. In addition, learned recognition has been shown to increase survival during staged encounters with live predators (Mirza and Chivers 2000; Darwish et al. 2005; Vilhunen 2006). Thus, under conditions of variable predation risks, learning is argued to allow prey to optimize the trade-off between predator avoidance and other fitness-related activities (G. E. Brown and Chivers 2005; Dall et al. 2005; G. E. Brown et al. 2011a).

A large body of research has investigated the mechanisms of predator recognition learning in fishes (Ferrari et al. 2010a; G. E. Brown et al. 2011c). A well-documented mechanism of learning is the so-called chemically mediated learning. Damage-released chemical alarm cues are a common feature in freshwater and marine fishes (Ferrari et al. 2010c), which are released following mechanical damage incurred during an attack by a predator. Given the mechanism of release, these chemosensory cues are reliable indicators of predation threats (Chivers et al. 2007, 2012; Ferrari et al. 2010c). When released into the water column and detected by nearby conspecifics and/or heterospecifics, these cues may elicit dramatic, short-term increases in species-specific antipredator behavior (Ferrari et al. 2010c). Recent studies demonstrate that alarm cues convey a surprising amount of information regarding local predation threats. For example, the response intensity of many prey fishes appears to be proportional to the concentration of alarm cue detected (e.g., Dupuch et al. 2004; G. E. Brown et al. 2006, 2009). Similarly, detecting alarm cues at concentrations below that needed to elicit an observable antipredator response are known to increase the use of secondary cues (i.e., visual information; G. E. Brown et al. 2004).

When paired with the visual and/or chemical cues of a novel predator, these alarm cues can facilitate the learned recognition of a novel predator (G. E. Brown et al. 2011a). For example, when juvenile rainbow trout are presented with the paired stimuli of a conspecific alarm cue (innate unconditioned stimulus) and the odor of a novel predator (conditioned stimulus), the trout will exhibit a strong increase in predator avoidance toward the alarm cue. However, when later presented with the predator odor, the trout will increase predator avoidance, demonstrating a learned response to the previously novel predator cue (G. E. Brown and Smith 1998). Following a single conditioning trial, these learned responses may persist for several weeks (G. E. Brown and Smith 1998). Control trials, in which the predator odor is paired with distilled water, fail to elicit any evidence of learning (G. E. Brown and Smith 1998).

A wealth of studies has demonstrated that this type of direct learning is common among aquatic prey species (reviewed in G. E. Brown et al. 2011a). Recent studies have shown that juvenile Atlantic salmon are capable of such chemically mediated learning under fully natural conditions (Leduc et al. 2007). More impressive, however, is the exceptional degree of sophistication present in this learning system. For example, fathead minnows (*Pimephales promelas*) are capable of learning threat-sensitive responses (i.e., the intensity of the behavioral response is directly proportional to the level of risk; G. E. Brown et al. 2006) via this mechanism. When paired with a low concentration of alarm cue (hence low risk), prey will exhibit a similarly low-intensity response to pike odor. However, when the pike odor is paired with a high concentration of alarm cue (hence high risk), the minnows learn to exhibit a high-intensity response (Ferrari et al. 2005). Recent experiments with HR rainbow trout extend these findings, showing that when conditioned to recognize pumpkinseed (*Lepomis gibbosus*) as predation threats, trout can generalize the learned response to the odors of predators that are taxonomically related to pumpkinseed (i.e., longear sunfish, *Lepomis megalotis*) but not to those of more distantly related predators (i.e., yellow perch, *Perca flavescens*; Brown et al. 2011c). Finally, when glowlight tetras (*Hemigrammus erythrozonus*) are conditioned with a conspecific alarm cue paired with the combined odor of largemouth bass (*Micropterus salmoides*), convict cichlids (*Amatitlania nigrofasciata*), and common goldfish (*Carassius auratus*), they are capable of exhibiting increased antipredator behavior in response to individual predator odors but not the odor of a predator not included in the cocktail (yellow perch; Darwish et al. 2005). Moreover, this cocktail learning was shown to increase survival during staged encounters with live predators (Darwish et al. 2005).

Learned predator recognition may also occur via indirect learning mechanisms. Initially, predator recognition can be facilitated via the mechanism of social or observational learning. Social learning may occur when prey acquire the recognition of novel predator cues in the absence of any direct experience (Mathis et al. 1996); simply observing an experienced conspecific (or heterospecific) prey respond to a predator cue can provide sufficient information to allow learning to occur. Such social learning may allow for the rapid transmission of recognition of novel predator cues within populations (G. E. Brown et al. 1997) and has been employed under hatchery conditions to enhance the learning of context-appropriate foraging patterns (C. Brown et al. 2003; Rodewald et al. 2011). Secondly, predator diet cues may also facilitate learning. For example, fathead minnows exposed to northern pike fed a diet of minnows learn to recognize the visual cues of pike (i.e., will respond to the sight of the predator), whereas minnows exposed to pike fed an unknown diet do not respond to the sight of the pike (Mathis and Smith 1993). Likewise, the response of juvenile Arctic charr (*Salvelinus alpinus*) to predator odors is enhanced when the predators have been fed charr versus when they are food deprived (Vilhunen and Hirvonen 2003). Finally, age of individuals seems to influence their ability to learn novel predator recognition. For example, Hawkins et al. (2008) demonstrated that juvenile Atlantic salmon exhibit age-specific sensitivity to novel predator odors. Under laboratory conditions, 10- to 15-week posthatching salmon were more responsive to pike odor than were younger or older conspecifics. Moreover, 16- to 20-week posthatching salmon were better able to learn to recognize novel predator odors than were younger salmon. Hutchison et al. (2012), however, found that whereas Murray cod fingerlings can learn to recognize novel predators, subadults exhibited no evidence of learning. Combined, these findings suggest a critical ontogenetic constraint on the timing of predator recognition learning.

Together, these studies demonstrate that chemically mediated predator recognition learning is a highly sophisticated and complex mechanism allowing for an incredible degree of behavioral plasticity. Under conditions of uncertain predation threats, the ability to modify predator avoidance responses based on recent experience likely confers significant fitness advantages (Dall et al. 2005; G. E. Brown et al. 2011a). However, if learning is so critical to the survival of wild prey populations, why should prestocking conditioning not confer increased survival benefits? The answer to this question might lie in the emerging question of retention of learned information (i.e., memory).

RETENTION OF LEARNED INFORMATION

Though there is a very large body of literature demonstrating the learning abilities and ecological constraints on learning in prey organisms (reviewed in G. E. Brown and Chivers 2005; G. E. Brown et al. 2011a), surprisingly little is known about the retention of learned information. The retention of learned predator recognition varies widely among prey fishes (Ferrari et al. 2010a). For example, following a single conditioning event, HR rainbow trout conditioned to recognize a novel predator will retain a detectable response for up to 21 days (G. E. Brown and Smith 1998), though the intensity of the response wanes after approximately 10 days (Mirza and Chivers 2000). Conversely, after a single conditioning, fathead minnows retained their learned response to a novel predator cue for at least 2 months with little evidence of a decrease in response intensity (Chivers and Smith 1994). Similar studies have shown that learned foraging preferences also vary within and between populations (Mackney and Hughes 1995).

Recently, Ferrari et al. (2010a) proposed a model of "adaptive forgetting," suggesting that the retention (how long prey will exhibit an observable response) to learned information is flexible and dependent on the certainty of this information. Under natural conditions, prey must balance the need to detect and avoid predation threats and to maximize foraging and reproduction (Lima and Dill 1990). The ability to balance these trade-offs depends on the availability of accurate and reliable information regarding risk associated with potential predators (Dall et al. 2005). In turn, the reliability of learned information should impact the duration of its retention (Ferrari et al. 2010a). For example, prey may outgrow gape limits of potential predators, reducing the value of learned recognition. Exhibiting an increased predator avoidance response toward this previously learned cue would represent a cost in the form of lost energy intake. However, if the prey were still at risk to the predator, failure to respond might result in death.

Ferrari et al. (2010a) suggested a number of intrinsic (i.e., prey growth rate, behavioral tactics) and extrinsic (i.e., predictability of predation threats, predator risk level) factors that would be expected to influence the retention of learned information. This model is particularly relevant to the issue of prestocking predator recognition training because hatchery selection may influence the very factors that shape the retention of learned information. Next, we will discuss several relevant examples from our recent work.

RETENTION AND THE EFFECTS OF HATCHERY SELECTION

Personality and Retention

A growing body of literature demonstrates consistent behavioral tactics, often referred to as "shy" vs. "bold" phenotypes, in a wide range of fishes (including salmonids; Budaev and Brown 2011). Generally speaking, individuals with bold phenotypes are more likely to continue foraging under the risk of predation, return to foraging sooner following an attack from a predator, and spend more time away from shelter compared to shy conspecifics (Budaev and Brown 2011). According to the framework of adaptive forgetting (Ferrari et al. 2010a), we might expect bold individuals to retain learned predator recognition less effectively than shy conspecifics due to the reduced value placed on predator avoidance (Tymchuk et al. 2007). This is relevant to the prestocking paradigm, because hatchery-reared fish generally exhibit bolder behavioral tactics (i.e., brown trout, *Salmo trutta*; Sundström et al. 2004) and attenuated stress responses than do wild-caught conspecifics (Lepage et al. 2000), leading to potentially maladaptive behavior patterns.

Recently, we directly tested this prediction with HR juvenile rainbow trout. Juvenile trout were classified as shy vs. bold based on their latency to escape from an opaque chamber into a large test arena (a reliable method of assessing behavioral tactics; C. Brown et al. 2005; Wilson and McLaughlin 2007) and conditioned to recognize a novel predator cue (pumpkinseed odor). When tested for recognition of the conditioned cue 24 h later, there was no difference in the intensity of the learned antipredator response (Figure 1). However, when tested 9 days postconditioning, we found that bold trout no longer exhibited any evidence of retention of the learned response. Shy trout exhibited strong responses, similar to those of the day 2 testing (Figure 1). These data suggest that though it is possible to condition HR fish to recognize predators, they simply may not retain the information long enough to gain a functional benefit due to their bold behavioral phenotypes (G. E. Brown et al. in press).

Growth Rates and Retention

Another common trait within hatchery settings is increased growth rates associated with both the reliable availability of food and the relaxation of competitive pressures (C. Brown and Laland 2002; Saikkonen et al. 2011). Ferrari et al. (2010a) suggested that increased growth rates should reduce the rela-

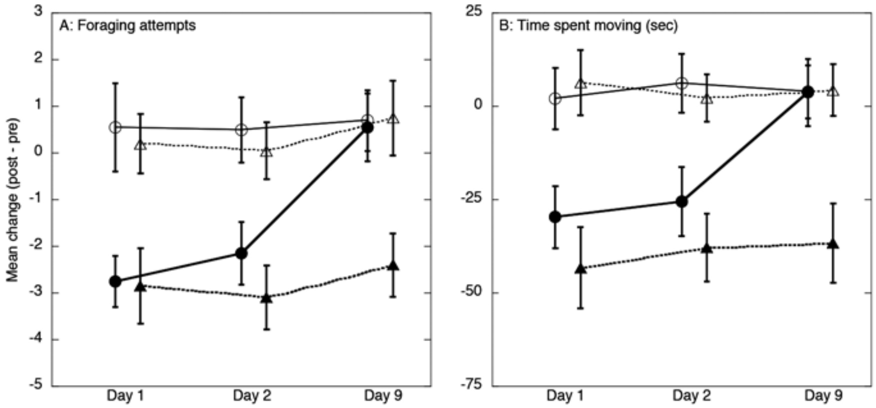

Figure 1. Mean (±SE) change in foraging attempts (A) and time moving (B) for shy (solid triangles) vs. bold (solid circles) rainbow trout conditioned to recognize pumpkinseed as a predation threat on day 1 and subsequently tested for recognition of pumpkinseed odor alone on day 2 and day 9. Shy phenotype trout exhibited significantly longer retention when compare to bold phenotype trout. Open symbols represent pseudoconditioned controls. Modified from G. E. Brown et al. (in press).

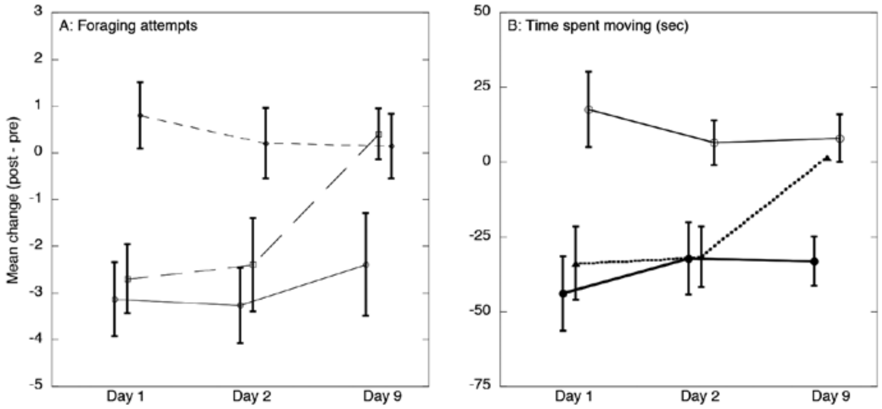

Figure 2. Mean (±SE) change in foraging attempts for juvenile rainbow trout conditioned to recognize pumpkinseed odor as a predation threat (circles) or pseudoconditioned (control; triangles) and subsequently exposed to pumpkinseed odor either 24 h postconditioning (day 2) or 8 days postconditioning (day 9). Panel A depicts results where groups of trout of similar initial mass were fed a high food (5% mbw day−1) or a low food (1% mbw day−1) ration the duration of the study. Panel B depicts results where trout of different initial masses were fed the same food ration (1% mbw day−1). Modified from G. E. Brown et al. (2011c).

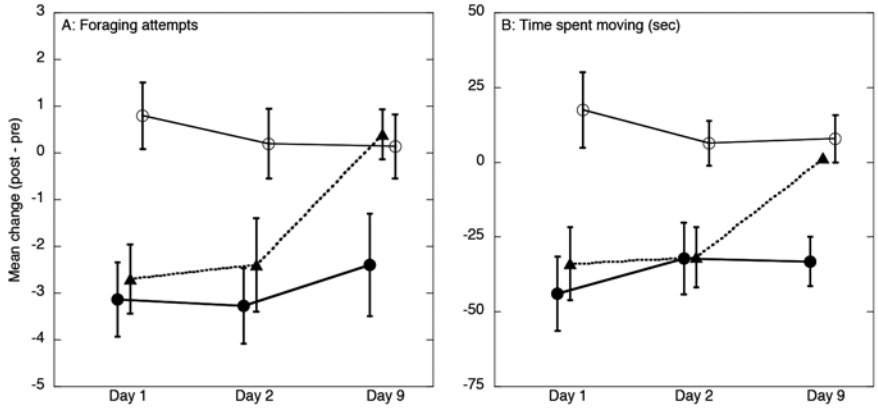

Figure 3. Mean (±SE) change in foraging attempts (A) and time moving (B) for juvenile rainbow trout conditioned with a high risk cue (circles), a low risk cue (triangles) or pseudoconditioned (squares) to recognize pumpkinseed odor as a predator cue. Modified from Ferrari et al. (2010b).

tive value of learned information. G. E. Brown et al. (2011b) tested this hypothesis under laboratory conditions with HR rainbow trout. Juvenile trout, matched for size, were reared on 1% or 5% mbw day^{-1} diets of standard trout chow for 7 days and then conditioned (or pseudoconditioned) to recognize a novel pumpkinseed predator. They were then either tested 24 h postconditioning (day 2) or held on the same 1% or 5% diet for an additional 8 days and then tested for recognition. The results suggest that though there was no difference in the intensity of the learned response between high and low food rations on day 2, only trout reared on the low food ration (low growth rate) showed any evidence of retention when tested on day 9. The observation that response intensity among conditioned trout on day 2 did not differ precludes the possibility that the observed differences on day 9 were due to hunger levels. Trout reared on the high growth rate ration were not different from pseudoconditioned controls (Figure 2A). These results were further supported by a companion study in which small (~0.6 g) and larger (~1.8 g) trout were fed the same 1% mbw day^{-1} rations and tested as above (Brown et al. 2011b). Despite a threefold difference in size, retention was similar between small and large trout (Figure 2B). Combined, these results demonstrate that growth rate at the time of conditioning influences the value of the learned information, leading to differential retention times.

Strength of Initial Conditioning

Several authors have shown that the strength of the initial conditioning event influences the overall intensity of learned predator recognition (Vilhunen and Hirvonen 2003; Ferrari et al. 2005; Zhao et al. 2006). For example, fathead minnows exhibit concentration dependent response intensities to conspecific alarm cues. Ferrari et al. (2005) found that the learned response to novel predator odors matched the intensity of the response during the initial conditioning event. More recently, Ferrari et al. (2010b) found that HR rainbow trout exhibited threat-sensitive retention of learned predator cues. Trout were conditioned to a high or low concentration of conspecific alarm cues (simulating high- vs. low-risk conditions) paired with the odor of pumpkinseeds (or pseudoconditioned) and tested for recognition. When tested for recognition 24 h postconditioning, they found that conditioned trout exhibited learned responses toward the predator cue but the intensity of response did not differ between those conditioned to high vs. low risk cues. However, when tested 8 days postconditioning, those initially exposed to the low risk cue did not retain the learned response (Figure 3).

Ontogenetic Constraints on Learning

Thought it has not been directly tested, it is possible that ontogenetic stage may also play an important role in the retention of learned predator recognition. As mentioned above, Hawkins et al. (2008) and Hutchison et al. (2012) have demonstrated age-specific propensities for chemically mediated learning in juvenile Atlantic salmon and Murray cod. Moreover, as salmonids undergo smoltification, they incur considerable physiological stress (Järvi 1990). This, combined with increased standard metabolic rates in smolts vs. nonsmolting conspecifics (Seppänen et al. 2010), might lead to a reduction in the value of learned predator recognition in favor of increased foraging demands. Several studies (Damsgård and Arnesen 1998; Skilbrei and Hansen 2004) showed a short-term reduction in growth rate and foraging during the smoltification phase but this is typically followed by an extended period of rapid growth. Such a shift in the value of predator avoidance vs. foraging benefits could lead to a reduction in retention (Ferrari et al. 2010a, 2010b).

However, size (ontogeny) has been shown to significantly influence risk-taking tactics in juvenile coho salmon (*Onchorhynchus kisutch*). Reinhardt and Healey (1999) compared the latency to resume foraging (as a measure of antipredator response intensity) among small (~1.5 g) vs. large (~3.5 g) coho salmon reared on similar food rations. Given that maximum potential growth rate is size dependent, larger fish will be capable of realizing a higher percentage of potential growth compared to smaller conspecifics during peak growing seasons (Reinhardt and Healey 1999). Reinhardt and Healey (1999) found that among the small-sized cohort, prior growth rate had a significant positive relationship with the latency to resume foraging following exposure to a standardized predation threat, suggesting that those with lower realized potential growth were more willing to accept increased risk in order to continue foraging in accordance with the asset protection model (Clark 1994). However, they found no effect of prior growth on the risk-taking tactics of the larger cohort. According to Ferrari et al. (2010c), prey that are more willing to accept risk in order to continue foraging (i.e., bold) should show reduced retention periods compared to more risk averse individuals. Thus, potential for growth influencing risk-taking tactics (asset protection) rather than actual growth (G. E. Brown et al. 2011b) may also shape retention.

Photo 1. Behavioral observations of juvenile Atlantic salmon in the Catamaran Brook, New Brunswick. The orange markers (upper left) indicate foraging territories of individual salmon. Photo Credit: G. E. Brown.

Photo 2. Mesh enclosures anchored in the Catamaran Brook, New Brunswick. Enclosures can be stocked with tagged salmon and allow for long-term studies of behavior under natural conditions. Photo Credit: C. K. Elvidge.

Implications for Prestocking Conditioning

Taken together, we see that the mechanism of chemically mediated predator recognition learning is an incredibly complex and sophisticated system, allowing for the acquisition of complex, context-specific behavioral response patterns within a wide variety of aquatic prey species. Moreover, an emerging field of research suggests that the question of how long to retain learned information is just as important to prey species as is the question of what to learn. Clearly, both learning and retention are highly plastic processes, shaped by environmental variability. If predator recognition learning is to result in increased poststocking survival, as suggested by a variety of authors (Suboski and Templeton 1989; C. Brown and Laland 2001; Fernö et al. 2011), we should revisit the design of prestocking conditioning paradigms in light of the results presented above. Next, we suggest a number of possible avenues for future studies. Many of the topics discussed below have previously been considered in the context of hatchery practices with an aim to enhance growth, quality, and survival, as well as the effectiveness of hatchery practices as a conservation tool (i.e., Sharma et al. 2005; Paquet et al. 2011). Thus, we limit our discussion to the relevance toward life skills training. Any findings must be considered in light of current best practices within the hatchery setting.

POSSIBLE AVENUES FOR FUTURE RESEARCH

One possibility to overcome this potential retention issue associated with prestocking conditioning would be to increase the strength of the initial conditioning event. Increasing the number of conditioning events may strengthen the initial learning and hence extend the retention of prestocking conditioning. Vilhunen (2006) found that HR Arctic charr exposed to four sequential conditioning events exhibited stronger learned responses than those conditioned a single time. Moreover, multiple conditioning events enhanced survival during staged encounters with predators. Typically, prestocking training studies have actively conditioned HR salmonids once or twice. It is possible that multiple conditioning events would extend the duration of retention, allowing for increased poststocking benefits. Likewise, based on the findings of Ferrari et al. (2010a), increased concentrations of alarm cues, indicating higher risks, should increase the strength of the initial conditioning. A recent study by Ferrari et al. (2012) demonstrated that woodfrog tadpoles (*Rana sylvatica*) that have been conditioned to recognize a novel predator odor four times retained their learned response longer than those conditioned once. This could combine with the potential benefits of social learning (C. Brown et al. 2003; Vilhunen et al. 2005).

A potential difficulty associated with repeated conditioning might be that HR fish may habituate to the predator odor. Though Vilhunen (2006) found that repeated conditionings enhanced the strength of learning, Berejikian et al. (2003) suggested that HR Chinook salmon may habituate to repeated exposures to the predator odor. There are, however, several differences between these two studies, the most relevant of which include the fact that Berijikian et al. (2003) tested Chinook salmon that were roughly twice the size as the Arctic charr tested by Vilhunen (2006). The observed differences could be related to species-specific differences in learning abilities or ontogenetic effects. Additional work is needed to examine the potential limitations associated with habituation.

A second potential avenue would be to reduce the latency between conditioning and stocking. In-stream or near-shore enclosures could be used to hold stocked fish prior to release. Such enclosures would expose HR salmonids to natural flow and drift regimes and would allow for acclimation prior to release. Large groups could then be conditioned and released. Recent work by Olson et al. (2012) suggested that mass conditioning may allow for the effective prestocking conditioning of HR fishes. Enclosure conditioning could also take advantage of potential social learning (C. Brown et al. 2003; Vilhunen et al. 2005; D'Anna et al. 2012). Vihunen et al. (2005) demonstrated that the effectiveness of social predator recognition learning is greatest when a relatively small number of experienced prey are housed with naïve prey.

Third, as described above, growth rate at the time of conditioning appears to influence retention of acquired predator recognition in at least one HR salmonid. Studies are needed to determine the potential effectiveness of placing HR salmonids on a restricted food ration prior to stocking. For example, HR stocks fed with on-demand feeders could be switched to fixed-ration feeders. Limiting the available foraging opportunities for a short time frame (a few days) may have an impact on retention without increasing stress or competition among stock populations (Ashley 2007).

Fourth, a limited number of studies examining the potential benefits of prestocking conditioning on postrelease survival have been conducted on smolts. Additional studies focused on presmolt life history stages are needed. Though it is clear that under laboratory conditions, smolts can indeed acquire recognition of novel predators (i.e., Berejikian et al. 1999), the increased physiological stress associated with smoltification and migration (Järvi 1990) may function to reduce the value of learned information. It is possible that young-of-the-year fry would exhibit longer retention periods, allowing for potential poststocking survival benefits.

Fifth, as mentioned earlier, HR fish may exhibit maladaptive or poorly developed foraging behavior in addition to impaired predator recognition. Several authors (i.e., Brown and Laland 2002; Rodewald et al. 2011) have successfully employed social learning and/or environmental enrichment to encourage context-appropriate foraging behavior in HR fishes prior to stocking. Under natural conditions, prey must balance the need to forage and avoid predators (Lima and Dill 1990). As such, there is a strong interaction between the two suites of behaviors. Combining context-appropriate foraging and predator recognition into an overall life skills training approach (C. Brown and Laland 2001) may further enhance the poststocking survival of HR fishes. In addition, as described above, prey can be conditioned to recognize multiple predators simultaneously (i.e., Darwish et al. 2005) and can generalize learned recognition across predators (i.e., G. E. Brown et al. 2011c). Learning multiple predators' cues at the same time or generalizing across ecologically relevant predators would further increase the ability of HR fishes to balance foraging—predator-avoidance tradeoffs—and may enhance poststocking survival.

The final issue that needs careful consideration is the habitat characteristics of both the conditioning environment and the place where the fish are to be released. Interactions between habitat characteristic and learning are at their infancy, but there are a few noteworthy studies that should provide us with issues to consider. For example, Gazdewich and Chivers (2002) conditioned minnows to recognize yellow perch as a predator and then staged encounters in two different habitat types. There was a clear effect of the predator training on prey survival, but this was only evident when the encounters were staged in one habitat type. Considering the pre- and postconditioning environment may be crucial for the success of training programs. In another study, Smith et al. (2008) conditioned rainbow trout to recognize a novel predator odor at either pH 6.0 or 7.0. A week later, the fish that were tested for recognition of the odor at the pH used during conditioning displayed antipredator responses, whereas those tested at the other pH did not. This study points to the need to consider the water quality parameters of the water body in which the fish are released. A simple change in pH may render learning ineffective and the training programs a waste of valuable resources.

Taken together, the research described in our review suggests that more research is needed to investigate the potential benefits associated with prestocking predator recognition training. The behavioral ecology literature suggests that learning is an adaptive phenotype that confers significant benefits under conditions of variable predation risk. Moreover, this literature suggests that the question of how long learned information is retained is equally as important as what information is learned.

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W.F. Thompson Award for Best Student Paper Published in 2011

Nominations are open for the W.F. Thompson Award, which will be given by the American Institute of Fishery Research Biologists (AIFRB) to recognize the best student paper in fisheries science published during 2011. The award will consist of a check for $1000, a certificate, and a one-year membership in AIFRB at an appropriate level. The requirements for eligibility are as follows:

(1) the paper must be based on research performed while the student was a candidate for a Bachelor's, Master's, or Ph.D degree at a college or university in the Western Hemisphere;

(2) the results of the research must have been submitted to the recognized scientific journal in which it was eventually published, or to the editor of the book in which it was eventually published, within three (3) years of termination of student status;

(3) papers that are considered for the award must be concerned with freshwater or marine biological resources;

(4) the paper must be in English; and

(5) the student must be the senior author of the paper.

Nominations may be submitted by professors or other mentors, associates of the students, or by the students themselves.

The deadline for receipt of nominations is January 31, 2013. The nominations should be sent to the Chairman of the W.F. Thompson Award Committee, Dr. Frank M. Panek, USGS-Leetown Science Center, 11649 Leetown Rd, Kearneysville, WV 25430 (email: fpanek@usgs.gov).

Each nomination must be accompanied by a copy of the paper (unless it is easily available on the internet) and a résumé.

The papers will be judged by knowledgeable subject matter reviewers selected by the Chairman and members of the Committee on the basis of contribution to fisheries science, originality, and presentation.

The National Ecological Observatory Network: An Observatory Poised to Expand Spatiotemporal Scales of Inquiry in Aquatic and Fisheries Science

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ABSTRACT: *Large spatiotemporal-scale fisheries research amid pervasive environmental change requires scientific resources beyond the capabilities of individual laboratories. Here we introduce the aquatics program within a novel institution, the National Ecological Observatory Network (NEON), poised to substantially advance spatiotemporal scales of inquiry in fisheries research. NEON will collect high-quality data from sites distributed throughout the United States, including Alaska, Hawaii, and Puerto Rico, for 30 years. Data products will include hundreds of metrics that comprehensively quantify the biological, chemical, and hydrogeomorphic attributes of streams, lakes, and rivers in the observatory network. Coupling observations from NEON terrestrial, atmospheric, and airborne programs will facilitate unique inquiries in ecohydrology. All NEON-generated data will be rigorously quality controlled and posted to an entirely open-access web portal. Proposals that expand the observatory scope through additional observations, sites, or experiments are encouraged. Thus, NEON represents an unprecedented and dynamic resource for fisheries researchers in the coming decades.*

La red del Observatorio Ecológico Nacional: un sistema listo para expandir la escala espacio-temporal de la investigación en la ciencia acuática y pesquera

RESUMEN: La investigación pesquera en grandes escalas espacio-temporales, dentro de un ambiente cambiante, requiere de recursos científicos que van más allá de las capacidades de laboratorios individuales. En la presente contribución se introduce el programa “aquatics” concebido en el seno de una institución de reciente formación, el Observatorio Ecológico Nacional (NEON) que fue diseñado para mejorar de forma sustancial la escala de investigación espacio-temporal de las ciencias pesqueras. NEON recolectará datos de alta calidad, dentro de un periodo de 30 años, de distintos sitios distribuidos a lo largo de los Estados Unidos de Norteamérica, incluyendo Alaska, Hawái y Puerto Rico. Los datos incluirán cientos de medidas que cuantifican los atributos biológicos, químicos e hidrogeomorfológicos de arroyos, lagos y ríos que abarca el observatorio. El acoplamiento de observaciones de los programas terrestres, atmosféricos y aéreos de NEON facilitará la investigación eco-hidrológica. Todos los datos generados por NEON pasarán por un riguroso control de calidad y serán puestos a disposición del público en general en un portal de internet. Se exhortan aquellas propuestas que, a través de la adición de observaciones, sitios o experimentos, estén encaminadas a expandir el ámbito del observatorio. Así, NEON representa un recurso, dinámico y sin precedentes, para los investigadores pesqueros en las próximas décadas.

INTRODUCTION

Understanding the multiscaled spatial and temporal processes that structure aquatic ecosystems is a fundamental challenge in fisheries management and conservation. For example, the suite of physical controls that shape habitat templates in rivers operate with observable signatures spanning approximately 15 orders of magnitude across time and space (Minshall 1988), whereas processes occurring among and within interacting populations of organisms exhibit an arguably equivalent degree of spatiotemporal heterogeneity (Fausch et al. 2002). Complicating matters further, freshwater and terrestrial ecosystems are inexorably linked through nutrient (Marcarelli et al. 2011), prey (Wipfli and Baxter 2010), and water subsidies also operating at variable spatiotemporal scales. Finite resources inevitably limit the spatial and temporal extent of virtually all ecological studies, resulting in a high likelihood of overlooking or mischaracterizing important patterns and processes (Cooper et al. 1998). Such knowledge gaps inevitably lead to uncertainties when developing science-informed management decisions.

Applying broad-scale spatiotemporal data often proves to be an effective means of addressing such challenges. For instance, long-term data sets from widely distributed locations have been recently used to highlight greater than expected phenological responses of plants to climate change (Wolkovich et al. 2012), demonstrate spatially pervasive trends of rising water temperatures in streams and rivers (Kaushal et al. 2010), and evaluate the current status of marine fisheries on a global spatial scale (Worm et al. 2009). Yet the information resources that led to such findings represent the exception in ecology, with the majority of collected data within the field remaining proprietary and inaccessible despite the clear need for openness in such a collaborative, interdisciplinary science (Reichman et al. 2011). Furthermore, even when data are freely available, poorly documented metadata, incomplete provenance, and/or inconsistent methodology can render comparability among locations or across time spans impossible (Peters 2010).

Fortunately, several recently initiated large-scale environmental observatories will soon expand scales of inquiry in disciplines with ties to fisheries science for all researchers. Such networks aim to freely provide multidecadal data records collected using standardized methodology to allow trend comparisons among widely dispersed sites. For instance, the National Science Foundation (NSF)-supported Ocean Observatory Initiative will begin publishing 25 years worth of open-access multivariate oceanographic data from a network of deepwater and coastal arrays dispersed throughout the western hemisphere starting in 2015 (Cowles et al. 2010). Another NSF-funded initiative, the Critical Zone Observatory (CZO; http://www.criticalzone.org), freely publishes hydrologic, chemical, and physical data from the vadose zones of seven locations throughout the United States and Puerto Rico (Anderson et al. 2008; Lin et al. 2011). Lake ecologists may access an unprecedented catalog of information amassed by the Global Lake Ecological Observatory Network (GLEON; gleon.org), a grassroots network of scientists integrating scalable environmental data from lakes around the world (Hanson 2008; Kratz et al. 2006).

Here we introduce an observatory poised to become a valuable resource for fisheries scientists: the National Ecological Observatory Network (NEON). The observatory is an NSF-funded project currently being constructed by an independent 501(3)(c) nonprofit corporation (NEON, Inc.; headquartered in Boulder, Colorado). The explicit mission of NEON is to enable continental-scale ecological forecasting (i.e., identifying broad-scale patterns across North America and using these to help predict future trends) by providing infrastructure and high-quality, standardized data collected throughout the United States, including Alaska, Hawaii, and Puerto Rico. Specifically, NEON was explicitly designed to address Grand Challenge questions in the environmental sciences put forth by the National Research Council (NRC 2001). NEON-generated data are thus strategically intended to provide standardized observations and experimental data to increase understanding of how (1) climate change, (2) land use change, and (3) invasive species interact to impact (1) biogeochemical cycles, (2) biodiversity, (3) ecohydrological processes, and (4) the spread of infectious diseases (Figure 1; NEON 2011).

During the scheduled 30 years of operation, NEON will archive and provide open access to more than 600 data products. Parameters will range from standard descriptive field measurements, such as indicators of water quality (e.g., NO_3 concentrations, total organic matter, and acid neutralizing capacity) to complex metrics derived from multiple variables (e.g., stream metabolism, fish biodiversity, NO_3 flux). Each measurement will be subjected to a rigorous quality assurance/quality control check. All observatory-generated data will be posted to an open-access web portal for research community and general public use. NEON will operate in 60 sites distributed among 20 ecoclimatic domains selected to maximize objective representation of

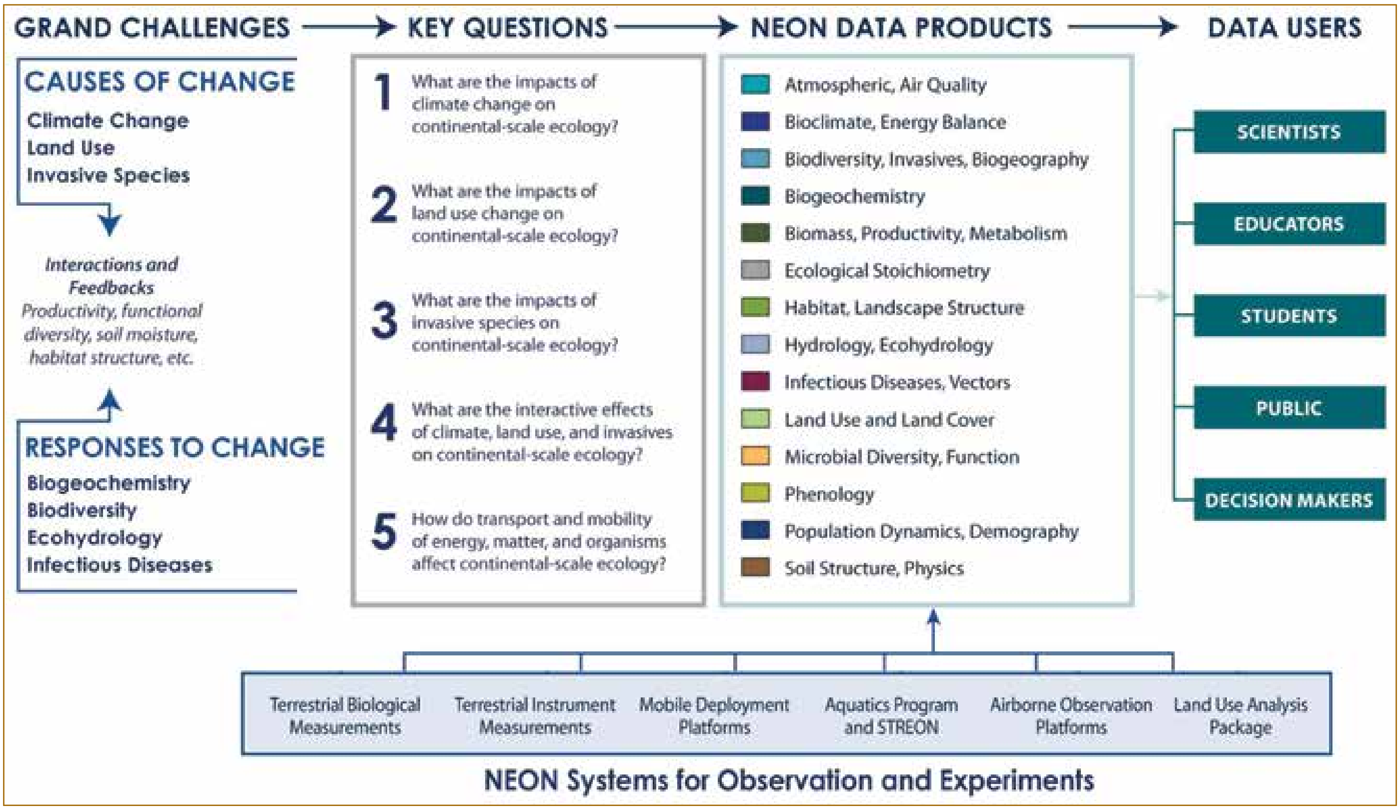

Figure 1. The theoretical basis of the NEON observatory. National Resource Council (NRC) Grand Challenges in environmental sciences have alluded to key questions that NEON data products are meant to help multiple communities address.

continental-scale environmental variability (Keller et al. 2008). The observatory is also a platform upon which researchers identifying an impetus for additional data or seeking to use NEON infrastructure for novel experiments are encouraged to apply for external funding to support their work.

Within NEON, an Aquatic Program will implement a sampling regime for 212 data products from 36 wadable streams, nonwadable rivers, and lakes throughout the United States. The Aquatic Program within NEON aims to address NRC-posited Grand Challenges in aquatic ecosystems with the exception of infectious disease dynamics. Aquatic data will include quantitative metrics characterizing diversity among multiple biological assemblages (fish, invertebrates, macrophytes, algae, and periphyton) and comprehensive biogeochemical, hydrologic, and geomorphic data. The following sections provide an overview of the data products to be derived by the NEON Aquatic Program and how they stand to benefit fisheries scientists. Because of the number of parameters to be collected, a comprehensive description of all planned data products would reach beyond the scope of this article. However, a full, descriptive list of planned data products may be freely accessed online (Keller 2010; Keller et al. 2010).

BIOLOGICAL DATA

Providing comprehensive data that enable the detection of long-term trends in biological assemblages among North American ecosystems represents a fundamental NEON goal. Data products derived from NEON biological collections in aquatic sites will include the diversity, richness, relative abundance, and spatial distribution of microbes, algae, aquatic plants, macroinvertebrates, and fishes. Individual weights and lengths of fishes will also be quantified, with the exception of sensitive species or populations that prohibit such handling. NEON field crews will collect microbial biofilm, algal, and benthic macroinvertebrate community samples two to three times per year and fish sampling will occur once per year in streams and lakes. Zooplankton samples will also be collected in all lakes. Sampling regimes for fish will consist of electrofishing, gill netting, and/or minnow traps depending on site characteristics. During the 30-year period of NEON operations, special attention will be paid to invasive species and data will denote when organisms are not native. Riparian vegetation surveys will be undertaken at each site once per year during peak leaf out. Finally, phenologically important dates associated with riparian vegetation (leaf out, fall, and senescence) that dictate patterns in evapotranspiration and associated trends in stream hydrology will be recorded at each site.

In addition to biological data collected using conventional methodology, NEON will help advance molecular techniques that catalog species and improve biomonitoring efforts. NEON will work with existing partners, including the United States Environmental Protection Agency and Barcode of Life Datasystems, to develop novel DNA barcode databases (Hajibabaei et al. 2007) for select aquatic and terrestrial taxonomic groups that are morphologically difficult to distinguish and speciose. In aquatic ecosystems, a subset of benthic macroinvertebrates will be targeted for DNA barcoding. Though the initial target aquatic taxa for DNA barcoding has yet to be determined, the group will likely possess difficult taxonomic attributes, a ubiquitous distribution and significant potential for biomonitoring applications, such as nonbiting midges (Chironomidae; Raunio et al. 2011).

CHEMICAL AND BIOGEOCHEMICAL DATA

Water quality in aquatic ecosystems is strongly integrated with surrounding terrestrial and atmospheric environments through multiple spatiotemporally heterogeneous processes (Williamson et al. 2008). Such relationships influence fish habitat, water quality, and ecosystem services, though fish may simultaneously shape water chemistry through nutrient transport, via ecosystem engineering (Moore 2006), and by creating biogeochemical hotspots (McIntyre et al. 2008). NEON will provide continuous and discrete chemical data of surface water (up to 35 parameters) at aquatic sites via in situ sensors and water samples collected up to 26 times per year. At lake sites, NEON water chemistry samples will span locations across lake surfaces and at multiple depths to quantify epilimnetic and hypolimnetic processes. These observations will help to define the seasonality of chemical parameters such as total and dissolved nutrients, cations, and anions. Isotopic ratios (i.e., δN^{15}, O^{18}, S^{34}, and C^{13}) in detritus, surface and subsurface water, particulate organic matter, and primary producer samples will also be collected to structure food webs and quantify links between chemical and biological processes and among environments. Because benthic zone sediments act as source, sink, or transformation centers of biogeochemical cycles, NEON will quantify sediment chemistry (up to 23 parameters including dissolved nutrients, cations, and anions) at least annually at all aquatic sites. Complementary metrics pertaining to grain size and structure will help determine sorption and oxygen depletion potentials. At sites where the likelihood of metal contamination is considered significant, NEON will measure sediment and water column metal concentrations. In addition to data derived from grab samples, continuous monitoring sensors will measure parameters such as turbidity, pH, conductivity, dissolved oxygen, temperature, and select nutrients, providing valuable real-time information on the chemical dynamics that affect aquatic organisms.

Aquatic chemistry parameters will also include in-house calculations of high-order biogeochemical metrics. NEON will produce measurements of whole-stream metabolism in wadable streams, which is a key indicator of processes that couple aquatic, terrestrial and atmospheric environments (Carpenter et al. 2005). Changes in land use and subsequent nutrient export from surrounding ecosystems can influence metabolism in receiving waters, ultimately impacting primary production and biological oxygen demand (Mulholland et al. 2001). In some cases, excessive nutrient inputs elevate primary productivity to rates that induce eutrophication, oxygen depletion, and fish kills (Dybas 2005). Given the value of metabolism as an integrator of environmental change, NEON will continuously quantify metabolism in wadable stream sites using a two-stage oxygen-depletion method. Associated data products will include relationships between discharge and stream reaeration rate coefficients, which will enable the calculation of continuous rates of gross primary production and ecosystem respiration per unit channel area and length. Other high-order biogeochemical metrics to be quantified by NEON include flux estimates for nitrogen, phosphorus, and carbon.

HYDROLOGIC, GEOMORPHIC, AND GROUNDWATER DATA

Climate models indicate that global changes in hydrologic cycles are imminent and will significantly affect aquatic ecosystems worldwide. In northeastern North America, heavy precipitation events are predicted to occur more frequently, whereas in the arid southwest precipitation is anticipated to decrease (Solomon et al. 2009). Severe precipitation events may induce water quality degradation in small streams and lakes, because greater fractions of water budgets could potentially be transmitted via overland flow. Such events impact the thermal attributes of aquatic ecosystems: groundwater infiltration is thermally consistent, whereas the temperature of water delivered during events as overland flow may be highly variable (Brown and Hannah 2008). Pulse- and press-dynamic changes in precipitation, water temperature fluctuations, and hydrology associated with climate change will impact the reproductive success of many fishes (Daufresne and Boët 2007). NEON will continuously record stream stage and calculate instantaneous discharge at all wadable stream sites. Additionally, aquatic sites (including lakes) will be instrumented with a network of up to eight riparian monitoring wells (≤30 m deep) to quantify local groundwater contributions at locations where such infrastructure is feasible. Sensors deployed in wells will provide near-continuous data on groundwater level, temperature, and conductivity. The well network will be spatially designed to capture coverage of influent–effluent groundwater chemistry, hydraulic gradients, and flow directions. Coupling NEON biological and biogeochemical attributes with sensor-derived groundwater well, in-stream surface water, and atmospheric/meteorological station data will allow researchers to conduct unprecedented analyses in ecohydrology.

Morphology surveys will be conducted annually to monitor changes in aquatic site physical attributes. At each stream and river site, NEON typically secures access to conduct research within a 1,000-m reach, and morphology surveys will cover this entire extent. Morphological data products in wadable stream systems will include channel attributes such as slope, sinuosity, and the relative linear extent of specific habitat types (i.e., pools, riffles, and runs). Features will be mapped with respect to fixed coordinate systems to assess questions such as whether and how channel attributes evolve over time. Additionally, the abundance, location, and mobility of large woody debris (fundamentally important to aquatic ecosystems; Gregory et al. 2003) will be quantified during morphology surveys. In lakes, detailed bathymetry surveys will be conducted using acoustic technology with high-precision differential Global Positioning Systems.

ATMOSPHERIC, TERRESTRIAL, AND REMOTELY SENSED DATA

NEON data collected outside of aquatic systems will likely also prove a valuable resource in many fisheries science applications. Terrestrial NEON data products consist of physical, chemical, and biological data, including soil metrics, evapotranspiration, phenological attributes (such as leaf senescence and emergence), and biochemical vegetation parameters. Such characteristics directly influence hydrologic cycles and water quality; thus, NEON data will enable investigative efforts relating terrestrial dynamics to hydrogeomorphic attributes in aquatic ecosystems. NEON will quantify stable isotope data signatures from multiple biotic and abiotic components of terrestrial and atmospheric environments. Consequently, stable isotope-based modeling of energy and material subsidies between terrestrial and aquatic food webs, an important phenomenon in both systems (Paetzold et al. 2005; Wipfli and Baxter 2010), will be possible across the network. NEON will collect a comprehensive suite of high-resolution data on atmospheric parameters from tower infrastructures, including total and photosynthetically active solar radiation, deposition, and wind speed/direction. These data may be used to quantify atmospheric controls on the physicochemical attributes of NEON aquatic ecosystems. Additionally, the NEON tower infrastructure will measure the chemical composition of dust and precipitation, thereby facilitating studies investigating deposition impacts on primary productivity in lake and marine ecosystems (Miller et al. 2007; Elser et al. 2009).

Data products will also include remotely sensed information derived from an Airborne Observation Platform (AOP). NEON will collect spectroscopic, photogrammetric, and light detection and ranging (LiDAR) data from flights deployed once annually over all sites in each domain. AOP observations will be converted to multiple high-order data products, such as land cover, canopy moisture, chemistry and structure, and disturbance metrics. These remotely sensed data are meant to bridge scales between satellite and terrestrially derived data. Integrating such information with aquatic and terrestrial observations should facilitate unprecedented analyses in watershed science.

STREON—THE FIRST NEON NETWORK EXPERIMENT

As mentioned above, NEON encourages proposals submitted by external scientists who use observatory facilities to conduct novel experiments. The first among these will be the Stream Experimental Observatory Network (STREON), an experimental program that will serve as a long-term assessment of stream ecosystem responses to drivers of environmental change (eutrophication and the extirpation of large-bodied organisms). STREON will consist of two treatments: (1) the nutrient most likely limiting local primary production (nitrogen or phosphorous) will be enriched by 5× ambient concentrations and (2) large-bodied organisms such as fish and amphibians will be electrically excluded from patches of benthic habitat (sediment baskets) during an annual 8- to 12-week period (Figure 2). Additionally, the likely nonlimiting nutrient (nitrogen or phosphorus) will be chronically added at an N:P ratio of 20:1. Nutrient enrichment treatments will be applied immediately downstream of the regular aquatic NEON reach in 10 sites (Table 1, Figure 2), and consumer exclusion apparatuses (and control replicates) will be deployed in both reaches. Data associated with STREON will include all standard NEON aquatic site measurements collected in both reaches. Additionally, sediment baskets linked to the consumer exclusion treatment will be incubated in closed recirculation chambers to quantify benthic metabolism and nutrient uptake.

Past chronic nutrient enrichment experiments have demonstrated distinct temporal thresholds of whole-ecosystem effects and elevated fish growth rates in treatment reaches (Benstead et al. 2007), and studies similar to the consumer exclusion component have revealed how fishes and other large-bodied organisms induce trophic cascades and/or serve as ecosystem engineers (Greathouse et al. 2006). What renders STREON unique from past efforts is the scope: the experiment will run over a 10-year period in 10 geoclimatically distinct streams across the continent. STREON will operate using standardized data quality assurance procedures to ensure that the experiment is as consistent as possible among sites. As with all NEON-generated information, STREON data will be open access, quality assured/quality controlled and available to the public via a web portal.

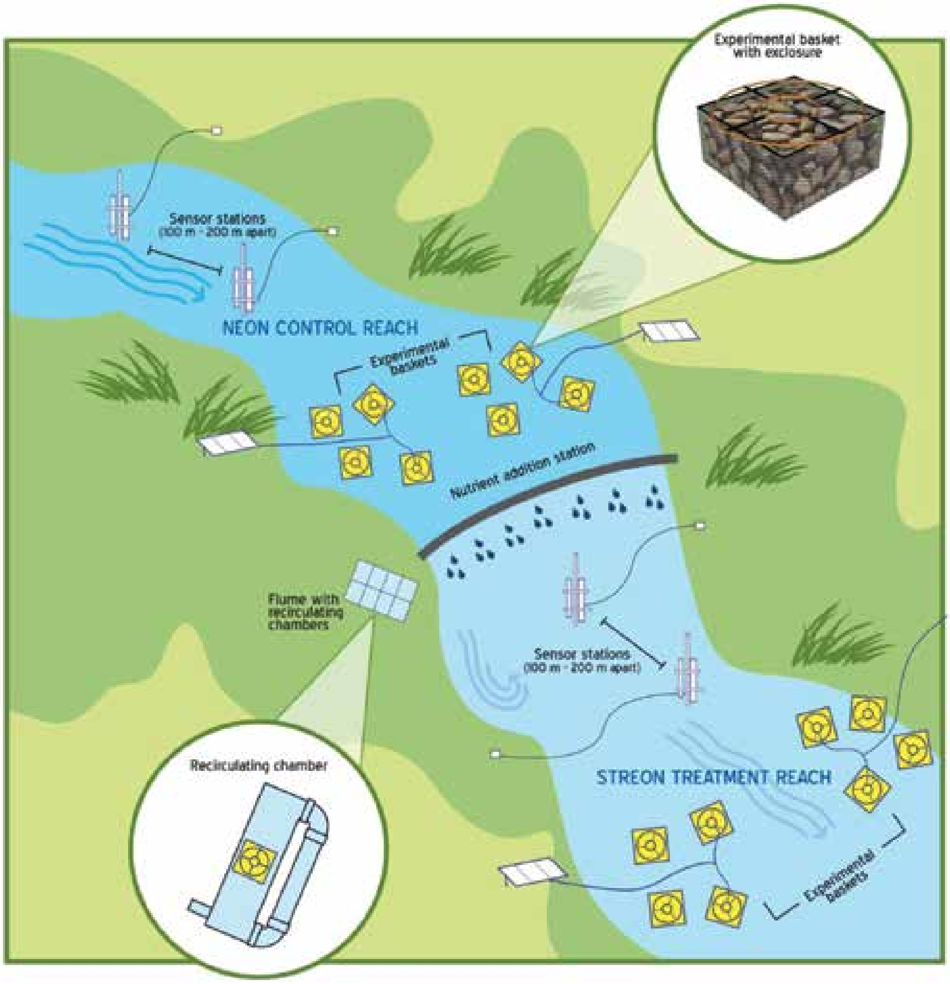

Figure 2. Experimental design of the STREON program at a typical site.

Metric and Protocol Development

The metrics to be collected and posted by NEON were specifically selected to help address NRC Grand Challenges in the environmental sciences and were identified during the planning and design phases of NEON development. From 2005 to 2011, NEON held multiple workshops and meetings intended to solicit recommendations on metric selection from external researchers in various subdisciplines of ecology. The resulting comprehensive suite of data products to be collected may be found in Keller (2010) and Keller et al. (2010). However, the NEON suite of data products will not necessarily remain static during the 30 years of operations: researchers may apply for funding (through agencies external to NEON) to expand the scope of data products that NEON collects (explained further in The NEON Structure: Current and Future section below).

For each NEON-generated data product, including all described in the preceding sections, specific protocols defining field and laboratory procedures will be written by NEON staff ecologists and peer-reviewed by active members in the research community. Protocol methodology will attempt to outline the best-known sampling practices for NEON field technicians. Preliminary protocol drafts are distributed to a voluntary working group of scientists external to NEON for review. Working group members possess the expertise required to assess such protocols and include scientists from academia, government agencies, and nonprofit organizations. For example, the aquatics technical working group reviews all aquatics program protocols and is comprised of 18 aquatic ecologists from nine universities or colleges, three federal agencies, and two nonprofit research institutions (currently active members of all working groups are listed on the NEON website). Finalized protocols will be made available to the community as open-access online resources so that researchers wishing to apply NEON methodology to maximize the comparability of data they collect may do so.

Protocols are developed to maximize data comparability among sites. Wherever possible, NEON personnel will apply identical methodology across sites. Procedures applied will represent those most appropriate for the setting where local environmental conditions significantly affect the efficacy of a certain method. For instance, when sampling benthic macroinvertebrates, Surber samplers will be used in mid- to high-gradient streams with hard substrates, whereas sites with sandy or silty substrates will be sam-

TABLE 1. NEON candidate aquatic sites and examples of fish species found in these water bodies. Sites listed are pending land use agreements (for site updates visit the NEON website). Numbers in the first column correspond to those illustrated in Figure 4. Italicized stream names denote sites in the STREON program.

Site	Name, State	Watershed area (km2; lotic systems) or surface area (ha; lakes)	Fish community attributes at site
1	West Branch Bigelow Creek, MA	0.3	No fishes present
2	Sawmill Brook, MA	4.0	No fishes present
3	*Baisman Run, MD*	1.7	Six species including brook trout (Salvelinus fontinalis), rosyside dace (Clinostomus funduloides), and longnose dace (Rhinichthys cataractae)
4	Posey Creek, VA	2.2	Currently unknown, but likely mottled sculpin (Cottus bairdi), creek chub (Semotilus atromaculatus), and blacknose dace (Rhinichthys atratulus)
5	Suggs Lake, FL	31.5	Fourteen recorded species, including spotted gar (Lepisosteus oculatus), bowfin (Amia calva), and warmouth (Lepomis gulosus)
6	Barco Lake, FL	10.1	Warmouth, largemouth bass (Micropterus salmoides), and bluegill (Lepomis macrochirus)
7	Ichawaynochaway Creek, GA	2,683.2	Fifty recorded species including goldstripe darter (Etheostoma parvipinne), shoal bass (Micropterus cataractae), and spotted bullhead (Ameiurus serracanthus)
8	*Río Cupeyes, PR*	11.3	American eel (Anguilla rostrada), mountain mullet (Angonostomus monticola), and bigmouth sleeper (Gobiomorus dormitor)
9	Río Guillarte, PR	11.9	Currently unknown; likely similar to Río Cupeyes
10	Lake Clara, WI	27.4	At least five species characteristic of north-temperate lakes, including yellow perch (Perca flavescens), largemouth bass, and northern pike (Esox lucius)
11	Pickerel Creek, WI	34.9	Currently unknown
12	*Kings Creek, KS*	12.4	Twenty recorded species including orangethroat darter (Etheostoma spectabile), orangespotted sunfish (Lepomis humilis), and shorthead redhorse (Moxostoma macrolepidotum)
13	McDowell Creek, KS	214.4	Thirty-six recorded species, including carmine shiner (Notropis percobromus), southern redbelly dace (Phoxinus erythrogaster), and longnose gar (Lepisosteus osseus)
14	LeConte Creek, TN	9.1	Brook trout and mottled sculpin (Cottus bairdi)
15	*Walker Branch, TN*	0.4	Creek chub and western blacknose dace (Rhinichthys obtusus)
16	Black Warrior River, AL	15,159.3	One hundred twenty-six recorded species including Tuskaloosa darter (Etheostoma douglasi), redeye bass (Micropterus coosae), and black redhorse (Moxostoma duquesnei)
17	Lower Tombigbee River, AL	47,102.4	One hundred twenty-one recorded species, including paddlefish (Polyodon spathula), river redhorse (Moxostoma carinatum), and crystal darter (Ammocrypta asprella)
18	*Mayfield Creek, AL*	17.0	Currently unknown, but could include >25 species. Supports populations of Tombigbee darter (Etheostoma lachneri), least brook lamprey (Lampetra aepyptera), and bluehead chub (Nocomis leptochephalus)
19	Prairie Pothole, ND	11.0	Currently unknown; likely supports populations of brook stickleback (Culea inconstans) and black bullhead (Ameirus melas)
20	Prairie Lake, ND	30.0	Currently unknown; likely similar to Prairie Pothole lake
21	Arikaree River, CO	2,874.9	Nineteen species, including brassy minnow (Hybognathus hanksinsoni), northern plains killifish (Fundulus kansae), and orangethroat darter
22	South Pond, OK	0.8	No fishes present
23	Pringle Creek, TX	18.1	Currently unknown; likely supports populations of mimic shiner (Notropis volucellus), blackstripe topminnow (Fundulus notatus), and logperch (Percina caprodes)
24	Bozeman Creek, MT	48.7	Currently unknown
25	Blacktail Deer Creek, WY	38.9	Brook trout
26	Fool Creek, CO	2.4	Currently unknown
27	Como Creek, CO	4.8	Greenback cutthroat trout (Oncorhynchus clarki stomias)
28	*Sycamore Creek, AZ*	345.0	Longfin dace (Agosia chrysogaster) and desert sucker (Pantosteus clarki)
29	Red Butte Creek, UT	16.7	Bonneville cutthroat trout (O. clarki utah)
30	East Branch Planting Creek, OR	1.6	Currently unknown; likely supports populations of coastal cutthroat trout (O. clarki clarki)
31	*McRae Creek, OR*	5.2	Coastal cutthroat trout
32	Providence Creek, CA	1.3	No fishes present
33	*Convict Creek, CA*	52.1	Brook trout (Salvelinus fontinalis), brown trout (Salmo trutta), rainbow trout (Oncorhynchus mykiss)
34	Toolik Lake, AK	146.7	At least five species including lake trout (Salvelinus namaycush), Arctic grayling (Thymallus arcticus), and round whitefish (Prosopium cylindraceum)
35	*Oksrukuyik Creek, AK*	73.5	Arctic grayling and slimy sculpin (Cottus cognatus)
36	*Caribou Creek, AK*	30.7	Arctic grayling and slimy sculpin

pled using hand corers. Posted data will specify methodological approaches, and the open-access protocols used to collect the data will allow interested researchers to determine the rationale concerning methodological decisions. Sample collection timing will also be coordinated to maximize data comparability among sites. NEON will identify periods where maximum biological diversity is expected for each target assemblage using externally collected historical data from each domain.

NEON Site Selection Process and Aquatic Sites

Sites in the NEON network are chosen to simultaneously maximize representation among major North American ecosystems and allow researchers to address environmental questions of regional concern. To distribute sites throughout major ecological gradients of North America, NEON used multivariate geographic clustering (Hargrove and Hoffman 1999) to partition the continental United States, Alaska, Hawaii, and Puerto Rico into 20 ecoclimatic domains. All domains (excluding Hawaii) include one to three aquatic sites that fall into two categories: core sites, which will remain fixed in place during the entire 30 years of NEON operations, and relocatable sites, which are intended to move approximately every 5 years to capture variation within a domain and address regional questions of interest. Sites were selected to represent the greatest degree of characteristic ecological attributes of the corresponding domains. Core sites typically consist of ecosystems that are minimally impacted by anthropogenic stressors. Relocatable sites may be in areas impacted by anthropogenic stressors and are usually paired with either core sites or other relocatables to allow contrasting measurements between impacted and relatively intact ecosystems. The data collected from all sites may be used to extrapolate relationships that identify the driving causes of long-term ecological changes to areas not sampled but where partial, extensively sampled, or gridded information is available.

Currently, the candidate aquatic sites in the NEON network include 26 wadable streams, three nonwadable rivers, and seven lakes representing characteristic aquatic ecosystems among a majority of North American ecoregions (Table 1, Figures 3 and 4). Sites are considered as candidates until a land use agreement is obtained. NEON aquatic site selection is informed by external scientific input from those familiar with the respective domain and follows the same criteria of terrestrial and atmospheric site selection: core sites are situated in relatively intact watersheds, whereas relocatable sites may be anthropogenically impacted. Wherever possible, aquatic sites are located adjacent to (i.e., <5 km) NEON tower and terrestrial sites to help couple data among ecosystems. NEON lotic ecosystem sizes range from small, first-order, fishless streams to large rivers that support highly diverse fish communities. The network of sites in Domain 8, the Ozarks Complex, may prove particularly valuable for fisheries and aquatic ecosystem science because they consist of three sites with nested catchments of various sizes within a large river watershed. Domain 8 sites were specifically selected to span the river continuum (Vannote et al. 1980) of the Tombigbee River watershed and include reaches with more than 100 recorded fish species.

The NEON Structure: Current and Future

NEON is an NSF-funded project managed and maintained by an independent, nonprofit corporation (NEON, Inc.) implemented through the Large Facilities Office (LFO). Examples of well-known observatories managed under this program include the Arecibo and Gemini Satellite Observatories. Programs implemented through the LFO typically undergo a multiyear review process with incremental developmental steps prior to operations termed the major research equipment and facilities construction (MREFC) process. Construction funds were awarded in fiscal year 2011; a 5-year construction phase (where sites are fitted with sensors and data collection begins) followed by a 30-year operations phase is now set to ensue. Within each domain, NEON crews stationed in local offices will perform field operations. Central NEON headquarters is located in Boulder, Colorado.

All data will be posted on an open-access, NEON-maintained Internet portal. The portal system will include comprehensive search interfaces, filtering capabilities (e.g., searching within regional and/or date criteria), and decision-support functions to help investigators become fully aware of all available data pertinent to their inquiries. The data acquisition portal is currently under development and many design specifications have yet to be finalized. However, NEON will collaborate with several existing data management initiatives, such as the National Water Quality Monitoring Council and BioOne, to assist with portal development. External researchers will also be consulted to help maximize data portal functionality. Regardless of the final design, an open-source metadata structure and provenance process will ensure that users understand where and how all data are derived. All data will undergo stringent quality assurance/quality control product definition, statistical, and modeling analysis to ensure the identification of erroneous readings. Wherever possible, data will be cross-checked using related sensors or measurements among the NEON data streams. Researchers and the public will be able to access NEON-derived design and protocol documents using the web portal to ensure data comparability and methodological repeatability outside of the observatory. For instance, the standardized, peer-reviewed field protocol applied for fish sampling will be downloadable so that reliably comparable data may be collected elsewhere.

Educational resources and tools are being developed at NEON to ensure that observatory-generated information, including data, is accessible and usable for all interested users. In partnership with stakeholder communities, NEON will employ a variety of approaches to engage communities in the scientific process. Planned educational activities include social media applications, online learning modules, citizen science projects, student research and internship programs, short courses, and workshops to help individuals at all levels of professional development effectively use observatory-generated data. Graduate students from any institution will be able to participate in a competitive field and data analysis course to help familiarize themselves with NEON resources. The NEON web portal will be an interface to many educational resources, including

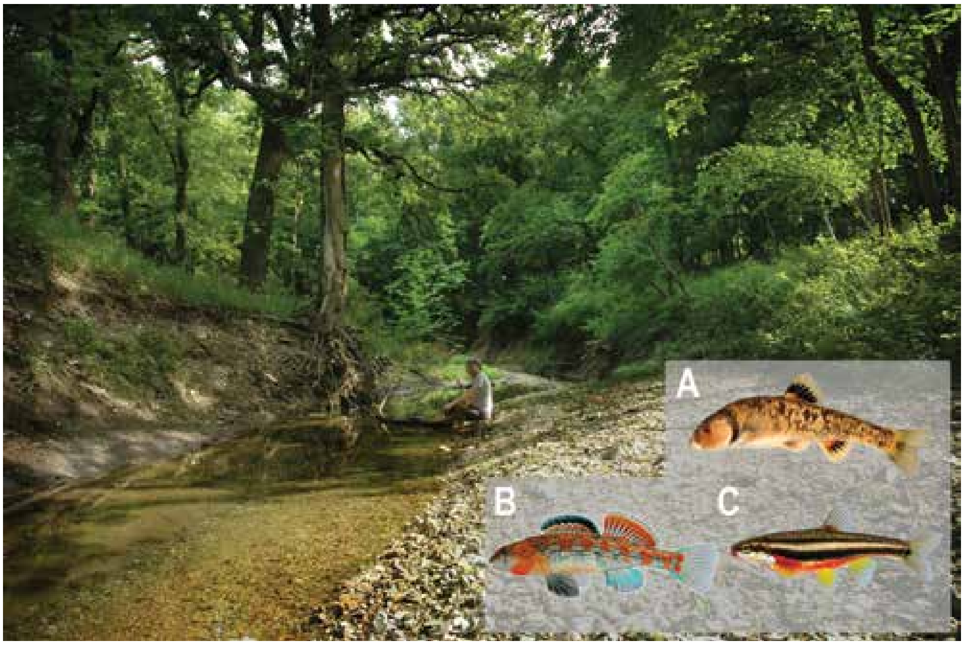

Figure 3. Kings Creek, a NEON candidate core aquatic and STREON site located within the Konza Prairie Biological Station near Manhattan, Kansas. NEON will collect population estimates of fishes, including (A) central stoneroller, (B) orangethroat darter, and (C) southern redbelly dace in Kings Creek for 30 years. Additionally, data from the STREON experiment will allow any interested researcher to explore how populations of these fishes respond to chronic nutrient enrichment and how their extirpation might impact ecological processes in the benthic zone.

Figure 4. Map of NEON North American domains and locations of aquatic sites in the observatory. Site numbers correspond to those listed in Table 1.

online learning modules for students hoping to use NEON data. Citizen science programs will enable participants to collect, contribute, interpret, and visualize scientific data that may significantly contribute to scientific inquiry. Project Budburst, the first among such initiatives (comanaged by the Chicago Botanical Garden and NEON), provides an interface for amateur botanists to report the dates of phenological events such as leaf out and senescence at any location. Interested researchers may now access thousands of phenological event data recorded across the country over the past 4 years.

NEON aims to be a dynamic and valued resource by actively encouraging the scientific community to develop research projects that leverage NEON data, facilities, and infrastructure. Currently, the NSF Macrosystems Biology program, supporting research on biological systems at regional to continental scales, is a principal avenue for fostering scientific collaboration with NEON. Other NSF funding programs that have encouraged NEON collaboration to date include the Research Coordination Networks and Campus Cyberinfrastructure–Network Infrastructure and Engineering Program. New collaborative efforts that leverage NEON may also be funded by agencies other than NSF or nongovernmental institutions. Proposals that include the use or leveraging of NEON assets may be submitted by universities, nonprofit institutions, non-academic organizations, or federal agencies. Decisions regarding the use of NEON assets in novel work will be assessed for technical and logistical feasibility by NEON staff in accordance with policies and procedures currently in development and subject to NSF approval. Quantitative, interdisciplinary, and systems-oriented research on biological processes and their interactions with environmental change at continental scales will be particularly encouraged. Smaller scale initiatives, including new technology testing and implemention, will also be possible and promoted through collaborations with NEON scientists. Finally, collaborative research may be fostered through student internships with individuals mentored by both external and NEON scientists.

Successful analyses and forecasting in fisheries science at broad scales amid pervasive global environmental change will require unprecedented scientific resources. NEON aims to become a transformative tool in the ecological sciences by providing high-quality, nonproprietary, and comprehensive data across spatiotemporal scales beyond the capabilities of individual laboratories. The combined suite of aquatic, terrestrial, and atmospheric data generated by NEON will particularly enhance investigations of material and energy exchanges across apparent ecosystem boundaries, which are increasingly recognized as critically important in aquatic ecosystems (Lamberti et al.

2010). To learn more about NEON, including the observatory structure, data products, working group members, and construction updates, please visit the NEON website (neoninc.org).

ACKNOWLEDGMENTS

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SIUC Subunit Blends Research and Service in Pursuit of Professional Development

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Members of the Southern Illinois University Carbondale (SIUC) Subunit of the Illinois Chapter of the American Fisheries Society take a multi-faceted approach to promote the conservation of aquatic resources through personal, professional, and community development. From teaching youths about aquatic ecology and fish identification, to the development of the inaugural "Carp-A-Thon" for area anglers, the SIUC IL-AFS Subunit serves as an important community resource. This past year alone, members planned and participated in well over a dozen fisheries-related outreach events, including the Illinois Department of Natural Resources' Urban Fishing program, where members had the chance to introduce youngsters to the joys of angling and the importance and value of the great outdoors.

Opportunities abound for Subunit members to develop their fisheries and interpersonal skills by electrofishing area lakes, generating stock assessment reports, and presenting their findings to anglers and members of the community. This year, members experienced a unique opportunity to culture freshwater prawn as part of an SIUC-sponsored research project. At the end of the summer, the tasty crustaceans were harvested and sold to students and faculty of SIUC and greater Southern Illinois community as a fundraiser for the Subunit. Additionally, members gained pond-culture experience, learned about prawn biology, and collected data for a bioenergetics study.

The next few months are an exciting time for the SIUC IL-AFS Subunit, as members are currently developing monthly workshops to give new students out-of-the-classroom learning opportunities in electrofishing, lab and culture techniques, pond management, and boat maintenance, safety, and operation. These opportunities build professional skill sets, human and resource networks, and a sense of camaraderie among both new and old members of the fisheries community at SIUC. The SIUC Subunit also serves as an important means of mentoring undergraduate students by incorporating real field and lab experiences to supplement traditional classroom-style learning. Graduate students benefit from undergraduate assistance that is always available. This relationship is important to the growth of the program and describes the Subunit's mission. Encouraging academic excellence, robust research productivity, and community service are the focus of the SIUC IL-AFS Subunit. In addition to serving locally, the Subunit also has a history of helping the Illinois Chapter and AFS Sections at various levels. Through the Subunit, members feel a connection to our local cadre of fish-heads, as well as AFS and the broader fisheries community.

To learn more about the SIUC IL-AFS Subunit, please visit their website at http://fishstudent.rso.siu.edu. For more information on establishing a Student Subunit at your college or university, contact your state AFS Chapter.

(Left): SIUC IL-AFS member Jake Norman instructs beginning anglers on how to properly cast a rod and reel during the 2012 Illinois Department of Natural Resources' Urban Fishing program. Through this vital community resource, many children had the opportunity to catch their first fish, thus generating a newfound enthusiasm for fishing within the youngest members of the Southern Illinois community. (Center): From May through September 2012, SIUC IL-AFS members cultured freshwater prawn in SIUC-provided ponds. Members harvested the prawn in late September, and sold them by the pound as a fundraiser for the Subunit. Not only did Subunit members witness how tasty freshwater prawn are, but they also gained experience on data collection for a bioenergetics study and learned about prawn biology and pond culture techniques. Above, SIUC IL-AFS member and prawn fundraiser organizer Bonnie Mulligan holds a "blue claw" male prawn during the harvest. (Right): SIUC IL-AFS member and past-president John Bowzer holds a contestant's carp entry for the 1st annual Southern Illinois "Carp-A-Thon". The fishing tournament was sponsored in part by the SIUC IL-AFS, and served as both a platform to both raise awareness of the Bighead and Silver carp infiltration of local waterways and a fundraiser for the Subunit. Prizes were awarded to the anglers for "Biggest Carp" and "Top Ten Heaviest Fish."

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The **American Fisheries Society Student Writing Contest** recognizes students for excellence in the communication of fisheries research to the general public.

Undergraduate and graduate students are encouraged to submit a 500- to 700-word article explaining their own research or a research project in their lab or school. The article must be written in language understandable to the general public (i.e., journalistic style). The winning article will be published in ***Fisheries.***

Students may write about research that has been completed, is in progress, or is in the planning stages. The papers will be judged according to their quality and their ability to turn a scientific research topic into a paper for the general public and will be scored based upon a grading rubric. Check the AFS Web site (www.fisheries. org) awards page for the grading rubric.

American Fisheries Society Adopts New Policy, Encourages Efforts to Understand and Limit Effects of Lead in Sport Fishing Tackle on Fish and Wildlife

Jesse Trushenski and Paul Radomski

American Fisheries Society, Resource Policy Committee

In October of 2012, the American Fisheries Society (AFS) voted to adopt a new policy statement on "Lead in Sport Fishing Tackle." Like all AFS policies, this document represents the collective voice of the oldest, largest, and most influential professional organization dedicated to the fisheries sciences. The new policy draws attention to the negative effects of lead in the environment and encourages scientists, regulatory authorities, tackle manufacturers, the sport fishing community, and other stakeholders to work together to understand and limit any negative effects of lead-based tackle (e.g., sinkers, jigs) on fish and other organisms.

Lead is a naturally occurring but toxic element. Because of its negative effects on human and animal health, lead is banned in products such as gasoline, paint, and solder in many countries. However, lead is still commonly used in fishing tackle because it is readily available, dense, malleable, and inexpensive. Though lost fishing tackle can remain intact and relatively stable for decades or centuries in aquatic systems, if ingested by animals, the lead in these products becomes more biologically available and can result in lethal exposures. The effects of ingesting such tackle were established in waterbirds in the 1970s and 1980s, following lead poisoning events in localized populations of loons and swans. Although population-level effects have not been unequivocally demonstrated and lost tackle represents a relatively small fraction of the total amount of lead found in the environment (surface runoff, atmospheric deposition, and mining activities are more significant sources), given the likelihood of ingestion and the magnitude of organism-level effects of exposure following ingestion, it would seem prudent to assess, understand, and limit the negative effects of lead in sportfishing tackle on fish and other aquatic organisms.

This issue was reviewed by members of the AFS Resource Policy Committee (RPC), under the principal leadership of Paul Radomski, Tom Bigford, and Jesse Trushenski. In cooperation with a special committee established by then AFS President Wayne Hubert, Radomski and the other members of the RPC prepared a draft policy statement. Following review by the AFS RPC, governing board, and membership at large, the Society adopted the policy, calling for stakeholders to address the potential effects of lead in sportfishing tackle on fish populations.

Accordingly, the policy of the AFS, in regard to lead in sport fishing tackle, is to

1. Recognize that lead has been known for centuries to be toxic to biological organisms. Thus, the loss and subsequent ingestion of lead sinkers and jigheads by aquatic animals and the potential ramifications of lead ingestion is a natural resource management issue.
2. Understand that the impact of ingested lead on individuals of certain waterfowl species is generally accepted, but population-level impacts on fish and wildlife species are not well documented. Although conclusive scientific proof of these effects is not currently available, actions to inform, educate, and encourage sportfishing tackle manufacturers, users, and researchers to reduce future introductions of lead into aquatic ecosystems appears advisable. Accordingly, collaborate with fish and wildlife professionals, tackle manufacturers, anglers, policy makers. and the public to encourage the use of non-lead forms of small fishing sinkers and jigheads that are protective of potentially affected fish and wildlife populations.
3. Encourage scientifically rigorous research on lead tackle aimed at generating toxicological and environmental chemistry data including bioavailability assessments; support monitoring and modeling of exposure and effects on at-risk populations; encourage studies predicting consequences of exposure and long-term population-level effects of different tackle material; and encourage studies on reducing the economic and social barriers to nontoxic fishing tackle development and use.
4. Recognize that the hunting and angling communities can be important advocates and forces of change regarding natural resources issues and support educational efforts to promote greater public awareness and understanding of the consequences of lead exposure in wildlife species and the potential gains in environmental quality from use of lead-free fishing tackle.
5. Update policy language as focused research provides additional data on lead tackle-related impacts.

To read the full text of the new policy statement or any of the society's current policies, please visit the American Fisheries Society online at http://fisheries.org/policy_statements.

MISSION STATEMENT

Fisheries is the monthly peer-reviewed membership publication of the American Fisheries Society (AFS). Its goal is to provide timely, useful, and accurate information on fisheries science, management, and the fisheries profession for AFS members. Some types of articles which are suitable for *Fisheries* include fishery case histories, review or synthesis articles covering a specific issue, policy articles, perspective or opinion pieces, essays, teaching case studies, and current events or news features. We particularly encourage the submission of short-form (under 5 typeset pages) "mini-review" articles. Our goal is to move towards four science-based papers in each issue. We will waive page charges for even shorter articles (under 2 typeset pages) on such articles as current events in fisheries science, interviews with fisheries scientists, history pieces, informative how-to articles, etc. We also encourage articles that will expose our members to new or different fields, and that recognize the varied interests of our readers. Research articles may be considered if the work has broad implications or applications and the subject matter can be readily understood by professionals of a variety of backgrounds. *Fisheries* is the Society's flagship publication and is the mostly widely read fisheries science publication in the world. Accordingly, content submitted for consideration should appeal broadly to fisheries professionals and speak to the interests of the AFS membership. Lengthy, highly technical, or narrowly focused research articles are better suited to the AFS technical publications, and we encourage authors to consider the other AFS journals as venues for these works.

REVIEWED ARTICLES

***IMPORTANT**

The maximum length of articles accepted in *Fisheries* is 10 typeset pages (including photos, figures, tables, pull quotes, titles, translations, etc.). One full page of article text with absolutely no figures, tables, pull quotes, titles, headers, translations, or photos is approximately 880 words or 6100 characters including spaces. Please adhere to this standard, taking figures and other non-text content into consideration, when preparing manuscripts for submission to *Fisheries*.

Features, Perspectives, and Review Articles

We encourage submission of topical manuscripts of broad interest to our readership that address contemporary issues and problems in all aspects of fisheries science, management, and policy. Articles on fisheries ecology and aquatic resource management; biology of fishes, including physiology, culture, genetics, disease, and others; economics and social issues; educational/administrative concepts, controversies, techniques, philosophies, and developments; and other general interest, fisheries-oriented subjects will be considered. Policy and issue papers are welcome, particularly those focusing on current topics in fisheries policy. As noted above, we are particularly interested in mini-reviews, which should concisely but comprehensively summarize a topic under 5 typeset pages or less. Papers are judged on scientific and professional merit, relevance, and interest to fisheries professionals. Features and perspectives generally should not exceed 4,500 words (excluding references and tables) and should not cite more than 40 references. Please consult the managing editor PRIOR to submission for a length or reference limit exemption for review articles or articles of Society-wide significance.

Please submit your manuscript online using our manuscript tracking website at http://mc.manuscriptcentral.com/fisheries. If you cannot submit your manuscript online, please e-mail or phone the managing editor, Sarah Fox, for instructions: sgilbertfox@fisheries.org or 301-897-8616 x220 (for fastest response, please e-mail).

AUTHOR GUIDELINES
Fisheries 2013 Guide for Authors

Essays

Essays are thought-provoking or opinion articles based upon sound science. Essays may cover a wide range of topics, including professional, conservation, research, AFS, political, management, and other issues. Essays may be submitted in conjunction with a full feature article on the same topic. Essays can be up to 2,000 words, may include photographs or illustrations, and should not cite more than eight references. However, essays should provide scientific documentation, unlike unreviewed opinion pieces (below). Essays are peer-reviewed based on the following criteria: contribution to the ongoing debate, logical opinion based on good science, persuasiveness, and clarity of writing. Reviewer agreement with the opinion of the views expressed is not a criterion. Essays do not have page charges or abstracts. Essays should be formatted and submitted online as described above.

Fisheries Education

Fisheries will consider publication of case studies and other articles specifically intended as teaching tools. These articles, including case studies or short topical summaries, should be formatted to be used for teaching aids for courses taught at the undergraduate level. Fisheries Education articles should be readily understood by undergraduate students with basic training in biological/ecological sciences, and include background information, discussion questions, teaching notes, and references. Peer review of teaching case studies and educational topics will be handled by a special committee of the AFS Education Section.

Materials to Submit

- Assemble manuscripts in this order: title page, abstract page, text, references, tables, figure captions. Tables may be included at the end of the article file or may be submitted as separate files. Figures should not be embedded in the article file and should be submitted separately.
- Authors are strongly encouraged to submit a word processing file in either Word or plain text format.
- Figures/images should be in TIF (preferred), JPG, or PDF formats, and tables should be in Excel or Word formats.
- Word count is extremely important. (See limits for article types above.)
- The cover letter should explain how your paper is innovative, provocative, timely, and of interest to a broad audience. It should also include a list of potential reviewers who can provide an unbiased, informed, and thorough assessment of the manuscript. The cover letter can also be used to provide further explanation, if part of the information has been published or presented previously.
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    1. A blurb for the table of contents (this should be one sentence that explains the article and captures the reader's attention).
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General Instructions

- Consult current issues for additional guidance on format.
- Manuscripts should be double-spaced, including tables, references, and figure captions.

- Leave at least a 1-in margin on all sides. Indent all paragraphs. Number pages sequentially and use continuous line numbering,
- Use dictionary preference for hyphenation. Do not hyphenate a word at the end of a line. Use *Chicago Manual of Style, 14th edition* to answer grammar or usage questions.
- The first mention of a common name should be followed by the scientific name in parentheses. Our standard is C*ommon and Scientific Names of Fishes from the United States, Canada, and Mexico, 7th edition*.
- Define abbreviations the first time they are used in the text.
- Spell out one-digit numbers unless they are units of measure (e.g., four fishes, 3 mm, 35 sites). Use 1,000 instead of 1000; 0.13 instead of .13; % instead of percent.
- Use the name-and-year system for references in the text as follows:
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  6. Within parentheses, use a semicolon to separate different types of citations (Figure 4; Table 2), (Jones and Smith 1989; Felix and Anderson 1998). Arrange lists of citations chronologically (oldest first) in a text sentence.
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- Ensure that the abstract concisely states (150 words maximum) why you did the study, what you did, what you found, and what your results mean.

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- See "General Instructions."
- Set all type at left. Boldface primary subheads and italicize secondary subheads.
- Insert tabs—not spaces—for paragraph indents.
- Italicize any words that should appear in italics.
- Avoid footnotes by including the information in the text.

References

- Double-space between each reference entry but do not indent text. References will be formatted during the production process.
- Alphabetize entries first by the surnames of senior authors and the first word or acronym of corporate authors; second, by the initials of the senior authors with the same surname; and third, by the surnames of junior authors. References by a single author precede multi-authored works by the same senior author, regardless of date.
- List multiple works by the same author(s) chronologically, beginning with earliest date of publication.
- Distinguish papers by the same author(s) in the same year by putting lowercase letters after the date (1995a, 1995b).
- Use a long dash when the author(s) is/are the same as in the immediately preceding citation.
- "In press" citations must have been accepted for publication, and the name of the journal or publisher must be included.
- Insert a period and space after each initial of an author's name.
- Do not abbreviate journal names. Verify all entries against original sources, especially journal titles, accents, diacritical marks, and spelling in languages other than English.

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- Tables must be submitted in MS Word documents using the "Tables" tools, or as MS Excel files. Do not send tables as uneditable pictures that have been pasted into the document.
- Tables may be included with the article or submitted as separate files.
- Double-space everything, including the table title and column headings.
- Use single horizontal lines to separate column heads and to indicate the end of the table—other horizontal lines are not needed. Never use vertical lines.
- Use sentence-style captions for tables, not fragments.
- Capitalize only the first letter of the first word in each column and row entry (except initial caps for proper nouns).
- Tab between column items — DO NOT "space" between columns.
- Type "NA" (not applicable) where no entry applies in the table body. Do not add filler dashes.
- Label footnotes with lowercase, superscript letters, starting from the beginning of the alphabet (a, b, c).
- Redefine, in the table's caption or in a footnote, any acronyms that are used in the table but are mentioned only infrequently in the text.

Illustrations

Illustrations are photographs, drawings, or figures. Prepare illustrations using professional standards, and consult issues of *Fisheries* for examples.

- For review on the manuscript tracking system, we prefer digital photos (or scans). However, original film photos and slides can be used for final production. The managing editor or production editor will contact you after acceptance and let you know when to send original photos.
- Identify all people who appear in photographs, and identify photographer or agency responsible for photo. Caption must be in sentence, not fragment, form. Photos are not considered figures and do not need to be referenced in the text.
- Electronic photos should have good contrast, a size of at least 4 x 6 inches, at least 300 dots per inch (dpi) resolution, and be saved in TIF (preferred), JPG, or PDF formats. For black-and

white figures and graphs, please use a minimum resolution of 300 dpi. We cannot accept PowerPoint files. Hardcopy also must be submitted for production purposes after acceptance.

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Unit News and Other Departments

AFS members are encouraged to submit items for the Unit News, Member Happenings, Obituaries, Letters to the Editor, and Calendar departments. Dated material (calls for papers, meeting announcements, and nominations for awards) should be submitted as early as possible, but at least eight weeks before the requested month of publication. AFS Unit News and Letters should be kept under 400 words and may be edited for length or content. Obituaries for former or current AFS members may be up to 600 words long and a photo of the subject is welcome. Do NOT use the online manuscript tracking system to submit these items—the text and 300 dpi digital photos (TIF or JPG) for all departments except the Calendar should be e-mailed to the managing editor at sgilbertfox@fisheries.org, or mailed to the address below.

Calendar

Calendar items should include, in this order: the date, event title, location, and contact information (including a website, if there is one), and should be sent to the editor at sgilbertfox@fisheries.org.

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For information about submitting a Students' Angle column, please contact Student Subsection President Jeff Fore at jdfore@mizzou.edu.

Fisheries News

Brief items for the Fisheries News section are encouraged. Typical items include conservation news, science news, new programs of significance, major policy or regulatory initiatives, and other items that would be of interest to Fisheries readers. News items for the section should be no more than a few paragraphs; please consult the managing editor about submitting longer news articles.

Fisheries Forum (formerly Guest Editorials)

Authors are encouraged to submit most opinion pieces about fisheries science or management as essays for peer review. Occasionally, editorials about professional or policy issues may be inherently unsuitable for a scientific review. Sometimes these pieces are submitted by a committee, agency, or organization. Editorials should be 750–1,500 words, may be edited for length or content, and referred for outside review or rebuttal if necessary. A disclaimer may accompany Fisheries Forum editorials stating that the opinion is that of the author and not the American Fisheries Society.

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Please contact Book Review Editor Francis Juanes at 413-545-2758, juanes@uvic.ca, if you want to be added to the list of potential book reviewers.

New books (preferably two copies) submitted for review should be sent to:

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The Four Fs of Fish: Communicating the Public Value of Fish and Fisheries

Abigail J. Lynch and William W. Taylor

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"Fish? Why fish?!" This is a common question we are often asked by those outside our field upon learning our profession. They are curious as to why we devote our lives to the study, conservation, restoration, and propagation of fish and associated habitats. This question can come anywhere and at any time. Though it is a common inquiry, do we, as professionals and as a profession, have a good answer?

Effectively demonstrating the value of fish and the fisheries supply chain they create is as important for the future of our own profession as for the fish. This, however, is no easy task. The average American eats approximately 15.8 pounds of fish and shellfish per year (NOAA 2010) and less than 14% of adult Americans report that they participate in recreational fishing (USFWS 2012). So, in general, Americans have little to no direct interaction with fish. In spite of this, our role as fisheries professionals is to clearly articulate to the public and policy makers that fish are important and have value – locally, regionally, nationally, and internationally. Such demonstration of public value ensures that fish and fisheries are afforded appropriate consideration in decision making – from the dinner table to the United Nations general assembly floor. Fish are important; no, they are more than important. They are essential to the survival of mankind. Fish, after all, directly or indirectly contribute to subsistence, livelihoods, health, and prosperity for much of the world.

As fisheries professionals, we are all passionate about fish. This personal and professional passion emanates for many different reasons, as shown by the diversity of the American Fisheries Society sections and membership. However, our drive is often hard to explain to someone who doesn't share the same interest and wonder for fish, their habitats, and fisheries.

We [*the authors*] propose "The Four Fs of Fish": Food, Finances, Fun, and Function as a means to effectively communicate the public value of fish and fisheries. Surely, there are other values, but these four can start the discussion and hone our passion into something tangible to the public and policy makers.

FOOD

Perhaps the most direct argument to make in support of the importance of fish and their habitats is food. Capture fisheries are the last large-scale wild food resource in the world and aquaculture is a quickly growing sector. Both provide essential protein and nutrients to many across the globe. Fish directly provide more than 1.5 billion people with almost 20% of their animal protein and another 3.0 billion with at least 15% (FAO 2010). This equates to more than 40% of the world's human population.

Fish are also an important indirect source of protein for many others who generally do not realize it. Approximately 12.4% of global fishery production is reduced to fish meal and fish oil (FAO 2009), which is subsequently formulated into specialized feed for livestock and aquaculture operations. So, choosing between chicken and fish as meal options may, in fact, be choosing fish or reprocessed fish. We can do a better job of emphasizing the role of fish in other protein sources. For example, instead of asking "how's the chicken?" to someone enjoying a piece of fried chicken, ask "how's the fish?" By helping people understand the supply chain that leads to their meals, we will help them appreciate the importance of fish as a food source that provides healthy, nutritious meals for many at local and global scales.

FINANCES

People recognize the importance of economic impact or, as the old adage goes, money talks and employment walks. First-sale value of global capture fisheries production and aquaculture is approximately US$93.9 billion and US$98.4 billion, respectively, and US$192.3 billion, collectively (FAO 2010). Numbers that large can seem intangible, but the first-sale of value of fisheries basically equates to one-seventh of the U.S. Gross Domestic Product.

More than strict monetary value, fisheries are significant sources of employment, income, and livelihood. Globally, 44.9 million people are directly engaged in capture fisheries or in aquaculture (FAO 2010). So, fisheries employ over 20 times more people than Walmart, the world's largest private employer. Taking families and dependents into account, fisheries are an important source of income and livelihood for 8% of the world's population, around 540 million people (FAO 2010). And, these are just minimum estimates. These Food and Agriculture Organization of the United Nations (FAO) statistics are very likely a gross underestimate of their full value because obtaining accurate capture and employment statistics on small-scale fisheries, the bulk of the world's fisheries, is difficult as they are highly dispersed and underreported (Cochrane et al. 2011).

FUN

Fish, lest we forget, also provide fun. Recreational fishers, snorkelers, SCUBA divers, and hobby aquarists seek enjoyment and relaxation through interacting with fish and their habitats. Though we cannot over-emphasize the value of these experiences to the individuals who find fish fun, the financial value of recreation can be understood even by those choosing not to engage in these types of activities. In 2011, for example, American anglers spent $41.8 billion in support of fishing activities (e.g., trips, equipment, licenses; USFWS 2012). Even those who have never picked up a fishing rod or visited an aquarium can appreciate the employment and economic stimulus generated by recreational fishing and fish watching.

Fish are important components of most human systems. While some cultural values, like recreation and tourism, can be translated into economic impact, other religious, spiritual, or artistic values are more difficult to assess economically. Nonetheless, fish are symbolized in every major world religion and the natural beauty of aquatic ecosystems is commonly evoked in art.

FUNCTION

Without question, fishes are the most diverse, numerous group of vertebrates on the planet. The estimated 27,977 species of fishes make up more than half of the approximate 54,711 recognized living vertebrate species (Nelson 2006) and occupy almost all major aquatic habitats (Helfman et al. 2009). In this role, fishes are a particularly important taxa for biodiversity conservation and resilience of ecosystems to change (Naeem 2012). As such, they often serve as symbols of the health and integrity of their habitats. They are, for all practical purposes, the aquatic version of "canaries in a coal mine." Fish are critical links in aquatic systems – indicators of ecosystem health and a litmus test of what the potential impacts could be for humans.

For people who fish, eat fish, or recreate in aquatic environments, the value of fish and fisheries is an easy sell. They use and appreciate the resource and want to ensure that fish will be around for them and future generations to use. But, demonstrating the value of fish to those who have no direct contact with them can be daunting, especially when negotiating tradeoffs for water security, agriculture, power generation, and other sectoral interests. As a whole, we, as professionals can be better communicators. We need to be cognizant that others may not share our passion for fish and we must provide them with a clear rationale of why fish and their habitats should be important to them: Food, Finances, Fun, and Function. Our future and that of fishes depend on us to do just that – make fish meaningful and important to all!

Fast Stats

Food

- 3.0 billion people (>40% of global population) depend directly on fish as an important source of protein.

Finances

- 540 million people (8% of global population) depend upon fishery industries for livelihood and income.

Fun

- Anglers in the United States spend over $40 billion in support of fishing activities annually.

Function

- Fishes comprise more than half of all vertebrate species and occupy all major aquatic habitats.

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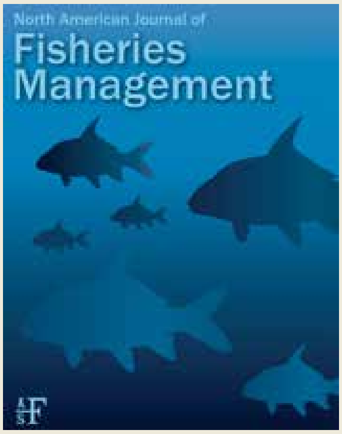
JOURNAL HIGHLIGHTS

North American Journal of Fisheries Management, Volume 32, Number 6, December 2012



[Management Brief] A Prototype Splitter Apparatus for Dividing Large Catches of Small Fish. *Martin A. Stapanian and William H. Edwards. 32: 1033–1038.*

Largemouth Bass Predation Effect on Stocked Walleye Survival in Illinois Impoundments. *Jonathan A. Freedman, R. John H. Hoxmeier, Lisa M. Einfalt, Ronald C. Brooks, and David H. Wahl. 32: 1039–1045.*

Habitat Associations of Fish Species of Greatest Conservation Need at Multiple Spatial Scales in Wadeable Iowa Streams. *Anthony R. Sindt, Michael C. Quist, and Clay L. Pierce. 32: 1046–1061.*

[Management Brief] The Potential for Vessel Interactions with Adult Atlantic Sturgeon in the James River, Virginia. *Matthew T. Balazik, Kevin J. Reine, Albert J. Spells, Charles A. Fredrickson, Michael L. Fine, Greg C. Garman, and Stephen P. McIninch. 32: 1062–1069.*

Elevated Streamflows Increase Dam Passage by Juvenile Coho Salmon during Winter: Implications of Climate Change in the Pacific Northwest. *Tobias J. Kock, Theresa L. Liedtke, Dennis W. Rondorf, John D. Serl, Mike Kohn, and Karin A. Bumbaco. 32: 1070–1079.*

Do Anglers Know What They Catch? Identification Accuracy and Its Effect on Angler Survey-Derived Catch Estimates. *Kevin S. Page, Richard D. Zweifel, George Carter, Nick Radabaugh, Michael Wilkerson, Matthew Wolfe, Michael Greenlee, and Kipp Brown. 32: 1080–1089.*

Effect of Survey Design and Catch Rate Estimation on Total Catch Estimates in Chinook Salmon Fisheries. *Joshua L. McCormick, Michael C. Quist, and Daniel J. Schill. 32: 1090–1101.*

Empirical Standard Weight Equation for the Aegean Chub Squalius fellowesii, an Endemic Freshwater Fish Species of Western Anatolia, Turkey. *Daniela Giannetto, Laura Pompei, Massimo Lorenzoni, and Ali Serhan Tarkan. 32: 1102–1107.*

Precision of Channel Catfish Catch Estimates Using Hoop Nets in Larger Oklahoma Reservoirs. *David R. Stewart and James M. Long. 32: 1108–1112.*

Improving Size Selectivity of Shrimp Trawls in the Gulf of Maine with a Modified Dual-Grid Size-Sorting System. *Pingguo He and Vincent Balzano. 32: 1113–1122.*

Incorporating Movement Patterns to Improve Survival Estimates for Juvenile Bull Trout. *Tracy Bowerman and Phaedra Budy. 32: 1123–1136.*

Performance of Surplus Production Models with Time-Varying Parameters for Assessing Multispecies Assemblages. *Geneviève M. Nesslage and Michael J. Wilberg. 32: 1137–1145.*

Influence of Environmental Variables and Species Interactions on Sport Fish Communities in Small Missouri Impoundments. *Paul H. Michaletz, Daniel V. Obrecht, and John R. Jones. 32: 1146–1159.*

[Management Brief] Sampling Glacial Lake Littoral Fish Assemblages with Four Gears. *Daniel J. Dembkowski, Melissa R. Wuellner, and David W. Willis. 32: 1160–1166.*

Impacts of Highway Construction on Redd Counts of Stream-Dwelling Brook Trout. *Marc Pépino, Jan Franssen, Marco A. Rodríguez, and Pierre Magnan. 32: 1167–1174.*

[Management Brief] Latitudinal Influence on Age Estimates Derived from Scales and Otoliths for Bluegills. *Lucas K. Kowalewski, Alexis P. Maple, Mark A. Pegg, and Kevin L. Pope. 32: 1175–1179.*

Privately Owned Small Impoundments in Central Alabama: A Survey and Evaluation of Management Techniques for Largemouth Bass and Bluegill. *Norman V. Haley III, Russell A. Wright, Dennis R. DeVries, and Micheal S. Allen. 32: 1180–1190.*

Frequency of Strong Year-Classes: Implications on Fishery Dynamics for Three Life History Strategies of Fishes. *Daniel J. Daugherty and Nathan G. Smith. 32: 1191–1200.*

[Management Brief] Sex at Length of Summer Flounder Landed in the New Jersey Recreational Party Boat Fishery. *Jason M. Morson, Eleanor A. Bochenek, Eric N. Powell, and Jennifer E. Gius. 32: 1201–1210.*

A Comparative and Experimental Evaluation of Performance of Stocked Diploid and Triploid Brook Trout. *Phaedra Budy, Gary P. Thiede, Andrew Dean, Devin Olsen, and Gilbert Rowley. 32: 1211–1224.*

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Strategies to Control a Common Carp Population by Pulsed Commercial Harvest. *Michael E. Colvin, Clay L. Pierce, Timothy W. Stewart, and Scott E. Grummer. 32: 1251–1264.*

Expanding Aerial–Roving Surveys to Include Counts of Shore-Based Recreational Fishers from Remotely Operated Cameras: Benefits, Limitations, and Cost Effectiveness. *C. B. Smallwood, K. H. Pollock, B. S. Wise, N. G. Hall, and D. J. Gaughan. 32: 1265–1276.*

Continued from page 3

registration fees to compensate the instructor and pay for the technology required to deliver the course effectively and add some funds to the AFS coffers.

No doubt, what I have prescribed for the Special Committee on Educational Requirements and the Continuing Education Committee is a lot of work for a set of volunteers and will likely take several years to accomplish. The tasks should probably become a matter of routine for the AFS, undertaken every 5–10 years to ensure that students and career professionals being trained in fisheries-related disciplines have the right educational foundation for meeting the challenges that lie ahead.

STUDENT FUNDING AVAILABLE

American Institute of Fishery Research Biologists (AIFRB)

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A benefit of AIFRB membership for students and associate members:

The Hubbs Research Assistance Award was established in 1986 to support travel expenses associated with professional development for AIFRB graduate students and other Associate members of the Institute in good standing. The award covers travel expenses associated with presenting results of an original research paper or research project of merit at scientific meetings or to conduct research at distant study sites. Each award is a maximum of $500; an individual may receive two awards in a lifetime. The number of awards varies each year depending on the annual budget approved by the Board. **Since 1986, a total of 154 awards have been given, including four in 2012, three of which funded student travel to present at this year's AFS meeting.**

NOMINATIONS are due JUNE 15 of each year
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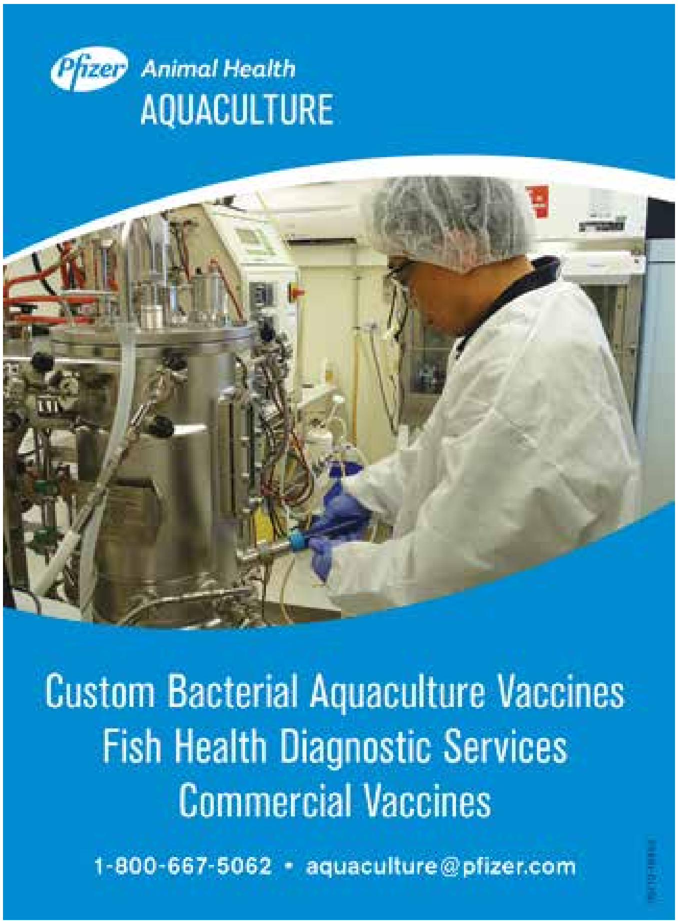
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(If space is available, events will also be printed in Fisheries magazine.)

More events listed at www.fisheries.org

DATE	EVENT	LOCATION	WEBSITE
February 5–7, 2013	32nd International Kokanee Workshop	Fort Collins, CO	Jesse Lepak at Jesse.Lepak@state.co.us
February 7–8, 2013	Winter Fisheries Training for Acoustic Tag & Hydroacoustic Assessments	Seattle, WA	www.HTIsonar.com/at_short_course.htm
February 14–15, 2013	Using Hydroacoustics for Fisheries Assessment		www.HTIsonar.com/at_short_course.htm
February 21–25, 2013	Fish Culture Section Mid-Year Business Meeting	Nashville, TN	www.was.org/WasMeetings/meetings/Default.aspx?code=AQ2013
February 21–25, 2013	Aquaculture 2013	Nashville, TN	www.was.org/WasMeetings/meetings/Default.aspx?code=AQ2013
March 13–16, 2013	31st Annual Salmonid Restoration Conference	Fortuna, CA	http://www.calsalmon.org/salmonid-restoration-conference/31st-annual-salmonid-restoration-conference
March 26–29, 2013	Responses of Arctic Marine Ecosystems to Climate Change Symposium	Anchorage, AK	seagrant.uaf.edu/conferences/2013/wakefield-arctic-ecosystems/index.php
April 8–12, 2013	7th International Fisheries Observer and Monitoring Conference (7th IFOMC)	Viña del Mar, Chile	www.ifomc.com/
April 15–18, 2013	Western Division of the AFS Annual Meeting	Boise, ID	www.idahoafs.org/meeting.php
April 25–26, 2013	NPAFC 3rd International Workshop on Migration and Survival Mechanisms of Juvenile Salmon and Steelhead in Ocean Ecosystems	Honolulu, HI	http://www.npafc.org/new/index.html
June 24–28, 2013	9th Indo-Pacific Fish Conference	Okinawa, Japan	http://www.fish-isj.jp/9ipfc
July 14–20, 2013	2nd International Conference on Fish Telemetry	Grahamstown, South Africa	Contact: Dr. Paul Cowley at tagfish@gmail.com
August 3–7, 2014	International Congress on the Biology of Fish	Edinburgh, United Kingdom	http://icbf2014.sls.hw.ac.uk

ANNOUNCEMENTS
January 2013 Jobs

Employers: to list a job opening on the AFS online job center submit a position description, job title, agency/company, city, state, responsibilities, qualifications, salary, closing date, and contact information (maximum 150 words) to jobs@fisheries.org. Online job announcements will be billed at $350 for 150 word increments. Please send billing information. Listings are free (150 words or less) for organizations with associate, official, and sustaining memberships, and for individual members, who are faculty members, hiring graduate assistants. if space is available, jobs may also be printed in *Fisheries* magazine, free of additional charge.

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Contact: E-mail cover letter and resume to below email Full job announcement at: www.fishsciences.net

Email: hr@fishsciences.net

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Email: resumes@explorecompany.com

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Professional

Salary: Editors receive an honorarium, and support to attend the AFS Annual Meeting.

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Responsibilities: : AFS Seeks Journal Editor

The American Fisheries Society (AFS) seeks a scientist with a broad perspective on fisheries to serve as editor of North American Journal of Fisheries Management (NAJFM). Editor must be committed to fast-paced deadlines, and would be appointed for a five-year renewable term which begins January 2013.

Duties include:

1. Deciding on the suitability of contributed papers, and advising authors on what would be required to make contributions publishable, using advice of associate editors and reviewers. Reviewing papers for scientific accuracy as well as for clarity, readability, and interest to the broad fisheries community;
2. Soliciting manuscripts to ensure broad coverage;
3. Setting editorial standards for NAJFM in keeping with the objectives of the publication in accordance with AFS policies, and guidance provided by the Publications Overview Committee and the NAJFM editorial board;
4. Making recommendations to enhance the vitality and prestige of the Journal.

Qualifications: This position requires marine and estuarine fisheries expertise.

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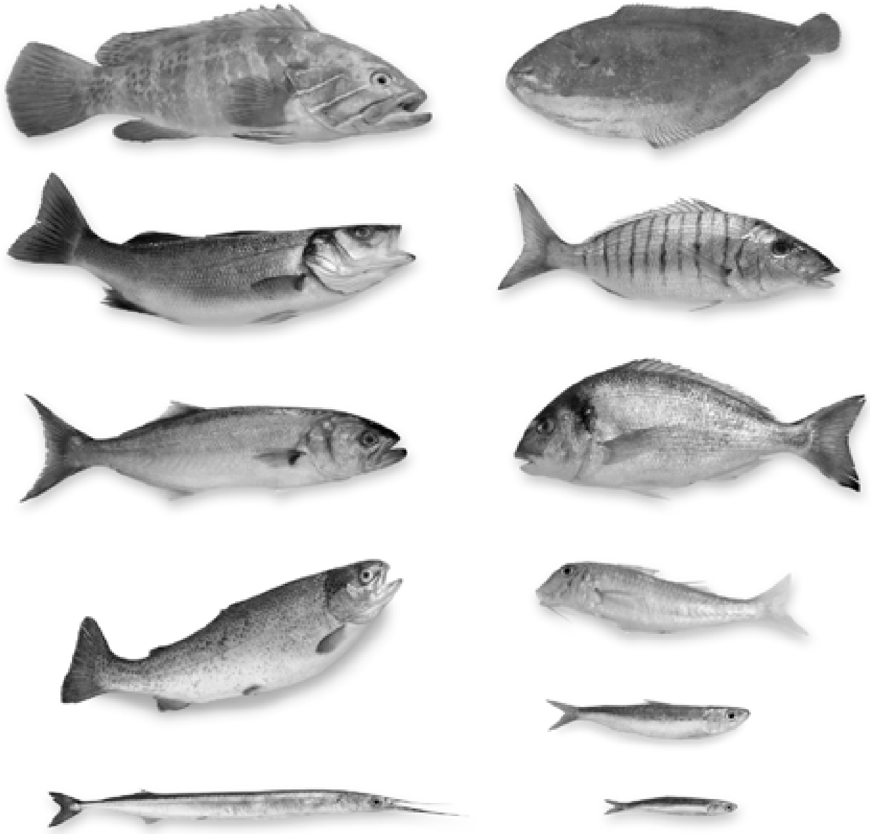
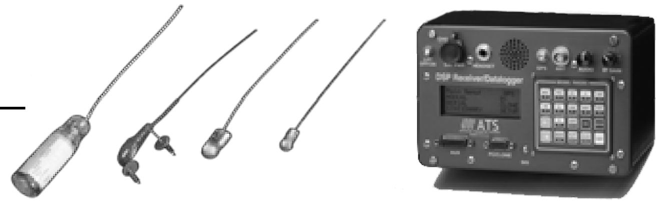
Contact: To Apply: For more information see the WDFW Employment Page for a complete listing at. This will explain job duties, minimum qualifications, competencies and desirable qualifications. If you have questions about this recruitment, you may contact Margaret Gordon, Recruitment Specialist at 360 902-2209.

Link: http://wdfw.wa.gov/employment/index.htm





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June 29, 2011

Office of Groundwater and Drinking Water
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Comments on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels

Dear Sir or Madam:

Thank you for the opportunity to provide comments on the Environmental Protection Agency's ("EPA") development of UIC Class II permitting guidance for hydraulic fracturing activities that use diesel fuels in fracturing fluids.

The Natural Resources Defense Council ("NRDC") is a national, non-profit legal and scientific organization with 1.3 million members and activists worldwide. Since its founding in 1970, NRDC has been active on a wide range of environmental issues, including fossil fuel extraction and drinking water protection. NRDC is actively engaged in issues surrounding oil and gas development and hydraulic fracturing, particularly in the Rocky Mountain West and Marcellus Shale regions.

Earthjustice is a non-profit public interest law firm originally founded in 1971. Earthjustice works to protect natural resources and the environment, and to defend the right of all people to a healthy environment. Earthjustice is actively addressing threats to air, water, public health and wildlife from oil and gas development and hydraulic fracturing in the Marcellus Shale and Rocky Mountain regions.

Founded in 1892, the Sierra Club works to protect communities, wild places, and the planet itself. With 1.4 million members and activists worldwide, the Club works to provide healthy communities in which to live, smart energy solutions to combat global warming, and an enduring legacy of for America's wild places. The Sierra club is actively addressing the environmental threats to our land, water, air from natural gas extraction across the United States.

General Comments

We appreciate EPA's decision to issue permitting guidance for hydraulic fracturing using diesel fuel. While this practice is regulated under the currently existing UIC Class II regulations, hydraulic fracturing also poses unique risks to USDWs. For that reason, we believe that EPA must promulgate new regulations in addition to permitting guidance. The issuance of permitting guidance under Class II is an important stopgap, but only through regulation that specifically address hydraulic fracturing using diesel can USDWs be adequately protected.

UNPERMITTED INJECTION OF DIESEL FUELS THROUGH HYDRAULIC FRACTURING IS A VIOLATION OF THE SAFE DRINKING WATER ACT

As an initial matter, EPA should use its proposed guidance to reemphasize an important point: the use of diesel fuel injection for hydraulic fracturing is already subject to the requirements of the Safe Drinking Water Act ("SDWA"), whether or not it is specifically addressed by EPA guidance or state UIC programs.

The statutory definition of "underground injection" as "the subsurface emplacement of fluids by well injection" plainly encompasses hydraulic fracturing. 42 U.S.C. § 300h(d)(1); see, e.g., Legal Environmental Assistance Found. v. EPA, 118 F.3d 1467, 1475 (11th Cir. 1997) (holding that the statute requires EPA to regulate hydraulic fracturing operations). SDWA underscores this point by excluding hydraulic fracturing from the definition of "underground injection," except where diesel fuel is used. 42 U.S.C. § 300h(d)(1)(B)(ii). Such an exclusion would be unnecessary if hydraulic fracturing were not otherwise a form of SDWA-regulated underground injection.

Because it represents a form of underground injection, all hydraulic fracturing with diesel fuel violates SDWA unless a permit has been issued. 42 U.S.C. § 300h(b)(1)(A); 40 C.F.R. §§ 144.1(d)(6), (g), 144.11.

Because diesel fuel contains carcinogenic benzene, toluene, ethylene, and xlyene ("BTEX") compounds it poses a major concern.[1] Therefore, when Congress exempted some hydraulic fracturing injections from the Act, it explicitly limited that exemption to wells where fluids "other than diesel fuels" are used. 42 U.S.C. § 300h(d)(1)(B)(ii).[2] For those hydraulic fracturing injections using diesel fuel, the SDWA Class II well program applies. See 40 C.F.R. § 144.6(b).

Nevertheless, many companies have continued to use diesel fuel without obtaining a permit. The minority staff of the House Committee on Energy and Commerce determined that between 2005 and 2009 "oil and gas service companies injected 32.2 million gallons of diesel fuel or hydraulic fracturing fluids containing diesel fuel in wells in 19 states."[3] The investigators determined that "no oil and gas service companies have sought – and no state and federal regulators have issued – permits for diesel fuel use in hydraulic fracturing."[4]

In light of this noncompliance (and assertions of confusion on the part of hydraulic fracturing service companies), EPA should reaffirm that these injections were illegal, and future injections without a permit are also illegal.

EPA should further clarify that these injections were barred under SDWA whether or not they occurred in a state with primacy to enforce SDWA, and whether or not such states had rules on the books. This is so because the SDWA requires each state to prohibit unpermitted injections. 42 U.S.C. § 300h(b)(1)(A).

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[1] For example, EPA described diesel as the "additive of greatest concern" in hydraulic fracturing operations.US EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* (June 2004) at ES-12.

[2] Of course, "[n]otwithstanding any other provision of [the SDWA]," including the hydraulic fracturing exemption, EPA retains its power to act against injection practices which "may present an imminent and substantial endangerment to the health of persons." 42 U.S.C. § 300i(a). EPA could also use this authority to address diesel injection.

[3] Letter from Reps. Waxman, Markey, and DeGette to EPA Administrator Lisa Jackson (Jan. 31, 2001) at 1.

[4] *Id.*; *see also* Dusty Horwitt, Environmental Working Group, *Drilling Around the Law* (2009) at 12-13 (documenting state and federal agency officials' failure to regulate these injections).

The statute leaves no room for states to simply ignore illegal injections to which the Act applies. Moreover, the SDWA regulations provide that each state program "must be administered in accordance" with various federal regulations, including 40 C.F.R. § 144.11, which prohibits "[a]ny underground injection, except into a well authorized by rule or except as authorized by permit." 40 C.F.R. § 145.11(a)(5). Thus, even if a state's rules do not explicitly address hydraulic fracturing injections with diesel fuel, the Class II permitting rules remain in place and govern all such injections.[5]

As the Congressional investigation demonstrates, oil and gas companies ignored these clear requirements.[6] In light of this apparently common failure to comply with the law, EPA would be well within its authority to ban diesel injection entirely. Diesel fuel injection is an inherent threat to safe drinking water. Cf. 42 U.S.C. § 300h(b)(1)(B) (applicants for permits must satisfactorily demonstrate that "the underground injection will not endanger drinking water sources"). Companies can and should be required to avoid using diesel fuel in their operations. But if EPA does not do so, it should at a minimum limit the threats it poses by issuing strong guidance and requiring permits to control injection practices.

Responses to EPA's Discussion Questions

WHAT SHOULD BE CONSIDERED AS "DIESEL FUELS?

The injection of any quantity of diesel fuels for hydraulic fracturing should be covered under EPA's UIC Class II regulations. This includes products derived from, containing, or mixed with diesel fuels or any fuel which could be used in a diesel engine.

At 40 CFR §80.2(x), "diesel fuel" is defined as:

Diesel fuel means any fuel sold in any State or Territory of the United States and suitable for use in diesel engines, and that is—

(1) A distillate fuel commonly or commercially known or sold as No. 1 diesel fuel or No. 2 diesel fuel;

(2) A non-distillate fuel other than residual fuel with comparable physical and chemical properties (e.g. , biodiesel fuel); or

(3) A mixture of fuels meeting the criteria of paragraphs (1) and (2) of this definition.

WHAT WELL CONSTRUCTION REQUIREMENTS SHOULD APPLY TO HF WELLS USING DIESEL FUELS?

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[5] States which do not enforce against scofflaw injectors risk their primacy, as EPA should make clear. *See* 42 U.S.C. § 300h(c) (providing that if EPA determines that "a state no longer meetings the requirements" of the SDWA, then EPA shall implement a federal program).

[6] Indeed, even diesel injection into wells permitted by rule is barred if the operator did not comply with the Class II regulations. These applicable rules include EPA's inventory requirements at 40 C.F.R. § 144.26, which trigger reporting of well location and operating status, and, for EPA-administered programs, reports on the "nature of injected fluids" and on the mechanical integrity of the well. *See* 40 C.F.R. § 144.22(prohibiting injection without inventory reporting). If operators inject into permitted-by-rule wells without complying with these and other applicable requirements, they further violate the SDWA.

Casing and Cement

Proper well construction is crucial to ensuring protection of USDWs. The first step to ensuring good well construction is ensuring proper well drilling techniques are used. This includes appropriate drilling fluid selection, to ensure that the wellbore will be properly conditioned and to minimize borehole breakouts and rugosity that may complicate casing and cementing operations. Geologic, engineering, and drilling data can provide indications of potential complications to achieving good well construction, such as highly porous or fractured intervals, lost circulation events, abnormally pressured zones, or drilling “kicks” or “shows.” These must be accounted for in designing and implementing the casing and cementing program. Reviewing data from offset wellbores can be helpful in anticipating and mitigating potential drilling and construction problems. Additionally, proper wellbore cleaning and conditioning techniques must be used to remove drilling mud and ensure good cement placement.

Hydraulic fracturing requires fluid to be injected into the well at high pressure and therefore wells must be appropriately designed and constructed to withstand this pressure. The casing and cementing program must:

- Properly control formation pressures and fluids
- Prevent the direct or indirect release of fluids from any stratum to the surface
- Prevent communication between separate hydrocarbon-bearing strata
- Protect freshwater aquifers/useable water from contamination
- Support unconsolidated sediments
- Protect and/or isolate lost circulation zones, abnormally pressured zones, and any prospectively valuable mineral deposits

Casing must be designed to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; corrosion; erosion; and hydraulic fracturing pressure. The casing design must include safety measures that ensure well control during drilling and completion and safe operations during the life of the well.

UIC Class II rules require that injection wells be cased and cemented to prevent movement of fluids into or between underground sources of drinking water and that the casing and cement be designed for the life of the well [40 CFR §146.22(b)(1)]. Achieving and maintaining mechanical integrity are crucial to ensuring these requirements. Operators must demonstrate that wells will be designed and constructed to ensure both internal and external mechanical integrity. Internal mechanical integrity refers to the absence of leakage pathways through the casing; external mechanical integrity refers to the absence of leakage pathways outside the casing, primarily through the cement.

The components of a well that ensure the protection and isolation of USDWs are steel casing and cement. Multiple strings of casing are used in the construction of oil and gas wells, including: conductor casing, surface casing, production casing, and potentially intermediate casing. For all casing strings, the design and construction should be based on Good Engineering Practices (GEP), Best Available Technology (BAT), and local and regional engineering and geologic data. All well construction materials must be compatible with fluids with which they may come into contact and be resistant to corrosion, erosion, swelling, or degradation that may result from such contact.

Conductor Casing:
Conductor casing is typically the first piece of casing installed and provides structural integrity and a conduit for fluids to drill the next section of the well. Setting depth is based on local geologic and engineering factors but is generally relatively shallow, typically down to bedrock. Depending on local conditions, conductor casing can either be driven into the ground or a hole drilled and the casing lowered into the hole. In the case where a hole is excavated, the space between the casing and the wellbore – the annulus – should be fully cemented from the base, or "shoe," of the casing to the ground surface, a practice referred to as "cementing to surface." A cement pad should also be constructed around the conductor casing to prevent the downward migration of fluids and contaminants.

Surface Casing:
Surface casing is used to: isolate and protect groundwater from drilling fluids, hydrocarbons, formation fluids, and other contaminants; provide a stable foundation for blowout prevention equipment; and provide a conduit for drilling fluids to drill the next section of the well.

Surface casing setting depth must be based on relevant engineering and geologic factors, but generally should be:

1. Shallower than any pressurized hydrocarbon-bearing zones
2. 100 feet below the deepest USDW

Surface casing must be fully cemented to surface by the pump and plug method. If cement returns are not observed at the surface, remedial cementing must be performed to cement the casing from the top of cement to the ground surface. If shallow hydrocarbon-bearing zones are encountered when drilling the surface casing portion of the hole, operators must notify regulators and take appropriate steps to ensure protection of USDWs.

Intermediate Casing:
Depending on local geologic and engineering factors, one or more strings of intermediate casing may be required. This will depend on factors including but not limited to the depth of the well, the presence of hydrocarbon-or fluid-bearing formations, abnormally pressured zones, lost circulation zones, or other drilling hazards. When used, intermediate casing should be fully cemented from the shoe to the surface by the pump and plug method. Where this is not possible or practical, the cement must extend from the casing shoe to 600 feet above the top of the shallowest zone to be isolated (e.g. productive zone, abnormally pressured zone, etc). Where the distance between the casing shoe and shallowest zone to be isolated makes this technically infeasible, multi-stage cementing must be used to isolate any hydrocarbon- or fluid-bearing formations or abnormally pressured zones and prevent the movement of fluids.

Production Casing:
To be most protective, one long-string production casing (i.e. casing that extends from the total depth of the well to the surface) should be used. This is preferable to the use of a production liner – in which the

casing does not extend to surface but is instead “hung” off an intermediate string of casing – as it provides an additional barrier to protect groundwater. The cementing requirements are the same as for intermediate casing.

Production Liner:

If production liner is used instead of long-string casing, the top of the liner must be hung at least 200 feet above previous casing shoe. The cementing requirements for production liners should be the same as for intermediate and production casing.

General:

For surface, intermediate, and production casing, a sufficient number of casing centralizers must be used to ensure that the casing is centered in the hole and in accordance with API Spec 10D (Specification for Bow-Spring Casing Centralizers) and API RP 10D-2 (Recommended Practice for Centralizer Placement and Stop Collar Testing). This is necessary to ensure that the cement is distributed evenly around the casing and is particularly important for directional and horizontal wells. In deviated wells, the casing will rest on the low side of the wellbore if not properly centralized, resulting in gaps in the cement sheath where the casing makes direct contact with the rock. Casing collars should have a minimum clearance of 0.5 inch on all sides to ensure a uniformly concentric cement sheath.

For any section of the well drilled through fresh water-bearing formations, drilling fluids must be limited to air, fresh water, or fresh water based mud and exclude the use of synthetic or oil-based mud or other chemicals. This typically applies to the surface casing and possibly conductor casing portions of the hole.

As recommended in API Guidance Document HF1: Hydraulic Fracturing Operations--Well Construction and Integrity Guidelines, all surface, intermediate, and production casing strings should be pressure tested. Drilling may not be resumed until a satisfactory pressure test is obtained. Casing must be pressure tested to a minimum of 0.22 psi/foot of casing string length or 1500 psi, whichever is greater, but not to exceed 70% of the minimum internal yield. If the pressure declines more than 10% in a 30-minute test or if there are other indications of a leak, corrective action must be taken.

Cement compressive strength tests must be performed on all surface, intermediate, and production casing strings. Casing must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi. The cement mixture must have a 72-hour compressive strength of at least 1200 psi. Additionally, the API free water separation must average no more than six milliliters per 250 milliliters of cement, tested in accordance with API RP 10B-2.

For cement mixtures without published compressive strength tests, the operator or service company must perform such tests in accordance with the current API RP 10B-6 and provide the results of these tests to regulators prior to the cementing operation. The test temperature must be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of cement. A better quality of cement may be required where local conditions make it necessary to prevent pollution or provide safer operating conditions.

As recommended in API Guidance Document HF1: Hydraulic Fracturing Operations--Well Construction and Integrity Guidelines, casing shoe tests should be performed immediately after drilling out of the surface or intermediate casing. These may include Formation Integrity Tests (FIT), Leak-Off Tests (LOT or XLOT), and pressure fall-off or pump tests. Casing shoe tests are used to ensure casing and cement integrity, determine whether the formations below the casing shoe can withstand the pressure to which they will be subjected while drilling the next section of the well, and gather data on rock mechanical properties. If any of the casing shoe tests fail, remedial action must be taken to ensure that no migrations pathways exist. Alternatively, the casing and cementing plan may need to be revised to include additional casing strings in order to properly manage pressure.

UIC Class II rules require that cement bond, temperature, or density logs be run after installing surface, intermediate, and production casing and cement [40 CFR §146.22(f)(2)(i)(B)]. Ideally, all three types of logs should be run. The term "cement bond log" refers to out-dated technology and the terms "cement evaluation logs," "cement integrity logs" or "cement mapping logs" are preferable. Cement integrity and location must be verified using cement evaluation tools that can detect channeling in 360 degrees. A poor cement job, in which the cement contains air pockets or otherwise does not form a complete bond between the rock and casing or between casing strings, can allow fluids to move behind casing from the reservoir into USDWs. Verifying the integrity of the cement job is crucial to ensure no unintended migration of fluids. Traditional bond logs cannot detect the fine scale channeling which may allow fluids to slowly migrate over years or decades and therefore the use of more advanced cement evaluation logs is crucial. (For further reading see, e.g., Lockyear et. al, 1990; Frisch et. al, 2005)

When well construction is completed, the operator should certify, in writing, that the casing and cementing requirements were met for each casing string.

In addition, it may be useful to review the casing and cementing regulations of states with long histories of oil and gas production such as Texas, Alaska, California, and Pennsylvania. Specific examples include:

- Requirements for casing and cementing record keeping for casing and cementing operations in the California Code of Regulations (CCR) at 14 CCR §1724
- Requirements for casing and cementing program application content in the Alaska Administrative Code (AAC) at 20 AAC §25.030(a)
- Cement chemical and physical degradation standard in the Pennsylvania Code (Pa. Code) at 25 Pa. Code §78.85(a)
- Requirement to report and repair defective casing or take the well out of service in the Pennsylvania Code at 25 Pa. Code §78.86
- Casing standard in gas storage areas in the Pennsylvania Code at 25 Pa. Code §78.75, in areas with gas storage
- Casing standard in coal development areas in the Pennsylvania Code at 25 Pa. Code §78.75, in areas with sufficient coal seams
- Casing testing and minimum overlap length standards in the California Code of Regulations at 14 CCR §1722

- Cement quality, testing, and remedial repair standard in the Alaska Administrative Code at 20 AAC §25.030
- Casing quality and amount standard in the Pennsylvania Code at 25 Pa. Code §78.84 and §78.71

Well Logs

After drilling the well but prior to casing and cementing operations, operators must obtain well logs to aid in the geologic, hydrologic, and engineer characterization of the subsurface. Open hole logs, i.e. logs run prior to installing casing and cement, should at a minimum include:

Gamma Ray Logs:
Gamma ray logs detect naturally occurring radiation. These logs are commonly used to determine generic lithology and to correlate subsurface formations. Shale formations have higher proportions of naturally radioactive isotopes than sandstone and carbonate formations. Thus, these formations can be distinguished in the subsurface using gamma ray logs.

Density/Porosity Logs:
Two types of density logs are commonly used: bulk density logs, which are in turn used to calculate density porosity, and neutron porosity logs. While not a direct measure of porosity, these logs can be used to calculate porosity when the formation lithology is known. These logs can be used to determine whether the pore space in the rock is filled with gas or with water.

Resistivity Logs:
These logs are used to measure the electric resistivity, or conversely conductivity, of the formation. Hydrocarbon- and fresh water-bearing formations are resistive, i.e. they cannot carry an electric current. Brine-bearing formations have a low resistivity, i.e. they can carry an electric current. Resistivity logs can therefore be used to help distinguish brine-bearing from hydrocarbon-bearing formations. In combination with Darcy's Law, resistivity logs can be used to calculate water saturation.

Caliper Logs:
Caliper logs are used to determine the diameter and shape of the wellbore. These are crucial in determining the volume of cement that must be used to ensure proper cement placement.

These four logs, run in combination, make up one of the most commonly used logging suites. Additional logs may be desirable to further characterize the formation, including but not limited to Photoelectric Effect, Sonic, Temperature, Spontaneous Potential, Formation Micro-Imaging (FMI), Borehole Seismic, and Nuclear Magnetic Resonance (NMR). The use of these and other logs should be tailored to site-specific needs. (For further reading see, e.g., Asquith and Krygowski, 2004)

UIC Class II rules have specific logging requirements "(f)or surface casing intended to protect underground sources of drinking water in areas where the lithology has not been determined" [40 CFR §146.22(f)(2)(i)]. For such wells, electric and caliper logs must be run before surface casing is installed [40 CFR §146.22(f)(2)(i)(A)]. Such logs should be run on all wells, not just those where lithology has not been determined, and the electric logs suite should include, at a minimum, caliper, resistivity and gamma ray or spontaneous potential logs. For intermediate and long string casing "intended to facilitate injection," UIC Class II rules require that electric porosity, gamma ray, and fracture finder logs be run before casing is installed [40 CFR §146.22(f)(2)(ii)(A) and (B)]. Hydraulic fracturing should be included in the definition of “injection.” Operators should also run caliper and resistivity logs. The term “fracture finder logs” refers to out-dated technology. More advanced tools for locating fractures should be used, such as borehole imaging logs (e.g. FMI logs) and borehole seismic.

Core and Fluid Sampling

While not specifically required by current UIC Class II regulations, operators of wells that will be hydraulically fractured using diesel should also obtain whole or sidewall cores of the producing and confining zone(s) and formation fluid samples from the producing zone(s). At a minimum, routine core analysis should be performed on core samples representative of the range of lithology and facies present in the producing and confining zone(s). Special Core Analysis (SCAL) should also be considered, particularly for samples of the confining zone, where detailed knowledge of rock mechanical properties is necessary to determine whether the confining zone can prevent or arrest the propagation of fractures. Operators should also record the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the producing and confining zone(s). Operators should prepare and submit a detailed report on the physical and chemical characteristics of the producing and confining zone(s) and formation fluids that integrates data obtained from well logs, cores, and fluid samples. This must include the fracture pressure of both the producing and confining zone(s).

WHAT WELL OPERATION, MECHANICAL INTEGRITY, MONITORING, AND REPORTING REQUIREMENTS SHOULD APPLY TO HF WELLS USING DIESEL FUELS?

Mechanical Integrity

Operators must maintain mechanical integrity of wells at all times. Mechanical integrity should be periodically tested by means of a pressure test with liquid or gas, a tracer survey such as oxygen activation logging or radioactive tracers, a temperature or noise log, and a casing inspection log. The frequency of such testing should be based on site and operation specific requirements and be delineated in a testing and monitoring plan prepared, submitted, and implemented by the operator.

Mechanical integrity and annular pressure should be monitored over the life of the well. Instances of sustained casing pressure can indicate potential mechanical integrity issues. The annulus between the production casing and tubing (if used) should be continually monitored. Continuous monitoring allows problems to be identified quickly so repairs may be made in a timely manner, reducing the risk that a wellbore problem will result in contamination of USDWs.

Operations and Monitoring

Each hydraulic fracturing treatment must be modeled using a 3D geologic and reservoir model, as described in the Area of Review requirements, prior to operation to ensure that the treatment will not endanger USDWs. Prior to performing a hydraulic fracturing treatment, operators should perform a pressure fall-off or pump test, injectivity tests, and/or a mini-frac. Data obtained from such tests can be used to refine the hydraulic fracture model, design, and implementation.

The hydraulic fracturing operation must be carefully and continuously monitored. In API Guidance Document HF1, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines, the

America Petroleum Institute recommends continuous monitoring of surface injection pressure, slurry rate, proppant concentration, fluid rate, and sand or proppant rate.

If at any point during the hydraulic fracturing operation the monitored parameters indicate a loss of mechanical integrity or if injection pressure exceeds the fracture pressure of the confining zone(s), the operation must immediately cease. If either occurs, the operator must notify the regulator within 24 hours and must take all necessary steps to determine the presence or absence of a leak or migration pathways to USDWs. Prior to any further operations, mechanical integrity must be restored and demonstrated to the satisfaction of the regulator and the operator must demonstrate that the ability of the confining zone(s) to prevent the movement of fluids to USDWs has not been compromised. If a loss of mechanical integrity is discovered or if the integrity of the confining zone has been compromised, operators must take all necessary steps to evaluate whether injected fluids or formation fluids may have contaminated or have the potential to contaminate any unauthorized zones. If such an assessment indicates that fluids may have been released into a USDW or any unauthorized zone, operators must notify the regulator within 24 hours, take all necessary steps to characterize the nature and extent of the release, and comply with and implement a remediation plan approved by the regulator. If such contamination occurs in a USDW that serves as a water supply, a notification must be placed in a newspaper available to the potentially affected population and on a publically accessible website and all known users of the water supply must be individually notified immediately by mail and by phone.

Techniques to measure actual fracture growth should be used, including downhole tiltmeters and microseismic monitoring. These techniques can provide both real-time data and, after data processing and interpretation, can be used in post-fracture analysis to inform fracture models and refine hydraulic fracture design. Tiltmeters measure small changes in inclination and provide a measure of rock deformation. Microseismic monitoring uses highly sensitive seismic receivers to measure the very low energy seismic activity generated by hydraulic fracturing (For further reading see, e.g., House, 1987; Maxwell et al., 2002; Le Calvez et al., 2007; Du et al., 2008; Warpinski et al., 2008; Warpinski, 2009; and Cipolla et al. 2011).

Hydraulic fracturing fluid and proppant can sometimes be preferentially taken up by certain intervals or perforations. Tracer surveys and temperature logs can be used to help determine which intervals were treated. Tracers can be either chemical or radioactive and are injected during the hydraulic fracturing operation. After hydraulic fracturing is completed, tools are inserted into the well that can detect the tracer(s). Temperature logs record the differences in temperature between zones that received fracturing fluid, which is injected at ambient surface air temperature, and in-situ formation temperatures, which can be in the hundreds of degrees Fahrenheit.

Operators should develop, submit, and implement a long-term groundwater quality monitoring program. Dedicated water quality monitoring wells should be used to help detect the presence of contaminants prior to their reaching domestic water wells. Placement of such wells should be based on detailed hydrologic flow models and the distribution and number of hydrocarbon wells. Baseline monitoring should begin at least a full year prior to any activity, with monthly or quarterly sampling to characterize seasonal variations in water chemistry. Monitoring should continue a minimum of 5 years prior to plugging and abandonment.

Reporting

At a minimum, operators must report:

- All instances of hydraulic fracturing injection pressure exceeding operating parameters as specified in the permit
- All instances of an indication of loss of mechanical integrity
- Any failure to maintain mechanical integrity
- The results of:
    - Continuous monitoring during hydraulic fracturing operations
    - Techniques used to measure actual fracture growth
    - Any mechanical integrity tests
- The detection of the presence of contaminants pursuant to the groundwater quality monitoring program
- Indications that injected fluids or displaced formation fluids may pose a danger to USDWs
- All spills and leaks
- Any non-compliance with a permit condition

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation:

1. Baseline water quality analyses for all USDWs within the area of review
2. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids
3. Proposed chemical additives (including proppant coating), reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the proposed concentration or rate and volume percentage of all additives

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation:

1. Actual source, volume, geochemistry and timing of withdrawal of all base fluids
2. Actual chemical additives used, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the actual concentration or rate and volume percentage of all additives
3. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes

Emergency and Remedial Response

Operators must develop, submit, and implement an emergency response and remedial action plan. The plan must describe the actions the operator will take in response to any emergency that may endanger human life or the environment – including USDWs – such as blowouts, fires, explosions, or leaks and spills of toxic or hazardous chemicals. The plan must include an evaluation of the ability of local resources to respond to such emergencies and, if found insufficient, how emergency response personnel and equipment will be supplemented. Operators should detail what steps they will take to respond to cases of suspected or known water contamination, including notification of users of the water source. The plan must describe what actions will be taken to replace the water supplies of affected individuals in the case of the contamination of a USDW.

The American Petroleum Institute has published recommended practices for developing a Safety and Environmental Management System (SEMS) plan, API Recommended Practice 75L: Guidance Document for the Development of a Safety and Environmental Management System for Onshore Oil and Natural Gas Production Operation and Associated Activities. This may be a useful document to reference when developing guidance.

WHAT SHOULD THE PERMIT DURATION BE AND HOW SHOULD CLASS II PLUGGING AND ABANDONMENT PROVISIONS BE ADDRESSED FOR CLASS II WELLS USING DIESEL FUELS FOR HF?

The permit should be valid for the life of the well. However, operators must request and receive approval prior to performing any hydraulic fracturing operations that occur subsequent to the initial hydraulic fracturing operation for which the permit was approved. This can be accomplished by means of a sundry or amended permit. Operators must provide updates to all relevant permit application data to the regulator.

Prior to plugging and abandoning a well, operators should determine bottom hole pressure and perform a mechanical integrity test to verify that no remedial action is required. Operators should develop and implement a well plugging plan. The plugging plan should be submitted with the permit application and should include the methods that will be used to determine bottom hole pressure and mechanical integrity; the number and type of plugs that will be used; plug setting depths; the type, grade, and quantity of plugging material that will be used; the method for setting the plugs, and; a complete wellbore diagram showing all casing setting depths and the location of cement and any perforations.

Plugging procedures must ensure that hydrocarbons and fluids will not migrate between zones, into USDWs, or to the surface. A cement plug should be placed at the surface casing shoe and extend at least 100 feet above and below the shoe. All hydrocarbon-bearing zones should be permanently sealed with a plug that extends at least 100 feet above and below the top and base of all hydrocarbon-bearing zones. Plugging of a well must include effective segregation of uncased and cased portions of the wellbore to prevent vertical movement of fluid within the wellbore. A continuous cement plug must be placed from at least 100 feet below to 100 feet above the casing shoe. In the case of an open hole completion, any hydrocarbon- or fluid-bearing zones shall be isolated by cement plugs set at the top and bottom of such formations, and that extend at least 100 feet above the top and 100 feet below the bottom of the formation.

At least 60-days prior to plugging, operators must submit a notice of intent to plug and abandon. If any changes have been made to the previously approved plugging plan the operator must also submit a revised plugging plan. No later than 60-days after a plugging operation has been completed, operators must submit a plugging report, certified by the operator and person who performed the plugging operation.

After plugging and abandonment, operators must continue to conduct monitoring and provide financial assurance for an adequate time period, as determined by the regulator, that takes into account site-specific characteristics including but not limited to:

- The results of hydrologic and reservoir modeling that assess the potential for movement of contaminants into USDWs over long time scales.
- Models and data that assess the potential degradation of well components (e.g. casing, cement) over time and implications for mechanical integrity and risks to USDWs.

WHAT SHOULD THE TIME FRAME BE FOR SUBMITTING A PERMIT FOR CLASS II WELLS USING DIESEL FUELS FOR HF?

All operators who wish to drill a Class II well using diesel fuel for hydraulic fracturing must submit a permit application to the regulator. Permit applications should be submitted within a reasonable timeframe but no less than 30 days prior to when the operator intends to begin construction. Under no circumstances shall activity commence until the application is approved and a permit is issued.

WHAT ARE IMPORTANT SITING CONSIDERATIONS?

Site Characterization & Planning

Detailed site characterization and planning and baseline testing prior to any oil and gas development are crucial. Site characterization and planning must take into account cumulative impacts over the life of a project or field.

Operators must submit to the regulator a statistically significant sample, as determined by the regulator, of existing and/or new geochemical analyses of each of the following, within the area of review:

1. Any and all sources of water that serve as USDWs in order to characterize baseline water quality. This data must be made publically available through an online, geographically-based reporting system. The sampling methodology must be based on local and regional hydrologic characteristics such as rates of precipitation and recharge and seasonal fluctuations. At a minimum, characterization must include:
    a. Standard water quality and geochemistry[7]
    b. Stable isotopes
    c. Dissolved gases
    d. Hydrocarbon concentration and composition. If hydrocarbons are present in sufficient quantities for analysis, isotopic composition must be determined

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[7] Including: Turbidity, Specific Conductance, Total Solids, Total Dissolved Solids, pH, Dissolved Oxygen, Redox State, Alkalinity, Calcium, Magnesium, Sodium, Potassium, Sulfate, Chloride, Fluoride, Bromide, Silica, Nitrite, Nitrate + Nitrite, Ammonia, Phosphorous, Total Organic Carbon, Aluminum, Antimony, Arsenic, Barium, Beryllium, Boron, Bromide, Cadmium, Chromium, Cobalt, Copper, Cyanide, Iron, Lead, Manganese, Mercury, Molybdenum, Nickel, Selenium, Silver, Strontium, Thallium, Thorium, Uranium, Vanadium, Zinc, Cryptosporidium, Giardia, Plate Count, Legionella, Total Coliforms, and Organic Chemicals including Volatile Organic Compounds (VOCs)

    e. Chemical compounds or constituents thereof, or reaction products that may be introduced by the drilling or hydraulic fracturing process. The use of appropriate marker chemicals is permissible provided that the operator can show scientific justification for the choice of marker(s).

  Operators should also consider testing for environmental tracers to determine groundwater age.

2. Any hydrocarbons that may be encountered both vertically and areally throughout the area of review;
3. The producing zone(s) and confining zone(s) and any other intervening zones as determined by the regulator. At a minimum, characterization must include:
    a. Mineralogy
    b. Petrology
    c. Major and trace element bulk geochemistry

Operators of wells that will be hydraulically fractured must demonstrate to the satisfaction of the regulator that the wells will be sited in a location that is geologically suitable. In order to allow the regulator to determine suitability, the owner or operator must provide:

1. A detailed analysis of regional and local geologic stratigraphy and structure including, at a minimum, lithology, geologic facies, faults, fractures, stress regimes, seismicity, and rock mechanical properties.
2. A detailed analysis of regional and local hydrology including, at a minimum, hydrologic flow and transport data and modeling and aquifer hydrodynamics; properties of the producing and confining zone(s); groundwater levels for relevant formations; discharge points, including springs, seeps, streams, and wetlands; recharge rates and primary zones, and; water balance for the area including estimates of recharge, discharge, and pumping
3. A detailed analysis of the cumulative impacts of hydraulic fracturing on the geology of producing and confining zone(s) over the life of the project. This must include, but is not limited to, analyses of changes to conductivity, porosity, and permeability; geochemistry; rock mechanical properties; hydrologic flow; and fracture mechanics.
4. A determination that the geology of the area can be described confidently and that the fate and transport of injected fluids and displaced formation fluids can be accurately predicted through the use of models.

Wells that will be hydraulically fractured must be sited such that a suitable confining zone is present. The operator must demonstrate to the satisfaction of the regulator that the confining zone:

1. Is of sufficient areal extent to prevent the movement of fluids to USDWs, based on the projected lateral extent of hydraulically induced fractures, injected hydraulic fracturing fluids, and displaced formation fluids over the life of the project;
2. Is sufficiently impermeable to prevent the vertical migration of injected hydraulic fracturing fluids or displaced formation fluids over the life of the project;
3. Is free of transmissive faults or fractures that could allow the movement of injected hydraulic fracturing fluids or displaced formation fluids to USDWs; and

4. Contains at least one formation of sufficient thickness and with lithologic and stress characteristics capable of preventing or arresting vertical propagation of fractures.
5. The regulator may require operators of wells that will be hydraulically fractured to identify and characterize additional zones that will impede or contain vertical fluid movement.

The site characterization and planning data listed above does not have to be submitted with each individual well application as long as such data is kept on file with the appropriate regulator and the well for which a permit is being sought falls within the designated area of review.

WHAT SUGGESTIONS DO YOU HAVE FOR REVIEWING THE AREA AROUND THE WELL TO ENSURE THERE ARE NO CONDUITS FOR FLUID MIGRATION, SEISMICITY, ETC.?

The area of review should be the region around a well or group of wells that will be hydraulically fractured where USDWs may be endangered. It should be delineated based on 3D geologic and reservoir modeling that accounts for the physical and chemical extent of hydraulically induced fractures, injected hydraulic fracturing fluids and proppant, and displaced formation fluids and must be based on the life of the project. The physical extent would be defined by the modeled length and height of the fractures, horizontal and vertical penetration of hydraulic fracturing fluids and proppant, and horizontal and vertical extent of the displaced formation fluids. The chemical extent would be defined by that volume of rock in which chemical reactions between the formation, hydrocarbons, formation fluids, or injected fluids may occur, and should take into account potential migration of fluids over time.

The model must take into account all relevant geologic and engineering information including but not limited to:

1. Rock mechanical properties, geochemistry of the producing and confining zone, and anticipated hydraulic fracturing pressures, rates, and volumes.
2. Geologic and engineering heterogeneities
3. Potential for migration of injected and formation fluids through faults, fractures, and manmade penetrations.
4. Cumulative impacts over the life of the project.

As actual data and measurements become available, the model must be updated and history matched. Operators must develop, submit, and implement a plan to delineate the area of review. The plan should include the time frame under which the delineation will be reevaluated, including those operational or monitoring conditions that would trigger such a reevaluation.

Within the area of review, operators must identify all wells that penetrate the producing and confining zones and provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the regulator may require. If any the wells identified are improperly constructed, completed, plugged, or abandoned, corrective action must be taken to ensure that they will not become conduits for injected or formation fluids to USDWs. Operators must develop, submit, and implement a corrective action plan.

WHAT INFORMATION SHOULD BE SUBMITTED WITH THE PERMIT APPLICATION?

In addition to the requirements at 40 CFR §146.24, operators should also submit the following information:

1. Information on the geologic structure, stratigraphy, and hydrogeologic properties of the proposed producing formation(s) and confining zone(s), consistent with Site Characterization and Planning requirements, including:
    a. Maps and cross-sections of the area of review
    b. The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not provide migration pathways for injected fluids or displaced formation fluids to USDWs
    c. Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the producing and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions
    d. Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the producing and confining zone(s)
    e. Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not affect the integrity of the confining zone(s)
    f. Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area
    g. Hydrologic flow and transport data and modeling
2. A list of all wells within the area of review that penetrate the producing or confining zone and a description of each well’s type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the regulator may require.
3. Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known
4. Baseline geochemical analyses of USDWs, hydrocarbons, and the producing and confining zone, consistent with the requirements for Site Characterization & Planning
5. Proposed area of review and corrective action plan that meet the Area of Review and Corrective Action Plan requirements
6. A demonstration that the operator has met the financial responsibility requirements
7. Proposed pre-hydraulic fracturing formation testing program to analyze the physical and chemical characteristics of the producing and confining zone(s), that meet the Well Log, Core, Fluid Sampling, and Testing requirements
8. Well construction procedures that meet the Well Construction requirements
9. Proposed operating data for the hydraulic fracturing operation:
    a. Operating procedure
    b. Calculated fracture gradient of the producing and confining zone(s)

    c. Maximum pressure, rate, and volume of injected fluids and proppant and demonstration that the proposed hydraulic fracturing operation will not initiate fractures in the confining zone or cause the movement of hydraulic fracturing or formation fluids that endangers a USDW

10. Proposed chemical additives:
    a. Service companies and operators must report all proposed additives by their type (e.g. breaker, corrosion inhibitor, proppant, etc), chemical compound or constituents, and Chemical Abstracts Service (CAS) number
    b. Service companies and operators must report the proposed concentration or rate and volume percentage of all additives
11. Proposed testing and monitoring plan that meets the testing and monitoring plan requirements
12. Proposed well plugging plan that meets the plugging plan requirements
13. Proposed emergency and remedial action plan
14. Prior to granting final approval for a hydraulic fracturing operation, the regulator should consider the following information:
    a. The final area of review based on modeling and using data obtained from the logging, sampling, and testing procedures
    b. Any updates to the determination of geologic suitability of the site and presence of an appropriate confining zone based on data obtained from the logging, sampling, and testing procedures
    c. Information on potential chemical and physical interactions and resulting changes to geologic properties of the producing and confining zone(s) due to hydraulic fractures and the interaction of the formations, formation fluids, and hydraulic fracturing fluids, based on data obtained from the logging, sampling, and testing procedures
    d. The results of the logging, sampling, and testing requirements
    e. Final well construction procedures that meet the well construction requirements
    f. Status of corrective action on the wells in the area of review
    g. A demonstration of mechanical integrity
    h. Any updates to any aspect of the plan resulting from data obtained from the logging, sampling, and testing requirements.

HOW COULD CLASS II FINANCIAL RESPONSIBILITY REQUIREMENTS BE MET FOR WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

Operators must demonstrate and maintain financial responsibility by means of a bond, letter of credit, insurance, escrow account, trust fund, or some combination of these financial mechanisms or any other mechanism approved by the regulator. The financial responsibility mechanism must cover the cost of corrective action, well plugging and abandonment, emergency and remedial response, long term monitoring, and any clean up action that may be necessary as a result of contamination of a USDW.

WHAT PUBLIC NOTIFICATION REQUIREMENTS OR SPECIAL ENVIRONMENTAL JUSTICE CONSIDERATIONS SHOULD BE CONSIDERED FOR AUTHORIZATION OF WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

EPA must ensure that there are opportunities for public involvement and community engagement throughout all steps of the process.

1. The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation:
    a. Baseline water quality analyses for all USDWs within the area of review
    b. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids
    c. Proposed chemical additives, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the proposed concentration or rate and volume percentage of all additives
2. The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation:
    a. Actual source, volume, geochemistry and timing of withdrawal of all base fluids
    b. Actual chemical additives, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the actual concentration or rate and volume percentage of all additives
    c. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes

WHAT ARE EFFICIENT ALTERNATIVES TO AUTHORIZE/PERMIT CLASS II WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

The use of area permits should not be allowed for wells that use diesel fuel for hydraulic fracturing. Each hydraulic fracturing operation is unique and designed for site-and well-specific needs. The fluid volumes required, chemical make-up of hydraulic fracturing fluid, and geology and hydrology of the producing and confining zones can vary from well to well.

In situations where multiple wells will be drilled from the same surface location or pad, it may be permissible to issue a group permit for all such wells. In requesting a group permit, operators must provide the regulator with an analysis demonstrating that the geology, hydrology, and operating parameters of all wells are sufficiently similar such that the issuance of a group permit will not pose increased risks to USDWs as compared to individual permits. If a group permit is approved, operators must still disclose information on injected chemicals for each individual well unless the type and volume of chemicals injected will be identical for each well. Operators must also still provide geochemical analyses of flowback and produced water for each individual well.

Conclusions

Thank you for your consideration of these comments. We are pleased that EPA is undertaking this effort to develop permitting guidance for hydraulic fracturing using diesel fuel. While this guidance is crucial to ensure that no further unpermitted hydraulic fracturing using diesel occurs, we urge EPA to begin the process of drafting new regulation that specifically addresses the unique risks hydraulic fracturing poses to USDWs.

Sincerely,

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ground water

Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers

by Tom Myers

Abstract

Hydraulic fracturing of deep shale beds to develop natural gas has caused concern regarding the potential for various forms of water pollution. Two potential pathways—advective transport through bulk media and preferential flow through fractures—could allow the transport of contaminants from the fractured shale to aquifers. There is substantial geologic evidence that natural vertical flow drives contaminants, mostly brine, to near the surface from deep evaporite sources. Interpretative modeling shows that advective transport could require up to tens of thousands of years to move contaminants to the surface, but also that fracking the shale could reduce that transport time to tens or hundreds of years. Conductive faults or fracture zones, as found throughout the Marcellus shale region, could reduce the travel time further. Injection of up to 15,000,000 L of fluid into the shale generates high pressure at the well, which decreases with distance from the well and with time after injection as the fluid advects through the shale. The advection displaces native fluids, mostly brine, and fractures the bulk media widening existing fractures. Simulated pressure returns to pre-injection levels in about 300 d. The overall system requires from 3 to 6 years to reach a new equilibrium reflecting the significant changes caused by fracking the shale, which could allow advective transport to aquifers in less than 10 years. The rapid expansion of hydraulic fracturing requires that monitoring systems be employed to track the movement of contaminants and that gas wells have a reasonable offset from faults.

Introduction

The use of natural gas (NG) in the United States has been increasing, with 53% of new electricity generating capacity between 2007 and 2030 projected to be with NG-fired plants (EIA 2009). Unconventional sources account for a significant proportion of the new NG available to the plants. A specific unconventional source has been deep shale-bed NG, including the Marcellus shale primarily in New York, Pennsylvania, Ohio, and West Virginia (Soeder 2010), which has seen over 4000 wells developed between 2009 and 2010 in Pennsylvania (Figure 1). Unconventional shale-bed NG differs from conventional sources in that the host-formation permeability is so low that gas does not naturally flow in timeframes suitable for development. Hydraulic fracturing (fracking, the industry term for the operation; Kramer 2011) loosens the formation to release the gas and provide pathways for it to move to a well.

Fracking injects up to 17 million liters of fluid consisting of water and additives, including benzene at concentrations up to 560 ppm (Jehn 2011), at pressures up to 69,000 kPa (PADEP 2011) into low permeability shale to force open and connect the fractures. This is often done using horizontal drilling through the middle of the shale with wells more than a kilometer long. The amount of injected fluid that returns to the ground surface after fracking ranges from 9% to 34% of the injected fluid (Alleman 2011; NYDEC 2009), although some would be formation water.

Many agency reports and legal citations (DiGiulio et al. 2011; PADEP 2009; ODNR 2008) and peer-reviewed articles (Osborn et al. 2011; White and Mathes

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Figure 1. Location of Marcellus shale in the northeastern United States. Location of Marcellus wells (dots) drilled from July 2009 to June 2010 and total Marcellus shale wells in New York and West Virginia. There are 4064 wells shown in Pennsylvania, 48 wells in New York, and 1421 wells in West Virginia. Faulting in the area is documented by PBTGS (2001), Isachsen and McKendree (1977), and WVGES (2011, 2010a, 2010b).

2006) have found more gas in water wells near areas being developed for unconventional NG, documenting the source can be difficult. One reason for the difficulty is the different sources; thermogenic gas is formed by compression and heat at depth and bacteriogenic gas is formed by bacteria breaking down organic material (Schoell 1980). The source can be distinguished based on both C and H isotopes and the ratio of methane to higher chain gases (Osborn and McIntosh 2010; Breen et al. 2007). Thermogenic gas can reach aquifers only by leaking from the well bore or by seeping vertically from the source. In either case, the gas must flow through potentially very thick sequences of sedimentary rock to reach the aquifers. Many studies which have found thermogenic gas in water wells found more gas near fracture zones (DiGiulio et al. 2011; Osborn et al. 2011; Breen et al. 2007), suggesting that fractures are pathways for gas transport.

A pathway for gas would also be a pathway for fluids and contaminants to advect from the fractured shale to the surface, although the transport time would be longer. Fracking fluid has been found in aquifers (DiGiulio et al. 2011; EPA 1987), although the exact source and pathways had not been determined. With the increasing development of unconventional NG sources, the risk to aquifers could be increasing. With so little data concerning the movement of contaminants along pathways from depth, either from wellbores or from deep formations, to aquifers, conceptual analyses are an alternative means to consider the risks.

The intent of this study is to characterize the risk factors associated with vertical contaminant transport from the shale to near-surface aquifers through natural pathways. I consider first the potential pathways for contaminant transport through bedrock and the necessary conditions for such transport to occur. Second, I estimate contaminant travel times through the potential pathways, with a bound on these estimates based on formation hydrologic parameters, using interpretative MODFLOW-2000 (Harbaugh et al. 2000) computations. The modeling does not, and cannot, account for all of the complexities of the geology, which could either increase or decrease the travel times compared to those considered herein. The article also does not include improperly abandoned boreholes which could cause rapid transport in addition to natural pathways.

Method of Analysis

Using the Marcellus shale region of southern New York (Figure 1), I consider several potential scenarios of transport from shale, 1500 m below ground surface (bgs) to the surface, beginning with pre-development steady state conditions to establish a baseline and then scenarios considering transport after fracking has potentially caused contaminants to reach formations above the shale. To develop the conceptual models and MODFLOW-2000 simulations, it is necessary first to consider the hydrogeology of the shale and the details of hydraulic fracturing, including details of how fracking changes the shale hydrogeologic properties.

Hydrogeology of Marcellus Shale

Shale is a mudstone, a sedimentary rock consisting primarily of clay- and silt-sized particles. It forms through the deposition of fine particles in a low energy environment, such as a lake- or seabed. The Marcellus shale formed in very deep offshore conditions during Devonian time (Harper 1999) where only the finest particles had remained suspended. The depth to the Marcellus shale varies to as much as 3000 m in parts of Pennsylvania, and averages about 1500 m in southern New York (Soeder 2010). Between the shale and the ground surface are layers of sedimentary rock, including sandstone, siltstone, and shale (NYDEC 2009).

Marcellus shale has very low natural intrinsic permeability, on the order of 10^{-16} Darcies (Kwon et al. 2004a, 2004b; Neuzil 1986, 1994). Schulze-Makuch et al. (1999) described Devonian shale of the Appalachian Basin, of which the Marcellus is a major part, as containing "coaly organic material and appear either gray or black" and being "composed mainly of tiny quartz grains <0.005 mm diameter with sheets of thin clay flakes." Median particle size is 0.0069 ± 0.00141 mm with a grain size distribution of <2% sand, 73% silt, and 25% clay. Primary pores are typically 5×10^{-5} mm in diameter, matrix porosity is typically 1% to 4.5% and fracture porosity is typically 7.8% to 9% (Schulze-Makuch et al. 1999 and references therein).

Porous flow in unfractured shale is negligible due to the low bulk media permeability, but at larger scales fractures control and may allow significant flow. The Marcellus shale is fractured by faulting and contains synclines and anticlines that cause tension cracks (Engelder et al. 2009; Nickelsen 1986). It is sufficiently fractured in some places to support water wells just 6 to 10 km from where it is being developed for NG at 2000 m bgs (Loyd and Carswell 1981). Conductivity scale dependency (Schulze-Makuch et al. 1999) may be described as follows:

$$K = Cv^m$$

K is hydraulic conductivity (m/s), C is the intercept of a log-log plot of observed K to scale (the K at a sample volume of 1 m^3), v is sample volume (m^3), and m is a scaling exponent determined with log-log regression; for Devonian shale, C equals $10^{-14.3}$, representing the intercept, and m equals 1.08 (Schulze-Makuch et al. 1999). The very low intercept value is a statistical but not geologic outlier because it corresponds with very low permeability values and demonstrates the importance of fracture flow in the system (Schulze-Makuch et al. 1999). Most of their 89 samples were small because the deep shale is not easily tested at a field-scale and no groundwater models have been calibrated for flow through the Marcellus shale. Considering a 1-km square area with 30-m thickness, the Kh would equal 5.96×10^{-7} m/s (0.0515 m/d). This effective K is low and the shale would be an aquitard, but a leaky one.

Contaminant Pathways from Shale to the Surface

Thermogenic NG found in near-surface water wells (Osborn et al. 2011; Breen et al. 2007) demonstrates the potential for vertical transport of gas from depth. Osborn et al. (2011) found systematic circumstantial evidence for higher methane concentrations in wells within 1 km of Marcellus shale gas wells. Potential pathways include advective transport through sedimentary rock, fractures and faults, and abandoned wells or open boreholes. Gas movement through fractures depends on fracture width (Etiope and Martinelli 2002) and is a primary concern for many projects, including carbon sequestration (Annunziatellis et al. 2008) and NG storage (Breen et al. 2007). Open boreholes and improperly sealed water and gas wells can be highly conductive pathways among aquifers (Lacombe et al. 1995; Silliman and Higgins 1990).

Pathways for gas suggest pathways for fluids and contaminants, if there is a gradient. Vertical hydraulic gradients of a up to a few percent, or about 30 m over 1500 m, exist throughout the Marcellus shale region as may be seen in various geothermal developments in New York (TAL 1981). Brine more than a thousand meters above their evaporite source (Dresel and Rose 2010) is evidence of upward movement from depth to the surface. The Marcellus shale, with salinity as high as 350,000 mg/L (Soeder 2010; NYDEC 2009), may be a primary brine source. Relatively uniform brine concentrations over large areas (Williams et al. 1998) suggest widespread advective transport. The transition from brine to freshwater suggests a long-term equilibrium between the upward movement of brine and downward movement of freshwater. Faults, which occur throughout the Marcellus shale region (Figure 1) (Gold 1999), could provide pathways (Konikow 2011; Caine et al. 1996) for more concentrated advective and dispersive transport. Brine concentrating in faults or anticline zones reflects potential preferential pathways (Wunsch 2011; Dresel and Rose 2010; Williams 2010; Williams et al. 1998).

In addition to the natural gradient, buoyancy would provide an additional initial upward push. At TDS equal to 350,000 mg/L, the density at 25 °C is approximately

1290 kg/m^3, or more than 29% higher than freshwater. The upward force would equal the difference in weight between the injected fluid and displaced brine. As an example, if 10,000,000 L does not return to the surface as flowback (Jehn 2011), the difference in mass between the volume of fracking fluid and displaced brine is approximately 3,000,000 kg, which would cause an initial upward force. The density difference would dissipate as the salt concentration in the fracking fluid increases due to diffusion across the boundary between the fluid and the brine.

In just Pennsylvania, more than 180,000 wells had been drilled prior to any requirement for documenting their location (Davies 2011), therefore the location of many wells is unknown and some have probably been improperly abandoned. These pathways connect aquifers through otherwise continuous aquitards; overpressurization of lower aquifers due to injection near the well pathway could cause rapid transport to higher aquifers (Lacombe et al. 1995). In the short fracking period, the region that is overpressurized remains relatively close to the gas well (see modeling analysis below), therefore it should be possible for the driller to locate nearby abandoned wells that could be affected by fracking. This article does not consider the potential contamination although unlocated abandoned wells of all types must be considered a potential and possibly faster source for contamination due to fracking.

Effect of Hydraulic Fracturing on Shale

Fracking increases the permeability of the targeted shale to make extraction of NG economically efficient (Engelder et al. 2009; Arthur et al. 2008). Fracking creates fracture pathways with up to 9.2 million square meters of surface area in the shale accessible to a horizontal well (King 2010; King et al. 2008) and connects natural fractures (Engelder et al. 2009; King et al. 2008). No post-fracking studies that documented hydrologic properties were found while researching this article (there is a lack of information about pre- and post-fracking properties; Schweitzer and Bilgesu 2009), but it is reasonable to assume the *K* increases significantly because of the newly created and widened fractures.

Fully developed shale typically has wells spaced at about 300-m intervals (Edwards and Weisset 2011; Soeder 2010). Up to eight wells may be drilled from a single well pad (NYDEC 2009; Arthur et al. 2008), although not in a perfect spoke pattern. Reducing by half the effective spacing did not enhance overall productivity (Edwards and Weisset 2011) which indicates that 300-m spacing creates sufficient overlap among fractured zones to assure adequate gas drainage. The properties controlling groundwater flow would therefore be affected over a large area, not just at a single horizontal well or set of wells emanating from a single well pad.

Fracking is not intended to affect surrounding formations, but shale properties vary over short ranges (King 2010; Boyer et al. 2006) and out-of-formation fracking is not uncommon. In the Marcellus shale, out-of-formation fracks have been documented 500 m above the top of the shale (Fisher and Warpinski 2011). These fractures could contact higher conductivity sandstone, natural fractures, or unplugged abandoned wells above the target shale. Also, fluids could reach surrounding formations just because of the volume injected into the shale, which must displace natural fluid, such as the existing brine in the shale.

Analysis of Potential Transport along Pathways

Fracking could cause contaminants to reach overlying formations either by fracking out of formation, connecting fractures in the shale to overlying bedrock, or by simple displacement of fluids from the shale into the overburden. Advective transport, considered as simple particle velocity, will manifest if there is a significant vertical component to the regional hydraulic gradient.

Numerical modeling, completed with the MODFLOW-2000 code (Harbaugh et al. 2000), provides flexibility to consider potential conceptual flow scenarios, but should be considered interpretative (Hill and Tiedeman 2007). The simulation considers the rate of vertical transport of contaminants to near the surface for the different conceptual models, based on an expected, simplified, realistic range of hydrogeologic aquifer parameters.

MODFLOW-2000 is a versatile numerical modeling code, but there is insufficient data regarding the geology and water chemistry between aquifers and the deep shale, such as salinity profiles or data concerning mixing of the brine with fracking fluid, to best use its capabilities. As more data becomes available, it may be useful to consider simulating the added upward force caused by the brine by using the SEAWAT-2000 module (Langevin et al. 2003).

Vertical flow would be perpendicular to the general tendency for sedimentary layers to have higher horizontal than vertical conductivity. Fractures and improperly abandoned wells would provide pathways for much quicker vertical transport than general advective transport. This article considers the fractures as vertical columns with model cells having much higher conductivity than the surrounding bedrock. The cell discretization is fine, so the simulated width of the fracture zones is realistic. Dual porosity modeling (Shoemaker et al. 2008) is not justified because turbulent vertical flow through the fractures is unlikely, except possibly during the actual fracking that causes out-of-formation fractures, a scenario not simulated here. MODFLOW-2000 has a module, MNW (Halford and Hanson 2002), that could simulate rapid transport through open bore holes. MNW should be used in situations where open boreholes or improperly abandoned wells are known or postulated to exist.

The thickness of the formations and fault would affect the simulation, but much less than the several-order-of-magnitude variation possible in the shale properties. The overburden and shale thickness were set equal to 1500 and 30 m, respectively, similar to that observed in southern New York. The estimated travel times are proportional for thicker or thinner sections. The overburden could be predominantly sandstone, with sections of shale, mudstone, and limestone. The vertical fault is assumed to be 6-m thick. The fault is an attempt at considering fracture flow, but the simulation treats the 6-m wide fault zone as homogeneous, which could underestimate the real transport rate in fracture-controlled systems which could be highly affected by dispersion. The simulation also ignores diffusion between the fracture and the adjacent shale matrix (Konikow 2011).

There are five conceptual models of flow and transport of natural and post-fracking transport from the level of the Marcellus shale to the near-surface to consider herein:

1. The natural upward advective flow due to a head drop of 30 m from below the Marcellus shale to the ground surface, considering the variability in both shale and overburden K. This is a steady state solution for upward advection through a 30-m thick shale zone and 1500-m overburden. Table 1 shows the chosen K values for shale and sandstone.
2. Same as number 1, but with a vertical fracture connecting the shale with the surface, created using a high-conductivity zone in a row of cells extending through all from above the shale to the surface. This emulates the conceptual model postulated for flow into the alluvial aquifers near stream channels, the location of which may be controlled by faults (Williams et al. 1998). The fault K varies from 10 to 1000 times the surrounding bulk sandstone K (K_{ss}).
3. This scenario tests the effect of extensive fracturing in the Marcellus shale by increasing the shale K (K_{sh}) from 10 to 1000 times its native value over an extensive area. This transient solution starts with initial conditions being a steady state solution from scenario 1. The K_{sh} increases from 10 to 1000 times at the beginning of the simulation, to represent the relatively instantaneous change on the regional shale hydrogeology imposed by the fracking. The simulation estimates both the changes in flux and the time for the system to reach equilibrium.
4. As number 3, considering the effect of the same changes in shale properties but with a fault as in number 2.
5. This scenario simulates the actual injection of 13 to 17 million liters of fluid in 5 d into fractured shale from a horizontal well with and without a fault.

Model Setup

The model domain was 150 rows and columns spaced at 3 m to form a 450-m square (Figure 2) with 50 layers bounded with no flow boundaries. The 30-m thick shale was divided into 10 equal thickness layers from layer 40 to 49. The overburden layer thickness varied from 3 m just above the shale to layer 34, 6 m from layer 33 to 29, 9 m from layer 28 to 26, 18 m in layer 25, 30 m from layer 24 to 17, 60 m from layer 16 to 6, 90 m from layer 5 to 3, and 100 m in layers 2 and 1. A 6-m wide column from layer 39 to the surface is added for some scenarios in the center two rows to simulate a higher K fault.

Table 1
Sandstone (ss) and Shale (sh) Conductivity (K) (m/d) and the Steady State Flux (m^3/d) for Model 1 Scenarios

Flux	K_{ss}	K_{sh}
1.7	0.1	0.00001
1.8	0.5	0.00001
1.9	1	0.00001
1.9	5	0.00001
2.0	10	0.00001
2.0	50	0.00001
2.0	100	0.00001
1.7	0.1	0.00001
9.5	0.1	0.00005
19.0	0.1	0.0001
81.2	0.1	0.0005
135.9	0.1	0.001
291.5	0.1	0.005
340.9	0.1	0.01
394.3	0.1	0.05
401.8	0.1	0.1
409.2	0.1	0.5
40.7	0.001	0.1
186.0	0.005	0.1
339.1	0.01	0.1
988.3	0.05	0.1
1297.3	0.1	0.1
1748.0	0.5	0.1
1826.1	1	0.1
1902.8	5	0.1
1915.4	10	0.1
338.3	0.1	0.01
984.1	0.5	0.01
1292.5	1	0.01
1731.5	5	0.01
1816.0	10	0.01
17.4	1	0.0001
86.3	1	0.0005
176.7	1	0.001
775.1	1	0.005
1292.5	1	0.01
2746.8	1	0.05
3183.2	1	0.1
3650.5	1	0.5
3719.9	1	1

The model simulated vertical flow between constant head boundaries in layers 50 and 1, as a source and sink, so that the overburden and shale properties control the flow. The head in layers 50 and 1 was 1580 and 1550 m, respectively, to create a gradient of 0.019 over the profile. Varying the gradient would have much less effect on transport than changing K over several orders of magnitude and was therefore not done.

Scenario 5 simulates injection using a WELL boundary in layer 44, essentially the middle of the shale, from columns 25 to 125 (Figure 2). It injects 15 million liters over one 5-d stress period, or 3030 m^3/d into 101 model cells at the WELL. The modeled K_{sh} was changed to its

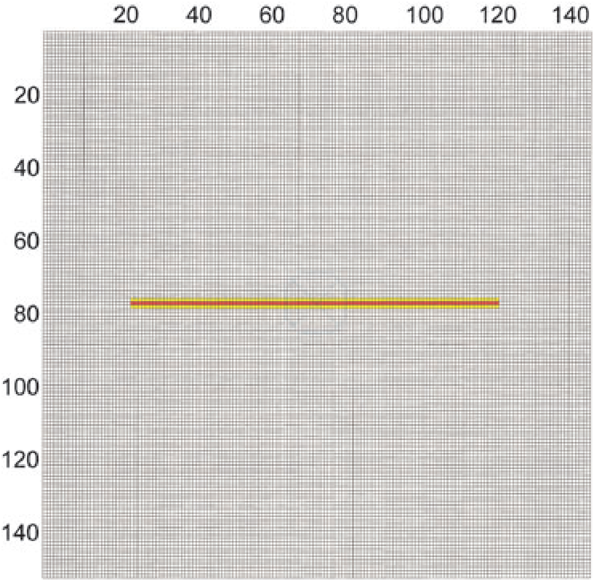

Figure 2. Model grid through layer 44 showing the horizontal injection WELL (red) and DRAIN cells (yellow) used to simulate flowback. There is only one monitoring well because the off-center well is not used in layer 44.

assumed fracked value at the beginning of the simulation. Simulating high rate injection generates very high heads in the model domain, similar to that found simulating oil discharging from the well in the Deepwater Horizon crisis (Hsieh 2011) and water quality changes caused by underground coal gasification (Contractor and El-Didy 1989). DRAIN boundaries on both sides of the WELL simulated return flow for 60 d after the completion of (Figure 2), after which the DRAIN was deactivated. The 60 d were broken into four stress periods, 1, 3, 6, and 50 d long, to simulate the changing heads and flow rates. DRAIN conductance was calibrated so that 20% of the injected volume returned within 60 d to emulate standard industry practice (Alleman 2011; NYDEC 2009). Recovery, continuing relaxation of the head at the well and the adjustment of the head distribution around the domain, occurred during the sixth period which lasted for 36,500 d.

There is no literature guidance to a preferred value for fractured shale storage coefficient, so I estimated S with a sensitivity analysis using scenario 3. With fractured K_{sh} equal to 0.001 m/d, two orders of magnitude higher than the in situ value, the time to equilibrium resulting from simulation tests of three fractured shale storage coefficients, 10^{-3}, 10^{-5}, and 10^{-7}/m, varied twofold (Figure 3). The slowest time to equilibrium was for $S = 10^{-3}$/m (Figure 3), which was chosen for the transient simulations because more water would be stored in the shale and flow above the shale would change the least.

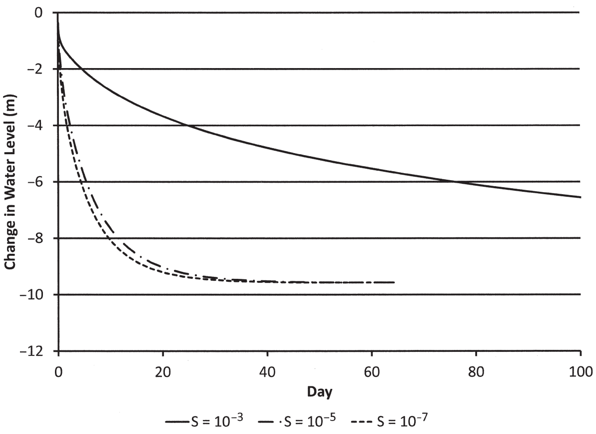

Figure 3. Sensitivity of the modeled head response to the storage coefficient used in the fractured shale for model layer 39 just above the shale.

Results

Scenario 1

Table 1 shows the conductivity and flux values for various scenarios. The steady state travel time for a particle through 1500 m of sandstone and shale equilibrates with one of the formations controlling the advection (Figure 4). For example, when the K_{sh} equals 1×10^{-5} m/d, transport time does not vary with K_{ss}. For K_{ss} at 0.1 m/d, transport time for varying K_{sh} ranges from 40,000 to 160 years. The lower travel time estimate is for K_{sh} similar to that found by Schulze-Makuch et al. (1999). The shortest simulated transport time of about 20 years results from both the sandstone and shale K equaling 1 m/d. Other sensitivity scenarios emphasize the control exhibited by one of the media (Figure 4). If K_{sh} is low, travel time is very long and not sensitive to K_{ss}.

Scenario 2

The addition of a fault with K one to two orders of magnitude more conductive than the surrounding sandstone increased the particle travel rate by about 10 times (compare Figure 5 with Figure 4). The fault K controlled the transport rate for K_{sh} less than 0.01 m/d. A highly

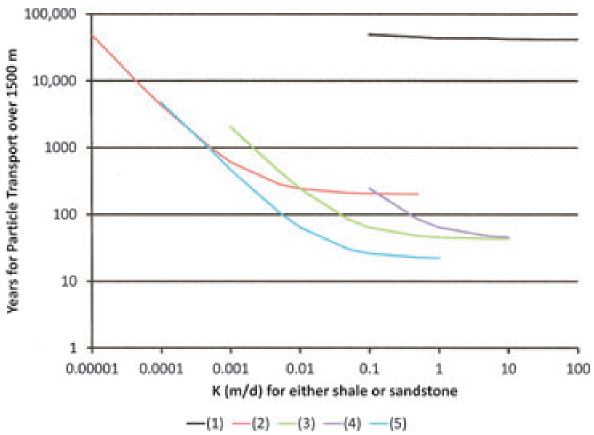

Figure 4. Sensitivity of particle transport time over 1500 m for varying shale and sandstone vertical K. Effective porosity equals 0.1. (1)—varying K_{ss}, $K_{sh} = 10^{-5}$ m/d; (2)—varying K_{ss}, $K_{sh} = 0.1$ m/d; (3)—varying K_{ss}, $K_{sh} = 0.1$ m/d; (4)—varying K_{ss}, $K_{sh} = 0.01$ m/d; and (5)—varying K_{ss}, $K_{sh} = 1.0$ m/d.

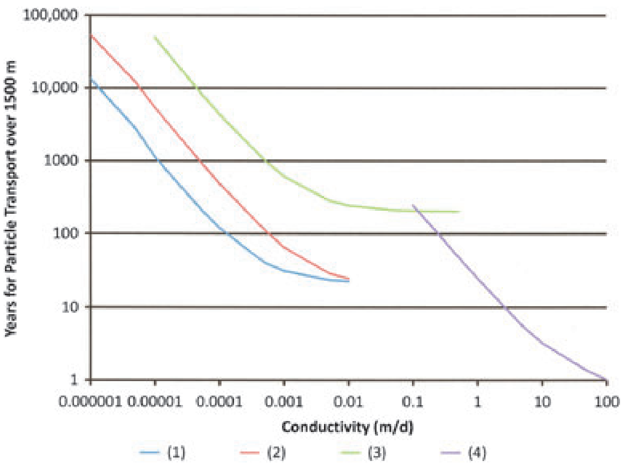

Figure 5. Variability of transport through various scenarios of changing the K for the fault or shale. Effective porosity equals 0.1. (1)—varying K_{sh}, K_{sh} = 0.01 m/d; (2)—varying K_{sh}, K_{sh} = 0.1 m/d; (3)—no fault; (4)—varying K fault, K_{sh} = 0.1 m/d, K_{sh} = 0.01 m/d. Unless specified, the vertical fault has K = 1 m/d for variable K_{sh}.

conductive fault could transport fluids to the surface in as little as a year for K_{sh} equal to 0.01 m/d (Figure 5). However, a fault did not significantly change the overall model flux, so with fault values are not shown in Table 1.

Scenarios 3 and 4

Scenarios 3 and 4 estimate the time to establish a new equilibrium once the K_{sh} changes, due to fracking, between values specified in scenarios 1 and 2. Equilibrium times vary by model layer as the changes propagate through the domain, and flux rate for the simulated changes imposed on natural background conditions. The fracking-induced changes cause a significant decrease in the head drop across the shale and the time for adjustment of the potentiometric surface to a new steady state depends on the new shale properties.

The time to equilibrium for one scenario 3 simulation, K_{sh} changing from 10^{-5} to 10^{-2} m/d with K_{ss} equal to 0.1 m/d, varied from 5.5 to 6.5 years, depending on model layer (Figure 6). Near the shale (layers 39 and 40), the potentiometric surface increased from 23 to 25 m reflecting the decreased head drop across the shale. One hundred meters higher, in layer 20, the potentiometric surface increased about 20 m. Simulation of scenario 4, with a fault with K = 1 m/d, decreased the time to equilibrium to from 3 to 6 years within the fault zone, depending on model layer (Figure 6). Highly fractured sandstone would allow more vertical transport, but advective flow would also increase so that the base K_{ss} would control the overall rate.

The flux across the upper boundary changed within 100 years for scenario 3 from 1.7 to 345 m^3/d, or 0.000008 to 0.0017 m/d, reflecting control by K_{ss}. There is little difference in the equilibrium fluxes between scenario 3 and 4 indicating that the fault primarily affects the time to equilibrium rather than the long-term flow rate.

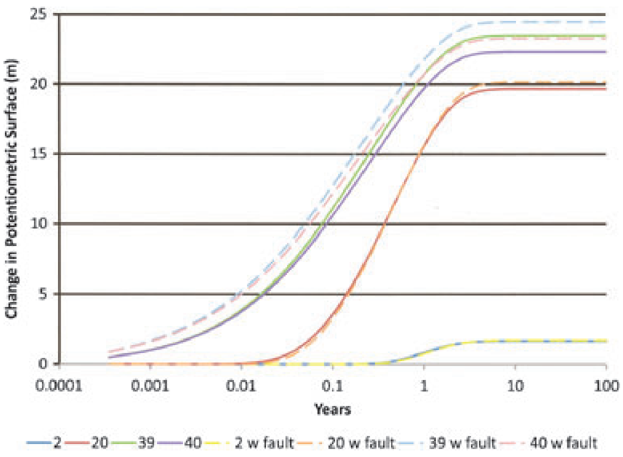

Figure 6. Monitoring well water levels for specified model layers due to fracking of the shale; monitor well in the center of the domain, including in the fault, K of the shale changes from 0.00001 to 0.01 m/d at the beginning of the simulation.

Scenario 5: Simulation of Injection

The injection scenarios simulate 15 million liters entering the domain at the horizontal well and the subsequent potentiometric surface and flux changes throughout. The highest potentiometric surface increases (highest injection pressure) occurred at the end of injection (Figure 7), with a 2400 m increase at the horizontal well. The simulated peak pressure both decreased and occurred longer after the cessation of injection with distance from the well (Figures 7 and 8). The pressure at the well returned to within 4 m of pre-injection levels in about 300 d (Figure 7). After injection ceases, the peak pressure simulated further from the well occurs longer from the time of cessation, which indicates there is a pressure divide beyond which fluid continues to flow away from the well bore while within which the fluid flows toward the well bore. The simulated head returned to near pre-injection levels slower with distance from the well (Figure 7), with levels at the edge of the shale (layer 40) and in the near-shale sandstone (layer 39) requiring several hundred days to recover. After recovering from injection, the potentiometric surface above the shale increased in response to flux through the shale adjusting to the change in shale properties (Figure 8), as simulated in scenario 3. The scenario required about 6000 d (16 years) for the potentiometric surface to stabilize at new, higher, levels (Figure 8). Removing the fault from the simulation had little effect on the time to stabilization, and is not shown.

Prior to injection, the steady flux for in situ shale (K_{sh} = 10^{-5} m/d) was generally less than 2 m^3/d and varied little with K_{ss} (Figure 4). Once the shale was fractured, the sandstone controlled the flux which ranges from 38 to 135 m^3/d as K_{ss} ranges from 0.01 to 0.1 m/d (Figure 9), resulting in particle travel times of 2390 and 616 years, respectively. More conductive shale would allow faster transport (Figure 4). Adding a fault to the scenario with K_{ss} equal to 0.01 m/d increased the flux to approximately 63 m^3/d and decreased the particle travel

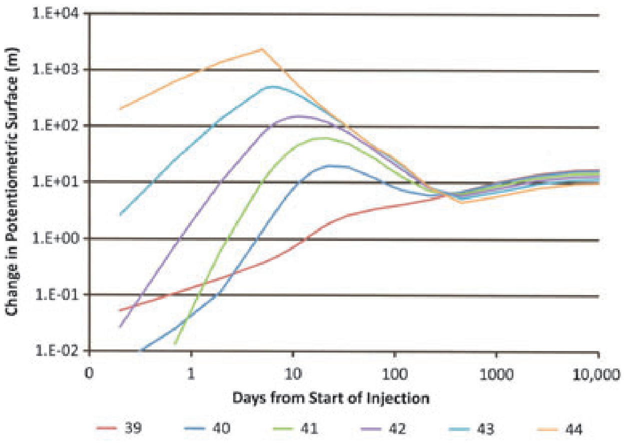

Figure 7. Simulated potentiometric surface changes by layer for specified injection and media properties. The monitoring point is in the center of the domain. Fault is included. K_{sh} = 0.01 m/d, K_{sh} = 0.001 m/d. S (fractured shale) = 0.001/m, S (ss) = 0.0001/m.

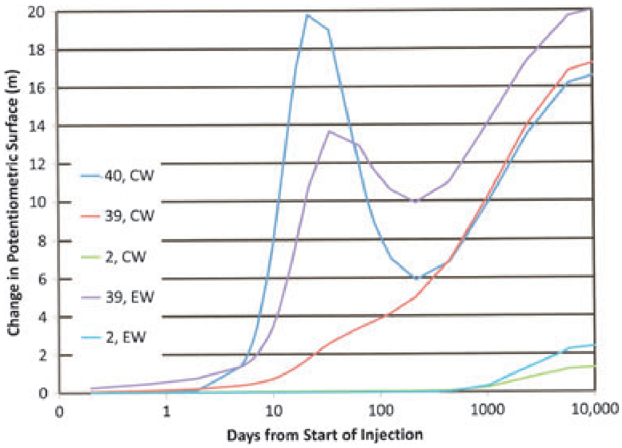

Figure 8. Simulated potentiometric surface changes for layers within the shale and sandstone. CW is center monitoring well and EW is east monitoring well, about 120 m from the centerline. Fault is included. The line for layer 2, CW plots beneath the line for layer 2, EW. K_{ss} = 0.01 m/d, K_{sh} = 0.001 m/d, S (fractured shale) = 0.001/m, S (ss) = 0.0001/m.

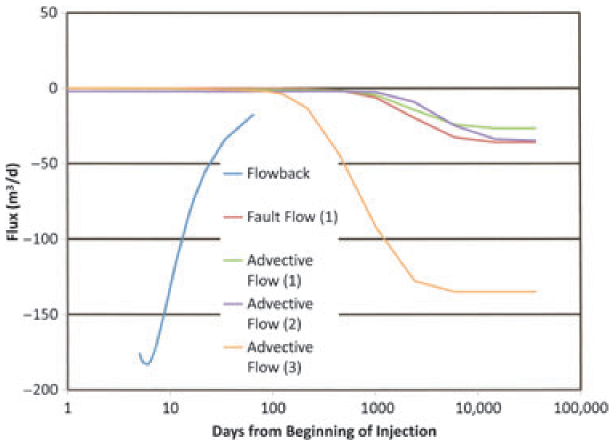

Figure 9. Comparison of flux for three scenarios. Flowback is the same for all scenarios. (1): Kss = 0.01 m/d, Ksh = 0.001 m/d, Fault K = 1 m/d; (2): Kss = 0.01 m/d, Ksh = 0.001 m/d, no fault; (3) Kss = 0.1 m/d, Ksh = 0.001 m/d, no fault.

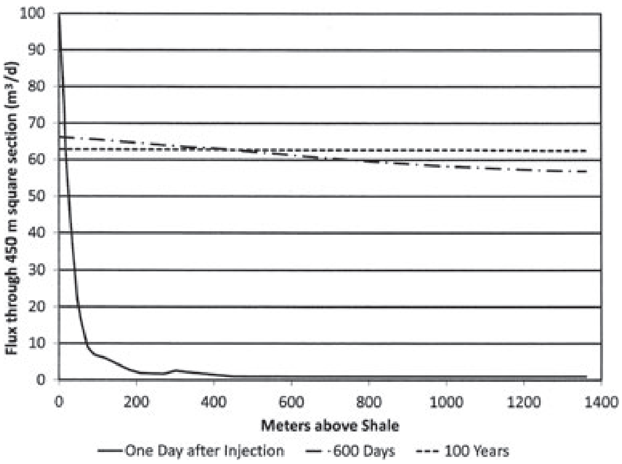

Figure 10. Upward flux across the domain section as a function of distance above the top of the shale layer. Cross section is 202,500 m^2.

time to 31 years. Approximately, 36 m^3/d flowed through the fault (Figure 9). The fault properties control the particle travel time, especially if the fault K is two or more orders of magnitude higher than the sandstone.

Simulated flowback varied little with K_{sh} because it had been calibrated to be 20% of the injection volume. A lower storage coefficient or higher K would allow the injected fluid to move further from the well, which would lead to less flowback.

Vertical flux through the overall section with a fault varies significantly with time, due to the adjustments in potentiometric surface. One day after injection, vertical flux exceeds significantly the pre-injection flux about 200 m above the shale (Figure 10). After 600 d, the vertical flux near the shale is about 68 m^3/d and in layer 2 about 58 m^3/d; it approaches steady state through all sections after 100 years with flux equaling about 62.6 m^3/d. The 100-year flux is 61.5 m^3/d higher than the pre-injection flux because of the changed shale properties.

Discussion

The interpretative modeling completed herein has revealed several facts about fracking. First, MODFLOW can be coded to adequately simulate fracking. Simulated pressures are high, but velocities even near the well do not violate the assumptions for Darcian flow. Second, injection for 5 d causes extremely high pressure within the shale. The pressure decreases with distance from the well. The time to maximum pressure away from the well lags the time of maximum pressure at the well. The pressure drops back to close to its pre-injection level at the well within 300 d, indicating the injection affects the flow for significantly longer periods than just during the fracking operation. Although the times may vary based on media properties, the difference would be at most a month or so, based on the various combinations of properties simulated. The system transitions within 6 years due to changes in the shale properties. The equilibrium transport rate would transition from a system requiring thousands of years to one requiring less than 100 years within less than 10 years.

Third, most of the injected water in the simulation flows vertically rather than horizontally through the shale. This reflects the higher K_{ss} 20 m above the well and the no flow boundary within 225 m laterally from the well, which emulates in situ shale properties that would manifest at some distance in the shale.

Fourth, the interpretative model accurately and realistically simulates long-term steady state flow conditions, with an upward flow that would advect whatever conservative constituents exist at depth. Using low, unfractured K values, the transport simulation may correspond with advective transport over geologic time although there are conditions for which it would occur much more quickly (Figure 4). If the K_{sh} is 0.01 m/d, transport could occur on the order of a few hundreds of years. Faults through the overburden could speed the transport time considerably. Reasonable scenarios presented herein suggest the travel time could be decreased further by an order of magnitude.

Fifth, fracking increases the K_{sh} by several orders of magnitude. Out-of-formation fracking (Fisher and Warpinski 2011) would increase the K in the overburden, thereby changing the regional hydrogeology. Vertical flow could change over broad areas if the expected density of wells in the Marcellus shale region (NYDEC 2009) actually occurs.

Sixth, if newly fractured shale or out-of-formation fractures come close to contacting fault fracture zones, contaminants could reach surface areas in tens of years, or less. Faults can decrease the simulated particle travel time several orders of magnitude.

Conclusion

Fracking can release fluids and contaminants from the shale either by changing the shale and overburden hydrogeology or simply by the injected fluid forcing other fluids out of the shale. The complexities of contaminant transport from hydraulically fractured shale to near-surface aquifers render estimates uncertain, but a range of interpretative simulations suggest that transport times could be decreased from geologic time scales to as few as tens of years. Preferential flow through natural fractures fracking-induced fractures could further decrease the travel times to as little as just a few years.

There is no data to verify either the pre- or post-fracking properties of the shale. The evidence for potential vertical contaminant flow is strong, but there are also almost no monitoring systems that would detect contaminant transport as considered herein. Several improvements could be made.

- Prior to hydraulic fracturing operations, the subsurface should be mapped for the presence of faults and measurement of their properties.
- A reasonable setback distance from the fracking to the faults should be established. The setback distance should be based on a reasonable risk analysis of fracking increasing the pressures within the fault.
- The properties of the shale should be verified, post-fracking, to assess how the hydrogeology will change.
- A system of deep and shallow monitoring wells and piezometers should be established in areas expecting significant development, before that development begins (Williams 2010).

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Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing

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Directional drilling and hydraulic-fracturing technologies are dramatically increasing natural-gas extraction. In aquifers overlying the Marcellus and Utica shale formations of northeastern Pennsylvania and upstate New York, we document systematic evidence for methane contamination of drinking water associated with shale-gas extraction. In active gas-extraction areas (one or more gas wells within 1 km), average and maximum methane concentrations in drinking-water wells increased with proximity to the nearest gas well and were 19.2 and 64 mg CH_4 L^{-1} ($n = 26$), a potential explosion hazard; in contrast, dissolved methane samples in neighboring nonextraction sites (no gas wells within 1 km) within similar geologic formations and hydrogeologic regimes averaged only 1.1 mg L^{-1} ($P < 0.05$; $n = 34$). Average $\delta^{13}C$-CH_4 values of dissolved methane in shallow groundwater were significantly less negative for active than for nonactive sites (−37 ± 7‰ and −54 ± 11‰, respectively; $P < 0.0001$). These $\delta^{13}C$-CH_4 data, coupled with the ratios of methane-to-higher-chain hydrocarbons, and δ^2H-CH_4 values, are consistent with deeper thermogenic methane sources such as the Marcellus and Utica shales at the active sites and matched gas geochemistry from gas wells nearby. In contrast, lower-concentration samples from shallow groundwater at nonactive sites had isotopic signatures reflecting a more biogenic or mixed biogenic/thermogenic methane source. We found no evidence for contamination of drinking-water samples with deep saline brines or fracturing fluids. We conclude that greater stewardship, data, and—possibly—regulation are needed to ensure the sustainable future of shale-gas extraction and to improve public confidence in its use.

groundwater | organic-rich shale | isotopes | formation waters | water chemistry

Increases in natural-gas extraction are being driven by rising energy demands, mandates for cleaner burning fuels, and the economics of energy use (1–5). Directional drilling and hydraulic-fracturing technologies are allowing expanded natural-gas extraction from organic-rich shales in the United States and elsewhere (2, 3). Accompanying the benefits of such extraction (6, 7) are public concerns about drinking-water contamination from drilling and hydraulic fracturing that are ubiquitous but lack a strong scientific foundation. In this paper, we evaluate the potential impacts associated with gas-well drilling and fracturing on shallow groundwater systems of the Catskill and Lockhaven formations that overlie the Marcellus Shale in Pennsylvania and the Genesee Group that overlies the Utica Shale in New York (Figs. 1 and 2 and Fig. S1). Our results show evidence for methane contamination of shallow drinking-water systems in at least three areas of the region and suggest important environmental risks accompanying shale-gas exploration worldwide.

The drilling of organic-rich shales, typically of Upper Devonian to Ordovician age, in Pennsylvania, New York, and elsewhere in the Appalachian Basin is spreading rapidly, raising concerns for impacts on water resources (8, 9). In Susquehanna County, Pennsylvania alone, approved gas-well permits in the Marcellus formation increased 27-fold from 2007 to 2009 (10).

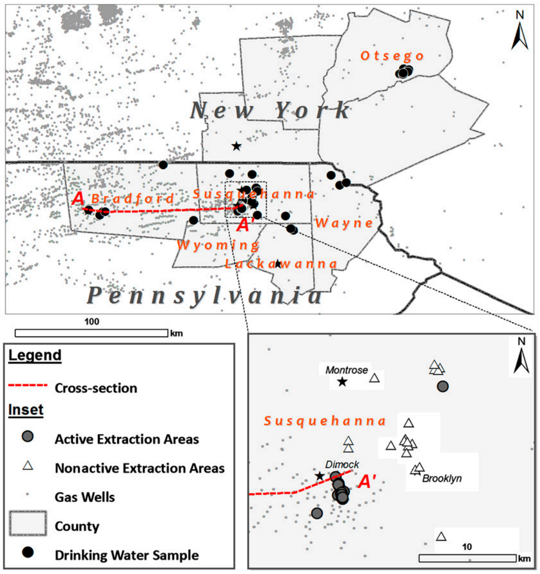

Fig. 1. Map of drilling operations and well-water sampling locations in Pennsylvania and New York. The star represents the location of Binghamton, New York. (*Inset*) A close-up in Susquehanna County, Pennsylvania, showing areas of active (closed circles) or nonactive (open triangles) extraction. A drinking-water well is classified as being in an active extraction area if a gas well is within 1 km (see *Methods*). Note that drilling has already spread to the area around Brooklyn, Pennsylvania, primarily a nonactive location at the time of our sampling (see inset). The stars in the inset represent the towns of Dimock, Brooklyn, and Montrose, Pennsylvania.

Concerns for impacts to groundwater resources are based on (*i*) fluid (water and gas) flow and discharge to shallow aquifers due to the high pressure of the injected fracturing fluids in the gas wells (10); (*ii*) the toxicity and radioactivity of produced water from a mixture of fracturing fluids and deep saline formation waters that may discharge to the environment (11); (*iii*) the potential explosion and asphyxiation hazard of natural gas; and (*iv*) the large number of private wells in rural areas that rely on shallow groundwater for household and agricultural use—up to one million wells in Pennsylvania alone—that are typically unregulated and untested (8, 9, 12). In this study, we analyzed groundwater from 68 private water wells from 36- to 190-m deep in

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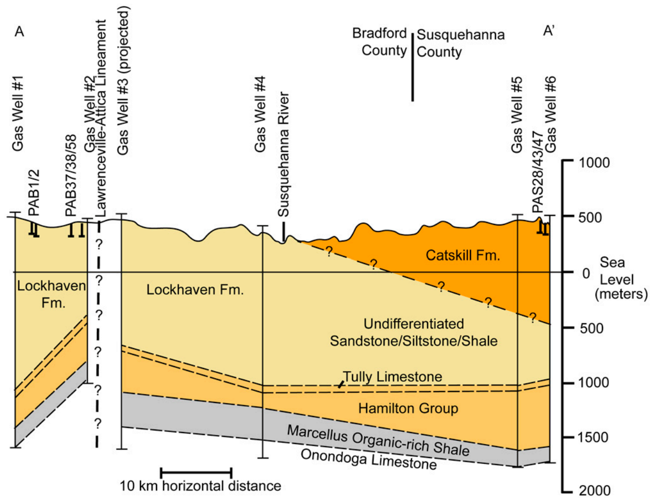

Fig. 2. Geologic cross-section of Bradford and western Susquehanna Counties created from gas-well log data provided by the Pennsylvania Department of Conservation and Natural Resources. The approximate location of the Lawrenceville-Attica Lineament is taken from Alexander et al. (34). The Ordovician Utica organic-rich shale (not depicted in the figure) underlies the Middle Devonian Marcellus at approximately 3,500 m below the ground surface.

northeast Pennsylvania (Catskill and Lockhaven formations) and upstate New York (Genesee formation) (see Figs. 1 and 2 and *SI Text*), including measurements of dissolved salts, water isotopes (^{18}O and ^{2}H), and isotopes of dissolved constituents (carbon, boron, and radium). Of the 68 wells, 60 were also analyzed for dissolved-gas concentrations of methane and higher-chain hydrocarbons and for carbon and hydrogen isotope ratios of methane. Although dissolved methane in drinking water is not currently classified as a health hazard for ingestion, it is an asphyxiant in enclosed spaces and an explosion and fire hazard (8). This study seeks to evaluate the potential impact of gas drilling and hydraulic fracturing on shallow groundwater quality by comparing areas that are currently exploited for gas (defined as active—one or more gas wells within 1 km) to those that are not currently associated with gas drilling (nonactive; no gas wells within 1 km), many of which are slated for drilling in the near future.

Results and Discussion

Methane concentrations were detected generally in 51 of 60 drinking-water wells (85%) across the region, regardless of gas industry operations, but concentrations were substantially higher closer to natural-gas wells (Fig. 3). Methane concentrations were 17-times higher on average (19.2 mg CH_4 L^{-1}) in shallow wells from active drilling and extraction areas than in wells from nonactive areas (1.1 mg L^{-1} on average; $P < 0.05$; Fig. 3 and Table 1). The *average* methane concentration in shallow groundwater in active drilling areas fell within the defined action level (10–28 mg L^{-1}) for hazard mitigation recommended by the US Office of the Interior (13), and our maximum observed value of 64 mg L^{-1} is well above this hazard level (Fig. 3). Understanding the origin of this methane, whether it is shallower biogenic or deeper thermogenic gas, is therefore important for identifying the source of contamination in shallow groundwater systems.

The $\delta^{13}C$-CH_4 and $\delta^{2}H$-CH_4 values and the ratio of methane to higher-chain hydrocarbons (ethane, propane, and butane) can typically be used to differentiate shallower, biologically derived methane from deeper physically derived thermogenic methane (14). Values of $\delta^{13}C$-CH_4 less negative than approximately −50‰ are indicative of deeper thermogenic methane, whereas values more negative than −64‰ are strongly indicative of microbial methane (14). Likewise, $\delta^{2}H$-CH_4 values more negative than about −175‰, particularly when combined with low $\delta^{13}C$-CH_4 values, often represent a purer biogenic methane origin (14).

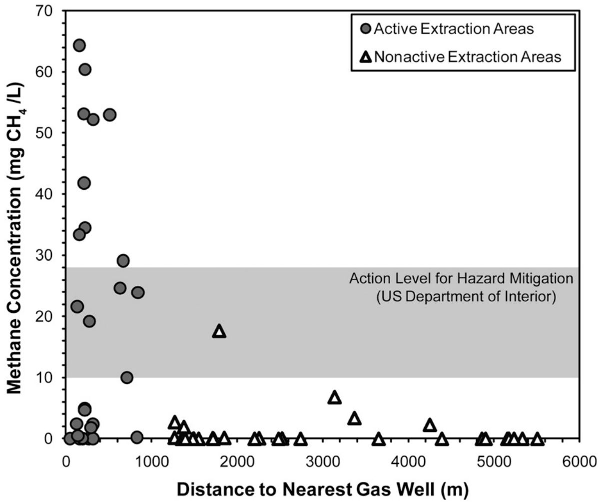

Fig. 3. Methane concentrations (milligrams of CH_4 L^{-1}) as a function of distance to the nearest gas well from active (closed circles) and nonactive (open triangles) drilling areas. Note that the distance estimate is an upper limit and does not take into account the direction or extent of horizontal drilling underground, which would decrease the estimated distances to some extraction activities. The precise locations of natural-gas wells were obtained from the Pennsylvania Department of Environmental Protection and Pennsylvania Spatial Data Access databases (ref. 35; accessed Sept. 24, 2010).

The average $\delta^{13}C$-CH_4 value in shallow groundwater in active drilling areas was -37 ± 7‰, consistent with a deeper thermogenic methane source. In contrast, groundwater from nonactive areas in the same aquifers had much lower methane concentrations and significantly lower $\delta^{13}C$-CH_4 values (average of -54 ± 11‰; $P < 0.0001$; Fig. 4 and Table 1). Both our $\delta^{13}C$-CH_4 data and $\delta^{2}H$-CH_4 data (see Fig. S2) are consistent with a deeper thermogenic methane source at the active sites and a more biogenic or mixed methane source for the lower-concentration samples from nonactive sites (based on the definition of Schoell, ref. 14).

Because ethane and propane are generally not coproduced during microbial methanogenesis, the presence of higher-chain hydrocarbons at relatively low methane-to-ethane ratios (less than approximately 100) is often used as another indicator of deeper thermogenic gas (14, 15). Ethane and other higher-chain hydrocarbons were detected in only 3 of 34 drinking-water wells from nonactive drilling sites. In contrast, ethane was detected in 21 of 26 drinking-water wells in active drilling sites. Additionally, propane and butane were detected (>0.001 mol %) in eight and two well samples, respectively, from active drilling areas but in no wells from nonactive areas.

Further evidence for the difference between methane from water wells near active drilling sites and neighboring nonactive sites is the relationship of methane concentration to $\delta^{13}C$-CH_4 values (Fig. 4*A*) and the ratios of methane to higher-chain hydro-

Table 1. Mean values ± standard deviation **of methane concentrations (as milligrams of CH_4 L^{-1}) and carbon isotope composition in methane in shallow groundwater $\delta^{13}C$-CH_4 sorted by aquifers and proximity to gas wells (active vs. nonactive)**

Water source, *n*	milligrams CH_4 L^{-1}	$\delta^{13}C$-CH_4, ‰
Nonactive Catskill, 5	1.9 ± 6.3	−52.5 ± 7.5
Active Catskill, 13	26.8 ± 30.3	−33.5 ± 3.5
Nonactive Genesee, 8	1.5 ± 3.0	−57.5 ± 9.5
Active Genesee, 1	0.3	−34.1
Active Lockhaven, 7	50.4 ± 36.1	−40.7 ± 6.7
Total active wells, 21	19.2	−37 ± 7
Total nonactive wells, 13	1.1	−54 ± 11

The variable *n* refers to the number of samples.

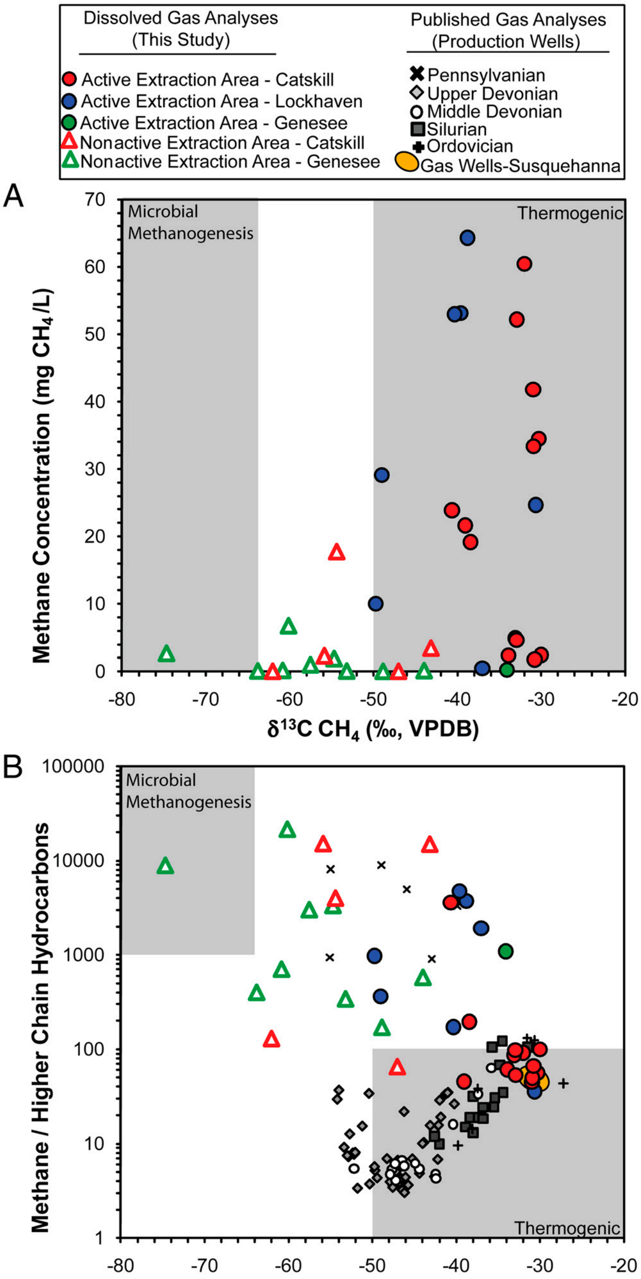

Fig. 4. (*A*) Methane concentrations in groundwater versus the carbon isotope values of methane. The nonactive and active data depicted in Fig. 3 are subdivided based on the host aquifer to illustrate that the methane concentrations and δ^{13}C values increase with proximity to natural-gas well drilling regardless of aquifer formation. Gray areas represent the typical range of thermogenic and biogenic methane taken from Osborn and McIntosh (18). VPDB, Vienna Pee Dee belemnite. (*B*) Bernard plot (15) of the ratio of methane to higher-chain hydrocarbons versus the δ^{13}C of methane. The smaller symbols in grayscale are from published gas-well samples from gas production across the region (16–18). These data generally plot along a trajectory related to reservoir age and thermal maturity (Upper Devonian through Ordovician; see text for additional details). The gas-well data in the orange ovals are from gas wells in our study area in Susquehanna County, Pennsylvania (data from Pennsylvania Department of Environmental Protection). Gray areas represent typical ranges of thermogenic and biogenic methane (data from Osborn and McIntosh, ref. 18).

carbons versus δ^{13}C-CH_4 (Fig. 4*B*). Methane concentrations not only increased in proximity to gas wells (Fig. 3), the accompanying δ^{13}C-CH_4 values also reflected an increasingly thermogenic methane source (Fig. 4*A*).

Using a Bernard plot (15) for analysis (Fig. 4*B*), the enriched δ^{13}C-CH_4 (approximately > -50‰) values accompanied by low ratios of methane to higher-chain hydrocarbons (less than approximately 100) in drinking-water wells also suggest that dissolved gas is more thermogenic at active than at nonactive sites (Fig. 4*B*). For instance, 12 dissolved-gas samples at active drilling sites fell along a regional gas trajectory that increases with reservoir age and thermal maturity of organic matter, with samples from Susquehanna County, Pennsylvania specifically matching natural-gas geochemistry from local gas wells (Fig. 4*B*, orange oval). These 12 samples and local natural-gas samples are consistent with gas sourced from thermally mature organic matter of Middle Devonian and older depositional ages often found in Marcellus Shale from approximately 2,000 m below the surface in the northern Appalachian Basin (14–19) (Fig. 4*B*). In contrast, none of the methane samples from nonactive drilling areas fell upon this trajectory (Fig. 4*B*); eight dissolved-gas samples in Fig. 4*B* from active drilling areas and all of the values from nonactive areas may instead be interpreted as mixed biogenic/thermogenic gas (18) or, as Laughrey and Baldassare (17) proposed for their Pennsylvanian gas data (Fig. 4*B*), the early migration of wet thermogenic gases with low-δ^{13}C-CH_4 values and high methane-to-higher-chain hydrocarbon ratios. One data point from a nonactive area in New York fell squarely in the parameters of a strictly biogenic source as defined by Schoell (14) (Fig. 4*B*, upper-left corner).

Carbon isotopes of dissolved inorganic carbon (δ^{13}C-DIC $>$ $+10$‰) and the positive correlation of δ^2H of water and δ^2H of methane have been used as strong indicators of microbial methane, further constraining the source of methane in shallow groundwater (depth less than 550 m) (18, 20). Our δ^{13}C-DIC values were fairly negative and show no association with the δ^{13}C-CH_4 values (Fig. S3), which is not what would be expected if methanogenesis were occurring locally in the shallow aquifers. Instead, the δ^{13}C-DIC values from the shallow aquifers plot within a narrow range typical for shallow recharge waters, with the dissolution of CO_2 produced by respiration as water passes downward through the soil critical zone. Importantly, these values do not indicate extensive microbial methanogenesis or sulfate reduction. The data do suggest gas-phase transport of methane upward to the shallow groundwater zones sampled for this study ($<$190 m) and dissolution into shallow recharge waters locally. Additionally, there was no positive correlation between the δ^2H values of methane and δ^2H of water (Fig. S4), indicating that microbial methane derived in this shallow zone is negligible. Overall, the combined gas and formation-water results indicate that thermogenic gas from thermally mature organic matter of Middle Devonian and older depositional ages is the most likely source of the high methane concentrations observed in the shallow water wells from active extraction sites.

A different potential source of shallow groundwater contamination associated with gas drilling and hydraulic fracturing is the introduction of hypersaline formation brines and/or fracturing fluids. The average depth range of drinking-water wells in northeastern Pennsylvania is from 60 to 90 m (12), making the average vertical separation between drinking-water wells and the Marcellus Shale in our study area between approximately 900 and 1,800 m (Fig. 2). The research area, however, is located in tectonically active areas with mapped faults, earthquakes, and lineament features (Fig. 2 and Fig. S1). The Marcellus formation also contains two major sets of joints (21) that could be conduits for directed pressurized fluid flow. Typical fracturing activities in the Marcellus involve the injection of approximately 13–19 million liters of water per well (22) at pressures of up to 69,000 kPa. The majority of this fracturing water typically stays underground and could in principle displace deep formation water upward into shallow aquifers. Such deep formation waters often have high concentrations of total dissolved solids >250,000 mg L^{-1}, trace toxic elements, (18), and naturally occurring radioactive materials, with activities as high as 16,000 picocuries per liter (1 pCi L^{-1} = 0.037 becquerels per liter) for ^{226}Ra compared to a drinking-water standard of 5 pCi L^{-1} for combined ^{226}Ra and ^{226}Ra (23).

We evaluated the hydrochemistry of our 68 drinking-water wells and compared these data to historical data of 124 wells in the Catskill and Lockhaven aquifers (24, 25). We used three types of indicators for potential mixing with brines and/or saline fracturing fluids: (*i*) major inorganic chemicals; (*ii*) stable isotope signatures of water (δ^{18}O, δ^{2}H); and (*iii*) isotopes of dissolved constituents (δ^{13}C-DIC, δ^{11}B, and ^{226}Ra). Based on our data (Table 2), we found no evidence for contamination of the shallow wells near active drilling sites from deep brines and/or fracturing fluids. All of the Na^{+}, Cl^{-}, Ca^{2+}, and DIC concentrations in wells from active drilling areas were consistent with the baseline historical data, and none of the shallow wells from active drilling areas had either chloride concentrations >60 mg L^{-1} or Na-Ca-Cl compositions that mirrored deeper formation waters (Table 2). Furthermore, the mean isotopic values of δ^{18}O, δ^{2}H, δ^{13}C-DIC, δ^{11}B, and ^{226}Ra in active and nonactive areas were indistinguishable. The ^{226}Ra values were consistent with available historical data (25), and the composition of δ^{18}O and δ^{2}H in the well-water appeared to be of modern meteoric origin for Pennsylvania (26) (Table 2 and Fig. S5). In sum, the geochemical and isotopic features for water we measured in the shallow wells from both active and nonactive areas are consistent with historical data and inconsistent with contamination from mixing Marcellus Shale formation water or saline fracturing fluids (Table 2).

There are at least three possible mechanisms for fluid migration into the shallow drinking-water aquifers that could help explain the increased methane concentrations we observed near gas wells (Fig. 3). The first is physical displacement of gas-rich deep solutions from the target formation. Given the lithostatic and hydrostatic pressures for 1–2 km of overlying geological strata, and our results that appear to rule out the rapid movement of deep brines to near the surface, we believe that this mechanism is unlikely. A second mechanism is leaky gas-well casings (e.g., refs. 27 and 28). Such leaks could occur at hundreds of meters underground, with methane passing laterally and vertically through fracture systems. The third mechanism is that the process of hydraulic fracturing generates new fractures or enlarges existing ones above the target shale formation, increasing the connectivity of the fracture system. The reduced pressure following the fracturing activities could release methane in solution, leading to methane exsolving rapidly from solution (29), allowing methane gas to potentially migrate upward through the fracture system.

Methane migration through the 1- to 2-km-thick geological formations that overlie the Marcellus and Utica shales is less likely as a mechanism for methane contamination than leaky well casings, but might be possible due to both the extensive fracture systems reported for these formations and the many older, uncased wells drilled and abandoned over the last century and a half in Pennsylvania and New York. The hydraulic conductivity in the overlying Catskill and Lockhaven aquifers is controlled by a secondary fracture system (30), with several major faults and lineaments in the research area (Fig. 2 and Fig. S1). Consequently, the high methane concentrations with distinct positive δ^{13}C-CH_4 and δ^{2}H-CH_4 values in the shallow groundwater from active areas could in principle reflect the transport of a deep methane source associated with gas drilling and hydraulic-fracturing activities. In contrast, the low-level methane migration to the surface groundwater aquifers, as observed in the nonactive areas, is likely a natural phenomenon (e.g., ref. 31). Previous studies have shown that naturally occurring methane in shallow aquifers is typically associated with a relatively strong biogenic signature indicated by depleted δ^{13}C-CH_4 and δ^{2}H-CH_4 compositions (32) coupled with high ratios of methane to higher-chain hydrocarbons (33), as we observed in Fig. 4*B*. Several models have been developed to explain the relatively common phenomenon of rapid vertical transport of gases (Rn, CH_4, and CO_2) from depth to the surface (e.g., ref. 31), including pressure-driven continuous gas-phase flow through dry or water-saturated fractures and density-driven buoyancy of gas microbubbles in aquifers and water-filled fractures (31). More research is needed across this and other regions to determine the mechanism(s) controlling the higher methane concentrations we observed.

Based on our groundwater results and the litigious nature of shale-gas extraction, we believe that long-term, coordinated sampling and monitoring of industry and private homeowners is needed. Compared to other forms of fossil-fuel extraction, hydraulic fracturing is relatively poorly regulated at the federal level. Fracturing wastes are not regulated as a hazardous waste under the Resource Conservation and Recovery Act, fracturing wells are not covered under the Safe Drinking Water Act, and only recently has the Environmental Protection Agency asked fracturing

Table 2. Comparisons of selected major ions and isotopic results in drinking-water wells from this study to data available on the same formations (Catskill and Lockhaven) in previous studies (24, 25) and to underlying brines throughout the Appalachian Basin (18)

	Active		Nonactive		Previous studies (background)		
	Lockhaven formation $N = 8$	Catskill formation $N = 25$	Catskill formation $N = 22$	Genesee group $N = 12$	Lockhaven formation (25) $N = 45$	Catskill formation (24) $N = 79$	Appalachian brines (18, 23) $N = 21$
Alkalinity as HCO_3^-,							
mg L^{-1}	285 ± 36	157 ± 56	127 ± 53	158 ± 56	209 ± 77	133 ± 61	150 ± 171
mM	[4.7 ± 0.6]	[2.6 ± 0.9]	[2.1 ± 0.9]	[2.6 ± 0.9]	[3.4 ± 1.3]	[2.2 ± 1.0]	[2.5 ± 2.8]
Sodium, mg L^{-1}	87 ± 22	23 ± 30	17 ± 25	29 ± 23	100 ± 312	21 ± 37	33,000 ± 11,000
Chloride, mg L^{-1}	25 ± 17	11 ± 12	17 ± 40	9 ± 19	132 ± 550	13 ± 42	92,000 ± 32,000
Calcium, mg L^{-1}	22 ± 12	31 ± 13	27 ± 9	26 ± 5	49 ± 39	29 ± 11	16,000 ± 7,000
Boron, μg L^{-1}	412 ± 156	93 ± 167	42 ± 93	200 ± 130	NA	NA	3,700 ± 3,500
δ^{11}B ‰	27 ± 4	22 ± 6	23 ± 6	26 ± 6	NA	NA	39 ± 6
^{226}Ra, *p*Ci L^{-1}	0.24 ± 0.2	0.16 ± 0.15	0.17 ± 0.14	0.2 ± 0.15	0.56 ± 0.74	NA	6,600 ± 5,600
δ^{2}H, ‰, VSMOW	−66 ± 5	−64 ± 3	−68 ± 6	−76 ± 5	NA	NA	−41 ± 6
δ^{18}O, ‰, VSMOW	−10 ± 1	−10 ± 0.5	−11 ± 1	−12 ± 1	NA	NA	−5 ± 1

Some data for the active Genesee Group and nonactive Lockhaven Formation are not included because of insufficient sample sizes (NA). Values represent means ±1 standard deviation. NA, not available.

N values for δ^{11}B ‰ analysis are 8, 10, 3, 6, and 5 for active Lockhaven, active Catskill, nonactive Genesee, nonactive Catskill, and brine, respectively. *N* values for ^{226}Ra are 6, 7, 3, 10, 5, and 13 for active Lockhaven, active Catskill, nonactive Genesee, nonactive Catskill, background Lockhaven, and brine, respectively. δ^{11}B ‰ normalized to National Institute of Standards and Technology Standard Reference Material 951. δ^{2}H and δ^{18}O normalized to Vienna Standard Mean Ocean Water (VSMOW).

firms to voluntarily report a list of the constituents in the fracturing fluids based on the Emergency Planning and Community Right-to-Know Act. More research is also needed on the mechanism of methane contamination, the potential health consequences of methane, and establishment of baseline methane data in other locations. We believe that systematic and independent data on groundwater quality, including dissolved-gas concentrations and isotopic compositions, should be collected before drilling operations begin in a region, as is already done in some states. Ideally, these data should be made available for public analysis, recognizing the privacy concerns that accompany this issue. Such baseline data would improve environmental safety, scientific knowledge, and public confidence. Similarly, long-term monitoring of groundwater and surface methane emissions during and after extraction would clarify the extent of problems and help identify the mechanisms behind them. Greater stewardship, knowledge, and—possibly—regulation are needed to ensure the sustainable future of shale-gas extraction.

Methods

A total of 68 drinking-water samples were collected in Pennsylvania and New York from bedrock aquifers (Lockhaven, 8; Catskill, 47; and Genesee, 13) that overlie the Marcellus or Utica shale formations (Fig. S1). Wells were purged to remove stagnant water, then monitored for pH, electrical conductance, and temperature until stable values were recorded. Samples were collected "upstream" of any treatment systems, as close to the water well as possible, and preserved in accordance with procedures detailed in *SI Methods*. Dissolved-gas samples were analyzed at Isotech Laboratories and water chemical and isotope (O, H, B, C, Ra) compositions were measured at Duke University (see *SI Methods* for analytical details).

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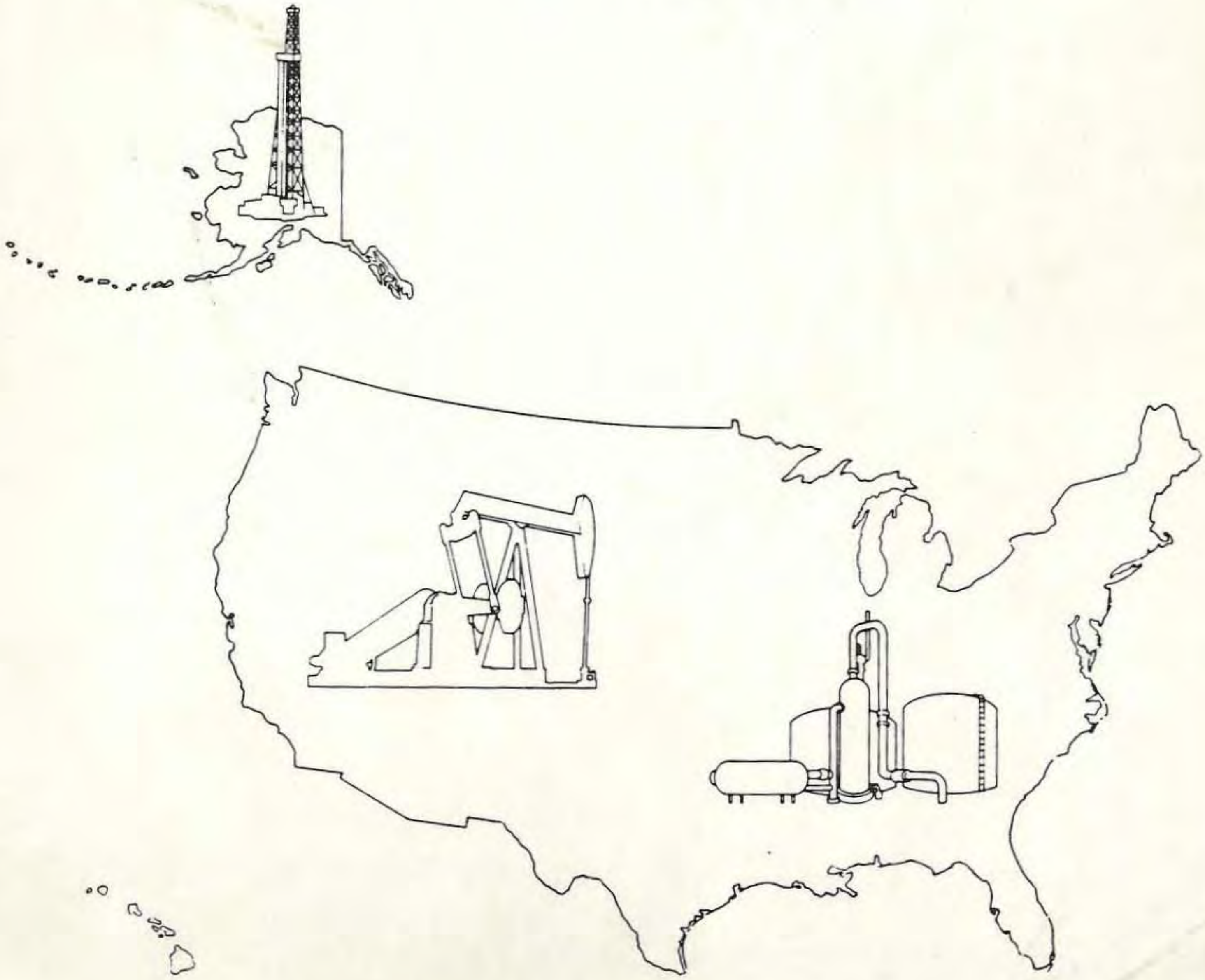
Solid Waste

EPA

Report to Congress

Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy

Volume 1 of 3
Oil and Gas



REPORT TO CONGRESS

MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT, AND PRODUCTION OF CRUDE OIL, NATURAL GAS, AND GEOTHERMAL ENERGY

VOLUME 1 OF 3

OIL AND GAS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Office of Solid Waste and Emergency Response
Washington, D.C. 20460

December 1987

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CHAPTER I

INTRODUCTION

STATUTORY REQUIREMENTS AND GENERAL PURPOSE

Under Section 3001(b)(2)(A) of the 1980 Amendments to the Resource Conservation and Recovery Act (RCRA), Congress temporarily exempted several types of solid wastes from regulation as hazardous wastes, pending further study by the Environmental Protection Agency (EPA).[1] Among the categories of wastes exempted were "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy." Section 8002(m) of the Amendments requires the Administrator to study these wastes and submit a final report to Congress. This report responds to those requirements. Because of the many inherent differences between the oil and gas industry and the geothermal energy industry, the report is submitted in three volumes. Volume 1 (this volume) covers the oil and gas industry; Volume 2 covers the geothermal energy industry; Volume 3 covers State regulatory summaries for the oil and gas industry and includes a glossary of terms. This report discusses wastes generated only by the onshore segment of the oil and gas industry.

The original deadline for this study was October 1982. EPA failed to meet that deadline, and in August 1985 the Alaska Center for the Environment sued the Agency for its failure to conduct the study.

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[1] EPA is also required to make regulatory determinations affecting the oil and gas and geothermal energy industries under several other major statutes. These include designing appropriate effluent limitations guidelines under the Clean Water Act, determining emissions standards under the Clean Air Act, and implementing the requirements of the underground injection control program under the Safe Drinking Water Act.

EPA entered into a consent order, obligating it to submit the final Report to Congress on or before August 31, 1987. In April 1987, this schedule was modified and the deadline for submittal of the final Report to Congress was extended to December 31, 1987.

Following submission of the current study, and after public hearings and opportunity for comment, the Administrator of EPA must determine either to promulgate regulations under the hazardous waste management provisions of RCRA (Subtitle C) or to declare that such regulations are unwarranted. Any regulations would not take effect unless authorized by an act of Congress.

This does not mean that the recommendations of this report are limited to a narrow choice between application of full Subtitle C regulation and continuation of the current exemption. Section 8002(m) specifically requires the Administrator to propose recommendations for "[both] Federal and non-Federal actions" to prevent or substantially mitigate any adverse effects associated with management of wastes from these industries. EPA interprets this statement as a directive to consider the practical and prudent means available to avert health or environmental damage associated with the improper management of oil, gas, or geothermal wastes. The Agency has identified a wide range of possible actions, including voluntary programs, cooperative work with States to modify their programs, and Federal action outside of RCRA Subtitle C, such as RCRA Subtitle D, the existing Underground Injection Control Program under the Safe Drinking Water Act, or the National Pollution Discharge Elimination System under the Clean Water Act.

In this light, EPA emphasizes that the recommendations presented here do <u>not</u> constitute a regulatory determination. Such a determination cannot be made until the public has had an opportunity to review and comment on this report (i.e., the determination cannot be made until June 1988). Furthermore, the Agency is, in several important areas, presenting optional approaches involving further research and consultation with the States and other affected parties.

STUDY APPROACH

The study factors are listed in the various paragraphs of Section 8002(m), which is quoted in its entirety as Exhibit 1 (page I-13). For clarity, the Agency has designed this report to respond specifically to each study factor within separate chapters or sections of chapters. It is important to note that although every study factor has been weighed in arriving at the conclusions and recommendations of this report, no single study factor has a determining influence on the conclusions and recommendations.

The study factors are defined in the paragraphs below, which also introduce the methodologies used to analyze each study area with respect to the oil and gas industry. More detailed methodological discussions can be found later in this report and in the supporting documentation and appendices.

STUDY FACTORS

The principal study factors of concern to Congress are listed in subparagraphs (A) through (G) of Section 8002(m)(1) (see Exhibit 1). The introductory and concluding paragraphs of the Section, however, also contain directives to the Agency on the content of this study. This work has therefore been organized to respond to the following comprehensive interpretation of the 8002(m) study factors.

Study Factor 1 - Defining Exempt Wastes

RCRA describes the exempt wastes in broad terms, referring to "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy." The Agency, therefore, relied to the extent possible on the legislative history of the amendments, which provides guidance on the definition of other wastes. The tentative scope of the exemption is discussed in Chapter II of this volume.

Study Factor 2 - Specifying the Sources and Volumes of Exempt Wastes

In response to Section 8002(m)(1)(A), EPA has developed estimates of the sources and volumes of all exempt wastes. The estimates are presented in Chapter II, "Overview of the Industry."

Comprehensive information on the volumes of exempt wastes from oil and gas operations is not routinely collected nationwide; however, estimates of total volumes produced can be made through a variety of approaches.

With respect to drilling muds and related wastes, two methods for estimating volumes are presented. The first, developed early in the study by EPA, estimates drilling wastes as a function of the size of reserve pits. The second method is based on a survey conducted by the American Petroleum Institute (API) on production of drilling muds and completion fluids, cuttings, and other associated wastes discharged to reserve pits. Both methods and their results are included in Chapter II.

Similarly, EPA and API developed independent estimates of produced water volumes. EPA's first estimates were based on a survey of the injection, production, and hauling reports of State agencies; API's were based on its own survey of production operations. Again, this report presents the results of both methodologies.

Study Factor 3 - Characterizing Wastes

Section 8002(m) does not directly call for a laboratory analysis of the exempted wastes, but the Agency considers such a review to be a necessary and appropriate element of this study. Analysis of the principal high-volume wastes (i.e., drilling fluids and produced waters) can help to indicate whether any of the wastes may be hazardous under the definitions of RCRA Subtitle C. Wastes were examined with regard to whether they exhibited any of the hazardous characteristics defined under 40 CFR 261 of RCRA, including extraction procedure toxicity, ignitability, corrosivity, and reactivity. Also, a compositional analysis was performed for the purpose of determining if hazardous constituents were present in the wastes at concentrations exceeding accepted health-based limits.

EPA therefore conducted a national screening type program that sampled facilities to compile relevant data on waste characteristics. Sites were selected at random in cooperation with State regulatory agencies, based on a division of the United States into zones (see Figure I-1). Samples were subjected to extensive analysis, and the results were subjected to rigorous quality control procedures prior to their publication in January 1987. Simultaneously, using a different sampling methodology, API sampled the same sites and wastes covered by the EPA-sponsored survey. Chapter II of this report, "Overview of the Industry," presents a summary of results of both programs.

Study Factor 4 - Describing Current Disposal Practices

Section 8002(m)(1)(B) calls for an analysis of current disposal practices for exempted wastes. Chapter III, "Current and Alternative Waste Management Practices," summarizes EPA's review, which was based on a number of sources. Besides reviewing the technical literature, EPA sent representatives to regulatory agencies of the major oil- and gas-producing States to discuss current waste management technologies with State representatives. In addition, early drafts of this study's characterizations of such technologies were reviewed by State and industry representatives.

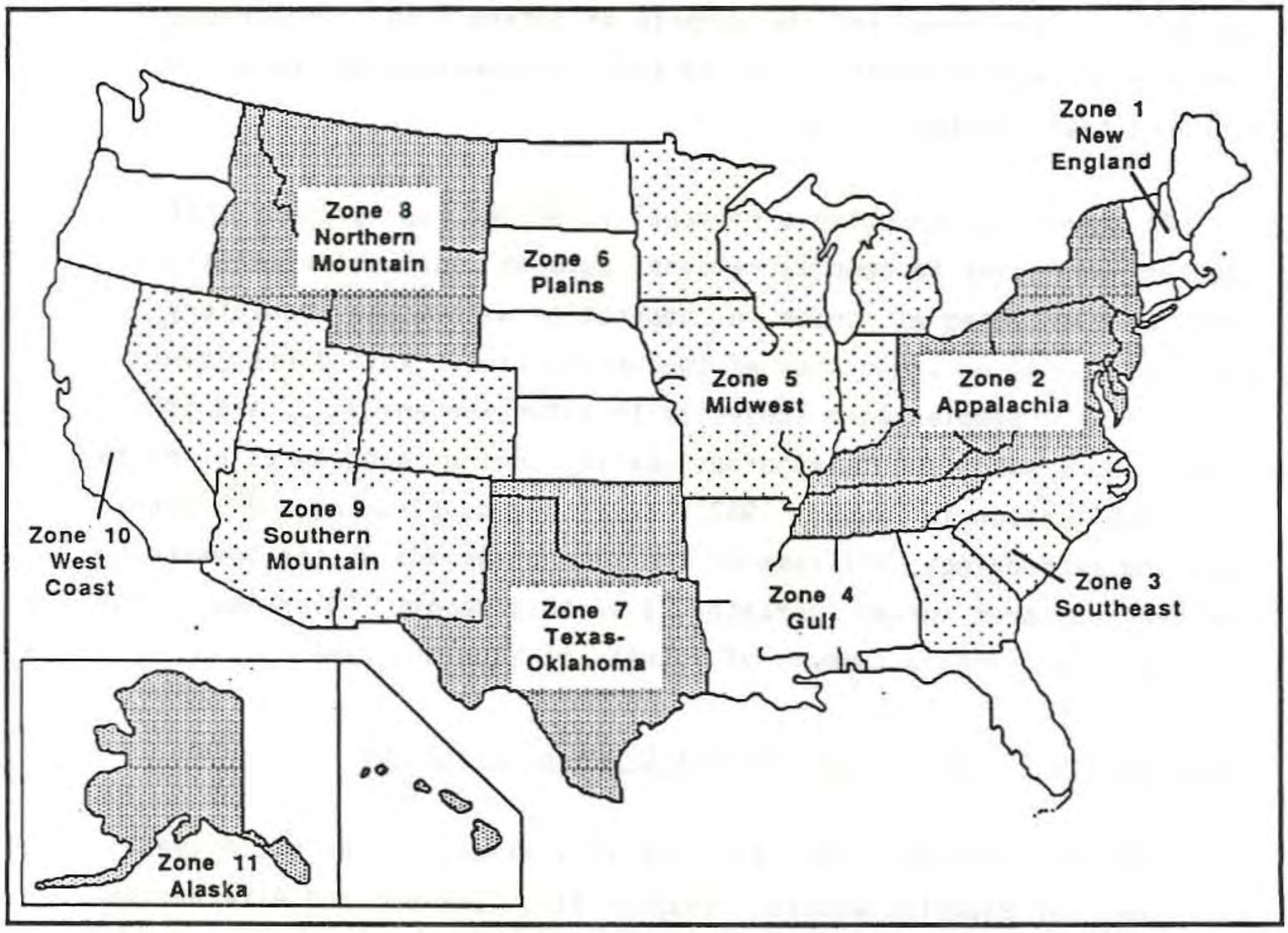

Figure I-1
Oil and Gas Production Zones
Divisions of the United States
Used for the
RCRA Section 8002(m) Study of
Oil and Gas Wastes

The Agency intentionally has not compiled an exhaustive review of waste management technologies used by the oil and gas industry. As stressed throughout this volume, conditions and methods vary widely from State to State and operation to operation. Rather, the Agency has described the principal and common methods of managing field-generated wastes and has discussed these practices in general and qualitative terms in relation to their effectiveness in protecting human health and the environment.

Study Factor 5 - Documenting Evidence of Damage to Human Health and the Environment Caused by Management of Oil and Gas Wastes

Section 8002(m)(1)(D) requires EPA to analyze "documented cases" of health and environmental damage related to surface runoff or leachate. Although EPA has followed this instruction, paragraph (1) of the section also refers to "adverse effects of such wastes [i.e., exempted wastes, not necessarily only runoff and leachate] on humans, water, air, health, welfare, and natural resources...."

Chapter IV, "Damage Cases," summarizes EPA's effort to collect documented evidence of harm to human health, the environment, or valuable resources. Cases were accepted for presentation in this report only if, prior to commencement of field work, they met the standards of the test of proof, defined as (1) a scientific study, (2) an administrative finding of damage under State or other applicable authority, or (3) determination of damage by a court. Many cases met more than one such test of proof.

A number of issues of interpretation have been raised that must be clarified at the outset. First, in the Agency's opinion, the case study approach, such as that called for by Section 8002(m), is intended only to define the nature and range of known damages, not to estimate the frequency or extent of damages associated with typical operations. The results presented here should not be interpreted as having statistical significance. The number of cases reported in each category bears no statistically significant relationship to the actual types and distribution of damages that may or may not exist across the United States.

Second, the total number of cases bears no implied or intended relationship to the total extent of damage from oil or gas operations caused at present or in the past.

Third, Section 8002(m)(1)(D) makes no mention of defining relationships between documented damages and violations of State or other Federal regulations. As a practical necessity, EPA has in fact relied heavily on State enforcement and complaint files in gathering documentation for this section of the report.[2] Consequently, a large proportion of cases reported here involve violations of State regulations. However, the fact that the majority of cases presented here involve State enforcement actions implies nothing, positive or negative, about the success of State programs in enforcing their requirements on industry.

Study Factor 6 - Assessing Potential Danger to Human Health or the Environment from the Wastes

Section 8002(m)(1)(C) requires analysis of the potential dangers of surface runoff and leachate. These potential effects can involve all types of damages over a long period of time and are not necessarily limited to the categories of damages for which documentation is currently available.

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[2] Other sources have included evidence submitted by private citizens or supplied by attorneys in response to inquiries from EPA researchers.

Several methods of estimating potential damages are available, and EPA has combined two approaches in responding to this study factor in Chapter V, "Risk Modeling." The first has been to use quantitative risk assessment modeling techniques developed for use elsewhere in the RCRA program. The second has been to apply more qualitative methods, based on traditional environmental assessment techniques.

The goal of both the quantitative and the qualitative risk assessments has been to define the most important factors in causing or averting human health risk and environmental risk from field operations. For the quantitative evaluation, EPA has adapted the EPA Liner Location Model, which was built to evaluate the impacts of land disposal of hazardous wastes, for use in analyzing drilling and production conditions. Since oil and gas operations are in many ways significantly different from land disposal of hazardous wastes, all revisions to the Liner Location Model and assumptions made in its present application have been extensively documented and are summarized in Chapter V. The procedures of traditional environmental assessment needed no modification to be applied.

As is true in the damage case work, the results of the modeling analysis have no statistical significance in terms of either the pattern or the extent of damages projected. The Agency modeled a subset of prototype situations, designed to roughly represent significant variations in conditions across the country. The results are very useful for characterizing the interactions of technological, geological, and climatic differences as they influence the potential for damages.

Study Factor 7 - Reviewing the Adequacy of Government and Private Measures to Prevent and/or Mitigate any Adverse Effects

Section 8002 (m)(1) requires that the report's conclusions of any adverse effects associated with current management of exempted wastes include consideration of the "adequacy of means and measures currently employed by the oil and gas industry, Government agencies, and others" to dispose of or recycle wastes or to prevent or mitigate those adverse effects.

Neither the damage case assessment nor the risk assessment provided statistically representative data on the extent of damages, making it impossible to compare damages in any quantitative way to the presence and effectiveness of control efforts. The Agency's response to this requirement is therefore based on a qualitative assessment of all the materials gathered during the course of assembling the report and on a review of State regulatory programs presented in Chapter VII, "Current Regulatory Programs." Chapter VII reviews the elements of programs and highlights possible inconsistencies, lack of specificity, potential problems in implementation, or gaps in coverage. Interpretation of the adequacy of these control efforts is presented in Chapter VIII, "Conclusions."

Study Factor 8 - Defining Alternatives to Current Waste Management Practices

Section 8002 (m)(1) requires EPA to analyze alternatives to current disposal methods. EPA's discussion in response to this study factor is incorporated in Chapter III, "Current and Alternative Waste Management Practices."

Chapter III merges the concepts of current and alternative waste management practices. It does not single out particular technologies as potential substitutes for current practices because of the wide variation in practices among States and among different types of operations. Furthermore, waste management technology in this field is fairly simple. At least for the major high-volume waste streams, no significant, field-proven, newly invented technologies that can be considered "innovative" or "emerging" are in the research or development stage.

Practices that are routine in one location may be considered innovative or alternative elsewhere. On the other hand, virtually every waste management practice that exists can be considered "current" in one specific situation or another.

This does not mean that improvements are not possible: in some cases, currently available technologies may not be properly selected, implemented, or maintained. Near-term improvements in waste management in these industries will likely be based largely on more effective use of what is already available.

Study Factor 9 - Estimating the Costs of Alternative Practices

Subparagraph (F) calls for analysis of costs of alternative practices. The first several sections of Chapter VI, "Costs and Economic Impacts of Alternative Waste Management Practices," present the Agency's analysis of this study factor.

For the purposes of this report, EPA based its cost estimates on 21 prototypical regional projects, defined so as to capture significant differences between major and independent companies and between stripper operations and other projects. The study evaluates costs of waste disposal only for the two principal high-volume waste streams of concern, drilling fluids and produced waters, employing as its baseline the use of unlined reserve pits located at the drill site and the disposal of produced waters in injection wells permitted under the Federal Underground Injection Control Program and located off site.

The study then developed two alternative scenarios that varied the incremental costs of waste management control technology, applied them to each prototype project, and modeled the cost impacts of each. The first scenario imposes a set of requirements typical of full Subtitle C management rules; the second represents a less stringent and extensive range of requirements based, in essence, on uniform nationwide use of the most up-to-date and effective controls now being applied by any of the States. Model results indicate cumulative annual costs, at the project level, of each of the more stringent control scenarios.

Study Factor 10 - Estimating the Economic Impacts on Industry of Alternative Practices

In response to the requirements of subparagraph (G), the final two sections of Chapter VI present the Agency's analysis of the potential economic impacts of nationwide imposition of the two control scenarios analyzed at the project level.

Both the cost and the economic impact predicted in this report are admittedly large. Many significant variations influence the economics of this industry and make it difficult to generalize about impacts on either the project or the national level. In particular, the price of oil itself greatly affects both levels. Fluctuations in the price of oil over the period during which this study was prepared have had a profound influence on project economics, making it difficult to draw conclusions about the current or future impacts of modified waste management practices.

Nevertheless, the Agency believes that the analysis presented here is a reasonable response to Congress's directives, and that the results, while they cannot be exact, accurately reflect the general impacts that might be expected if environmental control requirements were made more stringent.

EXHIBIT 1:

Section 8002(m) Resource Conservation and Recovery Act as amended by PL 96-482

"(m) Drilling Fluids, Produced Waters, and Other Wastes Associated with the Extraction, Development, or Production of Crude Oil or Natural Gas or Geothermal Energy.- (1) The Administrator shall conduct a detailed and comprehensive study and submit a report on the adverse effects, if any, of drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy on human health and the environment, including, but not limited to the effects of such wastes on humans, water, air, health, welfare, and natural resources and on the adequacy of means and measures currently employed by the oil and gas and geothermal drilling and production industry, Government agencies, and others to dispose of and utilize such wastes and to prevent or substantially mitigate such adverse effects. Such study shall include an analysis of-

"(A) the sources and volume of discarded material generated per year from such wastes;

"(B) present disposal practices:

"(C) potential danger to human health and the environment from the surface runoff or leachate;

"(D) documented cases which prove or have caused danger to human health and the environment from surface runoff or leachate;

"(E) alternatives to current disposal methods:

"(F) the cost of such alternatives; and

"(G) the impact of those alternatives on the exploration for, and development and production of, crude oil and natural gas or geothermal energy.

In furtherance of this study, the Administrator shall, as he deems appropriate, review studies and other actions of other Federal agencies concerning such wastes with a view toward avoiding duplication of effort and the need to expedite such study. The Administrator shall publish a report of such and shall include appropriate findings and recommendations for Federal and non-Federal actions concerning such effects.

"(2) The Administrator shall complete the research and study and submit the report required under paragraph (1) not later than twenty-four months from the date of enactment of the Solid Waste Disposal Act Amendments of 1980. Upon completion of the study, the Administrator shall prepare a summary of the findings of the study, a plan for research, development, and demonstration respecting the findings of the study, and shall submit the findings and the study, along with any recommendations resulting from such study, to the Committee on Environment and Public Works of the United States Senate and the Committee on Interstate and Foreign Commerce of the United states House of Representatives.

"(3) There are authorized to be appropriations not to exceed $1,000,000 to carry out the provisions of this subsection.

CHAPTER II

OVERVIEW OF THE INDUSTRY

DESCRIPTION OF THE OIL AND GAS INDUSTRY

The oil and gas industry explores for, develops, and produces petroleum resources. In 1985 there were approximately 842,000 producing oil and gas wells in this country, distributed throughout 38 States. They produced 8.4 million barrels[1] of oil, 1.6 million barrels of natural gas liquids, and 44 billion cubic feet of natural gas daily. The American Petroleum Institute estimates domestic reserves at 28.4 billion barrels of oil, 7.9 billion barrels of natural gas liquids, and 193 trillion cubic feet of gas. Petroleum exploration, development, and production industries employed approximately 421,000 people in 1985.[2]

The industry is as varied as it is large. Some aspects of exploration, development, and production can change markedly from region to region and State to State. Well depths range from as little as 30 to 50 feet in some areas to over 30,000 feet in areas such as the Anadarko Basin of Oklahoma. Pennsylvania has been producing oil for 120 years; Alaska for only 15. Maryland has approximately 14 producing wells; Texas has 269,000 and completed another 25,721 in 1985 alone. Production from a single well can vary from a high of about 11,500 barrels per day (the 1985 average for wells on the Alaska North Slope) to less than 10 barrels per day for many thousands of "stripper" wells located in Appalachia and

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[1] Crude oil production has traditionally been expressed in barrels. A barrel is equivalent to 5.61 ft^3, 0.158 m^3, or 42 U.S. gallons.

[2] These numbers, provided to EPA by the Bureau of Land Management (BLM), are generally accepted.

the more developed portions of the rest of the country.[3] Overall, 70 percent of all U.S. oil wells are strippers, operating on the margins of profitability. Together, however, these strippers contribute 14 percent of total U.S. production--a number that appears small, yet is roughly the equivalent of the immense Prudhoe Bay field in Alaska.

Such statistics make it clear that a short discussion such as this cannot provide a comprehensive or fully accurate description of this industry. The purpose of this chapter is simply to present the terminology used in the rest of this report[4] and to provide an overview of typical exploration, development, and production methods. With this as introduction, the chapter then defines which oil and gas wastes EPA considers to be exempt within the scope of RCRA Section 8002; estimates the volumes of exempt wastes generated by onshore oil and gas operations; and presents the results of sample surveys conducted by EPA and the American Petroleum Institute to characterize the content of exempt oil and gas wastes.

Exploration and Development

Although geological and geophysical studies provide information concerning potential accumulations of petroleum, the only method that can confirm the presence of petroleum is exploratory drilling. The majority of exploratory wells are "dry" and must be plugged and abandoned. When an exploratory well does discover a commercial deposit, however, many development wells are typically needed to extract oil or gas from that reservoir.

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[3] The definition of "stripper" well may vary from State to State. For example, North Dakota defines a stripper as a well that produces 10 barrels per day or less at 6,000 feet or less; 11 to 15 barrels per day from a depth of 6,001 feet to 10,000 feet; and 16 to 20 barrels per day for wells that are 10,000 feet deep.

[4] A glossary of terms is also provided in Volume 3.

Exploratory and development wells are mechanically similar and generate similar wastes up to the point of production. In order to bring a field into production, however, development wells generate wastes associated with well completion and stimulation; these processes are discussed below. From 1981 to 1985, exploration and development drilling combined averaged 73,000 wells per year (API 1986). Drilling activity declined in 1986 and by mid-1987 rebounded over 1986 levels.

In the early part of the century, cable-tool drilling was the predominant method of well drilling. The up-and-down motion of a chisel-like bit, suspended by a cable, causes it to chip away the rock, which must be periodically removed with a bailer. Although an efficient technique, cable-tool drilling is limited to use in shallow, low-pressure reservoirs. Today, cable-tool drilling is used on a very limited basis in the United States, having been replaced almost entirely by rotary drilling.

Rotary drilling provides a safe method for controlling high-pressure oil/gas/water flows and allows for the simultaneous drilling of the well and removal of cuttings, making it possible to drill wells over 30,000 feet deep. Figure II-1 illustrates the process. The rotary motion provided by mechanisms on the drill rig floor turns a drill pipe or stem, thereby causing a bit on the end of the pipe to gouge and chip away the rock at the bottom of the hole. The bit itself generally has three cone-shaped wheels tipped with hardened teeth and is weighted into place by thick-walled collars. Well casing is periodically cemented into the hole, providing a uniform and stable conduit for the drill stem as it drills deeper into the hole. The casing also seals off freshwater aquifers, high-pressure zones, and other troublesome formations.

Most rotary drilling operations employ a circulation system using a water- or oil-based fluid, called "mud" because of its appearance. The

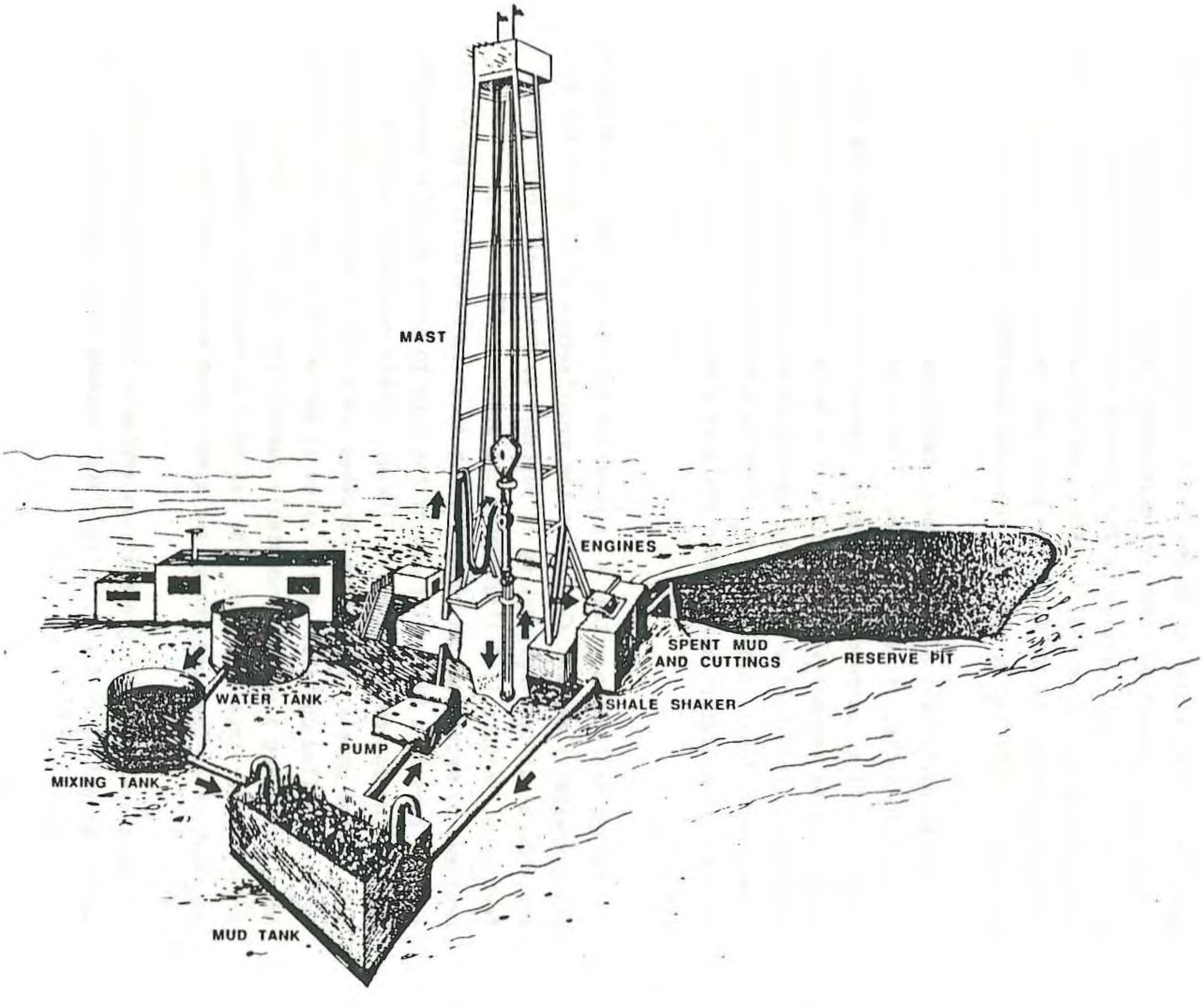

Figure II-1 Typical Rotary Drilling Rig

mud is pumped down the hollow drill pipe and across the face of the bit to provide lubrication and remove cuttings. The mud and cuttings are then pumped back up through the annular space between the drill pipe and the walls of the hole or casing. Mud is generally mixed with a weighting agent such as barite, and other mud additives, thus helping it serve several other important functions: (1) stabilizing the wellbore and preventing cave-ins, (2) counterbalancing any high-pressure oil, gas, or water zones in the formations being drilled, and (3) providing a medium to alleviate problems "downhole" (such as stuck pipe or lost circulation).

Cuttings are removed at the surface by shale shakers, desanders, and desilters; they are then deposited in the reserve pit excavated or constructed next to the rig. The reclaimed drilling mud is then recirculated back to the well. The type and extent of solids control equipment used influences how well the cuttings can be separated from the drilling fluid, and hence influences the volume of mud discharged versus how much is recirculated. Drilling mud must be disposed of when excess mud is collected, when changing downhole conditions require a whole new mud formulation, or when the well is abandoned. The reserve pit is generally used for this purpose. (Reserve pits serve multiple waste management functions. See discussion in Chapter III.) If the well is a dry hole, the drilling mud may be disposed of downhole upon abandonment.

The formation of a drilling mud for a particular job depends on types of geologic formations encountered, economics, availability, problems encountered downhole, and well data collection practices. Water-based drilling muds predominate in the United States. Colloidal materials, primarily bentonitic clay, and weighting materials, such as barite, are common constituents. Numerous chemical additives are available to give the mud precise properties to facilitate the drilling of the well; they include acids and bases, salts, corrosion inhibitors, viscosifiers, dispersants, fluid loss reducers, lost circulation materials, flocculants, surfactants, biocides, and lubricants. (See also Table III-2.)

Oil-based drilling fluids account for approximately 3 to 10 percent of the total volume of drilling fluids used nationwide. The oil base may consist of crude oil, refined oil (usually fuel oil or diesel), or mineral oil. Oil-based drilling fluid provides lubrication in directionally drilled holes, high-temperature stability in very deep holes, and protection during drilling through water-sensitive formations.

In areas where high-pressure or water-bearing formations are not anticipated, air drilling is considerably faster and less expensive than drilling with water- or oil-based fluids. (Air drilling cannot be used in deep wells.) In this process, compressed air takes the place of mud, cooling the bit and lifting the cuttings back to the surface. Water is injected into the return line for dust suppression, creating a slurry that must be disposed of. In the United States, air drilling is most commonly used in the Appalachian Basin, in southeastern Kansas/northeastern Oklahoma, and in the Four Corners area of the Southwest. Other low-density drilling fluids are used in special situations. Gases other than air, usually nitrogen, are sometimes useful. These may be dispersed with liquids or solids, creating wastes in the form of mist, foam, emulsion, suspension, or gel.

Potential producing zones are commonly measured and analyzed (logged) during drilling, a process that typically generates no waste. If hydrocarbons appear to be present, a drill stem test can tell much about their characteristics. When the test is completed, formation fluids collected in the drill pipe must be disposed of.

If tests show that commercial quantities of oil and gas are present, the well must be prepared for production or "completed." "Cased hole" completions are the most common type. First, production casing is run into the hole and cemented permanently in place. Then one or more strings of production tubing are set in the hole, productive intervals are isolated with packers, and surface equipment is installed. Actual completion involves the use of a gun or explosive charge that perforates the production casing and begins the flow of petroleum into the well.

During these completion operations, drilling fluid in the well may be modified or replaced by specialized fluids to control flow from the formation. A typical completion fluid consists of a brine solution modified with petroleum products, resins, polymers, and other chemical additives. When the well is produced initially, the completion fluid may be reclaimed or treated as a waste product that must be disposed of. For long-term corrosion protection, a packer fluid is placed into the casing/tubing annulus. Solids-free diesel oil, crude oil, produced water, or specially treated drilling fluid are preferred packer fluids.

Following well completion, oil or gas in the surrounding formations frequently is not under sufficient pressure to flow freely into the well and be removed. The formation may be impacted with indigenous material, the area directly surrounding the borehole may have become packed with cuttings, or the formation may have inherent low permeability.

Operators use a variety of stimulation techniques to correct these conditions and increase oil flow. Acidizing introduces acid into the production formation, dissolving formation matrix and thereby enlarging existing channels in carbonate-bearing rock. Hydraulic fracturing involves pumping specialized fluids carrying sand, glass beads, or similar materials into the production formation under high pressure; this creates fractures in the rock that remain propped open by the sand, beads, or similar materials when pressure is released.

Other specialized fluids may be pumped down a production well to enhance its yield; these can include corrosion inhibitors, surfactants, friction reducers, complexing agents, and cleanup additives. Although the formation may retain some of these fluids, most are returned to the surface when the well is initially produced or are slowly released over time. These fluids may require disposal, independent of disposal associated with produced water.

Drilling operations have the potential to create air pollution from several sources. The actual drilling equipment itself is typically run by large diesel engines that tend to emit significant quantities of particulates, sulfur oxides, and oxides of nitrogen, which are subject to regulation under the Clean Air Act. The particulates emitted may contain heavy metals as well as polycyclic organic matter (POMs). Particularly for deep wells, which require the most power to drill, and in large fields where several drilling operations may be in progress at the same time, cumulative diesel emissions can be important. Oil-fired turbines are also used as a source of power on newer drilling rigs. Other sources of air pollution include volatilization of light organic compounds from reserve pits and other holding pits that may be in use during drilling; these are exempt wastes. These light organics can be volatilized from recovered hydrocarbons or from solvents or other chemicals used in the production process for cleaning, fracturing, or well completion. The volume of volatile organic compounds is insignificant in comparison to diesel engine emissions.

Production

Production operations generally include all activities associated with the recovery of petroleum from geologic formations. They can be divided into activities associated with downhole operations and activities associated with surface operations. Downhole operations include primary, secondary, and tertiary recovery methods; well workovers; and well stimulation activities. Activities associated with surface operations include oil/gas/water separation, fluid treatment, and disposal of produced water. Each of these terms is discussed briefly below.

Downhole Operations

Primary recovery refers to the initial production of oil or gas from a reservoir using natural pressure or artificial lift methods, such as surface or subsurface pumps and gas lift, to bring it out of the formation and to the surface. Most reservoirs are capable of producing oil and gas by primary recovery methods alone, but this ability declines over the life of the well. Eventually, virtually all wells must employ some form of secondary recovery, typically involving injection of gas or liquid into the reservoir to maintain pressure within the producing formation. Waterflooding is the most frequently employed secondary recovery method. It involves injecting treated fresh water, seawater, or produced water into the formation through a separate well or wells.

Tertiary recovery refers to the recovery of the last portion of the oil that can be economically produced. Chemical, physical, and thermal methods are available and may be used in combination. Chemical methods involve injection of fluids containing substances such as surfactants and polymers. Miscible oil recovery involves injection of gases, such as carbon dioxide and natural gas, which combine with the oil. Thermal recovery methods include steam injection and in situ combustion (or "fire flooding"). When oil eventually reaches a production well, injected gases or fluids from secondary and tertiary recovery operations may be dissolved or carried in formation oil or water, or simply mixed with them; their removal is discussed below in conjunction with surface production operations.

Workovers, another aspect of downhole production operations, are designed to restore or increase production from wells whose flows are inhibited by downhole mechanical failures or blockages, such as sand or paraffin deposits. Fluids circulated into the well for this purpose must be compatible with the formation and must not adversely affect permeability. They are similar to completion fluids, described earlier. When the well is put back into production, the workover fluid may be reclaimed or disposed of.

Other chemicals may be periodically or continuously pumped down a production well to inhibit corrosion, reduce friction, or simply keep the well flowing. For example, methanol may be pumped down a gas well to keep it from becoming plugged with ice.

Surface Operations

Surface production operations generally include gathering of the produced fluids (oil, gas, gas liquids, and water) from a well or group of wells and separation and treatment of the fluids. See Figures II-2, II-3, and II-4. As producing reservoirs are depleted, their water/oil ratios may increase steeply. New wells may produce little if any water; stripper wells may vary greatly in the volume of water they produce. Some may produce more than 100 barrels of water for every barrel of oil, particularly if the wells are subject to waterflooding operations.

Virtually all of this water must be removed before the product can be transferred to a pipeline. (The maximum water content allowed is generally less than 1 percent.) The oil may also contain completion or workover fluids, stimulation fluids, or other chemicals (biocides, fungicides) used as an adjunct to production. Some oil/water mixtures may be easy to separate, but others may exist as fine emulsions that do

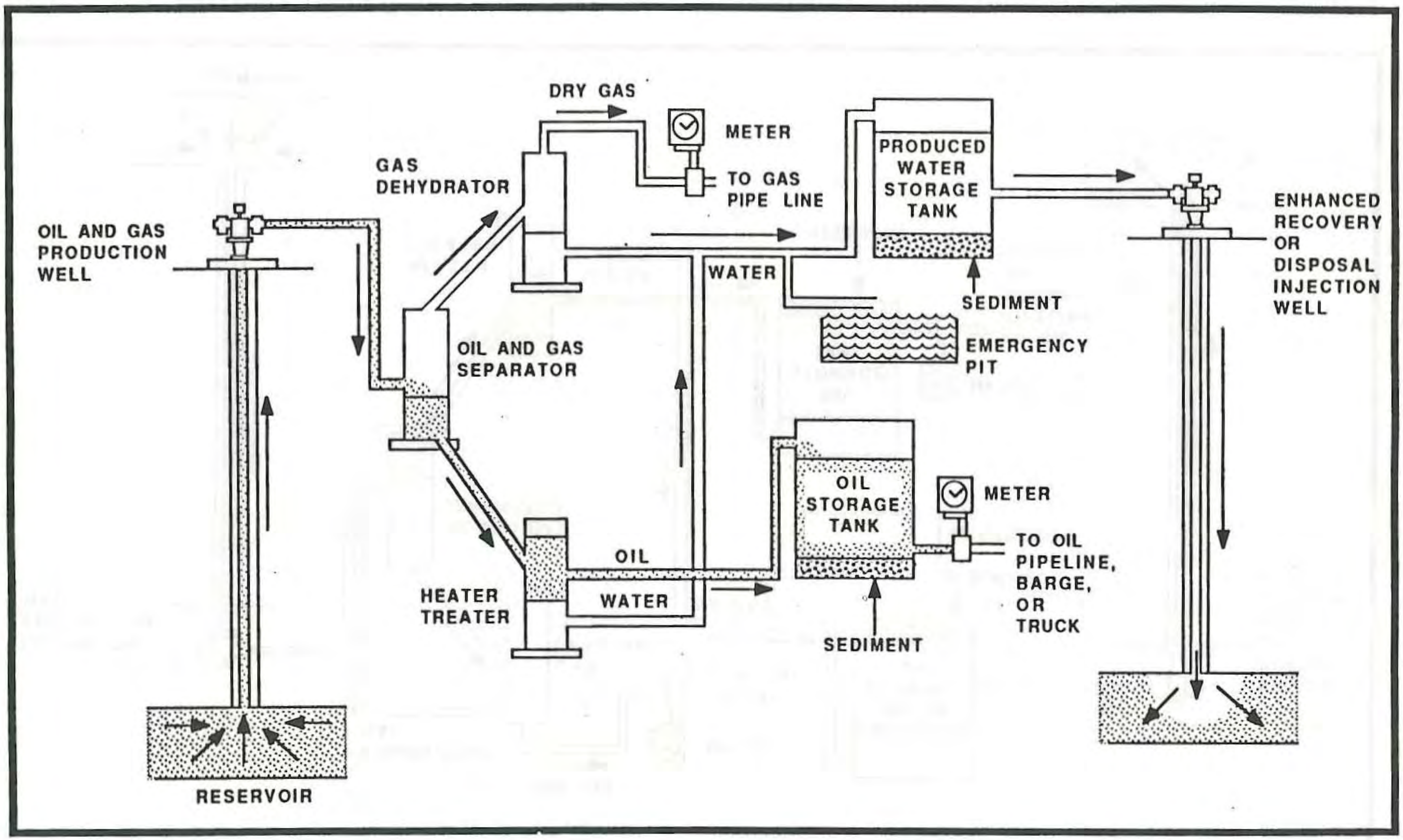

Figure II-2 Typical Production Operation, Showing Separation of Oil, Gas, and Water

Produced waters are not always injected as indicated in this figure. Produced water may be trucked to central treatment and disposal facilities, discharged into disposal pits, discharged to surface or coastal waters, or used for beneficial or agricultural use.

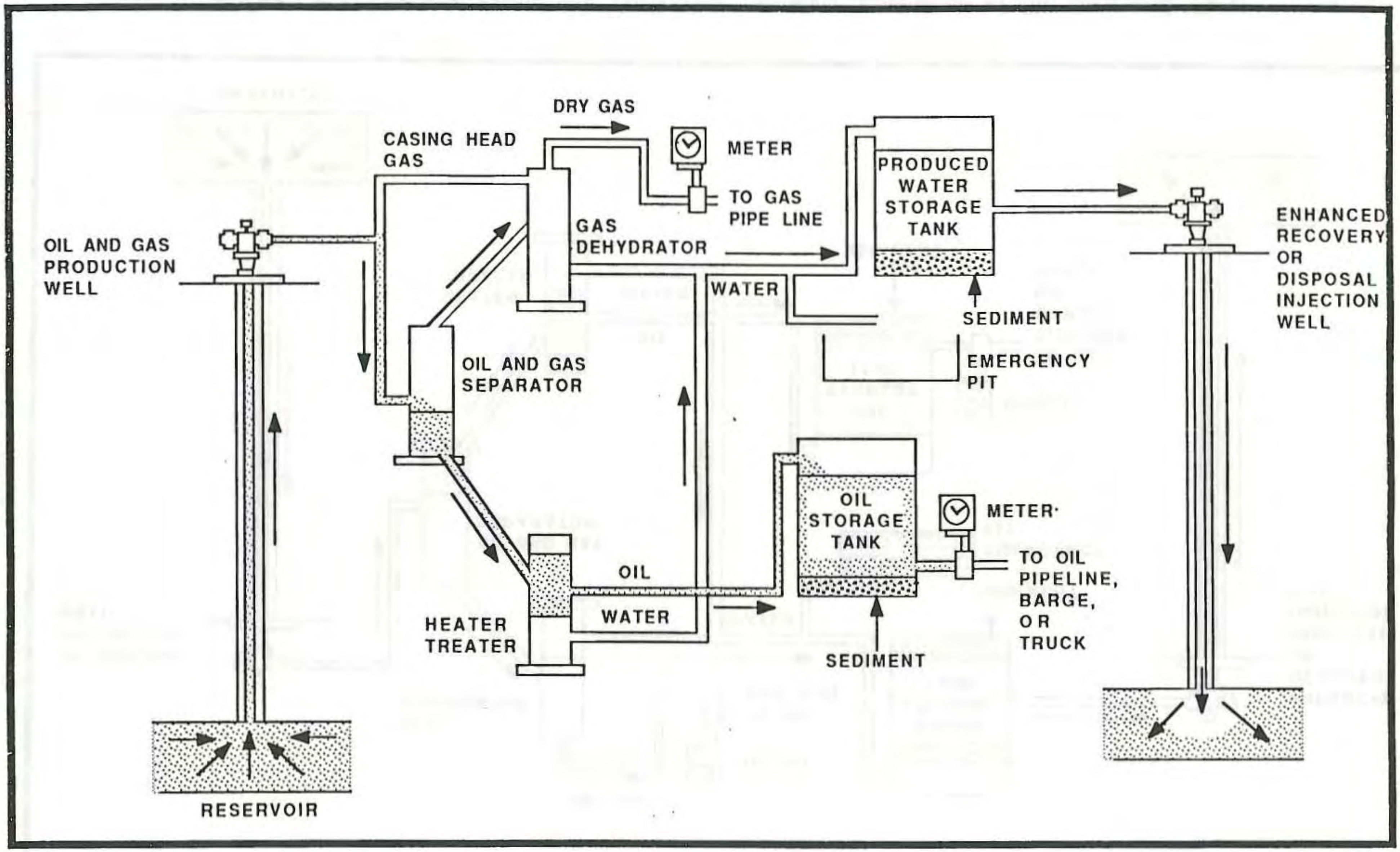

Figure II-3 Oil Production With Average H_2O Production With Dissolved/Associated Gas

Produced waters are not always injected as indicated in this figure. Produced water may be trucked to central treatment and disposal facilities, discharged into disposal pits, discharged to surface or coastal waters, or used for beneficial or agricultural use.

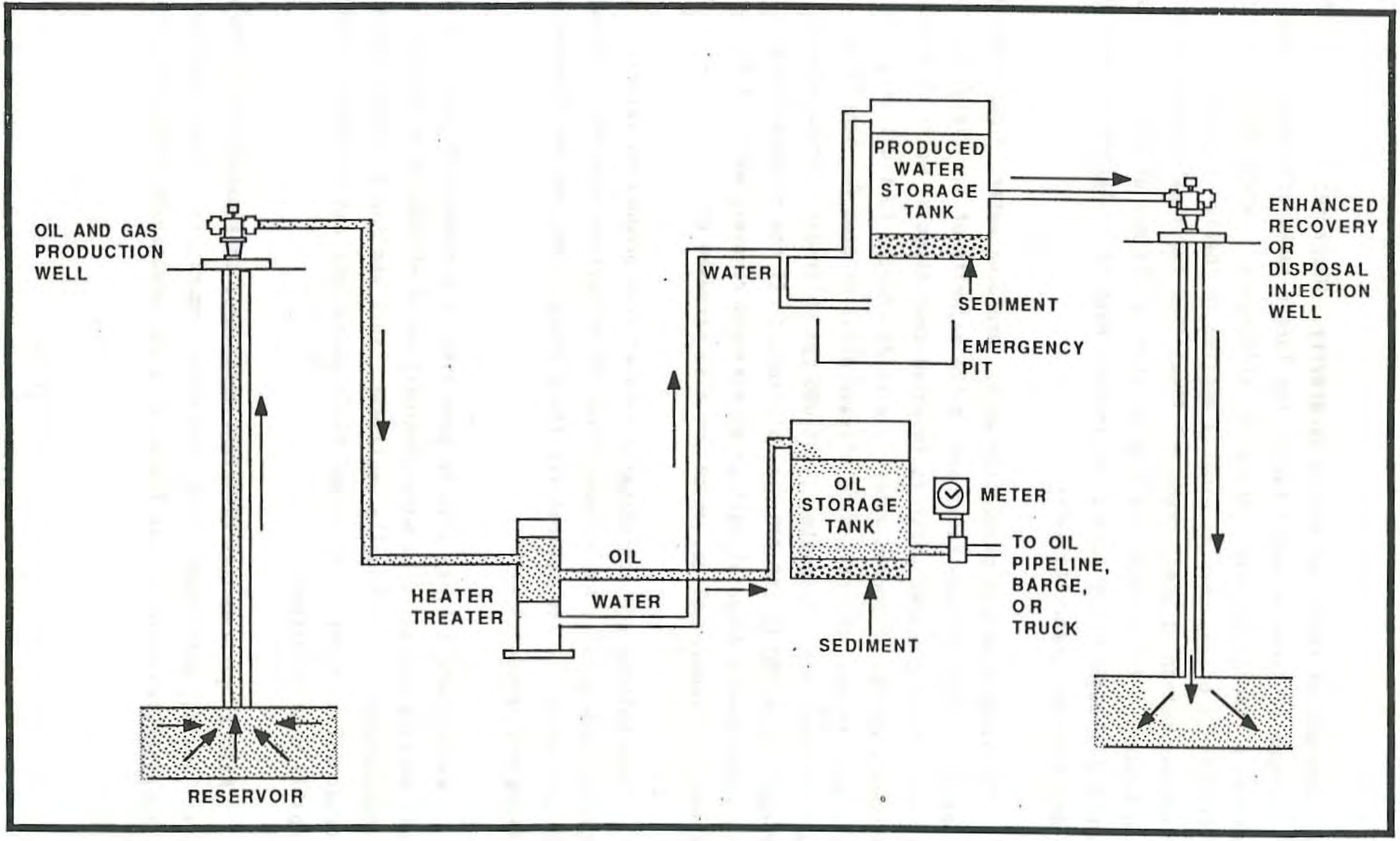

Figure II-4 High Oil/H_2O Ratio Without Significant Dissolved/Associated Gas

Produced waters are not always injected as indicated in this figure. Produced water may be trucked to central treatment and disposal facilities, discharged into disposal pits, discharged to surface or coastal waters, or used for beneficial or agricultural use.

not separate of their own accord by gravity. Where settling is possible, it is done in large or small tanks, the larger tanks affording longer residence time to increase separation efficiency. Where emulsions are difficult to break, heat is usually applied in "heater treaters." Whichever method is used, crude oil flows from the final separator to stock tanks. The sludges and liquids that settle out of the oil as tank bottoms throughout the separation process must be collected and discarded along with the separated water.

The largest volume production waste, produced water, flows from the separators into storage tanks and in the majority of oil fields is highly saline. Most produced water is injected down disposal wells or enhanced recovery wells. Produced water is also discharged to tidal areas and surface streams, discharged to storage pits, or used for beneficial or agricultural use. (Seawater is 35,000 ppm chlorides. Produced water can range from 5,000 to 180,000 ppm chlorides.) If the produced water is injected down a disposal well or an enhanced recovery well, it may be treated to remove solids, which are also disposed of.

Tank bottoms are periodically removed from production vessels. Tank bottoms are usually hauled away from the production site for disposal. Occasionally, if the bottoms are fluid enough, they may be disposed of along with produced water.

Waste crude oil may also be generated at a production site. If crude oil becomes contaminated with chemicals or is skimmed from surface impoundments, it is usually reclaimed. Soil and gravel contaminated by crude oil as a result of normal field operations and occasional leaks and spills require disposal.

Natural gas requires different techniques to separate out crude oil, gas liquids, entrained solids, and other impurities. These separation processes can occur in the field, in a gas processing plant, or both, but more frequently occur at an offsite processing plant. Crude oil, gas liquids, some free water, and entrained solids can be removed in conventional separation vessels. More water may be removed by any of several dehydration processes, frequently through the use of glycol, a liquid dessicant, or various solid dessicants. Although these separation media can generally be regenerated and used again, they eventually lose their effectiveness and must be disposed of.

Both crude oil and natural gas may contain the highly toxic gas hydrogen sulfide, which is an exempt waste. (Eight hundred ppm in air is lethal to humans and represents an occupational hazard, but not an ambient air toxics threat to human health offsite.) At plants where hydrogen sulfide is removed from natural gas, sulfur dioxide (SO_2) release results. (EPA requires compliance with the National Ambient Air Quality Standards (NAAQS) for sulfur dioxide; DOI also has authority to regulate these emissions.) Sulfur is often recovered from the hydrogen sulfide (H_2S) as a commercial byproduct. H_2S dissolved in crude oil does not pose any danger, but when it is produced at the wellhead in gaseous form, it poses serious occupational risks through possible leaks or blowouts. These risks are also present later in the production process when the H_2S is separated out in various "sweetening" processes. The amine, iron sponge, and selexol processes are three examples of commercial processes for removing acid gases from natural gas. Each H_2S removal process results in spent or waste separation media, which must be disposed of. EPA did not sample hydrogen sulfide and sulphur dioxide emissions because of their relatively low volume and infrequency of occurrence.

Gaseous wastes are generated from a variety of other production-related operations. Volatile organic compounds may also be released from minute leaks in production equipment or from pressure vents on separators and storage tanks. When a gas well needs to be cleaned out, it may be produced wide open and vented directly to the atmosphere.

Emissions from volatile organic compounds are exempt under Section 3001(b)(2)(A) of RCRA and represent a very low portion of national air emissions. Enhanced oil recovery steam generators may burn crude oil as fuel, thereby creating air emissions. These wastes are nonexempt.

DEFINITION OF EXEMPT WASTES

The following discussion presents EPA's tentative definition of the scope of the exemption.

Scope of the Exemption

The current statutory exemption originated in EPA's proposed hazardous waste regulations of December 18, 1978 (43 FR 58946). Proposed 40 CFR 250.46 contained standards for "special wastes"--reduced requirements for several types of wastes that are produced in large volume and that EPA believed may be lower in toxicity than other wastes regulated as hazardous wastes under RCRA. One of these categories of special wastes was "gas and oil drilling muds and oil production brines."

In the RCRA amendments of 1980, Congress exempted most of these special wastes from the hazardous waste requirements of RCRA Subtitle C, pending further study by EPA. The oil and gas exemption, Section 3001(b)(2)(A), is directed at "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas." The legislative history does not elaborate on the definition of drilling fluids or produced waters, but it does discuss "other wastes" as follows:

> The term "other wastes associated" is specifically included to designate waste materials intrinsically derived from the primary field operations associated with the exploration, development, or production of crude oil and natural gas. It would cover such substances as: hydrocarbon bearing soil in and around related facilities; drill cuttings; and materials (such as hydrocarbons,

> water, sand and emulsion) produced from a well in conjunction with crude oil and natural gas and the accumulated material (such as hydrocarbons, water, sand, and emulsion) from production separators, fluid treating vessels, storage vessels, and production impoundments. (H.R. Rep No. 1444, 96th Cong., 2d Sess. at 32 (1980)).
>
> The phrase "intrinsically derived from the primary field operations..." is intended to differentiate exploration, development, and production operations from transportation (from the point of custody transfer or of production separation and dehydration) and manufacturing operations.

In order to arrive at a clear working definition of the scope of the exemption under Section 8002(m), EPA has used these statements in conjunction with the statutory language of RCRA as a basis for making the following assumptions about which oil and gas wastes should be included in the present study.

- Although the legislative history underlying the oil and gas exemption is limited to "other wastes associated with the exploration development or production of crude oil or natural gas," the Agency believes that the rationale set forth in that history is equally applicable to produced waters and drilling fluids. Therefore, in developing criteria to define the scope of the Section 3001(b)(2) exemption, the Agency has applied this legislative history to produced waters and drilling fluids.
- The potential exists for small volume nonexempt wastes to be mixed with exempt wastes, such as reserve pit contents. EPA believes it is desirable to avoid improper disposal of hazardous (nonexempt) wastes through dilution with nonhazardous exempt wastes. For example, unused pipe dope should not be disposed of in reserve pits. Some residual pipe dope, however, will enter the reserve pit as part of normal field operations; this residual pipe dope does not concern EPA. EPA is undecided as to the proper disposal method for some other waste streams, such as rigwash that often are disposed of in reserve pits.

Using these assumptions, the test of whether a particular waste qualifies under the exemption can be made in relation to the following three separate criteria. No one criterion can be used as a standard when defining specific waste streams that are exempt. These criteria are as follows.

1. Exempt wastes must be associated with measures (1) to locate oil or gas deposits, (2) to remove oil or natural gas from the ground, or (3) to remove impurities from such substances, provided that the purification process is an integral part of primary field operations.[5]

2. Only waste streams intrinsic to the exploration for, or the development and production of, crude oil and natural gas are subject to exemption. Waste streams generated at oil and gas facilities that are not uniquely associated with the exploration, development, or production activities are <u>not</u> exempt. (Examples would include spent solvents from equipment cleanup or air emissions from diesel engines used to operate drilling rigs.)

   Clearly those substances that are extracted from the ground or injected into the ground to facilitate the drilling, operation, or maintenance of a well or to enhance the recovery of oil and gas are considered to be uniquely associated with primary field operations. Additionally, the injection of materials into the pipeline at the wellhead which keep the lines from freezing or which serve as solvents to prevent paraffin accumulation is intrinsically associated with primary field operations. With regard to injection for enhanced recovery, the injected materials must function primarily to enhance recovery of oil and gas and must be recognized by the Agency as being appropriate for enhanced recovery. An example would be produced water. In this context, "primarily functions" means that the main reason for injecting the materials is to enhance recovery of oil and gas rather than to serve as a means for disposing of those materials.

3. Drilling fluids, produced waters, and other wastes intrinsically derived from primary field operations associated with the exploration, development, or production of crude oil, natural gas, or geothermal energy are subject to exemption. Primary field operations encompass production-related activities but not transportation or manufacturing activities. With respect to oil production, primary field operations encompass those activities occurring at or near the wellhead, but prior to the transport of oil from an individual field facility or a centrally located facility to a carrier (i.e., pipeline or trucking concern) for transport to a refinery or to a refiner. With respect to natural gas production, primary field operations are those activities occurring at or near the wellhead or at the gas plant but prior to that point at which the gas is transferred from an individual field facility, a centrally located facility, or a gas plant to a carrier for transport to market.

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[5] Thus, wastes associated with such processes as oil refining, petrochemical-related manufacturing, or electricity generation are not exempt because those processes do not occur at the primary field operations.

> Primary field operations may encompass the primary, secondary, and tertiary production of oil or gas. Wastes generated by the transportation process itself are not exempt because they are not intrinsically associated with primary field operations. An example would be pigging waste from pipeline pumping stations.
>
> Transportation for the oil and gas industry may be for short or long distances. Wastes associated with manufacturing are not exempt because they are not associated with exploration, development, or production and hence are not intrinsically associated with primary field operations. Manufacturing (for the oil and gas industry) is defined as any activity occurring within a refinery or other manufacturing facility the purpose of which is to render the product commercially saleable.

Using these definitions, Table II-1 presents definitions of exempted wastes as defined by EPA for the purposes of this study. Note that this is a partial list only. Although it includes all the major streams that EPA has considered in the preparation of this report, others may exist. In that case, the definitions listed above would be applied to determine their status under RCRA.

Waste Volume Estimation Methodology

Information concerning volumes of wastes from oil and gas exploration, development, and production operations is not routinely collected nationwide, making it necessary to develop methods for estimating these volumes by indirect methods in order to comply with the Section 8002(m) requirement to present such estimates to Congress. For this study, estimates were compiled independently by EPA and by the American Petroleum Institute (API) using different methods. Both are discussed below.

Estimating Volumes of Drilling Fluids and Cuttings

EPA considered several different methodologies for determining volume estimates for produced water and drilling fluid.

Table II-1 Partial List of Exempt and Nonexempt Wastes

EXEMPT WASTES

Drill cuttings

Drilling fluids

Well completion, treatment, and stimulation fluids

Packing fluids

Sand, hydrocarbon solids, and other deposits removed from production wells

Pipe scale, hydrocarbon solids, hydrates, and other deposits removed from piping and equipment

Hydrocarbon-bearing soil

Pigging wastes from gathering lines

Wastes from subsurface gas storage and retrieval

Basic sediment and water and other tank bottoms from storage facilities and separators

Produced water

Constituents removed from produced water before it is injected or otherwise disposed of

Accumulated materials (such as hydrocarbons, solids, sand, and emulsion) from production separators, fluid-treating vessels, and production impoundments that are not mixed with separation or treatment media

Drilling muds from offshore operations

Appropriate fluids injected downhole for secondary and tertiary recovery operations

Liquid hydrocarbons removed from the production stream but not from oil refining

Gases removed from the production stream, such as hydrogen sulfide, carbon dioxide, and volatilized hydrocarbons

Materials ejected from a production well during the process known as blowing down a well

Waste crude oil from primary field operations

Light organics volatilized from recovered hydrocarbons or from solvents or other chemicals used for cleaning, fracturing, or well completion

NONEXEMPT WASTES

Waste lubricants, hydraulic fluids, motor oil, and paint

Waste solvents from clean-up operations

Off-specification and unused materials intended for disposal

Incinerator ash

Pigging wastes from transportation pipelines

Sanitary wastes, trash, and gray water

Gases, such as SOx, NOx, and particulates from gas turbines or other machinery

Drums (filled, partially filled, or cleaned) whose contents are not intended for use

Waste iron sponge, glycol, and other separation media

Filters

Spent catalysts

Wastes from truck- and drum-cleaning operations

Waste solvents from equipment maintenance

Spills from pipelines or other transport methods

Table II-1

EPA's estimates: For several regions of the country, estimates of volumes of drilling fluids and cuttings generated from well drilling operations are available on the basis of waste volume per foot of well drilled. Estimates range from 0.2 barrel/foot (provided by the West Virginia Dept. of Natural Resources) to 2.0 barrels/foot (provided by NL Baroid Co. for Cotton Valley formation wells in Panola County, Texas). EPA therefore considered the possibility of using this approach nationwide. If it were possible to generate such estimates for all areas of the country, including allowances for associated wastes such as completion fluids and waste cement, nationwide figures would then be comparatively easy to generate. They could be based on the total footage of all wells drilled in the U.S., a statistic that is readily available from API.

This method proved infeasible, however, because of a number of complex factors contributing to the calculation of waste-per-foot estimates that would be both comprehensive and valid for all areas of the country. For instance, the use of solids control equipment at drilling sites, which directly affects waste generation, is not standardized. In addition, EPA would have to differentiate among operations using various drilling fluids (oil-based, water-based, and gas-based fluids). These and other considerations caused the Agency to reject this method of estimating volumes of drilling-related wastes.

Another methodology would be to develop a formal model for estimating waste volumes based on all the factors influencing the volume of drilling waste produced. These factors would include total depth drilled, geologic formations encountered, drilling fluid used, solids control equipment used, drilling problems encountered, and so forth. Such a model could then be applied to a representative sample of wells drilled nationwide, yielding estimates that could then be extrapolated to produce nationwide volumes estimates.

This method, too, was rejected as infeasible. It would have required access to data derived from the driller's logs and mud logs maintained at individual well sites, which would have been very difficult to acquire. Beyond this, other data and analytical needs for building such a model proved to be beyond the resources available for the project.

With these methodologies unavailable, EPA developed its estimates by equating the wastes generated from a drilling operation with the volume of the reserve pit constructed to service the well. Typically, each well is served by a single reserve pit, which is used primarily for either temporary or permanent disposal of drilling wastes. Based on field observations, EPA made the explicit assumption that reserve pits are sized to accept the wastes anticipated from the drilling operation. The Agency then collected information on pit sizes during the field sampling program in 1986 (discussed later in this chapter), from literature searches, and by extensive contact with State and Federal regulatory personnel.

EPA developed three generic pit sizes (1,984-, 22,700-, and 87,240-barrel capacity) to represent the range of existing pits and assigned each State a percent distribution for each pit size based on field observation and discussion with selected State and industry personnel. For example, from the data collected, Utah's drilling sites were characterized as having 35 percent small pits, 50 percent medium pits, and 15 percent large pits. Using these State-specific percent distributions, EPA was then able to readily calculate an estimate of annual drilling waste volumes per year for each State. Because Alaska's operations are generally larger than operations in the other oil- and gas-producing States, Alaska's generic pit sizes were different (55,093- and 400,244-barrel capacity.)

Although the EPA method is relatively simple, relying on a well site feature that is easily observable (namely, the reserve pit), the method does have several disadvantages. It does not explicitly account for waste volume increases and decreases due to evaporation, percolation, and rainwater collection. The three generic pit sizes may not adequately represent the wide range of pit sizes used for drilling, and they all assume that the total volume of each reserve pit, minus a nominal 2 feet of freeboard, will be used for wastes. Finally, the information collected to determine the percent distributions of pit sizes within States may not adequately characterize the industry, and adjusting the distribution would require gathering new information or taking a new survey. All of these uncertainties detract from the accuracy of a risk assessment or an economic impact analysis used to evaluate alternative waste management techniques.

The American Petroleum Institute's estimates: As the largest national oil trade organization, the API routinely gathers and analyzes many types of information on the oil and gas industry. In addition, in conducting its independent estimates of drilling waste volumes, API was able to conduct a direct survey of operators in 1985 to request waste volume data--a method that was unavailable to EPA because of time and funding limitations. API sent a questionnaire to a sample of operators nationwide, asking for estimated volume data for drilling muds and completion fluids, drill cuttings, and other associated wastes discharged to the reserve pit. Completed questionnaires were received for 693 individual wells describing drilling muds, completion fluids, and drill cuttings; 275 questionnaires also contained useful information concerning associated wastes. API segregated the sampled wells so that it could characterize drilling wastes within each of 11 sampling zones used in this study and within each of 4 depth classes. Since API maintains a data base on basic information on all wells drilled in the U.S., including location and depth, it was able to estimate a volume of wastes for the more than 65,000 wells drilled in 1985. The API survey does have several significant limitations. Statistical representativeness of the survey is being analyzed by EPA. Respondents to the survey were primarily large oil companies. The survey was accompanied by a letter that may have influenced the responses. Also, EPA experience with operators indicates that they may underestimate reserve pit volumes.

Even though volumetric measurement and statistical analysis represent the preferred method for estimating drilling waste volumes, the way in which API's survey was conducted and the data were analyzed may have some drawbacks. Operators were asked to estimate large volumes of wastes, which are added slowly to the reserve pit and are not measured. Because the sample size is small in comparison to the population, it is questionable whether the sample is an unbiased representation of the drilling industry.

Estimating Volumes of Produced Water

By far the largest volume production waste from oil and gas operations is produced water. Of all the wastes generated from oil and gas operations, produced water figures are reported with the most frequency because of the reporting requirements under the Underground Injection Control (UIC) and National Pollution Discharge Elimination System (NPDES) programs.

EPA's estimates: Because produced water figures are more readily available than drilling waste data, EPA conducted a survey of the State agencies of 33 oil- and gas-producing States, requesting produced water data from injection reports, production reports, and hauling reports. For those States for which this information was not available, EPA derived estimates calculated from the oil/water ratio from surrounding States (this method used for four States) or derived estimates based on information provided by State representatives (this method used for six States).

API's estimates: In addition to its survey of drilling wastes, API conducted a supplemental survey to determine total volumes of produced water on a State-by-State basis. API sent a produced water survey form to individual companies requesting 1985 crude oil and condensate volumes and produced water volumes and distribution. Fourteen operators in 23 States responded. Because most of the operators were active in more than one State, API was able to include a total of 170 different survey points. API then used these data to generate water-to-oil ratios (number of barrels of water produced with each barrel of oil) for each operator in each State. By extrapolation, the results of the survey yield an estimate of the total volume of produced water on a statewide basis; the statewide estimated produced water volume total is simply the product of the estimated State ratio (taken from this survey) and the known total oil production for the State. API reports this survey method to have a 95 percent confidence level for produced water volumes. No standard deviation was reported with this confidence level.

For most States, the figure generated by this method agrees closely with the figure arrived at by EPA in its survey of State agencies in 33 oil-producing States. For a few States, however, the EPA and API numbers are significantly different; Wyoming is an example. Since most of the respondents to the API survey were major companies, their production operations may not be truly representative of the industry as a whole. Also, the API method did not cover all of the States covered by EPA.

Neither method can be considered completely accurate, so judgment is needed to determine the best method to apply for each State. Because the Wyoming State agency responsible for oil and gas operations believes that the API number is greatly in error, the State number is used in this report. Also, since the API survey did not cover many of the States in the Appalachian Basin, the EPA numbers for all of the Appalachian Basin States are used here. In all other cases, however, the API-produced water volume numbers, which were derived in part from a field survey, are believed to be more accurate than EPA numbers and are therefore used in this report.

Waste Volume Estimates

Drilling waste volumes for 1985, calculated by both the EPA and API methods, appear in Table II-2. Although the number of wells drilled for each State differs between the two methods, both methods fundamentally relied upon API data. The EPA method estimates that 2.44 billion barrels of waste were generated from the drilling of 64,508 wells, for an average of 37,902 barrels of waste per well. The API method estimates that 361 million barrels of waste were generated from the drilling of 69,734 wells, for an average of 5,183 barrels of waste per well. EPA has reviewed API's survey methodology and believes the API method is more reliable in predicting actual volumes generated. For the purposes of this report, EPA will use the API estimates for drilling waste volumes.

Produced water volumes for 1985, calculated by both the EPA and API methods, appear in Table II-3. The EPA method estimates 11.7 billion barrels of produced water. The API method estimates 20.9 billion barrels of produced water.

CHARACTERIZATION OF WASTES

In support of this study, EPA collected samples from oil and gas exploration, development, and production sites throughout the country and analyzed them to determine their chemical composition. The Agency designed the sampling plan to ensure that it would cover the country's wide range of geographic and geologic conditions and that it would randomly select individual sites for study within each area (USEPA 1987). One hundred one samples were collected from 49 sites in 26 different locations. Operations sampled included centralized treatment facilities, central disposal facilities, drilling operations, and production facilities. For a more detailed discussion of all aspects of EPA's sampling program, see USEPA 1987.

Table II-2 Estimated U.S. Drilling Waste Volumes, 1985

State	EPA method Number of wells drilled	EPA method Volume[a] 1,000 bbl	API method Number of wells drilled	API method Volume[b] 1,000 bbl
Alabama	343	15,179	367	5,994
Alaska	206	4,118	242	1,816
Arizona	3	56	3	23
Arkansas	975	43,147	1,034	8,470
California	3,038	82,276	3,208	4,529
Colorado	1,459	27,249	1,578	8,226
Florida	21	929	21	1,068
Georgia	NC[c]	NC	1	2
Idaho	NC	NC	3	94
Illinois	2,107	57,063	2,291	2,690
Indiana	910	24,645	961	1,105
Iowa	NC	NC	1	1
Kansas	5,151	96,818	5,560	17,425
Kentucky	2,141	8,683	2,482	4,874
Louisiana	4,645	205,954	4,908	46,726
Maryland	85	345	91	201
Michigan	823	22,289	870	3,866
Mississippi	568	25,136	594	14,653
Missouri	22	596	23	18
Montana	591	36,302	623	4,569
Nebraska	261	4,906	282	761
Nevada	34	1,070	36	335
New Mexico	1,694	31,638	1,780	13,908
New York	395	1,602	436	1,277
North Dakota	485	9,116	514	4,804
Ohio	3,413	13,842	3,818	8,139
Oklahoma	6,978	383,581	7,690	42,547
Oregon	5	135	5	5
Pennsylvania	2,466	10,001	2,836	8,130

Table II-2 (continued)

State	EPA method Number of wells drilled	 Volume[a] 1,000 bbl	API method Number of wells drilled	 Volume[b] 1,000 bbl
South Dakota	44	827	49	289
Tennessee	169	685	228	795
Texas	22,538	1,238,914	23,915	133,014
Utah	332	6,201	364	4,412
Virginia	85	345	91	201
Washington	NC[c]	NC[c]	4	15
West Virginia	1,188	4,818	1,419	3,097
Wyoming	1,409[d]	86,546[d]	1,497	13,528
U.S. Total	64,499	2,444,667	69,734	361,406

[a] Based on total available reserve pit volume, assuming 2 ft of freeboard (ref.).

[b] Based on total volume of drilling muds, drill cuttings, completion fluids, circulated cement, formation testing fluids, and other water and solids.

[c] Not calculated.

[d] EPA notes that for Wyoming, the State's numbers are 1,332 and 11,988,000, respectively.

Table II-3 Estimated U.S. Produced Water Volumes, 1985

State	EPA volumes 1,000 bbl	Source	API volumes 1,000 bbl	Source
Alabama	34,039	a	87,619	g
Alaska	112,780	b	97,740	g
Arizona	288	b	149	g
Arkansas	226,784	b	184,536	g
California	2,553,326	b	2,846,978	g
Colorado	154,255	d	388,661	g
Florida	85,052	b	64,738	g
Illinois	8,560	e	1,282,933	g
Indiana	5,846	d	--	h
Kansas	1,916,250	f	999,143	g
Kentucky	16,055	d	90,754	g
Louisiana	794,030	f	1,346,675	g
Maryland	0	b	---	h
Michigan	64,046	b	76,440	g
Mississippi	361,038	e	318,666	g
Missouri	2,177	a	--	h
Montana	159,343	b	223,558	g
Nebraska	73,411	b	164,688	g
Nevada	3,693	a	--	h
New Mexico	368,249	e	445,265	g
New York	4,918	e	--	h
North Dakota	88,529	b	59,503	g
Ohio	13,688	e	--	h
Oklahoma	1,627,390	f	3,103,433	g
Oregon	33	b	--	h
Pennsylvania	31,131	f	--	h
South Dakota	3,127	b	5,155	g
Tennessee	800	f	--	h
Texas	2,576,000	e	7,838,783	g
Utah	126,000	e	260,661	g
Virginia	0	b	--	h
West Virginia	7,327	d	2,844	g
Wyoming	253,476*	f	985,221	g
U.S. Total	11,671,641		20,873,243**	

Sources:
a. Injection Reports
b. Production Reports
c. Hauling Reports
d. Estimate calculated from water/oil ratio from surrounding States
e. Estimate calculated from water/oil ratio from other years for which data were available
f. Estimate calculated from information provided by State representative. See Table I-8, (Westec, 1987) to explain footnotes a-f
g. API industry survey
h. Not surveyed

* Wyoming states that 1,722,599,614 barrels of produced water were generated in the State in 1985. For the work done in Chapter VI, the State's numbers were used.

** Includes only States surveyed.

Central pits and treatment facilities receive wastes from numerous oil and gas field operations. Since large geographic areas are serviced by these facilities, the facilities tend to be very large; one pit in Oklahoma measured 15 acres and was as deep as 50 feet in places. Central pits are used for long-term waste storage and incorporate no treatment of pit contents. Typical operations accept drilling waste only, produced waters only, or both. Long-term, natural evaporation can concentrate the chemical constituents in the pit. Central treatment and disposal facilities are designed for reconditioning and treating wastes to allow for discharge or final disposal. Like central pits, central treatment facilities can accept drilling wastes only, produced water only, or both.

Reserve pits are used for onsite disposal of waste drilling fluids. These reserve pits are usually dewatered and backfilled. Waste byproducts present at production sites include saltwater brines (called produced waters), tank bottom sludge, and "pigging wax," which can accumulate in the gathering lines.

Extracts from these samples were prepared both directly and following the proposed EPA Toxicity Characteristic Leaching Procedure (TCLP). They were analyzed for organic compounds, metals, classical wet chemistry parameters, and certain other analytes.

API conducted a sampling program concurrent with EPA's. API's universe of sites was slightly smaller than EPA's, but where they overlapped, the results have been compared. API's methodology was designed to be comparable to that used by EPA, but API's sampling and analytical methods, including quality assurance and quality control procedures, varied somewhat from EPA's. These dissimilarities can lead to different analytical results. For a more detailed discussion of all aspects of API's sampling program, see API 1987.

Sampling Methods

Methods used by EPA and by API are discussed briefly below, with emphasis placed on EPA's program.

EPA Sampling Procedures

Pit sampling: All pit samples were composited grab samples. The EPA field team took two composited samples for each pit--one sludge sample and one supernatant sample. Where the pit did not contain a discrete liquid phase, only a sludge sample was taken. Sludge samples are defined by EPA for this report as tank bottoms, drilling muds, or other samples that contains a significant quantity of solids (normally greater than 1 percent). EPA also collected samples of drilling mud before it entered the reserve pit.

Each pit was divided into four quadrants, with a sample taken from the center of each quadrant, using either a coring device or a dredge. The coring device was lined with Teflon or glass to avoid sample contamination. This device was preferred because of its ease of use and deeper penetration. The quadrant samples were then combined to make a single composite sample representative of that pit.

EPA took supernatant samples at each of the four quadrant centers before collecting the sludge samples, using a stainless steel liquid thief sampler that allows liquid to be retrieved from any depth. Samples were taken at four evenly spaced depths between the liquid surface and the sludge-supernatant interface. EPA followed the same procedure at each of the sampling points and combined the results into a single composite for each site.

To capture volatile organics, volatile organic analysis (VOA) vials were filled from the first liquid grab sample collected. All other sludge and liquid samples were composited and thoroughly mixed and had any foreign material such as stones and other visible trash removed prior to sending them to the laboratory for analysis (USEPA 1987).

Produced water: To sample produced water, EPA took either grab samples from process lines or composited samples from tanks. Composite samples were taken at four evenly spaced depths between the liquid surface and the bottom of the tank, using only one sampling point per tank. Storage tanks that were inaccessible from the top had to be sampled from a tap at the tank bottom or at a flow line exiting the tank. For each site location, EPA combined individual samples into a single container to create the total liquid sample for that location. EPA mixed all composited produced water samples thoroughly and removed visible trash prior to transport to the laboratory (USEPA 1987).

Central treatment facilities: Both liquid and sludge samples were taken at central treatment facilities. All were composited grab samples using the same techniques described above for pits, tanks, or process lines (USEPA 1987).

API Sampling Methods

The API team divided pits into six sections and sampled in an "S" curve pattern in each section. There were 30 to 60 sample locations depending upon the size of the pit. API's sampling device was a metal or PVC pipe, which was driven into the pit solids. When the pipe could not be used, a stoppered jar attached to a ridged pole was used. Reserve pit supernatant was sampled using weighted bottles or bottom filling devices. Produced waters were usually sampled from process pipes or valves. API did not sample central treatment facilities (API 1987).

Analytical Methods

As for sampling methods, analytical methods used by EPA and by API were somewhat different. Each is briefly discussed below.

EPA Analytical Methods

EPA analyzed wastes for the RCRA characteristics in accordance with the Office of Solid Waste test methods manual (SW-846). In addition, since the Toxicity Characteristic Leaching Procedure (TCLP) has been proposed to be a RCRA test, EPA used that analytical procedure for certain wastes, as appropriate. EPA also used EPA methods 1624 and 1625, isotope dilution methods for organics, which have been determined to be scientifically valid for this application.

EPA's survey analyzed 444 organic compounds, 68 inorganics, 19 conventional contaminants, and 3 RCRA characteristics for a total of 534 analytes. Analyses performed included gas and liquid chromatography, atomic absorption spectrometry and mass spectrometry, ultraviolet detection method, inductively coupled plasma spectrometry, and dioxin and furan analysis. All analyses followed standard EPA methodologies and protocols and included full quality assurance/quality control (QA/QC) on certain tests (USEPA 1987).

Of these 534 analytes, 134 were detected in one or more samples. For about half of the sludge samples, extracts were taken using EPA's proposed Toxicity Characteristic Leaching Procedure (TCLP) and were analyzed for a subset of organics and metals. Samples from central pits and central treatment facilities were analyzed for 136 chlorinated dioxins and furans and 79 pesticides and herbicides (USEPA 1987).

API Analytical Methods

API analyzed for 125 organics, 29 metals, 15 conventional contaminants, and 2 RCRA characteristics for each sample. The same methods were used by API and EPA for analysis of metals and conventional pollutants with some minor variations. For organics analysis EPA used methods 1624C and 1625C, while API used EPA methods 624 and 625. While the two method types are comparable, method 1624 (and 1625C) may give a more accurate result because of less interference from the matrix and a lower detection limit than methods 624 and 625. In addition, QA/QC on API's program has not been verified by EPA. See USEPA 1987 for a discussion of EPA analytical methods.

Results

Chemical Constituents Found by EPA in Oil and Gas Extraction Waste Streams

As previously stated, EPA collected a total of 101 samples from drilling sites, production sites, waste treatment facilities, and commercial waste storage and disposal facilities. Of these 101 samples, 42 were sludge samples and 59 were liquid samples (USEPA 1987).

Health-based numbers in milligrams per liter (mg/L) were tabulated for all constituents for which there are Agency-verified limits. These are either reference doses for noncarcinogens (Rfds) or risk-specific doses (RSDs) for carcinogens. RSDs were calculated, using the following risk levels: 10-6 for class A (human carcinogen) and 10-5 for class B (probable human carcinogen). Maximum contaminant limits (MCLs) were used, when available, then Rfds or RSDs. An MCL is an enforceable drinking water standard that is used by the Office of Solid Waste when ground water is a main exposure pathway.

Two multiples of the health-based limits (or MCLs) were calculated for comparison with the sample levels found in the wastes. Multiples of 100 were used to approximate the regulatory level set by the EP toxicity test (i.e., 100 x the drinking water standards for some metals and pesticides). Multiples of 1,000 were used to approximate the concentration of a leachate which, as a first screen, is a threshold level of potential regulatory concern. Comparison of constituent levels found by direct analysis of waste with multiples of health-based numbers (or MCLs) can be used to approximate dispersion of this waste to surface waters. Comparison of constituent levels found by TCLP analysis of waste with multiples of health-based numbers (or MCLs) can be used to approximate dispersion of this waste to ground water.

For those polyaromatic hydrocarbons (PAHs) for which verified health-based numbers do not exist, limits were estimated by analogy with known toxicities of other PAHs. If structure activity analysis (SAR) indicated that the PAH had the potential to be carcinogenic, then it was assigned the same health-based number as benzo(a)pyrene, a potent carcinogen. If the SAR analysis yielded equivocal results, the PAH was assigned the limit given to indeno-(1,2,3-cd) pyrene, a PAH with possible carcinogenic potential. If the SAR indicated that the PAH was not likely to be carcinogenic, then it was assigned the same number as naphthalene, a noncarcinogen.

The analysis in this chapter does not account for the frequency of detection of constituents, or nonhuman health effects. Therefore, it provides a useful indication of the constituents deserving further study, but may not provide an accurate description of the constituents that have the potential to pose actual human health and environmental risks. Readers should refer to Chapter V, "Risk Modeling," for information on human health and environmental risks and should not draw any conclusions from the analysis presented in Chapter II about the level of risk posed by wastes from oil and gas wells.

EPA may further evaluate constituents that exceeded the health-based limit or MCL multiples to determine fate, transport, persistence, and toxicity in the environment. This evaluation may show that constituents designated as secondary in the following discussion may not, in fact, be of concern to EPA.

Although the Toxicity Characteristics Leaching Procedure (TCLP) was performed on the sludge samples, the only constituent in the leach exhibiting concentrations that exceeded the multiples previously described was benzene in production tank bottom sludge. All of the other chemical constituents that exceeded the multiples were from direct analysis of the waste.

Constituents Present at Levels of Potential Concern

Because of the limited number of samples in relation to the large universe of facilities from which the samples were drawn, results of the waste sampling program conducted for this study must be analyzed carefully. EPA is conducting a statistical analysis of these samples.

Table II-4 shows EPA and API chemical constituents that were present in oil and gas extraction waste streams in amounts greater than health-based limits multiplied by 1,000 (primary concern) and those constituents that occurred within the range of multiples of 100 and 1,000 (secondary concern). Benzene and arsenic, constituents of primary and secondary concern respectively, by this definition, were modeled in the risk assessment chapter (Chapter V). The table compares waste stream location and sample phase with the constituents found at that location and phase. Table II-5 shows the number of samples compared with the number of detects in EPA samples for each constituent of potential concern.

The list of constituents of potential concern is not final. EPA is currently evaluating the data collected at the central treatment facilities and central pits, and more chemical constituents of potential concern may result from this evaluation. Also, statistical analysis of the sampling data is continuing.

Table II-4 Constituents of Concern Found In Waste Streams Sampled by EPA and API

	Production			Central treatment			Central pit	Drilling		
	Midpoint	Tank bottom	Endpoint	Influent	Tank	Effluent	Central pit	Drilling mud	Tank bottoms	Pit
Chemical Constituents **Primary concern**										
Benzene	L#	S# S+	L L#•		S#	L S	S#		S#	S S•
Phenanthrene		S #	L L#•		S#		S #	S	S #	
Lead				S#		S#	S#		L#	L# L• S# S#•
Barium			L	S#	S#	S#	S#	S#	L	L# L#• S# S#•
Secondary concern										
Arsenic		S	L			S	S			S S•
Fluoride				S		S	S			L S
Antimony			L•							

Legend:
- L: Liquid sample > 100 x health-based number
- S: Sludge sample > 100 x health-based number
- #: Denotes > 1,000 x health-based number
- L,S: EPA samples
- L•,S•: API samples
- +: TCLP extraction
- — All values determined from direct samples except as denoted by "+"

Table II-5 EPA Samples Containing Constituents of Concern

	Production			Central treatment			Central pit	Drilling		
	Midpoint	Tank bottom	Endpoint	Influent	Tank	Effluent	Central pit	Drilling mud	Tank bottoms	Pit
Primary concern										
Benzene	L5 (3)	S1 (1) +	L21 (16)		S2 (1)	L3 (2) S3 (1)	S3 (1)		S1 (1)	S18 (7)
Phenanthrene		S1 (1)	L21 (5)		S2 (2)		S3 (1)	S2 (1)	S1 (1)	
Lead				S1 (1)		S3 (3)	S3 (3)		L1 (1)	L17 (17) S21 (21)
Barium			L24 (21)	S1 (1)	S2 (1)	S3 (3)	S3 (3)	S1 (1)	L1 (1)	L17 (17) S21 (21)
Secondary concern										
Arsenic		S1 (1)	L24 (9)			S3 (3)	S3 (1)			S21 (11)
Fluoride				S1 (1)		S3 (3)	S3 (3)			L17 (17) S20 (20)

Legend:

L:	Liquid sample
S:	Sludge sample
# (#)	Number of samples (number of detects)
+	TCLP extract and direct extracts

Comparison to Constituents of Potential Concern Identified in the Risk Analysis

This report's risk assessment selected the chemical constituents that are most likely to dominate the human health and environmental risks associated with drilling wastes and produced water endpoints. Through this screening process, EPA selected arsenic, benzene, sodium, cadmium, chromium VI, boron, chloride, and total mobile ions as the constituents to model for risk assessment.[6]

The chemicals selected for the risk assessment modeling differ from the constituents of potential concern identified in this chapter's analysis for at least three reasons. First, the risk assessment screening accounted for constituent mobility by examining several factors in addition to solubility that affect mobility (e.g., soil/water partition coefficients) whereas, in Chapter II, constituents of potential concern were not selected on the basis of mobility in the environment. Second, certain constituents were selected for the risk assessment modeling based on their potential to cause adverse environmental effects as opposed to human health effects; the Chapter II analysis considers mostly human health effects. Third, frequency of detection was considered in selecting constituents for the risk analysis but was not considered in the Chapter II analysis.

Facility Analysis

Constituents of potential concern were chosen on the basis of exceedances in liquid samples or TCLP extract. Certain sludge samples are listed in Tables II-4 and II-5, since these samples, through direct

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[6] Mobile ions modeled in the risk assessment include chloride, sodium, potassium, calcium, magnesium, and sulfate.

chemical analysis, indicated the presence of constituents at levels exceeding the multiples previously described. One sludge sample analyzed by the TCLP method contained benzene in an amount above the level of potential concern. This sample is included in Tables II-4 and II-5. The sludge samples are shown for comparison with the liquid samples and TCLP extract and were not the basis for choice as a constituent of potential concern. Constituents found in the liquid samples or the TCLP extract in amounts greater than 100 times the health-based number are considered constituents of potential concern by EPA.

Central Treatment Facility

Benzene, the only constituent found in liquid samples at the central treatment facilities, was found in the effluent in amounts exceeding the level of potential concern.

Central Pit Facility

No constituent was found in the liquid phase in amounts exceeding the level of potential concern at central pit facilities.

Drilling Facilities

Lead and barium were found in amounts exceeding the level of potential concern in the liquid phase of the tank bottoms and the reserve pits that were sampled. Fluoride was found in amounts that exceeded 100 times the health-based number in reserve pit supernatant.

Production Facility

Benzene was present in amounts that exceeded the level of potential concern at the midpoint and the endpoint locations. Exceedances of the level of potential concern that occurred only at the endpoint location were for phenanthrene, barium, arsenic, and antimony. Benzene was present in amounts exceeding the multiple of 1,000 in the TCLP leachate of one sample.

WASTE CHARACTERIZATION ISSUES

Toxicity Characteristic Leaching Procedure (TCLP)

The TCLP was designed to model a reasonable worst-case mismanagement scenario, that of co-disposal of industrial waste with municipal refuse or other types of biodegradable organic waste in a sanitary landfill. As a generic model of mismanagement, this scenario is appropriate for nonregulated wastes because those wastes may be sent to a municipal landfill. However, most waste from oil and gas exploration and production is not disposed of in a sanitary landfill, for which the test was designed. Therefore, the test may not reflect the true hazard of the waste when it is managed by other methods. However, if these wastes were to go to a sanitary landfill, EPA believes the TCLP would be an appropriate leach test to use.

For example, the TCLP as a tool for predicting the leachability of oily wastes placed in surface impoundments may actually overestimate that leachability. One reason for this overestimation involves the fact that the measurement of volatile compounds is conducted in a sealed system during extraction. Therefore, all volatile toxicants present in the waste are assumed to be available for leaching to ground water. None of the volatiles are assumed to be lost from the waste to the air. Since volatilization is a potentially significant, although as yet unquantified, route of loss from surface impoundments, the TCLP may overestimate the leaching potential of the waste. Another reason for overestimation is that the TCLP assumes that no degradation--either chemical, physical, or biological--will occur in the waste before the leachate actually leaves the impoundment. Given that leaching is not likely to begin until a finite time after disposal and will continue to occur over many years, the assumption of no change may tend to overestimate leachability.

Conversely, the TCLP may underestimate the leaching potential of petroleum wastes. One reason for this assumption is a procedural problem in the filtration step of the TCLP. The amount of mobile liquid phase that is present in these wastes and that may migrate and result in ground-water contamination is actually underestimated by the TCLP. The TCLP requires the waste to be separated into its mobile and residue solid phases by filtration. Some production wastes contain materials that may clog the filter, indicating that the waste contains little or no mobile fraction. In an actual disposal environment, however, the liquid may migrate. Thus, the TCLP may underestimate the leaching potential of these materials. Another reason for underestimation may be that the acetate extraction fluid used is not as aggressive as real world leaching fluid since other solubilizing species (e.g., detergents, solvents, humic species, chelating agents) may be present in leaching fluids in actual disposal units. The use of a citric acid extraction media for more aggressive leaching has been suggested.

Because the TCLP is a generic test that does not take site-specific factors into account, it may overestimate waste leachability in some cases and underestimate waste leachability in other cases. This is believed to be the case for wastes from oil and gas exploration and production.

The EPA has several projects underway to investigate and quantify the leaching potential of oily matrices. These include using filter aids to prevent clogging of the filter, thus increasing filtration efficiency, and using column studies to quantitatively assess the degree to which oily materials move through the soil. These projects may result in a leach test more appropriate for oily waste.

Solubility and Mobility of Constituents

Barium is usually found in drilling waste as barium sulfate (barite), which is practically insoluble in water (Considine 1974). Barium sulfate may be reduced to barium sulfide, which is water soluble. It is the relative insolubility of barium sulfate that greatly decreases its toxicity to humans; the more soluble and mobile barium sulfide is also much more toxic (Sax 1984). Barium sulfide formation from barium sulfate requires a moist anoxic environment.

The organic constituents present in the liquid samples in concentrations of potential concern were benzene and phenanthrene. Benzene was found in produced waters and effluent from central treatment facilities, and phenanthrene was found in produced waters.

An important commingling effect that can increase the mobility of nonpolar organic solvents is the addition of small amounts of a more soluble organic solvent. This effect can significantly increase the extent to which normally insoluble materials are dissolved. This solubility enhancement is a log-linear effect. A linear increase in cosolvent concentration can lead to a logarithmic increase in solubility. This effect is also additive in terms of concentration. For instance, if a number of cosolvents exist in small concentrations, their total concentration may be enough to have a significant effect on nonpolar solvents with which the cosolvents come in contact (Nkedi-Kizza 1985, Woodburn et al. 1986). Common organic cosolvents are acetone, toluene, ethanol, and xylenes (Brown and Donnelly 1986).

Other factors that must be considered when evaluating the mobility of these inorganic and organic constituents in the environment are the use of surfactants at oil and gas drilling and production sites and the general corrosivity of produced waters. Surfactants can enhance the solubility of many constituents in these waters. Produced waters have been shown to corrode casing (see damage cases in Chapter IV).

Changes in pH in the environment of disposal can cause precipitation of compounds or elements in waste and this can decrease mobility in the environment. Also adsorption of waste components to soil particles will attenuate mobility. This is especially true of soils containing clay because of the greater surface area of clay-sized particles.

Phototoxic Effect of Polycyclic Aromatic Hydrocarbons (PAH)

New studies by Kagan et al. (1984), Allred and Giesy (1985), and Bowling et al. (1983) have shown that very low concentrations (ppb in some cases) of polycyclic aromatic hydrocarbon (PAH) are lethal to some forms of aquatic wildlife when they are introduced to sunlight after exposure to the PAHs. This is called the phototoxic effect.

In the study conducted by Allred and Giesy (1985), it was shown that anthracene toxicity to Daphnia pulex resulted from activation by solar radiation of material present on or within the animals and not in the water. It appeared that activation resulted from anthracene molecules and not anthracene degeneration products. Additionally, it was shown that wavelengths in the UV-A region (315 to 380 nm) are primarily responsible for photo-induced anthracene toxicity.

It has been shown that PAHs are a typical component of some produced waters (Davani et al., 1986a). The practice of disposal of produced waters in unlined percolation pits is allowing PAHs and other constituents to migrate into and accumulate in soils (Eiceman et al., 1986a, 1986b).

pH and Other RCRA Characteristics

Of the RCRA parameters reactivity, ignitability, and corrosivity, no waste sample failed the first two. Reactivity was low and ignitability averaged 200°F for all waste tested. On the average, corrosivity parameters were not exceeded, but one extreme did fail this RCRA test (See Table II-6). A solid waste is considered hazardous under RCRA if its aqueous phase has a pH less than or equal to 2 or greater than or equal to 12.5. As previously stated, a sludge sample is defined by EPA in this document as a sample containing a significant quantity of solids (normally greater than 1 percent).

Of the major waste types at oil and gas facilities, waste drilling muds and produced waters have an average neutral pH. Waste drilling fluid samples ranged from neutral values to very basic values, and produced waters ranged from neutral to acidic values. In most cases the sludge phase tends to be more basic than the liquid phases. An exception is the tank bottom waste at central treatment facilities, which has an average acidic value. Drilling waste tends to be basic in the liquid and sludge phases and failed the RCRA test for alkalinity in one extreme case. At production facilities the pH becomes more acidic from the midpoint location to the endpoint. This is probably due to the removal of hydrocarbons. This neutralizing effect of hydrocarbons is also shown by the neutral pH values of the production tank bottom waste. An interesting anomaly of Table II-6 is the alkaline values of the influent and effluent of central treatment facilities compared to the acidic values of the tank bottoms at these facilities. Because central treatment facilities accept waste drilling fluids and produced waters, acidic constituents of produced waters may be accumulating in tank bottom sludges. The relative acidity of the produced waters is also indicated by casing failures, as shown by some of the damage cases in Chapter IV.

Table II-6 pH Values for Exploration, Development and Production Wastes (EPA Samples)

	Midpoint	Tank bottom	Endpoint	Influent	Tank	Effluent	Central pit	Tank bottoms	Pit
Production									
Sludge		7.0; 7.0; 7.0							
Liquid	6.4; 6.6; 8.0		2.7; 7.6; 8.1						
Central treatment									
Sludge				8.8; 8.8; 8.8	2.0; 3.9; 5.8	6.7; 8.2; 10.0			
Liquid				5.7; 6.5; 7.3		7.0; 8.2; 10.1			
Central pit									
Sludge							7.2; 8.0; 9.2		
Liquid							5.7; 7.5; 8.5		
Drilling									
Sludge									6.8; 9.0; 12.8
Liquid								7.1; 7.1; 7.1	6.5; 7.7; 12.7

Legend:

#; #; # - minimum; average; maximum

Use of Constituents of Concern

The screening analysis conducted for the risk assessment identified arsenic, benzene, sodium, cadmium, chromium VI, boron, and chloride as the constituents that likely pose the greatest human health and environmental risks. The risk assessment's findings differ from this chapter's findings since this chapter's analysis did not consider the frequency of detection of constituents, mobility factors, or nonhuman health effects (see Table II-7). Some constituents found in Table II-4 were in waste streams causing damages as documented in Chapter IV.

Table II-7 Comparison of Potential Constituents of Concern That Were Modeled in Chapter V

Chemical	Chapter II*	Chapter V**	Reasons for not including in Chapter V risk analysis ***
Benzene	P	Yes	N/A
Phenanthrene	P	No	Low frequency in drilling pit and produced water samples; low ground-water mobility; relatively low concentration-to-toxicity ratio; unverified reference dose used for Chapter 2 analysis.
Lead	P	No	Low ground-water mobility.
Barium	P	No	Low ground-water mobility.
Arsenic	S	Yes	N/A
Fluoride	S	No	Relatively low concentration-to-toxicity ratio.
Antimony	S	No	Low frequency in drilling pit and produced water samples.

* P = primary concern in Chapter II; S = secondary concern in Chapter II.

** Yes = modeled in Chapter V analysis; no = not modeled in Chapter V analysis.

*** Table summarizes primary reasons only; additional secondary reasons may also exist.

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CHAPTER III

CURRENT AND ALTERNATIVE WASTE MANAGEMENT PRACTICES

INTRODUCTION

Managing wastes produced by the oil and gas industry is a large task. By the estimates gathered for this report, in 1985 over 361 million barrels of drilling muds and 20.9 billion barrels of produced water were disposed of in the 33 States that have significant exploration, development, and production activity. In that same year, there were 834,831 active oil and gas wells, of which about 70 percent (580,000 wells) were stripper operations.

The focus of this section is to review current waste management technologies employed for wastes at all phases of the exploration-development-production cycle of the onshore oil and gas industry. It is convenient to divide wastes into two broad categories. The first category includes drilling muds, wellbore cuttings, and chemical additives related to the drilling and well completion process. These wastes tend to be managed together and may be in the form of liquids, sludges, or solids. The second broad category includes all wastes associated with oil and gas production. Produced water is the major waste stream and is by far the highest volume waste associated with oil and gas production. Other production-related wastes include relatively small volumes of residual bactericides, fungicides, corrosion inhibitors, and other additives used to ensure efficient production; wastes from oil/gas/water separators and other onsite processing facilities; production tank bottoms; and scrubber bottoms.[1]

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[1] For the purpose of this chapter, all waste streams, whether exempt or nonexempt, are discussed.

In addition to looking at these two general waste categories, it is also important to view waste management in relation to the sequence of operations that occurs in the life cycle of a typical well. The chronology involves both drilling and production--the two phases mentioned above--but it also can include "post-closure" events, such as seepage of native brines into fresh ground water from improperly plugged or unplugged abandoned wells or leaching of wastes from closed reserve pits.

Section 8002(m) of RCRA requires EPA to consider both current and alternative technologies in carrying out the present study. Sharp distinctions between current and alternative technologies are difficult to make because of the wide variation in practices among States and among different types of operations. Furthermore, waste management technology in this field is fairly simple. At least for the major high-volume streams, there are no significant newly invented, field-proven technologies in the research or development stage that can be considered "innovative" or "emerging." Although practices that are routine in one location may be considered innovative or alternative elsewhere, virtually every waste management practice that exists can be considered "current" in one specific situation or another. This is because different climatological or geological settings may demand different management procedures, either for technical convenience in designing and running a facility or because environmental settings in a particular region may be unique. Depth to ground water, soil permeability, net evapotranspiration, and other site-specific factors can strongly influence the selection and design of waste management practices. Even where geographic and production variables are similar, States may impose quite different requirements on waste management, including different permitting conditions.

Long-term improvements in waste management need not rely, however, purely on increasing the use of better existing technology. The Agency does foresee the possibility of significant technical improvements in future technologies and practices. Examples include incineration and other thermal treatment processes for drilling fluids; conservation, recycling, reuse, and other waste minimization techniques; and wet air oxidation and other proven technologies that have not yet been applied to oil and gas operations.

Sources of Information

The descriptions and interpretations presented here are based on State or Federal regulatory requirements, published technical information, observations gathered onsite during the waste sampling program, and interviews with State officials and private industry. Emphasis is placed on practices in 13 States that represent a cross-section of the petroleum extraction industry based on their current drilling activity, rank in production, and geographic distribution. (See Table III-1.)

Limitations

Data on the prevalence, environmental effectiveness, and enforcement of waste management requirements currently in effect in the petroleum-producing States are difficult to obtain. Published data are scarce and often outdated. Some of the State regulatory agencies that were interviewed for this study have only very limited statistical information on the volumes of wastes generated and on the relative use of the various methods of waste disposal within their jurisdiction. Time was not available to gather statistics from other States that have significant oil and gas activity. This lack of concrete data makes it difficult for EPA to complete a definitive assessment of available disposal options. EPA is collecting additional data on these topics.

Table III-1 States with Major Oil Production Used as Primary References in This Study

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Alaska
Arkansas
California
Colorado
Kansas
Louisiana
Michigan
New Mexico
Ohio
Oklahoma
Texas
West Virginia
Wyoming

DRILLING-RELATED WASTES

Description of Waste

Drilling wastes include a wide variety of materials, ranging in volume from the thousands of barrels of fluids ("muds") used to drill a well, to the hundreds of barrels of drill cuttings extracted from the borehole, to much smaller quantities of wastes associated with various additives and chemicals sometimes used to condition drilling fluids. A general description of each of these materials is presented in broad terms below.

Drilling Fluids (Muds)

The largest volume drilling-related wastes generated are the spent drilling fluids or muds. The composition of modern drilling fluids or muds can be quite complex and can vary widely, not only from one geographical area to another but also from one depth to another in a particular well as it is drilled.

Muds fall into two general categories: water-based muds, which can be made with fresh or saline water and are used for most types of drilling, and oil-based muds, which can be used when water-sensitive formations are drilled, when high temperatures are encountered, or when it is necessary to protect against severe drill string corrosion in hostile downhole environments. Drilling muds contain four essential parts: (1) liquids, either water or oil; (2) reactive solids, the viscosity- and density-building part of the system, often bentonite clays; (3) inert solids such as barite; and (4) additives to control the chemical, physical, and biological properties of the mud. These basic components perform various functions. For example, clays increase viscosity and density, barium sulfate (barite) acts as a weighting agent to maintain pressure in the well, and lime and caustic soda increase pH and control viscosity. Additional conditioning materials include polymers, starches, lignitic material, and various other chemicals (Canter et al. 1984).

Table III-2 presents a partial list, by use category, of additives to drilling muds (Note: this table is based on data that may, in some cases, be outdated.)

Cuttings

Well cuttings include all solid materials produced from the geologic formations encountered during the drilling process that must be managed as part of the content of the waste drilling mud. Drill cuttings consist of rock fragments and other heavy materials that settle out by gravity in the reserve pit. Other materials, such as sodium chloride, are soluble in fresh water and can pose problems in waste disposal. Naturally occurring arsenic may also be encountered in significant concentrations in certain wells and in certain parts of the country and must be disposed of appropriately. (Written communication with Mr. Don Basko, Wyoming Oil and Gas Conservation Commission.)

Waste Chemicals

In the course of drilling operations, chemicals may be disposed of by placing them in the well's reserve pit. These can include any substances deliberately added to the drilling mud for the various purposes mentioned above (see Table III-2).

Table III-2 Characterization of Oil and Gas Drilling Fluids

Source: Information in this table was taken from American Petroleum Institute (API) Bulletin 13F (1978). Drilling practices have evolved significantly in some respects since its publication; the information presented below may therefore not be fully accurate or current.

Bases

Bases used in formulating drilling fluid are predominantly fresh water, with minor use of saltwater or oils, including diesel and mineral oils. It is estimated that the industry used 30,000 tons of diesel oil per year in drilling fluid in 1978.[a]

Weighting Agents

Common weighting agents found in drilling fluids are barite, calcium carbonate, and galena (PbS).[b] Approximately 1,900,000 tons of barite, 2,500 tons of calcium carbonate, and 50 tons of galena (the mineral form of lead) are used in drilling each year.

Viscosifiers

Viscosifiers found in drilling fluid include:

• Bentonite clays	650,000 tons/year
• Attapulgite/sepiolite	85,000 tons/year
• Asphalt/gilsonite	10,000 tons/year
• Asbestos	10,000 tons/year
• Bio-polymers	500 tons/year

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[a] This figure included contributions from offshore operations. According to API, use of diesel oil in drilling fluid has been substantially reduced in the past 10 years principally as a result of its restricted use in offshore operations.

[b] API states that galena is no longer used in drilling mud.

Table III-2 (continued)

Dispersants

Dispersants used in drilling fluid include:

• Cadmium, chromium, iron, and other metal lignosulfonates	65,000 tons/year
• Natural, causticized chromium and zinc lignite	50,000 tons/year
• Inorganic phosphates	1,500 tons/year
• Modified tannins	1,200 tons/year

Fluid Loss Reducers

Fluid loss reducers used in drilling fluid include:

• Starch/organic polymers	15,000 tons/year
• Cellulosic polymers (CMC, HEC)	12,500 tons/year
• Guar gum	100 tons/year
• Acrylic polymers	2,500 tons/year

Lost Circulation Materials

Lost circulation materials used comprise a variety of nontoxic substances including cellophane, cotton seed, rice hulls, ground Formica, ground leather, ground paper, ground pecan and walnut shells, mica, and wood and cane fibers. A total of 20,000 tons of these materials is used per year.

Table III-2 (continued)

Surface Active Agents

Surface active agents (used as emulsifiers, detergents, defoamants) include:

Fatty acids, naphthenic acids, and soaps	5,000 tons/year
Organic sulfates/sulfonates	1,000 tons/year
Aluminum stearate	(quantity not available)

Lubricants

Lubricants used include:

Vegetable oils	500 tons/year
Graphite	<5 tons/year

Flocculating Agents

The primary flocculating agents used in drilling are:

Acrylic polymers	2,500 tons/year

Biocides

Biocides used in drilling include:

Organic amines, amides, amine salts	1,000 tons/year
Aldehydes (paraformaldehyde)	500 tons/year
Chlorinated phenols	<1 ton/year
Organosulfur compounds and organometallics	(quantity not available)

Miscellaneous

Miscellaneous drilling fluid additives include:

Ethoxylated alkyl phenols	1,800 tons/year
Aaliphatic alcohols	<10 tons/year
Aluminum anhydride derivatives and chrom alum	(quantities not available)

Table III-2 (continued)

Commercial Chemicals

Commercial chemicals used in drilling fluid include:

• Sodium hydroxide	50,000 tons/year
• Sodium chloride	50,000 tons/year
• Sodium carbonate	20,000 tons/year
• Calcium chloride	12,500 tons/year
• Calcium hydroxide/calcium oxide	10,000 tons/year
• Potassium chloride	5000 tons/year
• Sodium chromate/dichromate[a]	4,000 tons/year
• Calcium sulfate	500 tons/year
• Potassium hydroxide	500 tons/year
• Sodium bicarbonate	500 tons/year
• Sodium sulfite	50 tons/year
• Magnesium oxide	<10 tons/year
• Barium carbonate	(quantity not available)

These commercial chemicals are used for a variety of purposes including pH control, corrosion inhibition, increasing fluid phase density, treating out calcium sulfate in low pH muds, treating out calcium sulfate in high pH muds.

Corrosion Inhibitors

Corrosion inhibitors used include:

• Iron oxide	100 tons/year
• Ammonium bisulfite	100 tons/year
• Basic zinc carbonate	100 tons/year
• Zinc chromate	<10 tons/year

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[a] API states that sodium chromate is no longer used in drilling mud.

Fracturing and Acidizing Fluids

Fracturing and acidizing are processes commonly used to enlarge existing channels and open new ones to a wellbore for several purposes:

- To increase permeability of the production formation of a well;
- To increase the zone of influence of injected fluids used in enhanced recovery operations; and
- To increase the rate of injection of produced water and industrial waste material into disposal wells.

The process of "fracturing" involves breaking down the formation, often through the application of hydraulic pressure, followed by pumping mixtures of gelled carrying fluid and sand into the induced fractures to hold open the fissures in the rocks after the hydraulic pressure is released. Fracturing fluids can be oil-based or water-based. Additives are used to reduce the leak-off rate, to increase the amount of propping agent carried by the fluid, and to reduce pumping friction. Such additives may include corrosion inhibitors, surfactants, sequestering agents, and suspending agents. The volume of fracturing fluids used to stimulate a well can be significant.[2] Closed systems, which do not involve reserve pits, are used very occasionally (see discussion below). However, closed systems are widely used in California. Many oil and gas fields currently being developed contain low-permeability reservoirs that may require hydraulic fracturing for commercial production of oil or gas.

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[2] Mobile Oil Co. recently set a well stimulation record (single stage) in a Wilcox formation well in Zapata County, Texas, by placing 6.3 million pounds of sand, using a fracturing fluid volume of 1.54 million gallons (World Oil, January 1987).

The process of "acidizing" is done by injecting acid into the target formation. The acid dissolves the rock, creating new channels to the wellbore and enhancing existing ones. The two basic types of acidizing treatments used are:

- Low-pressure acidizing: acidizing that avoids fracturing the formation and allows acid to work through the natural pores (matrix) of the formation.
- Acid fracturing: acidizing that utilizes high pressure and high volumes of fluids (acids) to fracture rock and to dissolve the matrix in the target formation.

The types of acids normally used include hydrochloric acid (in concentrations ranging from 15 to 28 percent in water), hydrochloric-hydrofluoric acid mixtures (12 percent and 3 percent, respectively), and acetic acid. Factors influencing the selection of acid type include formation solubility, reaction time, reaction products effects, and the sludging and emulsion-forming properties of the crude oil. The products of spent acid are primarily carbon dioxide and water.

Spent fracturing and acidizing fluid may be discharged to a tank, to the reserve pit, or to a workover pit.

Completion and Workover Fluids

Completion and workover fluids are the fluids placed in the wellbore during completion or workover to control the flow of native formation fluids, such as water, oil, or gas. The base for these fluids is usually water. Various additives are used to control density, viscosity, and filtration rates; prevent gelling of the fluid; and reduce corrosion. They include a variety of salts, organic polymers, and corrosion inhibitors.

When the completion or workover operation is completed, the fluids in the wellbore are discharged into a tank, the reserve pit, or a workover pit.

Rigwash and Other Miscellaneous Wastes

Rigwash materials are compounds used to clean decks and other rig equipment. They are mostly detergents but can include some organic solvents, such as degreasers.

Other miscellaneous wastes include pipe dope used to lubricate connections in pipes, sanitary sewage, trash, spilled diesel oil, and lubricating oil.

All of these materials may, in many operations, be disposed of in the reserve pit.

ONSITE DRILLING WASTE MANAGEMENT METHODS

Several waste management methods can be used to manage oil and gas drilling wastes onsite. The material presented below provides a separate discussion for reserve pits, landspreading, annular disposal, solidification of reserve pit wastes, treatment and disposal of liquid wastes to surface water, and closed treatment systems.

Several waste management methods may be employed at a particular site simultaneously. Issues associated with reserve pits are particularly complex because reserve pits are both an essential element of the drilling process and a method for accumulating, storing, and disposing of wastes. This section therefore begins with a general discussion of several aspects of reserve pits--design, construction, operation, and closure--and then continues with more specific discussions of the other technologies used to manage drilling wastes.

Reserve Pits

Description

Reserve pits, an essential design component in the great majority of well drilling operations,[3] are used to accumulate, store, and, to a large extent, dispose of spent drilling fluids, cuttings, and associated drill site wastes generated during drilling, completion, and testing operations.

There is generally one reserve pit per well. In 1985, an estimated 70,000 reserve pits were constructed. In the past, reserve pits were used both to remove and dispose of drilled solids and cuttings and to store the active mud system prior to its being recycled to the well being drilled. As more advanced solids control and drilling fluid technology has become available, mud tanks have begun to replace the reserve pit as the storage and processing area for the active mud system, with the reserve pit being used to dispose of waste mud and cuttings. Reserve pits will, however, continue to be the principal method of drilling fluid storage and management.

A reserve pit is typically excavated directly adjacent to the site of the rig and associated drilling equipment. Pits should be excavated from undisturbed, stable subsoil so as to avoid pit wall failure. Where it is impossible to excavate below ground level, the pit berm (wall) is usually constructed as an earthen dam that prevents runoff of liquid into adjacent areas.

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[3] Closed systems, which do not involve reserve pits, are used very occasionally (see discussion below). However, closed systems are widely used in California.

In addition to the components found in drilling mud, common constituents found in reserve pits include salts, oil and grease, and dissolved and/or suspended heavy metals. Sources of soluble salt contamination include formation waters, downhole salt layers, and drilling fluid additives. Sources of organic contamination include lubricating oil from equipment leaks, well pressure control equipment testing, heavy oil-based lubricants used to free stuck drill pipe, and, in some cases, oil-based muds used to drill and complete the target formation.[4] Sources of potential heavy metal contamination include drilling fluid additives, drilled solids, weighting materials, pipe dope, and spilled chemicals (Rafferty 1985).

The reserve pit itself can be used for final disposal of all or part of the drilling wastes, with or without prior onsite treatment of wastes, or for temporary storage prior to offsite disposal. Reserve pits are most often used in combination with some other disposal techniques, the selection of which depends on waste type, geographical location of the site, climate, regulatory requirements, and (if appropriate) lease agreements with the landowner.

The major onsite waste disposal methods include:

- Evaporation of supernatant;
- Backfilling of the pit itself, burying the pit solids and drilled cuttings by using the pit walls as a source of material (the most common technique);
- Landspreading all or part of the pit contents onto the area immediately adjacent to the pit;

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[4] Charles A. Koch of the North Dakota Industrial Commission, Oil and Gas Division, states that "A company would not normally change the entire drilling fluid for just the target zone. This change would add drastically to the cost of drilling."

- Onsite treatment and discharge;
- Injecting or pumping all or part of the wastes into the well annulus; and
- Discharge to surface waters.

Another less common onsite management method is chemical solidification of the wastes.

Dewatering and burial of reserve pit contents (or, alternatively, landspreading the pit contents) are discussed here because they are usually an integral aspect of the design and operation of a reserve pit. The other techniques are discussed separately.

Dewatering of reserve pit wastes is usually accomplished through natural evaporation or skimming of pit liquids. Evaporation is used where climate permits. The benefits of evaporation may be overstated. In the arid climate of Utah, 93 percent of produced waters in an unlined pit percolated into the surrounding soil. Only 7 percent of the produced water evaporated (Davani et al. 1985). Alternatively, dewatering can be accomplished in areas of net precipitation by siphoning or pumping off free liquids. This is followed by disposal of the liquids by subsurface injection or by trucking them offsite to a disposal facility. Backfilling consists of burying the residual pit contents by pushing in the berms or pit walls, followed by compaction and leveling. Landspreading can involve spreading the excess muds that are squeezed out during the burial operation on surrounding soils; where waste quantities are large, landowners' permission is generally sought to disperse this material on land adjacent to the site. (This operation is different from commercial landfarming, which is discussed later.)

Environmental Performance

Construction of reserve pits is technically simple and straightforward. They do not require intensive maintenance to ensure proper function, but they may, in certain circumstances, pose environmental hazards during their operational phase.

Pits are generally built or excavated into the surface soil zones or into unconsolidated sediments, both of which are commonly highly permeable. The pits are generally unlined,[5] and, as a result, seepage of liquid and dissolved solids may occur through the pit sides and bottom into any shallow, unconfined freshwater aquifers that may be present. When pits are lined, materials used include plastic liners, compacted soil, or clay. Because reserve pits are used for temporary storage of drilling mud, any seepage of pit contents to ground water may be temporary, but it can in some cases be significant, continuing for decades (USEPA 1986).

Other routes of environmental exposure associated with reserve pits include rupture of pit berms and overflow of pit contents, with consequent discharge to land or surface water. This can happen in areas of high rainfall or where soil used for berm construction is particularly unconsolidated. In such situations, berms can become saturated and weakened, increasing the potential for failure. Leaching of pollutants after pit closure can also occur and may be a long-term problem especially in areas with highly permeable soils.

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[5] An API study suggests that 37 percent of reserve pits are lined with a clay or synthetic liner.

Annular Disposal of Pumpable Drilling Wastes

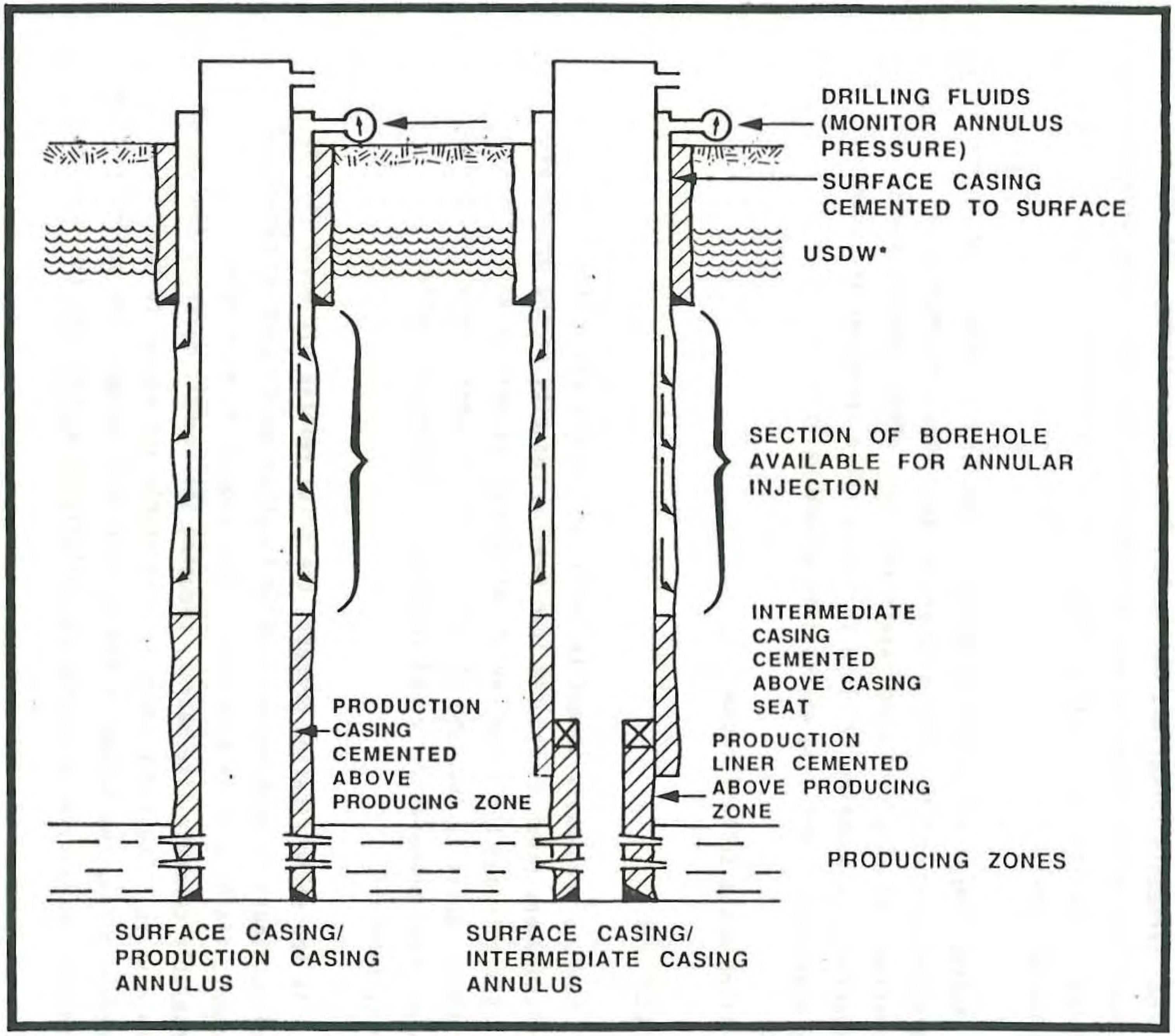
Description

Annular disposal involves the pumping of waste drilling fluids down the annulus created between the surface and intermediate casing of a well (see Figure III-1). (Disposal of solids is accomplished by using burial, solidification, landfarming, or landspreading techniques.) Disposal down the surface casing in the absence of an intermediate casing is also considered annular disposal. Annular disposal of pumpable drilling wastes is significantly more costly than evaporation, dewatering, or land application and is generally used when the waste drilling fluid contains an objectionable level of a contaminant or contaminants (such as chlorides, metals, oil and grease, or acid) which, in turn, limits availability of conventional dewatering or land application of drilling wastes. However, for disposal in a "dry" hole, costs may be relatively low. No statistics are available on how frequently annular injection of drilling wastes is used.

Environmental Performance

The well's surface casing is intended to protect fresh ground-water zones during drilling and after annular injection. To avoid adverse impacts on ground water in the vicinity of the well after annular injection, it is important that surface casing be sound and properly cemented in place. There is no feasible way to test the surface casing for integrity without incurring significant expense.

Assuming the annulus is open and the surface casing has integrity, the critical implementation factor is the pressure at which the reserve



* UNDERGROUND SOURCE OF DRINKING WATER
NOTE: NOT TO SCALE

Figure III-1 Annular Disposal of Waste Drilling Fluids pit contents are injected. The receiving strata are usually relatively shallow, permeable formations having low fracture pressures. If these pressures are exceeded during annular injection, the strata may develop vertical fractures, potentially allowing migration of drilling waste into freshwater zones.

Another important aspect of annular injection is identification and characterization of the confining shale layer above the receiving formation. Shallow confining layers are, very often, discontinuous. Any unidentified discontinuity close to the borehole increases the potential for migration of drilling wastes into ground water.

Drilling Waste Solidification

Description

Surface problems with onsite burial of reserve pit contents reported by landowners (such as reduced load-bearing capacity of the ground over the pit site and the formation of wet spots), as well as environmental problems caused by leaching of salts and toxic constituents into ground water, have prompted increased interest in reserve pit waste solidification.

In the solidification process, the total reserve pit waste (fluids and cuttings) is combined with solidification agents such as commercial cement, flash, or lime kiln dust. This process forms a relatively insoluble concrete-like matrix, reducing the overall moisture content of the mixture. The end product is more stable and easier to handle than reserve pit wastes buried in the conventional manner.. The solidification process can involve injecting the solidifying agents into the reserve pit or pumping the wastes into a mixing chamber near the pit. The waste does not have to be dewatered prior to treatment. Solidification can increase the weight and bulk of the treated waste, which may in some cases be a disadvantage of this method.

Environmental Performance

Solidification of reserve pit wastes offers a variety of environmental improvements over simple burial of wastes, with or without dewatering. By reducing the mobility of potentially hazardous materials, such as heavy metals, the process decreases the potential for contamination of ground water from leachate of unsolidified, buried reserve pit wastes. Bottom sludges, in which heavy metals largely accumulate, may continue to leach into ground water. (There are no data to establish whether the use of kiln dust would add harmful constituents to reserve pit waste. Addition of kiln dust would increase the volume of waste to be managed.)

Treatment and Discharge of Liquid Wastes to Land or Surface Water

Description

Discharge of waste drilling fluid to surface water is prohibited by EPA's zero discharge effluent guideline. However, in the Gulf Coast area, the liquid phase of waste drilling muds having low chloride concentrations is chemically treated for discharge to surface water. The treated aqueous phase (at an appropriate alkaline pH) can then be discharged to land or surface water bodies.[6] The addition of selected reagents to reserve pit liquids must achieve the necessary reactions to allow effective separation of the suspended solids prior to dewatering of the sludge in the reserve pit.

Onsite treatment methods used prior to discharge are commercially available for reserve pit fluids as well as for solids. They are typically provided by mobile equipment brought to the drill site. These methods include pH adjustment, aeration, coagulation and flocculation, centrifugation, filtration, dissolved gas flotation, and reverse osmosis. All these methods, however, are more expensive than the more common approach of dewatering through evaporation and percolation. Usually, a treatment company employs a combination of these methods to treat the sludge and aqueous phases of reserve pit wastes.

Environmental Performance

Treatment and discharge of liquid wastes are used primarily to shorten the time necessary to close a pit.

Closed Cycle Systems

Description

A closed cycle waste treatment system can be an alternative to the use of a reserve pit for onsite management and disposal of drilling

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[6] David Flannery states that his interpretation of EPA's effluent guidelines would preclude such a discharge. "On July 4, 1987, a petition was filed with EPA to revise the effluent guideline. If that petition is granted, stream discharges of drilling fluid and produced fluids would be allowed at least from operations in the Appalachian States."

wastes. Essentially an adaptation of offshore systems for onshore use, closed systems have come into use relatively recently. Because of their high cost, they are used very rarely, usually only when operations are located at extremely delicate sites (such as a highly sensitive wildlife area), in special development areas (such as in the center of an urbanized area), or where the cost of land reclamation is considered excessive. They can also be used where limited availability of makeup water for drilling fluid makes control of drill cuttings by dilution infeasible.

Closed cycle systems are defined as systems in which mechanical solids control equipment (shakers, impact type sediment separation, mud cleaners, centrifuges, etc.) and collection equipment (roll-off boxes, vacuum trucks, barges, etc.) are used to minimize waste mud and cutting volumes to be disposed of onsite or offsite. This in turn maximizes the volume of drilling fluid returned to the active mud system. Benefits derived from the use of this equipment include the following (Hanson et al. 1986):

- A reduction in the amount of water or oil needed for mud maintenance;
- An increased rate of drill bit penetration because of better solids control;
- Lower mud maintenance costs;
- Reduced waste volumes to be disposed of; and
- Reduction in reserve pit size or total elimination of the reserve pit.

Closed cycle systems range from very complex to fairly simple. The degree of solids control used is based on the mud type and/or drilling program and the economics of waste transportation to offsite disposal facilities (particularly the dollars per barrel charges at these facilities versus the cost per day for additional solids control equipment rental). Closed systems at drill sites can be operated to have recirculation of the liquid phase, the solid phase, or both. In reality, there is no completely closed system for solids because drill cuttings are always produced and removed. The closed system for solids, or the mud recirculation system, can vary in design from site to site, but the system must have sufficient solids handling equipment to effectively remove the cuttings from muds to be reused.

Water removed from the mud and cuttings can be reused. It is possible to operate a separate closed system for water reuse onsite along with the mud recirculation system. As with mud recirculation systems, the design of a water recirculation system can vary from site to site, depending on the quality of water required for further use. This may include chemical treatment of the water.

Environmental Performance

Although closed systems offer many environmental advantages, their high cost seriously reduces their potential use, and the mud and cuttings must still ultimately be disposed of.

Disposal of Drilling Wastes on the North Slope of Alaska--A Special Case

The North Slope is an arctic desert consisting of a wet coastal plain underlain by up to 2,500 feet of permafrost, the upper foot or two of which thaws for about 2 months a year. The North Slope is considered to be a sensitive area because of the extremely short growing season of the tundra, the short food chain, and the lack of species diversity found in this area. Because of the area's severe climate, field practices for management of drilling media and resulting waste are different on the North Slope of Alaska from those found elsewhere in the country. In the Arctic, production pads are constructed above ground using gravel. This type of construction prevents melting of the permafrost. Reserve pits are constructed on the production pads using gravel and native soils for the pit walls; they become a permanent part of the production facility. Pits are constructed above and below grade.

Because production-related reserve pits on the North Slope are permanent, the contents of these pits must be disposed of periodically. This is done by pumping the aqueous phase of a pit onto the tundra. This pumping can take place after a pit has remained inactive for 1 year to allow for settling of solids and freeze-concentration of constituents; the aqueous phase is tested for effluent limits for various constituents established by the State of Alaska. The National Pollutant Discharge Elimination System (NPDES) permit system does not cover these discharges. An alternative to pumping of the reserve pit liquids onto the tundra is to "road-spread" the liquid, using it as a dust control agent on the gravel roads connecting the production facilities. Prior to promulgation of new State regulations, no standards other than "no oil sheen" were established for water used for dust control. ADEC now requires that at the edge of the roads, any leachate, runoff, or dust must not cause a violation of the State water quality standards. Alaska is evaluating the need for setting standards for the quality of fluids used to avoid undesirable impacts. Other North Slope disposal options for reserve pit liquids include disposal of the reserve pit liquids through annular injection or disposal in Class II wells. The majority of reserve pit liquids are disposed of through discharge to the tundra.

Reserve pits on the North Slope are closed by dewatering the pit and filling it with gravel. The solids are frozen in place above grade and below grade. Freezing in place of solid waste is successful as long as hydrocarbon contamination of the pit contents is minimized. Hydrocarbon residue in the pit contents can prevent the solids from freezing completely. In above-grade structures thawing will occur in the brief summer. If the final waste surface is below the active thaw zone, the wastes will remain frozen year-round.

Disposal of produced waters on the North Slope is through subsurface injection. This practice does not vary significantly from subsurface injection of production wastes in the Lower 48 States, and a description of this practice can be found under "Production-Related Wastes" below.

Environmental Performance

Management of drilling media and associated waste can be problematic in the Arctic. Because of the severe climate, the reserve pits experience intense freeze-thaw cycles that can break down the stability of the pit walls, making them vulnerable to erosion. From time to time, reserve pits on the North Slope have breached, spilling untreated liquid and solid waste onto the surrounding tundra. Seepage of untreated reserve pit fluids through pit walls is also known to occur.

Controlled discharge of excess pit liquids is a State-approved practice on the North Slope; however, the long-term effects of discharging large quantities of liquid reserve pit waste on this sensitive environment are of concern to EPA, Alaska Department of Environmental Conservation (ADEC), and officials from other Federal agencies. The existing body of scientific evidence is insufficient to conclusively demonstrate whether or not there are impacts resulting from this practice.

OFFSITE WASTE MANAGEMENT METHODS

Offsite waste management methods include the use of centralized disposal pits (centralized injection facilities, either privately or commercially operated, will be discussed under "subsurface injection" of production wastes), centralized treatment facilities, commercial landfarming, and reconditioning and reuse of drilling media.

Centralized Disposal Pits

Description

Centralized disposal pits are used in many States to store and dispose of reserve pit wastes. In some cases, large companies developing an extensive oil or gas field may operate centralized pits within the field for better environmental control and cost considerations. Most centralized pits are operated commercially, primarily for the use of smaller operators who cannot afford to construct properly designed and sited disposal pits for their own use. They serve the disposal needs for drilling or production wastes from multiple wells over a large geographical area. Centralized pits are typically used when storage and disposal of pit wastes onsite are undesirable because of the high chloride content of the wastes or because of some other factor that raises potential problems for the operators.[7] Wastes are generally transported to centralized disposal pits in vacuum trucks. These centralized pits are usually located within 25 miles of the field sites they serve.

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[7] Operators, for instance, may be required under their lease agreements with landowners not to dispose of their pit wastes onsite because of the potential for ground-water contamination.

The number of commercial centralized pits in major oil-producing States may vary from a few dozen to a few hundred. The number of privately developed centralized pits is not known.

Technically, a centralized pit is identical in basic construction to a conventional reserve pit. It is an earthen impoundment, which can be lined or unlined and used to accumulate, store, and dispose of drilling fluids from drilling operations within a certain geographical area. Centralized pits tend to be considerably larger than single-well pits; surface areas can be as large as 15 acres, with depths as great as 50 feet. Usually no treatment of the pit contents is performed. Some centralized pits are used as separation pits, allowing for solids settling. The liquid recovered from this settling process may then be injected into disposal wells. Many centralized pits also have State requirements for oil skimming and reclamation.

Environmental Performance

Centralized pits are a storage and disposal operation; they usually perform no treatment of wastes.

Closure of centralized pits may pose adverse environmental impacts. In the past some pits have been abandoned without proper closure, sometimes because of the bankruptcy of the original operator. So far as EPA has been able to determine, only one State, Louisiana, has taken steps to avoid this eventuality; Louisiana requires operators to post a bond or irrevocable letter of credit (based on closing costs estimated in the facility plan) and have at least $1 million of liability insurance to cover operations of open pits.

Centralized Treatment Facilities

Description

A centralized treatment facility for oil and gas drilling wastes is a process facility that accepts such wastes solely for the purpose of conditioning and treating wastes to allow for discharge or final disposal. Such facilities are distinct from centralized disposal pits, which do not treat drilling wastes as part of their storage and disposal functions. The use of such facilities may remove the burden of disposal of wastes from the operators in situations where State regulations have imposed stringent disposal requirements for burying reserve pit wastes onsite.

Centralized treatment may be an economically viable alternative to onsite waste disposal for special drilling fluids, such as oil-based muds, which cannot be disposed of in a more conventional manner. The removal, hauling, and treatment costs incurred by treatment at commercial sites will generally outweigh landspreading or onsite burial costs. A treatment facility can have a design capacity large enough to accept a great quantity of wastes from many drilling and/or production facilities.

Many different treatment technologies can potentially be applied to centralized treatment of oil and gas drilling wastes. The actual method used at the particular facility would depend on a number of factors. One of these factors is type of waste. Currently, some facilities are designed to treat solids for pH adjustment, dewatering, and solidification (muds and cuttings), while others are designed to treat produced waters, completion fluids, and stimulation fluids. Some facilities can treat a combination of wastes. Other factors determining treatment method include facility capacity, discharge options and requirements, solid waste disposal options, and other relevant State or local requirements.

Environmental Performance

Experience with centralized treatment is limited. Until recently, it was used only for treatment of offshore wastes. Its use in recent years for onshore wastes is commercially speculative, being principally a commercial response to the anticipated impacts of stricter State rules pertaining to oil and gas drilling and production waste. The operations have not been particularly successful as business ventures so far.

Commercial Landfarming

Description

Landfarming is a method for converting reserve pit waste material into soil-like material by bacteriological breakdown and through soil incorporation. The method can also be used to process production wastes, such as production tank bottoms, emergency pit cleanouts, and scrubber bottoms. Incorporation into soil uses dilution, biodegradation, chemical alteration, and metals adsorption mechanisms of soil and soil bacteria to reduce waste constituents to acceptable soil levels consistent with intended land use.

Solid wastes are distributed over the land surface and mixed with soils by mechanical means. Frequent turning or disking of the soil is necessary to ensure uniform biodegradation. Waste-to-soil ratios are normally about 1:4 in order to restrict concentrations of certain pollutants in the mixture, particularly chlorides and oil (Tucker 1985). Liquids can be applied to the land surface by various types of irrigation including sprinkler, flood, and ridge and furrow. Detailed landfarming design procedures are discussed in the literature (Freeman and Deuel 1984).

Landfarming methods have been applied to reserve pit wastes in commercial offsite operations. The technique provides both treatment and final disposition of salts, oil and grease, and solids. Landfarming may eventually produce large volumes of soil-like material that must be removed from the area to allow operations to continue.

Requirements for later reuse or disposal of this material must be determined separately.

Environmental Performance

Landfarming is generally done in areas large enough to incorporate the volume of waste to be treated. In commercial landfarming operations where the volume of materials treated within a given area is large, steps must be taken to ensure protection of surface and ground water. It is important, for instance, to minimize application of free liquids so as to reduce rapid transport of fluids through the soils.

The process is most suitable for the treatment of organics, especially the lighter fluid fractions that tend to distribute themselves quickly into the soil through the action of biodegradation. Heavy metals are also "treated" in the sense that they are adsorbed onto clay particles in the soil, presumably within a few feet of where they are applied; but the capacity of soils to accept metals is limited depending upon clay content. Similarly, the ability of the soil to accept chlorides and still sustain beneficial use is also limited.

Some States, such as Oklahoma and Kansas, prohibit the use of commercial landfarming of reserve pit wastes. Other States, such as Louisiana, allow reuse of certain materials treated at commercial landfarming facilities. Materials determined to meet certain criteria after treatment can be reused for applications such as daily sanitary landfill covering or roadbed construction. When reusing landfarmed material, it is important that such material not adversely affect any part of the food chain.

Reconditioning and Reuse of Drilling Media

Description

Reconditioning and reuse of drilling media are currently practiced in a few well-defined situations. The first such situation involves the reconditioning of oil-based muds. This is a universal practice because of the high cost of oil used in making up this type of drilling media. A second situation involves the reuse of reserve pit fluids as "spud" muds, the muds used in drilling the initial shallow portions of a well in which lightweight muds can be used. A third situation involves the increased reuse of drilling fluid at one well, using more efficient solids removal. Less mud is required for drilling a single well if efficient solids control is maintained. Another application for reuse of drilling media is in the plugging procedure for well abandonment. Pumpable portions of the reserve pit are transported by vacuum truck to the well being closed. The muds are placed in the wellbore to prevent contamination of possibly productive strata and freshwater aquifers from saltwater strata. The ability to reuse drilling media economically varies widely with the distance between drilling operations, frequency and continuity of the drilling schedule, and compatibility between muds and formations among drill sites.

Environmental Performance

The above discussion raises the possibility of minimization of drilling fluids as an approach to limiting any potential environmental impacts of drilling-related wastes. Experience in reconditioning and reusing spud muds and oil-based muds does not provide any estimate of specific benefits that might be associated with recycling or reuse of most conventional drilling muds. Benefits from mud recycling at the project level can be considerable. From a national perspective, benefits are unknown. The potential for at least some increased recycling and reuse appears to exist primarily through more efficient management of mud handling systems. Specific attempts to minimize the volume of muds used are discouraged, at present, by two factors: (1) drilling mud systems are operated by independent contractors, for whom sales of muds are a primary source of income, and (2) the central concern of all parties is successful drilling of the well, resulting in a general bias in favor of using virgin materials.

In spite of these economic disincentives, recent industry studies suggest that the benefits derived from decreasing the volume of drilling mud used to drill a single well are significant, resulting in mud cost reductions of as much as 30 percent (Amoco 1985).

PRODUCTION-RELATED WASTES

Waste Characterization

Produced Water

When oil and gas are extracted from hydrocarbon reservoirs, varying amounts of water often accompany the oil or gas being produced. This is known as produced water. Produced water may originate from the reservoir being produced or from waterflood treatment of the field (secondary recovery). The quantity of water produced is dependent upon the method of recovery, the nature of the formation being produced, and the length of time the field has been producing. Generally, the ratio of produced water to oil or gas increases over time as the well is produced.

Most produced water is strongly saline. Occasionally, chloride levels, and levels of other constituents, may be low enough (i.e., less than 500 ppm chlorides) to allow the water to be used for beneficial purposes such as crop irrigation or livestock watering. More often, salinity levels are considerably higher, ranging from a few thousand parts per million to over 150,000 ppm. Seawater, by contrast, is typically about 35,000 ppm chlorides. Produced water also tends to contain quantities of petroleum hydrocarbons (especially lower molecular weight compounds), higher molecular weight alkanes, polynuclear aromatic hydrocarbons, and metals. It may also contain residues of biocides and other additives used as production chemicals. These can include coagulants, corrosion inhibitors, cleaners, dispersants, emulsion breakers, paraffin control agents, reverse emulsion breakers, and scale inhibitors.

Radioactive materials, such as radium, have been found in some oil field produced waters. Ra-226 activity in filtered and unfiltered produced waters has been found to range between 16 and 395 picocuries/liter; Ra-228 activity may range from 170 to 570 picocuries/liter (USEPA 1985). The ground-water standard for the Maximum Contaminant Level (MCL) for combined Ra-226 and Ra-228 is 5 picocuries/liter (40 CFR, Part 257, Appendix 1). No study has been done to determine the percentage of produced water that contains radioactive materials.

Low-Volume Production Wastes

Low-volume production-related wastes include many of the chemical additives discussed above in relation to drilling (see Table III-2), as well as production tank bottoms and scrubber bottoms.

Onsite Management Methods

Onsite management methods for production wastes include subsurface injection, the use of evaporation and percolation pits, discharge of produced waters to surface water, and storage.

Subsurface Injection

Description: Today, subsurface injection is the primary method for disposing of produced water from onshore operations, whether for enhanced oil recovery (EOR) or for final disposal. Nationally, an estimated 80 percent of all produced water is disposed of in injection wells permitted under EPA's Underground Injection Control (UIC) program under the authority of the Safe Drinking Water Act.[8] In the major oil-producing States, it is estimated that over 90 percent of production wastes are disposed of by this method. Subsurface injection may be done at injection wells onsite, offsite, or at centralized facilities. The mechanical design and procedures are generally the same in all cases.

In enhanced recovery projects, produced water is generally reinjected into the same reservoir from which the water was initially produced. Where injection is used solely for disposal, produced water is injected into saltwater formations, the original formation, or older depleted producing formations. Certain physical criteria make a formation suitable for disposal, and other criteria make a formation acceptable to regulatory authorities for disposal.

The sequence of steps by which waste is placed in subsurface formations may include:

- Separation of free oil and grease from the produced water;
- Tank storage of the produced water;
- Filtration;
- Chemical treatment (coagulation, flocculation, and possibly pH adjustment); and, ultimately,
- Injection of the fluid either by pumps or by gravity flow.

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[8] API states that 80 to 90 percent of all produced water is injected in Class II wells.

By regulation, injection for the purpose of disposal must take place below all formations containing underground sources of drinking water (USDWs). Figure III-2 displays a typical disposal well pumping into a zone located below the freshwater table (Templeton and Associates 1980). The type of well often preferred by State regulatory agencies is the well specifically drilled, cased, and completed to accept produced water and other oil and gas production wastes. Another type of disposal well is a converted production well, the more prevalent type of disposal and enhanced recovery well. An injection well's location and age and the composition of injected fluids are the important factors in determining the level of mechanical integrity and environmental protection the well can provide.

Although it is not a very widespread practice, some produced water is disposed of through the annulus of producing wells. In this method, produced water is injected through the annular space between the production casing and the production tubing (see Figure III-3).[9] Injection occurs using little or no pressure. The disposal zone is shallower than the producing zone in this case. Testing of annular disposal wells is involved and expensive.

One method of testing the mechanical integrity of the casing used for annular injection, without removing the tubing and packer, is through the use of radioactive tracers and sensing devices. This method involves the pumping of water spiked with a low-level radioactive tracer into the injection zone, followed by running a radioactivity-sensing logging tool through the tubing string. This procedure should detect any shallow casing leaks or any fluid migration between the casing and the borehole. Most State regulatory agencies discourage annular injection and allow the practice only in small-volume, low-pressure applications.

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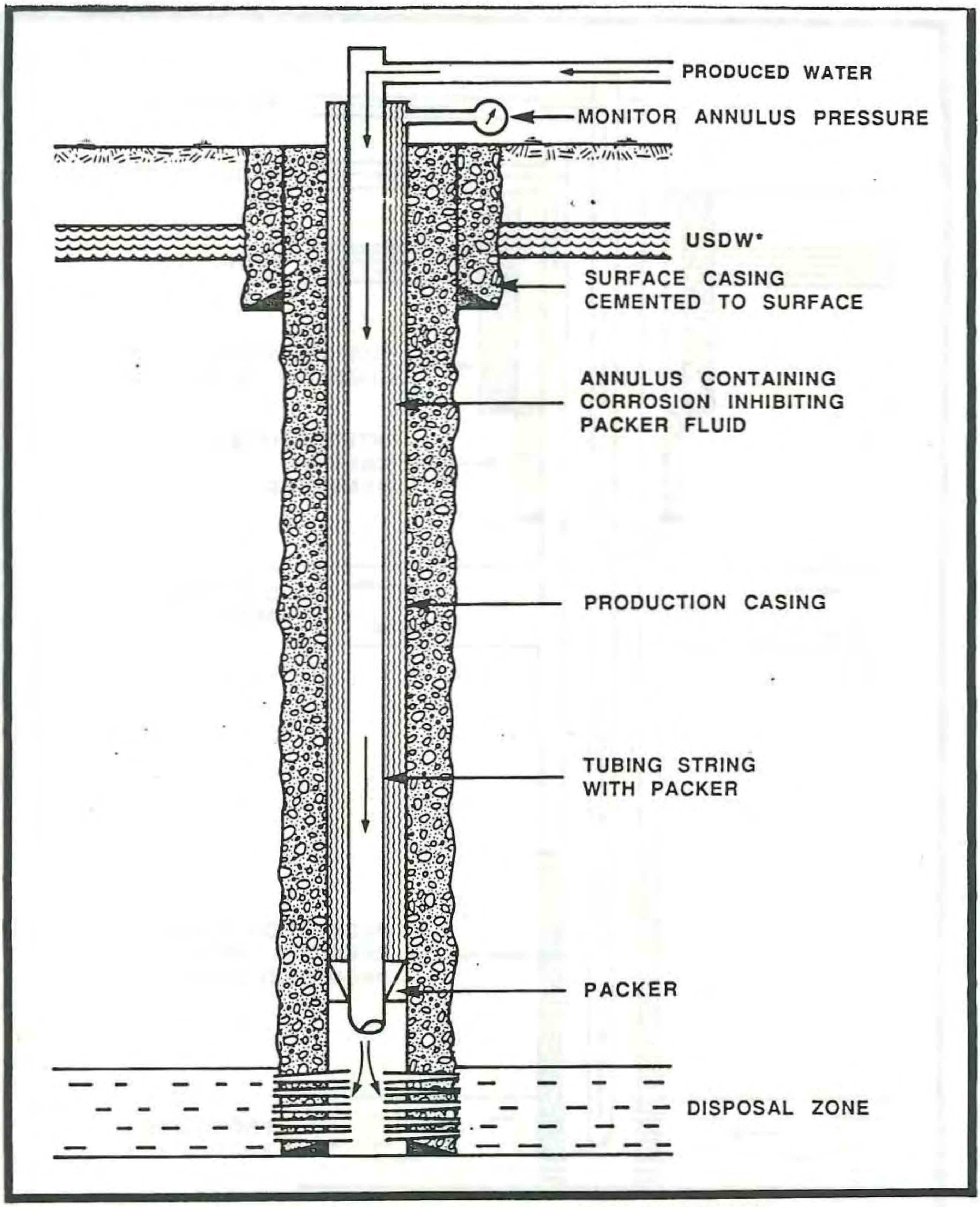
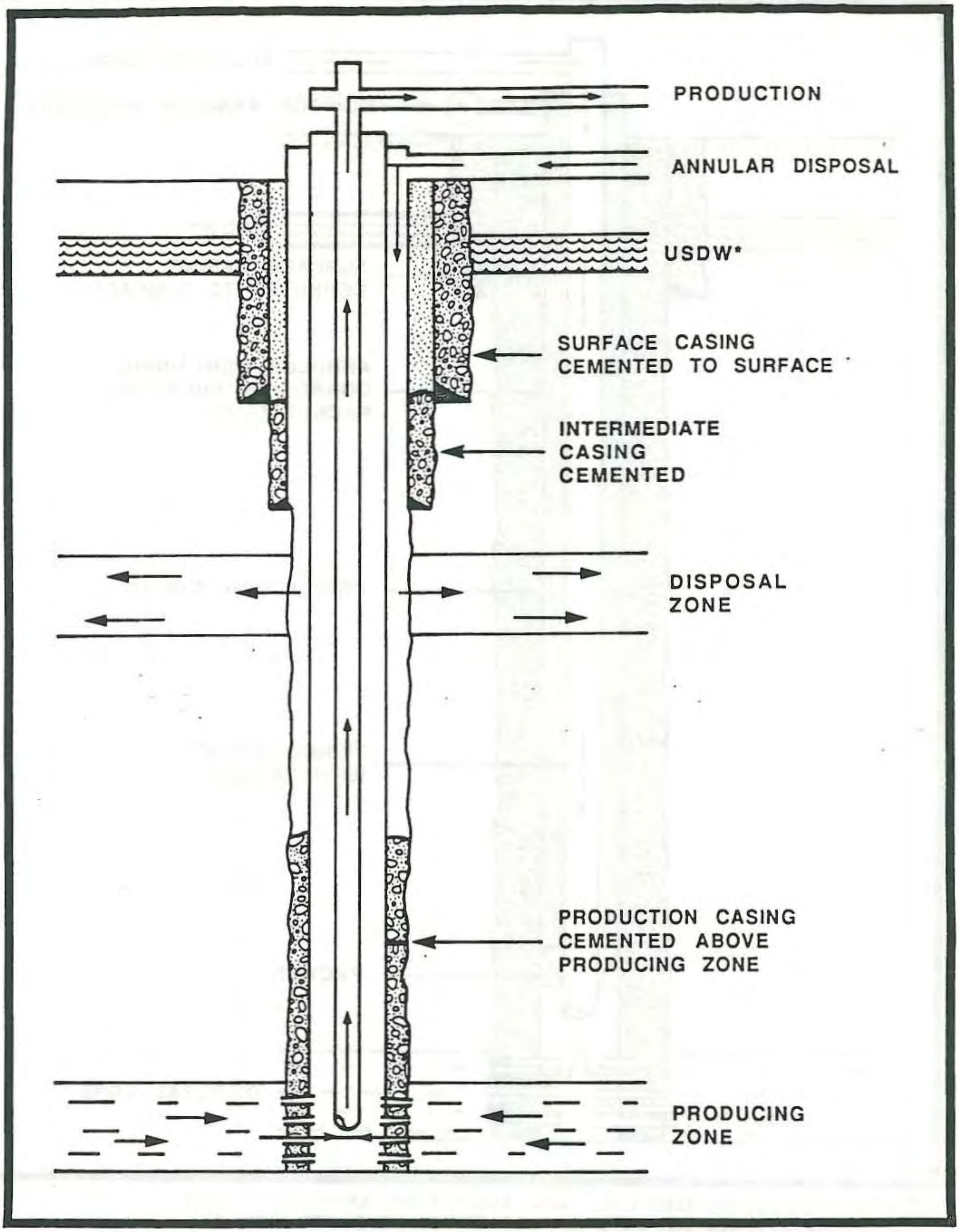
[9] In the State of Ohio, produced water is gravity-fed into the annulus rather than being pumped.



SOURCE: TEMPLETON, ELMER E., AND ASSOCIATES, ENVIRONMENTALLY ACCEPTABLE DISPOSAL OF SALT BRINES PRODUCED WITH OIL AND GAS, JANUARY, 1980.

* UNDERGROUND SOURCE OF DRINKING WATER
NOTE: NOT TO SCALE

Figure III-2 Typical Produced Water Disposal Well Design



SOURCE: TEMPLETON, ELMER E., AND ASSOCIATES, ENVIRONMENTALLY ACCEPTABLE DISPOSAL OF SALT BRINES PRODUCED WITH OIL AND GAS, JANUARY, 1980.

* UNDERGROUND SOURCE OF DRINKING WATER
NOTE: NOT TO SCALE

Figure III-3 Annular Disposal Outside Production Casing

Environmental performance: From the environmental standpoint, the primary issue with disposal of produced waters is the potential for chloride contamination of arable lands and fresh water. Other constituents in produced water may also affect the quality of ground water. Because of their high solubility in water, there is no practical way to immobilize chlorides chemically, as can be done with heavy metals and many other pollutants associated with oil and gas production.

Injection of produced water below all underground sources of drinking water is environmentally beneficial if proper safeguards exist to ensure that the salt water will reach a properly chosen disposal horizon, which is sufficiently isolated from usable aquifers. This can be accomplished by injecting water into played-out formations or as part of a waterflooding program to enhance recovery from a field. Problems to be avoided include overpressurization of the receiving formation, which could lead to the migration of the injected fluids or native formation fluids into fresh water via improperly completed or abandoned wells in the pressurized area. Another problem is leaking of injected fluids into freshwater zones through holes in the tubing and casing.

The UIC program attempts to prevent these potential problems. The EPA UIC program requires periodic mechanical integrity tests (MITs) to detect leaks in casing and ensure mechanical integrity of the injection well. Such testing can detect performance problems if it is conscientiously conducted on schedule. The Federal regulations require that mechanical integrity be tested for at least every 5 years. If leaks are detected or mechanical integrity cannot be established during the testing of the well, the response is generally to suspend disposal operations until the well is repaired or to plug and abandon the well if repair proves too costly or inefficient. The Federal regulations also require that whenever a new well or existing disposal well is permitted, a one-quarter mile radius around the well must be reviewed for the presence of manmade or natural conduits that could lead to injected fluids or native brines leaving the injection zone. In cases where improperly plugged or completed wells are found, the permit applicant must correct the problems or agree to limit the injection pressure. Major factors influencing well failure include the design, construction, and age of the well itself (converted producing wells, being older, are more likely to fail a test for integrity than newly constructed Class II injection wells); the corrosivity of the injected fluid (which varies chiefly in chloride content); and the injection pressure (especially if wastes are injected at pressures above specified permit limits).

Design, construction, operation, and testing: There is considerable variation in the actual construction of Class II wells in operation nationwide because many wells in operation today were constructed prior to enactment of current programs and because current programs themselves may vary quite significantly. The legislation authorizing the UIC program directed EPA to provide broad flexibility in its regulations so as not to impede oil and gas production, and to impose only requirements that are essential to the protection of USDWs. Similarly, the Agency was required to approve State programs for oil and gas wells whether or not they met EPA's regulations as long as they contained the minimum required by the Statute and were effective in protecting USDWs. For these reasons there is great variability in UIC requirements in both State-run and EPA-run programs. In general, requirements for new injection wells are quite extensive. Not every State, however, has required the full use of the "best available" technology. Furthermore, State requirements have evolved over time, and most injection wells operate with a lifetime permit. In practice, construction ranges from wells in which all USDWs are fully protected by two strings of casing and cementing, injection is through a tubing, and the injection zone is isolated by the packer and cement in the wellbore to shallow wells with one casing string, no packer, and little or no cement.

With respect to requirements for mechanical integrity testing of injection wells, Federal UIC requirements state that "an injection well has mechanical integrity if: (1) there is no significant leak in the casing, tubing or packer; and (2) there is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore." Translation of these general requirements into specific tests varies across States.

In addition to initial pressure testing prior to operation of injection wells, States (including those that do not have primacy under the UIC program) also require monitoring or mechanical integrity tests of Class II injection wells at least once every 5 years. In lieu of such a casing pressure test, the operator may, each month, monitor or record the pressure in the casing/tubing annulus during actual injection and report the pressure on a yearly basis.

To date, about 70 percent of all Class II injection wells have been tested nationwide, though statistics vary across EPA Regions. Data on these tests available at the Federal level are not highly detailed. Although Federal legislation lists a number of specific monitoring requirements (such as monitoring of injection pressures, volumes, and nature of fluid being injected and 5-year tests for mechanical integrity), technical information such as injection pressure and waste characterization is not reported at the Federal level. (These data are often kept at the State level.) Until recently, Federal data on mechanical integrity tests listed only the number of wells passing and failing within each State, without any explanation of the type of failure or its environmental consequences.

For injection wells used to access underground hydrocarbon storage and enhanced recovery, a well may be monitored on a field or project basis rather than on an individual well basis by manifold monitoring, provided the owner or operator demonstrates that manifold monitoring is comparable to individual well monitoring. Manifold monitoring may be used in cases where facilities consist of more than one injection well and operate with a common manifold. Separate monitoring systems for each well are not required provided the owner or operator demonstrates that manifold monitoring is comparable to individual well monitoring.

Under the Federal UIC program, all ground water with less than 10,000 mg/L total dissolved solids (TDS) is protected. Casing cemented to the surface is one barrier against contamination of USDWs. State programs vary in their requirements for casing and cementing. For example, Texas requires surface casing in strata with less than 3,000 ppm TDS; Louisiana, less than 1,500 ppm TDS; New Mexico, less than 5,000 ppm TDS. However, all wells must be designed to protect USDWs through a combination of surface casing, long string or intermediate casing, cementing, and geologic conditions.

Proximity to other wells and to protected aquifers: When a new injection well is drilled or an existing well is converted for injection, the area surrounding the site must be inspected to determine whether there are any wells of record that may be unplugged or inadequately plugged or any active wells that were improperly completed. The radius of concern includes that area within which underground pressures will be increased. All States have adopted at least the minimum Federal requirement of a one-quarter mile radius of review; however, the Agency is concerned that problems may still arise in instances where undocumented wells (such as dry holes) exist or where wells of record cannot be located.

States typically request information on the permit application about the proximity of the injection well to potable aquifers or to producing wells, other injection wells, or abandoned oil- or gas-producing wells within a one-quarter mile radius. In Oklahoma, for instance, additional restrictions are placed on UIC Class II wells within one-half mile of an active or reserve municipal water supply well unless the applicant can "prove by substantial evidence" that the injection well will not pollute a municipal water supply.

Although these requirements exist, it is important to recognize the following:

- Policy on review of nearby wells varies widely from State to State, and the injection well operator has had only a limited responsibility to identify possible channels of communication between the injection zone and freshwater zones.
- Many injection operations predate current regulations on the review of nearby wells and, because of "grandfather" clauses, are exempt.

Operation and maintenance: Incentives for compliance with applicable State or Federal UIC requirements will tend to vary according to whether a well is used for enhanced recovery or purely for waste disposal. Wells used for both purposes may be converted production wells or wells constructed specifically as Class II wells.

In order for enhanced recovery to be successful, it is essential for operators to ensure that fluids are injected into a specific reservoir and that pressures within the producing zone are maintained by avoiding any communication between that zone and others. Operators therefore have a strong economic incentive to be scrupulous in operating and maintaining Class II wells used for enhanced recovery.

On the other hand, economic incentives for careful operation of disposal wells may not be as strong. The purpose here is to dispose of fluids. The nature of the receiving zone itself, although regulated by State or Federal rules, is not of fundamental importance to the well operator as long as the receiving formation is able to accept injected fluids. Wells used for disposal are often older, converted production wells and may be subject to more frequent failures.

Evaporation and Percolation Pits

Description: Evaporation and percolation pits (see discussion above under "Reserve Pits") are also used for produced water disposal. An evaporation pit is defined as a surface impoundment that is lined by a clay or synthetic liner. An evaporation/percolation pit is one that is unlined.

Environmental performance: Evaporation of produced water can occur only under suitable climatic conditions, which limits the potential use of this practice to the more arid producing areas within the States. Percolation of produced water into soil has been allowed more often in areas where the ground water underlying the pit area is saline and is not suitable for use as irrigation water, livestock water, or drinking water. The use of evaporation and percolation pits has the potential to degrade usable ground water through seepage of produced water constituents into unconfined, freshwater aquifers underlying such pits.[10]

Discharge of Produced Waters to Surface Water Bodies

Description: Discharge of produced water to surface water bodies is generally done under the NPDES permit program. Under NPDES, discharges are permitted for (1) coastal or tidally influenced water, (2) agricultural and wildlife beneficial use, and (3) discharge of produced water from stripper oil wells to surface streams. Discharge under NPDES often occurs after the produced water is treated to control

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[10] This phenomenon is documented in Chapter IV.

pH and minimize a variety of common pollutants, such as oil and grease, total dissolved solids, and sulfates. Typical treatment methods include simple oil and grease separation followed by a series of settling and skimming operations.

Environmental performance: Direct discharge of produced waters must meet State or Federal permit standards. Although pollutants such as total organic carbon are limited in these discharges, large volumes of discharges containing low levels of such pollutants may be damaging to aquatic communities.[11]

Other Production-Related Pits

Description: A wide variety of pits are used for ancillary storage and management of produced waters and other production-related wastes. These can include:[12]

1. Basic sediment pit: Pit used in conjunction with a tank battery for storage of basic sediment removed from a production vessel or from the bottom of an oil storage tank. (Also referred to as a burn pit.)
2. Brine pit: Pit used for storage of brine used to displace hydrocarbons from an underground hydrocarbon storage facility.
3. Collecting pit: Pit used for storage of produced water prior to disposal at a tidal disposal facility, or pit used for storage of produced water or other oil and gas wastes prior to disposal at a disposal well or fluid injection well. In some cases, one pit is both a collecting pit and a skimming pit.
4. Completion/workover pit: Pit used for storage or disposal of spent completion fluids, workover fluids, and drilling fluid; silt; debris; water; brine; oil; scum; paraffin; or other materials that have been cleaned out of the wellbore of a well being completed or worked over.

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[11] This phenomenon is documented in Chapter IV.

[12] List adapted from Texas Railroad Commission Rule 8, amended March 5, 1984.

5. Emergency produced water storage pit: Pit used for storage of produced water for a limited period of time. Use of the pit is necessitated by a temporary shutdown of a disposal well or fluid injection well and/or associated equipment, by temporary overflow of produced water storage tanks on a producing lease, or by a producing well loading up with formation fluids such that the well may die. Emergency produced water storage pits may sometimes be referred to as emergency pits or blowdown pits.

6. Flare pit: Pit that contains a flare and that is used for temporary storage of liquid hydrocarbons that are sent to the flare during equipment malfunction but are not burned. A flare pit is used in conjunction with a gasoline plant, natural gas processing plant, pressure maintenance or repressurizing plant, tank battery, or well.

7. Skimming pit: Pit used for skimming oil off produced water prior to disposal of produced water at a tidal disposal facility, disposal well, or fluid injection well.

8. Washout pit: Pit located at truck yard, tank yard, or disposal facility for storage or disposal of oil and gas waste residue washed out of trucks, mobile tanks, or skid-mounted tanks.[13]

   The Wyoming Oil and Gas Conservation Commission would add pits that retain fluids for disposal by evaporation such as pits used for gas wells or pits used for dehydration facilities.

Environmental performance: All of these pits may cause adverse environmental impact if their contents leach, if they are improperly closed or abandoned, or if they are used for improper purposes. Although they are necessary and useful parts of the production process, they are subject to potential abuse. An example would be the use of an emergency pit for disposal (through percolation or evaporation) of produced water.

Offsite Management Methods

Road or Land Applications

Description: Untreated produced water is sometimes disposed of by application to roads as a deicing agent or for dust control.

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[13] The Alaska Department of Environmental Conservation questions whether pits described in Items 1, 6, and 8 should be exempt under RCRA.

Environmental performance: Road or land application of produced waters may cause contamination of ground water through leaching of produced water constituents to unconfined freshwater aquifers. Many States do not allow road or land application of produced waters.

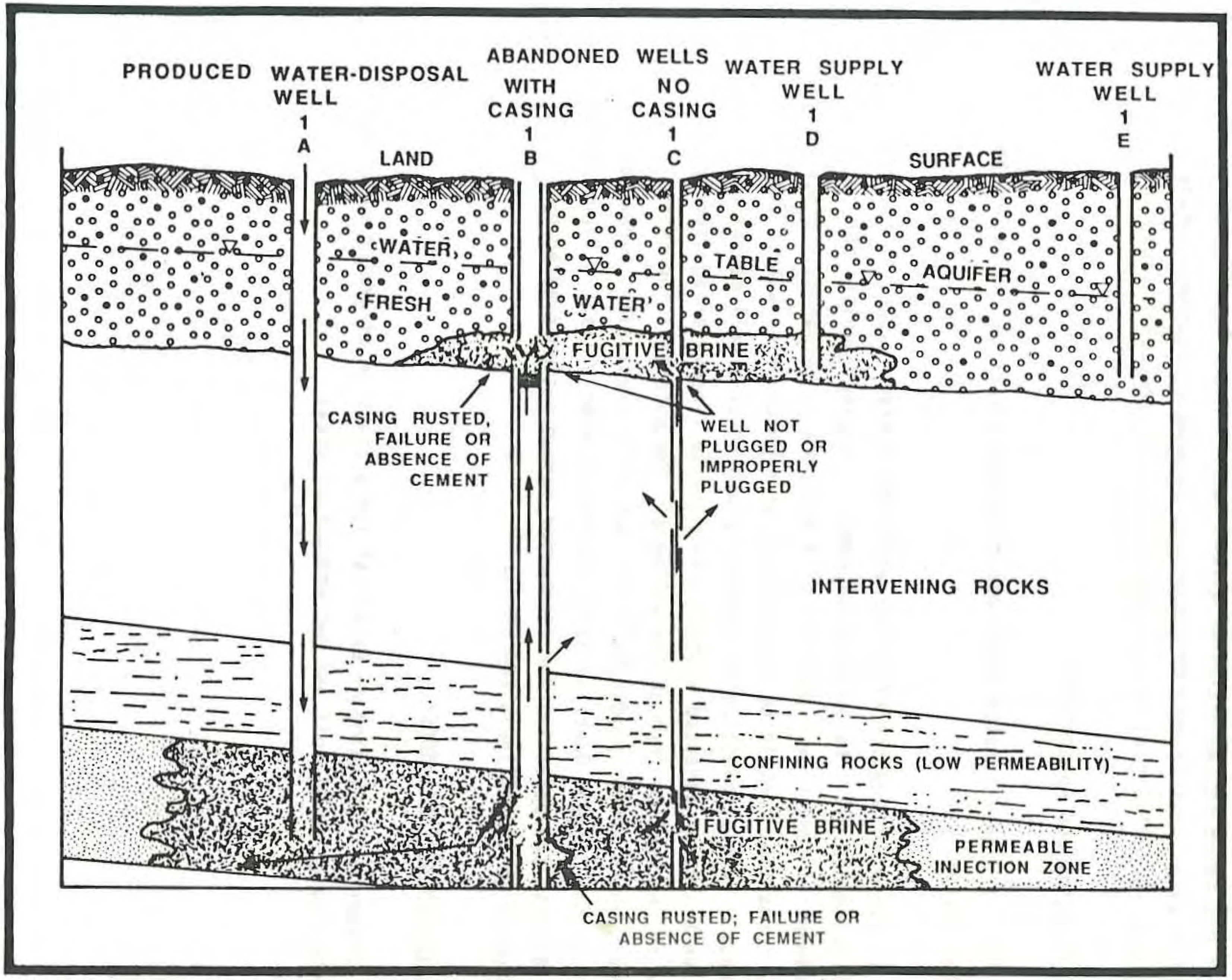
Well Plugging and Abandonment

There are an estimated 1,200,000 abandoned oil or gas wells in the United States.

To avoid degradation of ground water and surface water, it is vital that abandoned wells be properly plugged. Plugging involves the placement of cement over portions of a wellbore to permanently block or seal formations containing hydrocarbons or high-chloride waters (native brines). Lack of plugging or improper plugging of a well may allow native brines or injected wastes to migrate to freshwater aquifers or to come to the surface through the wellbore. The potential for this is highest where brines originate from a naturally pressurized formation such as the Coleman Junction formation found in West Texas. Figure III-4 illustrates the potential for freshwater contamination created by abandoned wells (Illinois EPA 1978).

Environmental Performance

Proper well plugging is essential for protection of ground water and surface water in all oil and gas production areas.



SOURCE: ILLINOIS EPA, ILLINOIS OIL FIELD BRINE DISPOSAL ASSESSMENT: STAFF REPORT, NOVEMBER 1978.

NOTE: NOT TO SCALE

Figure III-4 Pollution of a Fresh Water Aquifer Through Improperly

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CHAPTER IV

DAMAGE CASES

INTRODUCTION

Purpose of the Damage Case Review

The damage case study effort conducted for this report had two principal objectives:

To Respond to the Requirements of Section 8002(m)(C)

The primary objective was to respond to the requirements of Section 8002(m) of RCRA, which require EPA to identify documented cases that prove or have caused danger to human health and the environment from surface runoff or leachate. In interpreting this passage, EPA has emphasized the importance of strict documentation of cases by establishing a test of proof (discussed below) that all cases were required to pass before they could be included in this report. In addition, EPA has emphasized development of recent cases that illustrate damages created by current practices under current State regulations. This has been complicated in some instances by recent revisions to regulatory requirements in some States. The majority of cases presented in this chapter (58 out of 61) occurred during the last 5 years. Historical damages that occurred under prior engineering practices or under previous regulatory regimes have been excluded unless such historical damages illustrate health or environmental problems that the Agency believes should be brought to the attention of Congress now.[1] The overall objective is to present documented cases that show reasonably clear links of cause and effect between waste management practices and resulting damages, and to identify cases where damages have been most significant in terms of human health or environmental impacts.

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[1] The primary example of this is the problem of abandoned wells, discussed at length under Miscellaneous Issues below. The abandoned well problem results for the most part from inadequate past plugging practices. Although plugging practices have since been improved under State regulations, associated damages to health and the environment are continuing.

To Provide an Overview of the Nature of Damages Associated with Oil and Gas Exploration, Development, or Production Activities

In the course of accumulating damage cases, EPA has acquired a significant amount of information that has provided helpful insights into the nature of damages.

Methodology for Gathering Damage Case Information

The methodology for identifying, collecting, and processing damage cases was originally presented in draft form in the Technical Report published on October 31, 1986. The methodology, which differs minimally from the draft, is outlined below.

Information Categories

The damage case effort attempted to collect and record several categories of information on each case. Initially, this information was organized into a data base from which portions of cases were drawn for use in the final report. Categories of information were as follows:

1. Characterization of specific damage types: For each case, the environmental medium involved was determined (ground water, surface water, or land), along with the type of incident and characterization of damage. Only cases with documented damage were included. Types of potential health or environmental damages of interest are shown on Table IV-1.
2. The size and location of the site: Sites were located by nearest town and by county. Where significant hydrogeological or other pertinent factors are known, they were included; however, this type of information has been difficult to gather for all cases.
3. The operating status of the facility or site: All pertinent factors relating to the site's status (active, inactive, in process of shutdown, etc.) have been noted.

Table IV-1 Types of Damage of Concern to This Study

1. Human Health Effects (acute and chronic): While there are some instances where contamination has resulted in cases of acute adverse human health effects, such cases are difficult to document. Levels of pollution exposure caused by oil and gas operations are more likely to be in ranges associated with chronic carcinogenic and noncarcinogenic effects.

2. Environmental Effects: Impairment of natural ecosystems and habitats, including contaminating of soils, impairment of terrestrial or aquatic vegetation, or reduction of the quality of surface waters.

3. Effects on Wildlife: Impairment to terrestrial or aquatic fauna; types of damage may include reduction in species' presence or density, impairment of species' health or reproductive ability, or significant changes in ecological relationships among species.

4. Effects on Livestock: Morbidity or mortality of livestock, impairment in the marketability of livestock, or any other adverse economic or health-based impact on livestock.

5. Impairment of Other Natural Resources: Contamination of any current or potential source of drinking water, disruption or lasting impairment to agricultural lands or commercial crops, impairment of potential or actual industrial use of land, or reduction in current or potential use of land.

4. Identification of the type and volume of waste involved: While the type of waste involved has been easy to define, volumes often have not.

5. Identification of waste management practices: For each incident, the waste management practices associated with the incident have been presented.

6. Identification of any pertinent regulations affecting the site: State regulations in force across the oil- and gas-producing States are discussed at length in Appendix A. Since it would be unwieldy to attempt to discuss all pertinent regulations in relation to each site, each documented case includes a section on Compliance Issues that discusses significant regulatory issues associated with each incident as reported by sources or contacts.[2] In some cases, interpretations were necessary.

7. Type of documentation available: All documentation available for each case was included to the extent possible. For a few cases, documentation is extensive.

For the purpose of this report, the data base was condensed and is presented in Appendix C.

Sources and Contacts

No attempt was made to compile a complete census of current damage cases. States from which cases were drawn are listed on Table IV-2. As evident from the table, resources did not permit gathering of cases from all States.

Within each of the States, every effort was made to contact all available source categories listed in the Technical Report (see Table IV-3). Because time was extremely limited, the effort relied principally on information available through relevant State and local agencies and

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[2] All discussions have been reviewed by State officials and by any other sources or contacts who provided information on a case.

Table IV-2 States From Which Case Information Was Assembled

1. Alaska
2. Arkansas
3. California
4. Colorado
5. Kansas
6. Louisiana
7. Michigan
8. New Mexico
9. Ohio
10. Oklahoma
11. Pennsylvania
12. Texas
13. West Virginia
14. Wyoming

Table IV-3 Sources of Information Used in Developing Damage Cases

1. Relevant State or Local Agencies: including State environmental agencies; oil and gas regulatory agencies; State, regional, or local departments of health; and other agencies potentially knowledgeable about damages related to oil and gas operations.
2. EPA Regional Offices
3. Bureau of Land Management
4. Forest Service
5. Geological Survey
6. Professional or trade associations
7. Public interest or citizens' groups
8. Attorneys engaged in litigation

on contacts provided through public interest or citizens' groups. In some instances, cases were developed through contacts with private attorneys directly engaged in litigation. Because these nongovernmental sources often provided information on incidents of which State agencies were unaware, such cases were sometimes undocumented at the State level. State agencies were, however, provided with review drafts of case write-ups. They, in turn, provided extensive additional information and comments.

Case Study Development

Virtually all of the data used here were gathered through direct contacts with agencies and individuals, or through followup to those contacts, rather than through secondary references. For each State, researchers first contacted all State agencies that play a significant role in the regulation of oil or gas operations and set up appointments for field visits. At the same time, contacts and appointments were made where possible with local citizens' groups and private attorneys in each State. Visits were made in the period between December 1986 and February 1987. During that time, researchers gathered actual documentation and made as many additional contacts as possible.

Test of Proof

All cases were classified according to whether they met one or more formal tests of proof, a classification that was to some extent judgmental. Three tests were used, and cases were considered to meet the documentation standards of 8002(m)(C) if they met one or more of them.

The tests were as follows:

1. Scientific investigation: A case could meet documentation standards if damages were found to exist as part of the findings of a scientific study. Such studies could be extensive formal investigations supporting litigation or a State enforcement action, or they could, in some instances, be the results of technical tests (such as monitoring of wells) if such tests (a) were conducted with State-approved quality control procedures, and (b) revealed contamination levels in excess of an applicable State or Federal standard or guideline (such as a drinking water standard or water quality criterion).
2. Administrative ruling: A case could meet documentation standards if damages were found to exist through a formal administrative finding, such as the conclusions of a site report by a field investigator, or through existence of an enforcement action that cited specific health or environmental damages.
3. Court decision: The third way in which a case could be accepted was if damages were found to exist through the ruling of a court or through an out-of-court settlement.

EPA considered the possibility of basing its damage case review solely on cases that have been tried in court and for which damage determinations have been made by jury or judicial decision. This approach was rejected for a variety of reasons. First and most important, EPA wanted wherever possible to base its damage case work on scientific evidence and on evidence developed by States as part of their own regulatory control programs. Since States are the most important entity in controlling the environmental impacts of this industry, the administrative damage determinations they make are of the utmost concern to EPA. Second, comparatively few cases are litigated, and many litigated cases, perhaps a majority, are settled out of court and their records sealed through agreements between plaintiffs and defendants. Third, as data collected for this report indicate, many litigated cases are major cases in which the plaintiff may be a corporation or a comparatively wealthy landowner with the resources necessary to develop the detailed evidence necessary to successfully litigate a private suit (see damage case LA 65 on pages IV-78 and IV-79). Private citizens rarely bring cases to court because court cases are expensive to conduct, and most of these cases are settled out of court.

Review by State Groups and Other Sources

All agencies, groups, and individuals who provided documentation or who have jurisdiction over the sites in any specific State were sent draft copies of the damage cases. Because of the tight schedule for development of the report, there was limited time available for damage case review. Their comments were incorporated to the extent possible; EPA determined which comments should be included.

Limitations of the Methodology and Its Results

Schedule for Collection of Damage Case Information

The time period over which the damage case study work occurred was short, covering portions of three consecutive months. In addition, much of the field research was arranged or conducted over the December 1986-January 1987 holiday period, when it was often difficult to make contacts with State agency representatives or private groups. To the extent that resources permitted, followup visits were made to fill gaps. Nevertheless, coverage of some States had to be omitted entirely, and coverage in others (particularly Oklahoma) was limited.

Limited Number of Oil- and Gas-Producing States in Analysis

Of the States originally intended to be covered as discussed in the Technical Report, several were omitted from coverage; however, States visited account for a significant percentage of U.S. oil and gas production (see Table IV-2).

Difficulty in Obtaining a Representative Sample

In general, case studies are used to gain familiarity with ranges of issues involved in a particular study topic, not to provide a statistical representation of damages. Therefore, although every attempt was made to produce representative cases of damages associated with oil and gas operations, this study does not assert that its cases are a statistically representative record of damages in each State. Even if an attempt had been made to create a statistically valid study set, such as by randomly selecting drilling operations for review, it would have been difficult for a number of practical reasons.

First, record keeping varies significantly among States. A few States, such as Ohio, have unusually complete and up-to-date central records of enforcement actions and complaints. More often, however, enforcement records are incomplete and/or distributed throughout regional offices within the State. Schedules were such that only a few offices, usually only the State's central offices, were visited by researchers. Furthermore, their ability to collect files at each office was limited by the time available on site (usually 1 day, but never more than 3 days) and by the ability of each State to spare staff time to assist in the research. The number of cases found at each office and the amount of material gathered were influenced strongly by these constraints.

Second, very often damage claims against oil and gas operators are settled out of court, and information on known damage cases has often been sealed through agreements between landowners and oil companies.

This is typical practice, for instance, in Texas. In some cases, even the records of well-publicized damage incidents are almost entirely unavailable for review. In addition to concealing the nature and size of any settlement entered into between the parties, impoundment curtails access to scientific and administrative documentation of the incident.

A third general limitation in locating damage cases is that oil and gas activities in some parts of the country are in remote, sparsely populated, and unstudied areas. In these areas, no significant population is present to observe or suffer damages, and access to sites is physically difficult. To systematically document previously unreported damages associated with operations in more remote areas would have required an extensive original research project far beyond the resources available to this study.

Organization of This Presentation

As noted throughout this report, conditions affecting exploration, development, and production of oil and gas vary extensively from State to State, and by regions within States. While it would be logical to discuss damage cases on a State-by-State basis, the following discussion is organized according to the zones defined for other purposes in this project. Within each zone the report presents one or more categories of damages that EPA has selected as fairly illustrative of practices and conditions within that zone, focusing principally on cases of damage associated with management of high-volume wastes (drilling fluids and produced waters). Wherever possible, State-specific issues are discussed as well.

At the end of this chapter are a number of miscellaneous categories of damage cases that, although significant and well-documented, are associated either with management of lower volume exempt wastes or with types of damage not immediately related to management of wastes from current field operations. Such categories include damages caused by unplugged or improperly plugged abandoned wells.

NEW ENGLAND

The New England zone includes Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut. No significant oil and gas are found in this zone, and no damage cases were collected.

APPALACHIA

The Appalachian zone includes Delaware, Kentucky, Maryland, New Jersey, New York, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. Many of these States have minimal oil and gas production. Damage cases were collected from Ohio, West Virginia, and Pennsylvania.

Operations

Oil and gas production in the Appalachian Basin tends to be marginal, and operations are often low-budget efforts. Funds for proper maintenance of production sites may be limited. Although the absolute amount of oil produced in the Appalachian zone is small in comparison with the rest of the country, the produced water-to-product ratios are typically very high and produced waters contain high concentrations of chlorides.[3]

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[3] David Flannery, on behalf of various oil and gas trade organizations, states that "...in absolute terms, the discharge of produced water from wells in the Appalachian states is small."

In West Virginia in 1985, 1,839 new wells were completed at an average depth of 4,270 feet. Only 18 exploratory wells were drilled in that year. In Pennsylvania 4,627 new wells were completed in 1985 to an average depth 2,287 feet; 59 exploratory wells were drilled in that year. Activity in Ohio is developmental rather than exploratory, with only 78 exploratory wells drilled in 1985 out of a total of 6,297 wells completed. The average depth of a new well in 1985 was 3,760 feet.

Types of Operators

Oil and gas production in the Appalachian Basin is dominated by small operators, some well-established, some new to the industry. Major companies still hold leases in some areas. Since most extraction in this zone is economically marginal, many operators are susceptible to market fluctuations.

Major Issues

Contamination of Ground Water from Reserve Pits

Damage case incidents resulting from unlined reserve pits, with subsequent migration of contaminants into ground water, are found in the State of Ohio.

> In 1982, drilling activities of an unnamed oil and gas company contaminated the well that served a house and barn owned by a Mr. Bean, who used the water for his dairy operations. Analysis done on the water well by the Ohio Department of Agriculture found high levels of barium, iron, sodium, and chlorides. (Barium is a common constituent of drilling mud.) Because the barium content of the water well exceeded State standards, Mr. Bean was forced to shut down his dairy operations. Milk produced at the Bean farm following contamination of the water well contained 0.63 mg/L of barium. Concentrations of chlorides, barium, iron, sodium, and other residues in the water well were above the U.S. EPA's Secondary Drinking Water Standards. Mr. Bean drilled a new well, which also became contaminated. As of September 1984, Mr. Bean's water

> well was still showing signs of contamination from the drilling-related wastes. It is not known whether Mr. Bean was able to recover financially from the disruption of his dairy business. (OH 49)[4]

This case is a violation of current Ohio regulations regarding drilling mud and produced waters.

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Illegal Disposal of Oil Field Wastes in Ohio

Illegal disposal of oil field wastes is a problem in Ohio, as elsewhere, but the State is making an aggressive effort to increase compliance with State waste disposal requirements and is trying to maintain complete and up-to-date records. The State has recently banned all saltwater disposal pits. A legislative initiative during the spring of 1987 attempted to overturn the ban. The attempt was unsuccessful.

> The Miller Sand and Gravel Co., though an active producer of sand and gravel, has also served as an illegal disposal site for oil field wastes. An investigation by the Ohio Department of Natural Resources (DNR) found that the sand and gravel pits and the surrounding swamp were contaminated with oil and high-chloride produced waters. Ohio inspectors noted a flora kill of unspecified size. Ohio Department of Health laboratory analysis of soil and liquid samples from the pits recorded chloride concentrations of 269,000 mg/L. The surrounding swamp chloride concentrations ranged from 303 mg/L (upstream from the pits) to 60,000 mg/L (area around the pits). This type of discharge is prohibited by State regulations. (OH 45)[5]

This discharge was a violation of State regulations.

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[4] References for case cited: Ohio EPA, Division of Public Water Supply, Northeast District Office, interoffice communication from E. Mohr to M. Hilovsky describing test results on Mr. Bean's water well, 7/21/86. Letters from E. Mohr, Ohio EPA, to Mr. Bean and Mr. Hart explaining water sampling results, 10/20/82. Letter from Miceli Dairy Products Co. to E. Mohr, Ohio EPA, explaining test results from Mr. Bean's milk and water well. Letters from E. Mohr, Ohio EPA, to Mr. Bean explaining water sampling results from tests completed on 10/7/82, 2/2/83, 10/25/83, 6/15/84, 8/3/84, and 9/17/84. Generalized stratigraphic sequence of the rocks in the Upper Portion of the Grand River Basin.

[5] References for case cited: Ohio EPA, Division of Wastewater Pollution Control, Northeast District Office, interoffice communication from E. Mohr to D. Hasbrauck, District Chief, concerning the results from sampling at the sand and gravel site. Ohio Department of Health, Environmental Sample Submission Reports from samples taken on 6/22/82.

> Equity Oil & Gas Funds, Inc., operates Well #1 on the Engle Lease, Knox County. An Ohio DNR official inspected the site on April 5, 1985. There were no saltwater storage tanks on site to collect the high-chloride produced water that was being discharged from a plastic hose leading from the tank battery into a culvert that, in turn, emptied into a creek. The inspector took photos and samples. Both produced water and oil and grease levels were of sufficient magnitude to cause damage to flora and fauna, according to the notice of violation filed by the State. The inspector noted that a large area of land along the culvert had been contaminated with oil and produced water. The suspension order indicated that the "...violations present an imminent danger to public health and safety and are likely to result in immediate and substantial damage to natural resources." The operator was required by the State to "...restore the disturbed land surface and remove the oil from the stream in accordance with Section 1509.072 of Ohio Revised Statutes...." (OH 07)[6]

This was an illegal discharge that violated Ohio regulations. In another case:

> Zenith Oil & Gas Co. operated Well #1 in Hopewell Township. The Ohio DNR issued a suspension order to Zenith in March of 1984 after State inspectors discovered produced water discharges onto the surrounding site from a breech in a produced water pit and pipe leading from the pit. A Notice of Violation had been issued in February 1984, but the violations were still in effect in March 1984. A State inspection of an adjacent site, also operated by Zenith Oil & Gas Co., discovered a plastic hose extending from one of the tank batteries discharging high-chloride produced water into a breached pit and onto the site surface. Another tank was discharging produced water from an open valve directly onto the site surface. State inspectors also expressed concern about lead and mercury contamination from the discharge. Lead levels in the discharge were 2.5 times the accepted level for drinking water, and mercury levels were 925 times the acceptable levels for drinking water, according to results filed for the State by a private laboratory. The State issued a suspension order stating that the discharge was "...causing contamination and pollution..." to the surface and subsurface soil, and in order to remedy the problem the operator would have to restore the disturbed land. (Ohio no longer allows the use of produced water disposal pits.) (OH 12)[7]

This was an illegal discharge that violated Ohio regulations.

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[6] References for case cited: The Columbus Water and Chemical Testing Lab, lab reports. Ohio Department of Natural Resources, Division of Oil and Gas, Notice of Violation, 5/5/85.

[7] References for case cited: Ohio Department of Natural Resources, Division of Oil and Gas, Suspension Order #84-07, 3/22/84. Muskingum County Complaint Form. Columbus Water and Chemical Testing Lab sampling report.

Contamination of Ground Water from Annular Disposal of Produced Water

Ohio allows annular disposal of produced waters. This practice is not widely used elsewhere because of its potential for creating ground-water contamination. Produced water containing high levels of chlorides tends to corrode the single string of casing protecting ground water from contamination during annular disposal. Such corrosion creates holes in a well's casing that can allow migration of produced water into ground water. Under the Federal UIC program, Ohio requires operators of annular disposal wells to conduct radioactive tracer surveys to determine whether produced water is being deposited in the correct formations. Tracer surveys are more expensive than conventional mechanical integrity tests for underground injection wells, and only 2 percent of all tracer surveys were witnessed by DNR inspectors in 1985.

The Donofrio well was a production oil well with an annular disposal hookup fed by a 100-bbl produced water storage tank. In December 1975, shortly after completion of the well, tests conducted by the Columbus Water and Chemical Testing Lab on the Donofrio residential water well showed chloride concentrations of 4,550 ppm. One month after the well contamination was reported, several springs on the Donofrio property showed contamination from high-chloride produced water and oil, according to Ohio EPA inspections. On January 8, 1976, Ohio EPA investigated the site and reported evidence of oil overflow from the Donofrio well production facility, lack of diking around storage tanks, and the presence of several produced water storage pits. In 1986, 11 years after the first report of contamination, a court order was issued to disconnect the annular disposal lines and to plug the well. The casing recovered from the well showed that its condition ranged from fair to very poor. The casing was covered with rust and scale, and six holes were found.[8] (OH 38)[9]

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[8] Comments in the Docket by David Flannery and American Petroleum Institute (API) pertain to OH 38. Mr. Flannery states that "...the water well involved in that case showed contamination levels which predated the commencement of annular disposal...." EPA believes this statement refers to bacterial contamination of the well discovered in 1974. (EPA notes that the damage case discusses chloride contamination of the water well, not bacterial contamination.)

[9] References for case cited: Ohio Department of Natural Resources, Division of Oil and Gas, interoffice communication from M. Sharrock to S. Kell on the condition of the casing removed from the Donofrio well. Communication from Attorney General's Office, E.S. Post, discussing court order to plug the Donofrio well. Perry County Common Pleas Court Case #19262. Letter from R.M. Kimball, Assistant Attorney General, to Scott Kell, Ohio Department of Natural Resources, presenting case summary from 1974 to 1984. Ohio Department of Health lab sampling reports from 1976 to 1985. Columbus Water and Chemical Testing Lab, sampling reports from 12/1/75, 7/27/84, and 8/3/84.

This well could not pass the current criteria for mechanical integrity under the UIC program.

An alternative to annular disposal of oil field waste is underground injection in Class II wells, using tubing and packer, but these Class II disposal wells are significantly more expensive than annular disposal operations.

Illegal Disposal of Oil and Gas Waste in West Virginia

Environmental damage from illegal disposal of wastes associated with drilling and production is by far the most common type of problem in West Virginia. Results of illegal disposal include fish kills, vegetation kills, and death of livestock from drinking polluted water. Fluids illegally disposed of include oil, produced waters of up to 180,000 ppm chlorides, drilling fluids, and fracturing fluids that can have a pH of as low as 3.0 (highly acidic).

Illegal disposal in this State takes many forms, including draining of saltwater holding tanks into streams, breaching of reserve pits into streams, siphoning of pits into streams, or discharging of vacuum truck contents into fields or streams.

Enforcement is difficult both because of limited availability of State inspection and enforcement personnel and because of the remote location of many drill sites (see Table VII-7). Many illegal disposal incidents come to light through complaints from landowners or anonymous informers.

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Beginning in 1979, Allegheny Land and Mineral Company of West Virginia operated a gas well, #A-226, on the property of Ray and Charlotte Willey. The well was located in a corn field where cattle were fed in winter, and within 1,000 feet of the Willey's residence. The well was also adjacent to a stream known as the Beverlin Fork. Allegheny Land and Mineral operated another gas well above the residence known as the #A-306, also located on property owned by the Willeys. Allegheny Land and Mineral maintained open reserve pits and an open waste ditch, which ran into Beverlin Fork. The ditch served to dispose of produced water, oil, drip gas, detergents, fracturing fluids, and waste production chemicals. Employees of the company told the Willeys that fluids in the pits were safe for their livestock to drink.

The Willeys alleged that their cattle drank the fluid in the reserve pit and became poisoned, causing abortions, birth defects, weight loss, contaminated milk, and death. Hogs were also allegedly poisoned, resulting in infertility and pig still-births, according to the complaint filed in the circuit court of Doddridge County, by the Willeys, against Allegheny Land and Mineral. The Willeys claimed that the soil on the farm was contaminated, causing a decrease in crop production and quality; that the ground water of the farm was contaminated, polluting the water well from which they drew their domestic water supply; and that the value of their real estate had been diminished as a result of these damages. Laboratory tests of soil and water from the property confirmed this contamination. The Willeys incurred laboratory expenses in having testing done on livestock, soil, and water. A judgment filed in the circuit court of Doddridge County was entered in 1983 wherein the Willeys were awarded a cash settlement in court for a total of $39,000 plus interest and costs.[10] (WV 18)[11]

This practice would violate current West Virginia regulations.

On February 23, 1983, Tom Ancona, a fur trapper, filed a complaint concerning a fish kill on Stillwell Creek. A second complaint was also filed anonymously by an employee of Marietta Royalty Co. Ancona, accompanied by a State fisheries biologist, followed a trail consisting of dead fish, frogs, and salamanders up to a drill site operated by Marietta Royalty Co., according to the complaint filed with the West Virginia DNR. There they found a syphon hose draining the drilling waste pit into a tributary of Stillwell Creek. Acid levels at the pit measured a pH of 4.0, enough to shock and kill aquatic life, according to West Virginia District Fisheries Biologist Scott Morrison. Samples and photographs were taken by the DNR. No dead aquatic life was found above the sample

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[10] West Virginia Department of Energy states that "...now the Division does not allow that type of practice, and would not let a landowner subvert the reclamation law."

[11] References for case cited: Complaint form filed in circuit court of Doddridge County, West Virginia, #81-c-18. Judgment form filed in circuit court of Doddridge County, West Virginia. Water quality summary of Ray Willey farm. Letter from D. J. Horvath to Ray Willey. Water analysis done by Mountain State Environmental Service. Veterinary report on cattle and hogs of Willey farm. Lab reports from National Veterinary Services Laboratories documenting abnormalities in Willey livestock.

site. Marietta Royalty Co. was fined a total of $1,000 plus $30 in court costs.[12] (WV 20)[13]

This discharge was in direct violation of West Virginia regulations.

Illegal Disposal of Oil Field Waste in Pennsylvania

In Pennsylvania, disposing of oil and gas wastes into streams prior to 1985 violated the State's general water quality criteria, but the regulations were rarely enforced. In a study conducted by the U. S. Fish and Wildlife Service, stream degradation was found in relation to chronic discharges to streams from oil and gas operations:

> The U.S. Fish and Wildlife Service conducted a survey of several streams in Pennsylvania from 1982-85 to determine the impact on aquatic life over a period of years resulting from discharge of oil field wastes to streams. The area studied has a history of chronic discharges of wastes from oil and gas operations. The discharges were primarily of produced water from production and enhanced recovery operations. The streams studied were Miami Run, South Branch of Cole Creek, Panther Run, Foster Brook, Lewis Run, and Pithole Creek. The study noted a decline downstream from discharges in all fish populations and populations of frogs, salamanders, and crayfish. (PA 02)[14]

These discharges of produced waters are presently allowed only under the National Pollutant Discharge Elimination System (NPDES) permit system.

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[12] The West Virginia Department of Energy states that "This activity has now been regulated under West Virginia's general permit for drilling fluids. Under that permit there would have been no environmental damage."

[13] References for case cited: Complaint Form #6/170/83, West Virginia Department of Natural Resources, 2/25/83. West Virginia Department of Natural Resources Incident Reporting Sheet, 2/26/83. Sketches of Marietta drill site. Complaint for Summons or Warrant, 3/28/83. Summons to Appear, 3/18/83. Marietta Royalty Prosecution Report, West Virginia Department of Natural Resources. Interoffice memorandum containing spill investigation details on Marietta Royalty incident.

[14] References for case cited: U.S. Fish and Wildlife, Summary of Data from Five Streams in Northwest Pennsylvania, 3/85. Background information on the streams selected for fish tissue analysis, undated but after 10/23/85. Tables 1 through 3 on point source discharge samples collected in the creeks included in this study, undated but after 10/30/84.

The long-term environmental impacts of chronic, widespread illegal disposal include loss of aquatic life in surface streams and soil salt levels above those tolerated by native vegetation. In 1985, Pennsylvania established State standards concerning this type of discharge. Discharges are now permitted under the NPDES system.

The northwestern area of Pennsylvania was officially designated as a hazardous spill area (Clean Water Act, Section 311(k)) by the U.S.EPA in 1985 because of the large number of oily waste discharges that have occurred there. Even though spills are accidental releases, and thus do not constitute wastes routinely associated with the extraction of oil and gas under the sense of the 3001 exemption, spills in this area of Pennsylvania appear to represent deliberate, routine, and continuing illegal disposal of waste oil.

Breaching of pits, opening of tank battery valves, and improper oil separation have resulted in an unusually high number of sites discharging oil directly to streams. The issue was originally brought to the attention of the State through a Federal investigation of the 500,000 acre Allegheny National Forest. That investigation discovered 500 separate spills. These discharges have affected stream quality, fish population, and other related aquatic life.

> The U.S. EPA declared a four-county area (including Mckean, Warren, Venango, and Elk counties) a major spill area in the summer of 1985. The area is the oldest commercial oil-producing region in the world. Chronic low-level releases have occurred in the region since earliest production and continue to this day. EPA and other agencies (e.g., U.S. Fish and Wildlife, Pennsylvania Fish and Game, Coast Guard) were concerned that continued discharge into the area's streams has already and will in the future have major environmental impact. The area is dotted with thousands of marginal stripper wells (producing a high ratio of produced water to oil), as well as thousands of abandoned wells and pits. In the Allegheny Reservoir itself, divers spotted 20 of 81 known improperly plugged or unplugged wells, 7 of which were leaking oily high-chloride produced water into the reservoir and have since been plugged. EPA is concerned that many others are also leaking native oily produced water.

> The Coast Guard (USCG) surveyed the forest for oil spills and produced water discharges, identifying those of particular danger to be cleaned immediately, by government if necessary. In the Allegheny Forest alone, USCG identified over 500 sites where oil was leaking from wells, pits, pipelines, or storage tanks. In 59 cases, oil was being discharged directly into streams; 217 sites showed evidence of past discharges and were on the verge of discharging again into the Allegheny Reservoir. Illegal disposal of oil field wastes has had a detrimental effect on the environment: "...there has been a lethal effect on trout streams and damage to timber and habitat for deer, bear and grouse." On Lewis Run, 52 discharge sites have been identified and the stream supports little aquatic life. Almost all streams in the Allegheny Forest have suppressed fish population as a "...direct result of pollution from oil and gas activity." (API notes that oil and produced water leaks into streams are prohibited by State and Federal regulations.)[15] (PA 09)[16]

These leaks are prohibited by State and Federal regulations. However, discharges are allowed, by permit, under the NPDES program.

Damage to Water Wells from Oil or Gas Well Drilling and Fracturing

In West Virginia, the minimum distance established for separating oil or gas wells from drinking water wells is 200 feet. Siting of oil or gas drill sites near domestic water wells is not uncommon.[17] West Virginia has no automatic provision requiring drillers to replace water wells lost in this way; owners must replace them at their own expense

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[15] Comments in the docket by API pertain to PA 09. API states that "...litigation is currently pending with respect to this case in which questions have been raised about the factual basis for government action in this case."

[16] References for case cited: U.S. Geological Survey letter from Buckwalter to Rice concerning sampling of water in northern Pennsylvania, 10/27/86. Pennsylvania Department of Environmental Resources press release on analysis of water samples, undated but after 8/83. Oil and Water: When One of the By products of High-grade Oil Production is a Low-grade Allegheny National Forest, It's Time to Take a Hard Look at Our Priorities, by Jim Morrison, Pennsylvania Wildlife, Vol. 8, No. 1. Pittsburgh Press, "Spoiling a Wilderness," 1/22/84; "Oil Leaking into Streams at 300 Sites in Northwestern Area of the State," 1985. Warren Times, "Slick Issues Underscore Oil Cleanup in National Forest," 1986.

[17] According to members of the Legal Aid Society of Charleston, West Virginia, landowners have little control over where oil and gas wells are sited. Although a provision exists for hearings to be held to question the siting of an oil or gas well, this process is rarely used by private landowners for economic and other reasons.

or sue the driller. Where there is contamination of a freshwater source, State regulations presume an oil or gas drilling site is responsible if one is located within 1,000 feet of the water source.

During the fracturing process, fractures can be produced, allowing migration of native brine, fracturing fluid, and hydrocarbons from the oil or gas well to a nearby water well. When this happens, the water well can be permanently damaged and a new well must be drilled or an alternative source of drinking water found.

> In 1982, Kaiser Gas Co. drilled a gas well on the property of Mr. James Parsons. The well was fractured using a typical fracturing fluid or gel. The residual fracturing fluid migrated into Mr. Parson's water well (which was drilled to a depth of 416 feet), according to an analysis by the West Virginia Environmental Health Services Lab of well water samples taken from the property. Dark and light gelatinous material (fracturing fluid) was found, along with white fibers. (The gas well is located less than 1,000 feet from the water well.) The chief of the laboratory advised that the water well was contaminated and unfit for domestic use, and that an alternative source of domestic water had to be found. Analysis showed the water to contain high levels of fluoride, sodium, iron, and manganese. The water, according to DNR officials, had a hydrocarbon odor, indicating the presence of gas. To date Mr. Parsons has not resumed use of the well as a domestic water source. (API states that this damage resulted from a malfunction of the fracturing process. If the fractures are not limited to the producing formation, the oil and gas are lost from the reservoir and are unrecoverable.)[18] (WV 17)[19]

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[18] Comments in the Docket pertain to WV 17, by David Flannery and West Virginia Department of Energy. Mr. Flannery states that "...this is an area where water problems have been known to occur independent of oil and gas operations." EPA believes that the "problems" Mr. Flannery is referring to are the natural high level of fluoride, alkalinity, sodium, and total dissolved solids in the water. However, the constituents of concern found in this water well were the gelatinous material associated with the fracturing process, and hydrocarbons. West Virginia Department of Energy states that the WVDOE "...had no knowledge that the Pittsburg sand was a fresh water source." Also, WVDOE pointed out that WV Code 22B-1-20 "...requires an operator to cement a string of casing 30 feet below all fresh water zones." According to case study records, Kaiser Gas Co. did install a cement string of casing 30 feet below the Pittsburg sand, from which Mr. Parson drew his water.

[19] References for case cited: Three lab reports containing analysis of water well. Letter from J. E. Rosencrance, Environmental Health Services Lab, to P. R. Merritt, Sanitarian, Jackson County, West Virginia. Letter from P. R. Merritt to J. E. Rosencrance requesting analysis. Letter from M. W. Lewis, Office of Oil and Gas, to James Parsons stating State cannot help in recovering expenses, and Mr. Parsons must file civil suit to recover damages. Water well inspection report - complaint. Sample report forms.

There were no violations of West Virginia regulations in this case.

Damage cases involving drilling activity in proximity to residential areas are known to have occurred in Pennsylvania:

> Civil suit was brought by 14 families living in the village of Belmar against a Meadville-based oil drilling company, Norwesco Development Corporation, in June 1986. Norwesco had drilled more than 200 wells near Belmar, and residents of the village claimed that the activity had contaminated the ground water from which they drew their domestic water supply. The Pennsylvania Department of Environmental Resources and the Pennsylvania Fish Commission cited Norwesco at least 19 times for violations of State regulations. Norwesco claimed it was not responsible for contamination of the ground water used by the village of Belmar. Norwesco suggested instead that the contamination was from old, long-abandoned wells. The Pennsylvania Department of Environmental Resources (DER) agreed with Belmar residents that the contamination was from the current drilling operations. Ground water in Belmar had been pristine prior to the drilling operation of Norwesco. All families relying on the ground water lost their domestic water supply. The water from the contaminated wells would "...burn your eyes in the shower, and your skin is so dry and itchy when you get out." Families had to buy bottled water for drinking and had to drive, in some cases, as far as 30 miles to bathe. Not only were residents not able to drink or bathe using the ground water; they could not use the water for washing clothes or household items without causing permanent stains. Plumbing fixtures were pitted by the high level of total dissolved solids and high chloride levels.
>
> In early 1986, DER ordered Norwesco to provide Belmar with an alternative water supply that was equal in quality and quantity to what the Belmar residents lost when their wells were contaminated. In November 1986 Norwesco offered a cash settlement of $275,000 to construct a new water system for the village and provided a temporary water supply. (PA 08)[20]

This case represents a violation of Pennsylvania regulations.

Problems with Landspreading in West Virginia

Landspreading of drilling muds containing up to 25,000 ppm chlorides was allowed in West Virginia until November 1, 1987. The new limit is 12,500 ppm chlorides. These concentrations of chlorides are considerably

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[20] References for case cited: Pittsburgh Press, "Franklin County Village Sees Hope after Bad Water Ordeal," 12/7/86. Morning News, "Oil Drilling Firm Must Supply Water to Homes," 1/7/86; "Village Residents Sue Drilling Company," 6/7/86.

higher than concentrations permitted for landspreading in other States and are several times higher than native vegetation can tolerate. Landspreading of these high-chloride muds may result in damage to arable land. This waste drilling mud may kill surface vegetation where the mud is directly applied; salts in the wastes can leach into surrounding soil, affecting larger plants and trees. Leaching of chlorides into shallow ground water is also a potential problem associated with this practice.

> In early 1986 Tower Drilling land-applied the contents of a reserve pit to an area 100 feet by 150 feet. All vegetation died in the area where pit contents were directly applied, and three trees adjacent to the land application area were dying allegedly because of the leaching of high levels of chlorides into the soil. A complaint was made by a private citizen to the West Virginia DNR. Samples taken by West Virginia DNR of the contaminated soil measured 18,000 ppm chlorides.[21] (WV 13)[22]

Land applying reserve pit contents with more than 12,500 ppm chlorides is now in violation of West Virginia regulations.

Problems with Enhanced Oil Recovery (EOR) and Abandoned Wells in Kentucky

The Martha Oil Field, located in northeastern Kentucky, is situated on the border of Lawrence and Johnson counties and occupies an area in excess of 50 square miles. Oil production began in the early 1920s and secondary recovery operations or waterflooding commenced in 1955. Ashland Exploration, Inc., operated UIC-permitted injection wells in the area. Approximately 8,500 barrels of fresh water were being injected per day at an average pressure of 700 pounds per square inch.

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[21] Comments in the Docket by David Flannery and API pertain to WV 13. The statements by API and Mr. Flannery are identical. They state that it might not be "...possible to determine whether it was the chloride concentration alone which caused the vegetation stress." Also, they claim that the damage was short term and "...full recovery of vegetation was made." Neither commenter submitted supporting documentation.

[22] References for case cited: West Virginia Department of Natural Resources complaint form #6/131/86. Analytical report on soil analysis of kill area.

Several field investigations were conducted by the U.S. Environmental Protection Agency, Region IV, to appraise the potential for and extent of contamination of ground-water resources. Field inspections revealed widespread contamination of underground sources of drinking water (USDWs).

> From April 29 through May 8, 1986, representatives of the U.S. EPA, Region IV, conducted a surface water investigation in the Blaine Creek watershed near Martha, Kentucky. The study was requested by the U.S. EPA Water Management Division to provide additional baseline information on stream water quality conditions in the Blaine Creek area. Blaine Creek and its tributaries have been severely impacted by oil production activities conducted in the Martha field since the early 1900s. The Water Management Division issued an administrative order requiring that waterflooding of the oil-bearing strata cease by February 4, 1986, and also requiring that direct or indirect brine discharges to area streams cease by May 7, 1986.
>
> For the study in 1986, 27 water chemistry sampling stations, 13 of which were also biological sampling stations, were established in the Blaine Creek watershed. Five streams in the study area were considered control stations. Biological sampling indicated that macroinvertebrates in the immediate Martha oil field area were severely impacted. Many species were reduced or absent at all stations within the oil field. Blaine Creek stations downstream of the oil field, although impacted, showed gradual improvement in the benthic macroinvertebrates. Control stations exhibited the greatest diversity of benthic macroinvertebrate species. Water chemistry results for chlorides generally indicated elevated levels in the Martha oil field drainage area. Chloride values in the affected area of the oil field ranged from 440 to 5,900 mg/L. Control station chloride values ranged from 3 to 42 mg/L.
>
> In May of 1987, EPA, Region IV, conducted another surface water investigation of the Blaine Creek watershed. The study was designed to document changes in water quality in the watershed 1 year following the cessation of oil production activities in the Martha oil field. By May of 1987, the major operator in the area, Ashland Exploration, Inc., had ceased operations. Some independently owned production wells were still in service at this time. Chloride levels, conductivity, and total dissolved solids levels had significantly decreased at study stations within the Martha oil field. Marked improvements were observed in the benthic invertebrate community structures at stations within the Martha field. New species that are considered sensitive to water quality conditions were present in 1987 at most of the biological sampling stations, indicating that significant water quality improvements had occurred following cessation of oil production activities in the Martha field. Chloride levels in one stream in the Blaine Creek watershed decreased from 5,900 mg/L to 150 mg/L.[23]

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[23] References for case cited: Martha Oil Field Water Quality Study, Martha, Kentucky, U.S. EPA, Athens, Georgia, May 1986. Martha Oil Field Water Quality Study, Martha, Kentucky, U.S. EPA, Athens, Georgia, May 1987.

In response to EPA's notice of violations and other requirements, Ashland proposed to EPA that it would properly plug and abandon all existing injection wells, oil production wells, and water-supply wells and most gas production wells in the Martha field. EPA, Region IV, issued to Ashland an Order on Consent With Administrative Civil Penalty under the authority of Section 1423(9)(2) of the SDWA. Ashland has paid an administrative penalty of $125,000 and will plug and abandon approximately 1,433 wells in compliance with EPA standards. If warranted, Ashland will provide alternative water supplies to private water well users whose supplies have been adversely affected by oil production activities.

SOUTHEAST

The Southeast zone includes North Carolina, South Carolina, and Georgia. There is little oil and gas activity in this zone. No field research was conducted to collect damage cases in this zone.

GULF

The Gulf zone includes Arkansas, Louisiana, Mississippi, Alabama, and Florida. Attention in the damage case effort was focused on Arkansas and Louisiana, the two major producers of the zone.

Operations

Operations in Arkansas are predominantly small to mid-sized operations in mature production areas. A significant percentage of production in this area comes from stripper wells, which produce large volumes of associated produced water containing high levels of chlorides. For Arkansas, most production occurs in the southern portion of the State.

The average depth of a new well drilled in Arkansas in 1985 was 4,148 feet. That year 121 exploratory wells were drilled and 1,055 new wells were completed.

Louisiana has two distinct production areas. The northern half of the State is dominated by marginal stripper production from shallow wells in mature fields. The southern half of Louisiana has experienced most of the State's development activity in the last decade. There has been heavy, capital-intensive development of the Gulf Coast area, where gas is the principal product. Wells tend to be of medium depth; operations are typically located in or near coastal wetland areas on barge platforms or small coastal islands. Operators dredge canals and estuaries to gain access to sites.

In this area, reserve pits are constructed out of the materials found on coastal islands, mainly from peat, which is highly permeable and susceptible to damage after exposure to reserve pit fluids. Reserve pits on barges are self-contained, but are allowed to be discharged in particular areas if levels of certain constituents in wastes are below specified limits. If certain constituents are found in concentrations above these limits in the waste, they must be injected or stored in pits (unlined) on coastal islands.

For many operators in the Gulf Coast area, produced water is discharged directly to adjacent water bodies. Fields in this region have an average water/oil ratio of from 4:1 to 6:1. The Louisiana Department of Environmental Quality (DEQ) is now requiring that operators apply for permits for these discharges. At this writing, the Louisiana DEQ had received permit applications for approximately 750 to 800 discharge points. Results of field work done by the Louisiana DEQ, the Louisiana Geological Survey, and the Louisiana University Marine Consortium show that roughly 1.8 to 2.0 million barrels of produced water are discharged daily in this area. According to the Louisiana Geological Survey, many receiving water bodies contain fresh water, with some receiving water bodies 70 times fresher than the oil field discharges. The U.S. Fish and Wildlife Service has stated that it will aggressively oppose any permits for produced water discharges in the Louisiana wetlands of the Gulf Coast.

The average depth of a new well drilled in northern Louisiana in 1985 was 2,713 feet; along the Gulf Coast it was 10,150 feet. In the northern part of the State, 244 exploratory wells were drilled and 4,033 production wells were completed. In the southern part of the State, 215 exploratory wells were drilled and 1,414 production wells were completed.

Types of Operators

In Arkansas, operators are generally small to mid-sized independents, including some established operators and others new to the industry. Because production comes mostly from stripper wells, operators tend to be vulnerable to market fluctuations.

Northern Louisiana's operators, like those in Arkansas, tend to be small to mid-sized independents. They share the same economic vulnerabilities with their neighbors in Arkansas. In addition, however, Louisiana's more marginal operations may be particularly stressed by the new Rule 29B, which requires the closing out and elimination of all current and future onsite produced water disposal pits by 1989. Estimated closing costs per pit are $20,000.

Operators in southern Louisiana tend to be major companies and large independents. They are less susceptible to fluctuating market conditions in the short term. Projects in the south tend to be larger than those in the north and are located in more environmentally sensitive areas.

Major Issues

Ground-Water Contamination from Unlined Produced Water Disposal Pits and Reserve Pits

Unlined produced water disposal pits have been used in Louisiana for many years and are only now being phased out under Rule 29B. Past practice has, however, resulted in damages to ground water and danger to human health.

> In 1982, suit was brought on behalf of Dudley Romero et al. against operators of an oil waste commercial disposal facility, PAB Oil Co. The plaintiffs stated that their domestic water wells were contaminated by wastes dumped into open pits in the PAB Oil Co. facility which were alleged to have migrated into the ground water, rendering the water wells unusable. Oil field wastes are dumped into the waste pits for skimming and separation of oil. The pits are unlined. The PAB facility was operating prior to Louisiana's first commercial oil field waste facility regulations. After promulgation of new regulations, the facility continued to operate for 2 years in violation of the new regulations, after which time the State shut down the facility.
>
> The plaintiff's water wells are downgradient of the facility, drilled to depths of 300 to 500 feet. Problems with water wells date from 1979. Extensive analysis was performed by Soil Testing Engineers, Inc., and U.S. EPA, on the plaintiff's water wells adjacent to the site to determine the probability of the well contamination coming from the PAB Oil Co. site. There was also analysis on surface soil contamination. Soil Testing

Engineers, Inc., determined that it was possible for the wastes in the PAB Oil Co. pits to reach and contaminate the Romeros' water wells. Surface sampling around the perimeter of the PAB Oil Co. site found high concentrations of metals. Resistivity testing showed that plumes of chloride contamination in the water table lead from the pits to the water wells. Borings that determined the substrata makeup suggested that it would be possible for wastes to contaminate the Romero ground water within the time that the facility had been in operation if the integrity of the clay cap in the pit had been lost (as by deep excavation somewhere within it). The pit was 12 feet deep and within range to percolate into the water-bearing sandy soil.

The plaintiffs complained of sickness, nausea, and dizziness, and a loss of cattle. The case was settled out of court. The plaintiffs received $140,000 from PAB Oil Co. (LA 67)[24]

Unlined commercial disposal pits are now illegal in Louisiana.

The ground in this area is highly permeable, allowing pit contents to leach into soil and ground water. Waste constituents potentially leaching into ground water from unlined pits include arsenic, cadmium, chromium, copper, lead, nickel, zinc, and chlorides. There have been incidents illustrating the permeability of subsurface formations in this area.[25]

Allowable Discharge of Drilling Mud into Gulf Coast Estuaries

Under existing Louisiana regulations, drilling muds from onshore operations may be discharged into estuaries of the Gulf of Mexico. The State issues permits for this practice on a case-by-case basis. These

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[24] References for case cited: Soil Testing Engineers, Inc., Brine Study, Romero, et al., Abbeville, Louisiana, 10/19/82. U.S. EPA lab analysis of pits and wells, 10/22/81. Dateline, Louisiana: Fighting Chemical Dumping, by Jason Berry, May-June, 1983.

[25] A gas well operated by Conoco, which had been plugged and abandoned, blew out below the surface from December 11, 1985, to January 9, 1986. The blowout sent gas through fault zones and permeable formations to the land surface owned by Claude H. Gooch. The gas could be ignited by a match held to the ground. The gas was also determined to be a potential hazard to drinking water wells in the immediate area.

estuaries are often valuable commercial fishing grounds. Since the muds can contain high levels of toxic metals, the possibility of bioaccumulation of these metals in shellfish or finfish is of concern to EPA.

> In 1984, the Glendale Drilling Co., under contract to Woods Petroleum, was drilling from a barge at the intersection of Taylor's Bayou and Cross Bayou. The operation was discharging drill cuttings and mud into the bayou within 1,300 feet of an active oyster harvesting area and State oyster seeding area. At the time of discharge, oyster harvests were in progress. (It is State policy in Louisiana not to grant permits for the discharge of drill cuttings within 1,300 feet of an active oyster harvesting area. The Louisiana Department of Environmental Quality does not allow discharge of whole mud into estuaries.)
>
> A State Water Pollution Control Division inspector noted that there were two separate discharges occurring from the barge and a low mound of mud was protruding from the surface of the water beneath one of the discharges. Woods Petroleum had a letter from the Louisiana Department of Environmental Quality authorizing them to discharge the drill cuttings and associated mud, but this permit would presumably not have been issued if it had been known that the drilling would occur near an oyster harvesting area. While no damage was noted at time of inspection, there was great concern expressed by the Louisiana Oyster Growers Association, the Louisiana Department of Wildlife and Fisheries, Seafood Division, and some parts of the Department of Water Pollution Control Division of the Department of Environmental Quality. The concern of these groups stemmed from the possibility that the discharge of muds and cuttings with high content of metals may have long-term impact on the adjacent commercial oyster fields and the State oyster seed fields in nearby Junop Bay. In such a situation, metals can precipitate from the discharge, settling in progressively higher concentrations in the bayou sediments where the oysters mature. The bioaccumulation of these metals by the oysters can have an adverse impact on the oyster population and could also lead to human health problems if contaminated oysters are consumed.
>
> The Department of Environmental Quality decided in this case to direct the oil company to stop the discharge of drill cuttings and muds into the bayou. In this instance, the Department of Environmental Quality ordered that a drill cutting barge be used to contain the remainder of the drill cuttings. The company was not ordered to clean up the mound of drill cuttings that it had already deposited in the bayou. (LA 20)[26]

Activities in this case, though allowed by the State, are illegal according to State law.

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[26] References for case cited: Louisiana Department of Environmental Quality, Water Pollution Control Division, Office of Water Resources, internal memorandum, 6/3/85.

Illegal Disposal of Oil Field Waste in the Louisiana Gulf Coast Area

The majority of damage cases collected in Louisiana involve illegal disposal or inadequate facilities for containment of wastes generated by operations on the Gulf Coast. For example:

> Two Louisiana Water Pollution Control inspectors surveyed a swamp adjacent to a KEDCO Oil Co. facility to assess flora damage recorded on a Notice of Violation issued to KEDCO on 3/13/81. The Notice of Violation discussed produced water discharges into an adjacent canal that emptied into a cypress swamp from a pipe protruding from the pit levee. Analysis of a sample collected by a Mr. Martin, the complainant, who expressed concern over the high-chloride produced water discharge into the canal he used to obtain water for his crawfish pond, showed salinity levels of 32,000 ppm (seawater is 35,000 ppm).
>
> On April 15, 1981, the Water Pollution Control inspectors made an effort to measure the extent of damage to the trees in the cypress swamp. After surveying the size of the swamp, they randomly selected a compass bearing and surveyed a transect measuring 200 feet by 20 feet through the swamp. They counted and then classified all trees in the area according to the degree of damage they had sustained. Inspectors found that "...an approximate total area of 4,088 acres of swamp was severely damaged." Within the randomly selected transect, they classified all trees according to the degree of damage. Out of a total of 105 trees, 73 percent were dead, 18 percent were stressed, and 9 percent were normal. The inspectors' report noted that although the transect ran through a heavily damaged area, there were other areas much more severely impacted. They therefore concluded, based upon data collected and firsthand observation, that the percentages of damaged trees recorded "...are a representative, if not conservative, estimate of damage over the entire affected area." In the opinion of the inspectors, the discharge of produced water had been occurring for some time, judging by the amount of damage sustained by the trees. KEDCO was fined $9,500 by the State of Louisiana and paid $4,500 in damages to the owner of the affected crawfish farm. (LA 45)[27]

This discharge was in violation of Louisiana regulations.

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[27] References for case cited: Louisiana Department of Natural Resources, Water Pollution Control Division, internal memo, Cormier and St. Pe to Givens, concerning damage evaluation of swamp near the KEDCO Oil Co. facility 6/24/81. Notice of Violation, Water Pollution Control Log #2-8-81-21.

Most of the damage cases collected involved small operations run by independent companies. Some incidents, however, involved major oil companies:

> Sun Oil Co. operates a site located in the Chacahoula Field. A Department of Natural Resources inspector noted a site configuration during an inspection (6/25/82) of a tank battery surrounded by a pit levee and a pit (30 yards by 50 yards). The pit was discharging produced water into the adjacent swamp in two places, over a low part in the levee and from a pipe that had been put through the ring levee draining directly into the swamp. Produced water, oil, and grease were being discharged into the swamp. Chloride concentrations from samples taken by the inspectors ranged from 2,948 to 4,848 ppm, and oil and grease concentrations measured 12.6 to 26.7 ppm. The inspector noted that the discharge into the swamp was the means by which the company drains the tank battery ring levee area. A notice of violation was issued to Sun Oil by the Department of Natural Resources. (LA 15)[28]

This discharge was in violation of Louisiana regulations.

Some documented cases noted damage to agricultural crops:

> Dr. Wilma Subra documented damage to D.T. Caffery's sugar cane fields adjacent to a production site, which included a saltwater disposal well, in St. Mary Parish., The operator was Sun Oil. The documentation was collected between July of 1985 and November of 1986 and included reports of salt concentrations in soil at various locations in the sugar cane fields, along with descriptions of accompanying damage. Dr. Subra noted that the sugar cane fields had various areas that were barren and contained what appeared to be sludge. The production facility is upgradient from the sugar cane fields, and Dr. Subra surmised that produced water was discharged onto the soil surface from the facility and that a plume of salt contamination spread downgradient, thereby affecting 7.3 acres of sugar cane fields, over a period of a year and a half.
>
> In July 1985, Dr. Subra noted that the cane field, though in bad condition, was predominantly covered with sugar cane. There were, however, weeds or barren soil covering a portion of the site. The patch of weeds and barren soil matched the area of highest salt concentration. In the area where the topography suggested that brine concentrations would be lowest, the sugar cane appeared healthy. Subsequent field investigation and soil sampling conducted by Dr. Subra in November of 1986 found the field to be nearly barren, with practically no sugar cane growing.

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[28] References for case cited: Louisiana Department of Natural Resources, Water Pollution Control Division, internal memo from Cormier to Givens, 8/16/82, concerning Sun Oil Co. brine discharge, Chacahoula Field. Log #2-8-81-122. Lab analysis, 7/2/82.

Dr. Subra measured concentrations of salts in the soil ranging from a low of 1,403 ppm to 35,265 ppm at the edge of the field adjacent to the oil operation. Sun has undertaken a reclamation project to restore the land. It is estimated that the project will take 2 to 3 years to complete. In the interim, Sun Oil Co. will pay the sugar cane farmer for loss of crops.[29] (LA 63)[30]

The State of Louisiana has not taken any enforcement action in this case; it is unclear whether any State regulations were violated.

Most damage associated with illegal disposal involves disposal of produced water containing high levels of chloride (brine). Illegal disposal of other types of oil field waste also result in environmental damage:

Chevco-Kengo Services, Inc. operates a centralized disposal facility near Abbeville, Louisiana. Produced water and other wastes are transported from surrounding production fields by vacuum truck to the facility. Complaints were filed by private citizens alleging that discharges from the facility were damaging crops of rice and crawfish, and that the facility represented a threat to the health of nearby residents. An inspection of the site by the Water Pollution Control Division of the Department of Natural Resources found that a truck washout pit was emptying oil field wastes into a roadside ditch flowing into nearby coulees.

Civil suit was brought by private citizens against Chevco-Kengo Services, Inc., asking for a total of $4 million in property damages, past and future crop loss, and exemplary damages. Lab analysis performed by the Department of Natural Resources of waste samples indicated high metals content of the wastes, especially in samples taken from the area near the facility and in the adjacent rice fields, indicating that the discharge of wastes from the facility was the source of damage to the surrounding land. The case is in litigation.[31] (LA90)[32]

The State did not issue a notice of violation in this case. However, this type of discharge is illegal.

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[29] API states that an accidental release occurred in this case. EPA records show this release lasted 2 years.

[30] References for case cited: Documentation from Dr. Wilma Subra, including a series of maps documenting changes in the sugar cane over a period of time, 12/86. Maps showing location of sampling and salt concentrations.

[31] API states that these discharges were accidental.

[32] References for case cited: Louisiana Department of Natural Resources, Water Pollution Control Division, internal memo, lab analysis, and photographs, 8/25/83. Letter from Westland Oil Development Corp. to Louisiana Department of Natural Resources, 4/15/83.

Illegal Disposal of Oil Field Waste in Arkansas

The majority of damage cases found in Arkansas relate to illegal dumping of produced water and oily waste from production units. Damages typically include pollution of surface streams and contamination of soil with high levels of chlorides and oil, documented or potential contamination of ground water with elevated levels of chlorides, and damage to vegetation (especially forest and timberland), from exposure to high levels of chlorides.

> An oil production unit operated by Mr. J. C. Langley was discharging oil and produced water in large quantities onto the property of Mr. Melvin Dunn and Mr. W. C. Shaw. The oil and produced water discharge allegedly caused severe damage to the property, interfered with livestock on the property, and delayed construction of a planned lake. Mr. Dunn had spoken repeatedly with a company representative operating the facility concerning the oil and produced water discharge, but no changes occurred in the operation of the facility. A complaint was made to Arkansas Department of Pollution Control and Ecology (ADPCE), the operator was informed of the situation, and the facility was brought into compliance. Mr. Dunn then hired a private attorney in order that remedial action be taken. It is not known whether the operator cleaned up the damaged property.[33] (AR 07)[34]

This discharge was in violation of Arkansas regulations.

> On September 20, 1984, an anonymous complaint was filed with ADPCE concerning the discharge of oil and produced water in and near Smackover Creek from production units operated by J. S. Beebe Oil Account. Upon investigation by ADPCE, it was found that saltwater was leaking from a salt water disposal well located on the site. Mr. Beebe wrote a letter stating his willingness to correct the situation. On November 16, 1984, the site was again investigated by ADPCE, and it was found that pits on location were being used as the primary disposal facility and were

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[33] API states that this incident constituted a spill and is therefore a non-RCRA issue.

[34] References for case cited: Arkansas Department of Pollution Control and Ecology (ADPCE) Complaint form, #EL 1721, 5/14/84. Letter from Michael Landers, attorney to Mr. Dunn, requesting investigation from Wayne Thomas concerning Langley violations. Letter from J. C. Langley to Wayne Thomas, ADPCE, denying responsibility for damages of Dunn and Shaw property, 6/5/84. Certified letter from Wayne Thomas to J. C. Langley discussing violations of facility and required remedial actions, 5/30/87. Map of violation area, 5/29/84. ADPCE oil field waste survey documenting unreported oil spill on Langley unit, 5/25/84. Letter from Michael Landers, attorney to ADPCE, discussing damage to property of Dunn and Shaw, 5/11/84.

> overflowing and leaking into Smackover Creek. The ADPCE issued a Notice of Violation (LIS 84-066) and noted that the pits were below the creek level and overflowed into the creek when heavy rains occurred. One pit was being siphoned over the pit wall, while waste from another pit was flowing onto the ground through an open pipe. The floors and walls of the pits were saturated, allowing seepage of waste from the pits. ADPCE ordered Mr. Beebe to shut down production and clean up the site and fined him $10,500. (AR 10)[35]

These discharges were occurring in violation of Arkansas regulations.

The State of Arkansas has limited resources for inspecting disposal facilities associated with oil and gas production. (See Table VII-7.) Furthermore, the two State agencies responsible for regulating oil and gas operations (the Arkansas Oil and Gas Commission (OGC) and the Arkansas Department of Pollution Control and Ecology (ADPCE)) have overlapping jurisdictions. In the next case, the landowner is the Arkansas Game and Fish Commission, which attempted to enforce a permit it issued to the operator for drilling activity on the Commission's land. As of summer 1987, no permit had been issued by either the OGC or the ADPCE.

> In 1983 and again in 1985, James M. Roberson, an oil and gas operator, was given surface access by the Arkansas Game and Fish Commission for drilling in areas in the Sulphur River Wildlife Management Area (SRWMA), but was not issued a drilling permit by either of the State agencies that share jurisdiction over oil and gas operations. Surface rights are owned by the Arkansas Game and Fish Commission. The Commission attempted to write its own permits for this operation to protect the wildlife management area resources. Mr. Roberson repeatedly violated the requirements contained in these surface use permits, and the Commission also determined that he was in violation of general State and Federal regulations applicable to his operation in the absence of OGC or ADPCE permits. These violations led to release of oil and high-chloride produced water into the wetland areas of the Sulphur River and Mercer Bayou from a leaking saltwater disposal well and illegal produced water disposal pits maintained by the operator.

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[35] References for case cited: ADPCE complaint form #EL 1792, 9/20/84, and 8/23/84. ADPCE inspection report, 9/5/84. Letter from ADPCE to J. S. Beebe outlining first run of violations, 9/6/84. Letter stating willingness to cooperate from Beebe to ADPCE, 9/14/84. ADPCE complaint form #EL 1789, 9/19/84. ADPCE inspection report, 9/25 and 9/26/84. ADPCE complaint form #EL 1822, 11/16/84. ADPCE Notice of Violation, Findings of Fact, Proposed Order and Civil Penalty Assessment, 11/21/84. Map of area. Miscellaneous letters.

> Oil and saltwater damage to the area was documented in a study conducted by Hugh A. Johnson, Ph.D., a professor of biology at Southern Arkansas University. His study mapped chloride levels around each well site and calculated the affected area. The highest chloride level recorded in the wetland was 9,000 ppm (native vegetation begins to be stressed from exposure to 250 ppm chlorides). He found that significant areas around each well site had dead or stressed vegetation related to excessive chloride exposure. The Game and Fish Commission fears that continued discharges of produced water and oil in this area will threaten the last remaining forest land in the Red River bottoms.[36] (AR 04)[37]

These discharges were in violation of State and Federal regulations.

Jurisdiction in the above case is unclear. Under a 1981 amendment to the State Oil and Gas Act, OGC was granted formal permit authority over oil and gas operations, but this authority is to be shared in certain situations with the ADPCE. Jurisdiction is to be shared where Underground Injection Control (UIC) wells are concerned, but is not clearly defined with respect to construction or management of reserve pits or disposal of drilling wastes. ADPCE has made attempts to clarify the situation by issuing informal letters of authorization to operators, but these are not universally recognized throughout the State. (A full discussion of this issue can be found in Chapter VII and in Appendix A.)

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[36] API states that the Arkansas Water and Air Pollution Act gives authority at several levels to require cleanup of these illegal activities and to prevent further occurrences. EPA believes that even though State and Federal Laws exist which prohibit this type of activity, no mechanism for enforcement is in place.

[37] References for case cited: Letter from Steve Forsythe, Department of the Interior (DOI), to Pat Stevens, Army Corps of Engineers (ACE), stating that activities of Mr. Roberson have resulted in significant adverse environmental impacts and disruptions and that DOI recommends remedial action be taken. Chloride Analysis of Soil and Water Samples of Selected Sites in Miller County, Arkansas, by Hugh A. Johnson, Ph.D., 10/22/85. Letter to Pat Stevens, ACE, from Dick Whittington, EPA, discussing damages caused by Jimmy Roberson in Sulphur River Wildlife Management Area (SRWMA) and recommending remedial action and denial of new permit application. Oil and Gas well drilling permits dated 1983 and 1985 for Roberson activities. A number of letters and complaints addressing problems in SRWMA resulting from activities of James Roberson. Photographs. Maps.

Improperly Operated Injection Wells

Improper operation of injection wells raises the potential for long-term damage to ground-water supplies, as the following case from Arkansas illustrates.

> On September 19, 1984, Mr. James Tribble made a complaint to the Arkansas Department of Pollution Control and Ecology concerning salt water that was coming up out of the ground in his yard, killing his grass and threatening his water well. There are many oil wells in the area, and water flooding is a common enhanced recovery method at these sites. Upon inspection of the wells nearest to his residence, it was discovered that the operator, J. C. McLain, was injecting salt water into an unpermitted well. The salt water was being injected into the casing, or annulus, not into tubing. Injection into the unsound casing allegedly allowed migration into the freshwater zone. A produced water pit at the same site was near overflowing. State inspectors later noted in a followup inspection that the violations had been corrected. No fine was levied. (AR 12) [38]

Operation of this well would now be in violation of UIC requirements.

MIDWEST

The Midwest zone includes the States of Michigan, Iowa, Indiana, Wisconsin, Illinois, and Missouri. Damage cases were collected in Michigan.

Operations

Michigan produces both oil and gas from limestone reef formations at sites scattered throughout the State at a depth of 4,000 to 6,000 feet.

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[38] References for case cited: ADPCE Complaint form, #EL 1790, 9/19/84. ADPCE inspection report, 9/20/84. Letter from ADPCE to Mr. J. C. McLain describing violations and required corrective action, 9/21/84. ADPCE reinspection report, 10/11/84.

Oil and gas development is relatively new in this area, and most production is primary (that is, as yet it involves no enhanced or secondary recovery methods, such as water flooding). Exploration in Michigan is possibly the most intense currently under way anywhere in the country. The average depth of new wells drilled in 1985 was 4,799 feet. In that year 863 wells were completed, of which 441 were exploration wells.

Types of Operators

Operators in Michigan include everything from small independent companies to the major oil companies.

Major Issues

Ground-Water Contamination in Michigan

All the damage cases gathered in Michigan are based on case studies written by the Michigan Geological Survey, which regulates oil and gas operations in the State. All of these cases deal with ground water contamination with chlorides. While the State has documented that damages have occurred in all cases, sources of damages are not always evident. Usually, several potential sources of contamination are listed for each case, and the plume of contamination is defined by using monitoring wells. Most of the cases involve disposal of produced waters.

> In June 1983, a water well owned by Mrs. Geneva Brown was tested after she had filed a complaint to the Michigan Geological Survey. After responding, the Michigan Geological Survey found a chloride concentration of 490 ppm in the water. Subsequent sampling from the water well of a neighbor, Mrs. Dodder, showed that her well measured 760 ppm chloride in August. There are a total of 15 oil and gas wells in the area surrounding the contaminated water wells. Only five of the wells are still producing, recovering a combination of oil and produced water. The source of the pollution was evidently the H. E. Trope, Inc., crude oil separating facilities and brine storage tanks located upgradient from the contaminated water wells. Monitoring wells were installed to confirm the source of the contamination. Stiff diagrams were used to confirm the similarity of the constituents of the formation brine and the chloride contamination of the

> affected water wells. Sample results located two plumes of chloride contamination ranging in concentration from 550 to 1,800 ppm that are traveling in a southeasterly direction downgradient from the produced water storage tanks and crude oil separator facilities owned by H.E. Trope. (MI 05)[39]

Produced water spills from production facilities are covered by Michigan regulations.

Ground-water contamination in the State has also been caused by injection wells, as illustrated by the following case:

> In April 1980, residents of Green Ridge Subdivision, located in Section 15, Laketon Township, Muskegon County, complained of bad-tasting water from their domestic water wells. Some wells sampled by the local health department revealed elevated chloride concentrations. Because of the proximity of the Laketon Oil Field, an investigation was started by the Michigan Geological Survey. The Laketon Oil Field consists of dry holes, producing oil wells, and a produced water disposal well, the Harris Oil Corp. Lappo #1. Oil wells produce a mixture of oil and produced water. The produced water is separated and disposed of by gravity in the produced water disposal well and is then placed back in the producing formation. After reviewing monitoring well and electrical resistivity survey data, the Michigan Geological Survey concluded that the source of the contamination was the Harris Oil Corp. Lappo #1 produced water disposal well, which was being operated in violation of UIC regulations. (MI 06)[40]

This disposal well was being operated in violation of State regulations.

Damage to ground water under a drill site can occur even where operators take special precautions for drilling near residential areas. An example follows:

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[39] References for case cited: Open file report, Michigan Department of Natural Resources, Investigation of Salt-Contaminated Groundwater in Cat Creek Oil Field, Hersey Township, conducted by D. W. Forstat, 1984. Appendix includes correspondence relating to investigation, area water well drilling logs, Stiff diagrams and water analysis, site monitor well drilling logs, and water sample analysis for samples used in the investigation.

[40] References for case cited: Open file report, Michigan Department of Natural Resources, Investigation of Salt-Contaminated Groundwater in Green Ridge Subdivision, Laketon Township, conducted by B. P. Shirey, 1980. Appendix includes correspondence relating to investigation, area water well drilling logs, Stiff diagrams and water analysis, site monitor well drilling logs, and water sample analysis for samples used in the investigation.

> Drilling operations at the Burke Unit #1 caused the temporary chloride contamination of two domestic water wells and longer lasting chloride contamination of a third well closer to the drill site. The operation was carried out in accordance with State regulations and special site restrictions required for urban areas, using rig engines equipped with mufflers, steel mud tanks for containment of drilling wastes, lining for earthen pits that may contain salt water, and the placement of a conductor casing to a depth of 120 feet to isolate the well from the freshwater zone beneath the rig.
>
> The drilling location is underlain by permeable surface sand, with bedrock at a depth of less than 50 feet. Contamination of the ground water may have occurred when material flushed from the mud tanks remained in the lined pit for 13 days before removal. (The material contained high levels of chlorides, and liners can leak.) According to the State report, this would have allowed for sufficient time for contaminants to migrate into the freshwater aquifer. A leak from the produced water storage tank was also reported by the operator to have occurred before the contamination was detected in the water wells. One shallow well was less than 100 feet directly east of the drill pit area and 100 to 150 feet southeast of the produced water leak site. Chloride concentrations in this well measured by the Michigan Geological Survey were found to range from 750 (9/5/75) to 1,325 (5/23/75) ppm. By late August, two of the wells had returned to normal, while the third well still measured 28 times its original background concentration of chloride. (MI 04)[41]

In this case, damages resulted from practices that are not in violation of State regulations.

PLAINS

The Plains zone includes North Dakota, South Dakota, Nebraska, and Kansas. All of these States have oil and gas production, but for this study, Kansas was the only State visited for damage case collection. Discussion is limited to that State.

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[41] References for case cited: Open file report, Michigan Department of Natural Resources, Report on Ground-Water Contamination, Sullivan and Company, J.D. Burke No. 1, Pennfield Township, conducted by J. R. Byerlay, 1976. Appendix includes correspondence relating to investigation, area water well drilling logs, Stiff diagrams and water analysis, site monitor well drilling logs, and water sample analysis for samples used in the investigation.

Operations

Oil and gas production in Kansas encompasses a wide geographical area and ranges from marginal oil production in the central and eastern portions of the State to significant gas production in the western portion of the State. Kansas is the home of one of the largest gas fields in the world, the Giant Hugoton field. Other major areas of oil production in Kansas include the Central Kansas Uplift area, better known as the "Kansas Oil Patch," the El Dorado Field in the east and south, and the Eastern Kansas Shoestring sandstone area. The Eastern Kansas Shoestring sandstone production area is composed mainly of marginal stripper operations. The overall ratio of produced water to oil in Kansas is about 40:1, but the ratio varies depending on economic conditions, which may force the higher water-to-oil ratio wells (i.e., those in the Mississippian and Arbuckle producing formations) to shut down.

The average depth of a new well drilled in Kansas in 1985 was 3,770 feet. In that year 6,025 new wells were completed. Of those, 1,694 were exploratory.

Types of Operators

Operators in Kansas include the full range from majors to small independents. The Hugoton area is dominated by majors and mid-sized to large independents. Spotty oil production in the northern half of eastern Kansas is dominated by small independent producers, and oil production is densely developed in the southern half.

Major Issues

Poor Lease Maintenance

There are documented cases in Kansas of damage associated with inadequate lease maintenance and illegal operation of pits. These cases commonly result in contamination of soil and surface water with high levels of chlorides as well as long-term chloride contamination of ground water.

> Temple Oil Company and Wayside Production Company operated a number of oil production leases in Montgomery County. The leases were operated with illegally maintained saltwater containment ponds, improperly abandoned reserve pits, unapproved emergency saltwater pits, and improperly abandoned saltwater pits. Numerous oil and saltwater spills were recorded during operation of the sites. Documentation of these incidents started in 1977 when adjacent landowners began to complain about soil pollution, vegetation kills, fish kills, and pollution of freshwater streams due to oil and saltwater runoff from these sites. The leases also contain a large number of abandoned, unplugged wells, which may pose a threat to ground water.[42] Complaints were received by the Conservation Division, Kansas Department of Health and the Environment (KDHE), Montgomery County Sheriff, and Kansas Fish and Game Commission. A total of 39 violations on these leases were documented between 1983 and 1984.
>
> A sample taken by KDHE from a 4 1/2-foot test hole between a freshwater pond and a creek on one lease showed chloride concentrations of 65,500 ppm. Water samples taken from pits on other leases showed chloride concentrations ranging from 5,000 to 82,000 ppm.
>
> The Kansas Corporation Commission (KCC) issued an administrative order in 1984, fining Temple and Wayside a total of $80,000. Initially, $25,000 was collected, and the operators could reapply for licenses to operate in Kansas in 36 months if they initiated adequate corrective measures. The case is currently in private litigation. The KCC found that no progress had been made towards bringing the leases into compliance and, therefore, reassessed the outstanding $55,000 penalty. The KCC has since sought judical enforcement of that penalty in the District Court, and a journal entry has been signed and was reviewed by the KCC and is now ready to be filed in District Court. Additionally, in a separate lawsuit between the landowners, the lessors, and the Temples regarding operation of the leases, the landowners were successful and the leases have reverted back to the landowners. The new operators are prevented from operating without KCC authority. (KS 01)[43]

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[42] Comments in the Docket by the Kansas Corporation Commission (Beatrice Stong) pertain to KS 01. With regard to the abandoned wells, Kansas Corporation Commission states that these wells are "...cemented from top to bottom...", they have "...limited resource energy..." and the static fluid level these reservoirs could sustain are "...well below the location of any drinking or usable water."

[43] References for case cited: The Kansas Corporation Commission Court Order describing the evidence and charges against the Temple Oil Co., 5/17/84.

This case represents habitual violation of Kansas regulations.

On January 31, 1986, the Kansas Department of Health and the Environment (KDHE) inspected the Reitz lease in Montgomery County, operated by Marvin Harr of El Dorado, Arkansas. The lease included an unpermitted emergency pond containing water that had 56,500 ppm chlorides. A large seeping area was observed by KDHE inspectors on the south side of the pond, allowing the flow of salt water down the slope for about 30 feet. The company was notified and was asked to apply for a permit and install a liner because the pond was constructed of sandy clay and sandstone. The operator was directed to immediately empty the pond and backfill it if a liner was not installed. On February 24, the lease was reinspected by KDHE and the emergency pond was still full and actively seeping. It appeared that the lease had been shut down by the operator. A "pond order" was issued by KDHE requiring the company to drain and backfill the pond. On April 29, the pond was still full and seeping.

Water samples taken from the pit by KDHE showed chloride concentrations of from 30,500 ppm (4/29/86) to 56,500 ppm (1/31/86). Seepage from the pit showed chloride concentrations of 17,500 ppm (2/24/86). The Kansas Department of Health and the Environment stated that "...the use of the pond...has caused or is likely to cause pollution to the soil and the waters of the State." An administrative penalty of $500 was assessed against the operator, and it was ordered that the pond be drained and backfilled. (KS 08)[44]

This activity is in violation of current Kansas regulations.

Such incidents are a recognized problem in Kansas. On May 13, 1987, the Kansas Corporation (KCC) added new lease maintenance rules to their oil and gas regulations. These new rules require permits for all pits, drilling and producing, and require emptying of emergency pits within 48 hours. Spills must now be reported in 24 hours. The question of concern is how stringently these rules can be enforced, in the light of the evident reluctance of some operators to comply. (See Table VII-7.)

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[44] References for case cited: Kansas Department of Health and Environment Order assessing civil penalty, in the matter of Marvin Harr, Case No. 86-E-77, 6/10/86. Pond Order issued by Kansas Department of Health and Environment, in the matter of Marvin Harr, Case No. 86-PO-008, 3/21/86.

Unlined Reserve Pits

Problems with unlined reserve pits are illustrated in the following cases.

> Between February 9 and 27, 1986, the Elliott #1 was drilled on the property of Mr. Lawrence Koehling. The Hutchinson Salt member, an underground formation, was penetrated during the drilling of Elliott #1. The drilling process dissolved between 100 and 200 cubic feet of salt, which was disposed of in the unlined reserve pit. The reserve pit lies 200 feet away from a well used by Mr. Koehling for his ranching operations. Within a few weeks of the drilling of the Elliott #1, Mr. Koehling's nearby well began to pump water containing a saltwater drilling fluid.
>
> Ground water on the Koehling ranch has been contaminated with high levels of chlorides allegedly because of leaching of the reserve pit fluids into the ground water. Water samples taken from the Koehling livestock water well by the KCC Conservation Division showed a chloride concentration of 1650 mg/L. Background concentrations of chlorides were in the range of 100 to 150 ppm. It is stated in a KCC report, dated November 1986, that further movement of the saltwater plume can be anticipated, thus polluting the Koehling domestic water well and the water well used by a farmstead over 1 mile downstream from the Koehling ranch. It is also stated in this KCC report that other wells drilled in the area using unlined reserve pits would have similarly affected the groundwater.
>
> The KCC now believes the source of ground-water contamination is not the reserve pit from the Elliott #1. The KCC has drilled two monitoring wells, one 10 feet from the edge of the reserve pit location and the other within 400 feet of the affected water well, between the affected well and the reserve pit. The monitoring well drilled 10 feet from the reserve pit site tested 60 ppm chlorides. (EPA notes that it is not known if this monitoring well was located upgradient from the reserve pit.) The monitoring well drilled between the affected well and the reserve pit tested 750 ppm chlorides. (EPA notes that the level of chlorides in this monitoring well is more than twice the level of chlorides allowed under the EPA drinking water standards). The case is still open, pending further investigation. EPA believes that the evidence presented to date does not refute the earlier KCC report, which cited the reserve pit as the source of ground-water contamination, since the recent KCC report does not suggest an alternative source of contamination. (KS 05)[45]

Unpermitted reserve pits are in violation of current Kansas regulations.

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[45] References for case cited: Summary Report, Koehling Water Well Pollution, 22-10-15W, KCC, Conservation Division, Jim Schoof, Chief Engineer, 11/86.

> Mr. Leslie, a private landowner in Kansas, suspected that chloride contamination of a natural spring occurred as a result of the presence of an abandoned reserve pit used when Western Drilling Inc. drilled a well (Leslie #1) at the Leslie Farm. Drilling in this area required penetration of the Hutchinson Salt member, during which 200 to 400 cubic feet of rock salt was dissolved and discharged into the reserve pit. The ground in the area consists of highly unconsolidated soils, which would allow for migration of pollutants into the ground water. Water at the top of the Leslie #1 had a conductivity of 5,050 umhos. Conductivity of the spring water equaled 7,250 umhos. As noted by the KCC, "very saline water" was coming out of the springs. Conductivity of 2,000 umhos will damage soil, precluding growth of vegetation. No fines were levied in this case as there were no violations of State rules and regulations. The Leslies filed suit in civil court and won their case for a total of $11,000 from the oil and gas operator.[46] (KS 03)[47]

Current Kansas regulations call for a site-by-site evaluation to determine if liners for reserve pits are appropriate.

Problems with Injection Wells

Problems with injection wells can occur as a result of inadequate maintenance, as illustrated by the following case.

> On July 12, 1981, the Kansas Department of Health and the Environment (KDHE) received a complaint from Albert Richmeier, a landowner operating an irrigation well in the South Solomon River valley. His irrigation well had encountered salty water. An irrigation well belonging to an adjacent landowner, L. M. Paxson, had become salty in the fall of 1980. Oil has been produced in the area since 1952, and since 1962 secondary recovery by water flooding has been used. Upon investigation by the KDHE, it was discovered that the cause of the pollution was a saltwater injection well nearby, operated by Petro-Lewis. A casing profile caliper log was run by an operator-contractor under the direction of KDHE staff, which revealed numerous holes in the casing of the injection well. The producing formation, the Kansas City-Lansing, requires as much as 800 psi at the wellhead while injecting fluid to create a profitable enhanced oil recovery project. To remediate the contamination, the alluvial aquifer was pumped, and the initial chloride concentration of 6,000 mg/L was lowered to 600 to 700 mg/L in a year's time. Chloride contamination in some areas was lowered from 10,000 mg/L to near background levels. However, a contamination problem continues in the Paxson well, which shows chlorides in the range of 1,100 mg/L even though KDHE, through pumping, has tried to reduce the

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[46] API states that KDHE had authority over pits at this time. The KCC now requires permits for such pits.

[47] Reference for case cited: Final Report, Gary Leslie Saltwater Pollution Problem, Kingman County, KCC Conservation Division, Jim Schoof, Chief Engineer, 9/86. Contains letters, memos, and analysis pertaining to the case.

concentration. After attempts at repair, Petro-Lewis decided to plug the injection well.[48] (KS 06)[49]

Operation of such a well would violate current Kansas and UIC regulations.

TEXAS/OKLAHOMA

The Texas/Oklahoma zone includes these two States, both of which are large producers of oil and gas. As of December 1986, Texas ranked as the number one producer in the U.S. among all oil-producing States. Because of scheduling constraints, research on this zone concentrated on Texas, and most of the damage cases collected come from that State.

Operations

Oil and gas operations in Texas and Oklahoma began in the 1860s and are among the most mature and extensively developed in the U.S. These two States include virtually all types of operations, from large-scale exploratory projects and enhanced recovery projects to marginal small-scale stripper operations. In fact, the Texas/Oklahoma zone includes most of the country's stripper well production. Because of their maturity, many operations in the area generate significant quantities of associated produced water.

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[48] Comments in the Docket by the KCC (Bill Bryson) pertain to KS 06. KCC states that of the affected irrigation wells, one is "...back in service and the second is approaching near normal levels as it continues to be pumped." API states that Kansas received primacy for the UIC program in 1984.

[49] References for case cited: Richmeier Pollution Study, Kansas Department of Health and Environment, G. Blackburn and W. R. Bryson, 1983.

Development of oil and gas reserves remains active. In 1985, some 9,176 new wells were completed in Oklahoma, 385 of which were exploration wells. In Texas in the same year, 25,721 wells were completed on shore, 3,973 of which were exploration wells. The average depth of wells in the two areas is comparable: Oklahoma, 4,752 feet; Texas, 4,877 feet. Because the scale and character of operations varies so widely, cases of environmental damage from this zone are also varied and are not limited to any particular type of operation.

Types of Operators

Major operators are the principal players in exploration and development of deep frontiers and capital-intensive secondary and tertiary recovery projects. As elsewhere, the major companies have the best record of compliance with environmental requirements of all types; they are least likely to cut corners on operations, tend to use high-quality materials and methods when drilling, and are generally responsible in handling well abandonment obligations.

Smaller independent operators in the zone are more susceptible to fluctuating market conditions. They may lack sufficient capital to purchase first-quality materials and employ best available operating methods.

Major Issues

Discharge of Produced Water and Drilling Muds into Bays and Estuaries of the Texas Gulf Coast

Texas allows the discharge of produced water into tidally affected estuaries and bays of the Gulf Coast from nearby onshore development. Cases in which permitted discharges have created damage include:

> In Texas, oil and gas producers operating near the Gulf Coast are permitted to discharge produced water into surface streams if they are found to be tidally affected. Along with the produced water, residual production chemicals and organic constituents may be discharged, including lead, zinc, chromium, barium, and water-soluble polycyclic aromatic hydrocarbons (PAHs). PAHs are known to accumulate in sediment, producing liver and lip tumors in catfish and affecting mixed function oxidase systems of mammals, rendering a reduced immune response. In 1984, a study conducted by the U.S. Fish and Wildlife Service of sediment in Tabb's Bay, which receives discharged produced water as well as discharges from upstream industry (i.e., discharges from ships in the Houston Ship Channel), indicates severe degradation of the environment by PAH contamination. Sediment was collected from within 100 yards of several tidal discharge points of oil field produced water. Analytical results of these sediments indicated severe degradation of the environment by PAH contamination. The study noted that sediments contained no benthic fauna, and because of wave action, the contaminants were continuously resuspended, allowing chronic exposure of contaminants to the water column. It is concluded by the U.S. Fish and Wildlife Service that shrimp, crabs, oysters, fish, and fish-eating birds in this location have the potential to be heavily contaminated with PAHs. While these discharges have to be within Texas Water Quality Standards, these standards are for conventional pollutants and do not consider the water soluble components of oil that are in produced water such as PAHs.[50] (TX 55)[51]

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[50] NPDES permits have been applied for, but EPA has not issued permits for these discharges on the Gulf Coast. The Texas Railroad Commission (TRC) issues permits for these discharges. The TRC disagrees with the source of damage in this case.

[51] References for case cited: Letter from U.S. Department of the Interior, Fish and Wildlife Service, signed by H. Dale Hall, to Railroad Commission of Texas, discussing degradation of Tabb's Bay because of discharge of produced water in upstream estuaries; includes lab analysis for polycyclic aromatic hydrocarbons in Tabb's Bay sediment samples. Texas Railroad Commission Proposal for Decision on Petronilla Creek case documenting that something other than produced water is killing aquatic organisms in the creek. (Roy Spears, Texas Parks and Wildlife, did LC50 study on sunfish and sheepshead minnows using produced water and Aranssas Bay water. Produced water diluted to proper salinity caused mortality of 50 percent. (Seawater contains 19,000 ppm chlorides.)

These discharges are not in violation of existing regulations.

Produced water discharges contain a high ratio of calcium ions to magnesium ions. This high ratio of calcium to magnesium has been found by Texas Parks and Wildlife officials to be lethal to common Atlantic croaker, even when total salinity levels are within tolerable limits. In a bioassay study conducted by Texas Parks and Wildlife, this fish was exposed to various ratios of calcium to magnesium, and it was found that in 96-hour LC50 studies, mortality was 50 percent when exposed to calcium-magnesium ratios of 6:1, the natural ratio being 1:3. Nearly all of oil field produced water discharges on file with the Army Corps of Engineers in Galveston contain ratios exceeding the 6:1 ratio, known to cause mortality in Atlantic croaker as established by the LC50 test.[52] (TX 31)[53]

These discharges are not in violation of current regulations.

Until very recently, the Texas Railroad Commission (TRC) allowed discharge of produced water into Petronilla Creek, parts of which are 20 miles inland and not tidally affected.

For over 50 years, oil operators (including Texaco and Amoco) have been allowed to discharge produced water into Petronilla Creek, a supposedly tidally influenced creek. Discharge areas were as much as 20 miles inland and contained fresh water. In 1981, the pollution of Petronilla Creek from discharge of produced water became an issue when studies done by the Texas Parks and Wildlife and Texas Department of Water Resources documented the severe degradation of the water and damage to native fish and vegetation. All freshwater species of fish and vegetation were dead because of exposure to toxic constituents in discharge liquid. Portions of the creek were black or bright orange in color. Heavy oil slicks and oily slime were observable along discharge areas.

Impacts were observed in Baffin Bay, into which the creek empties. Petronilla Creek is the only freshwater source for Baffin Bay, which is a nursery for many fish and shellfish in the Gulf of Mexico. Sediments in Baffin Bay show elevated levels of toxic constituents found in Petronilla Creek. For 5 years, the Texas Department of Water Resources and Texas Parks and Wildlife, along with environmental groups, worked to have the discharges stopped. In 1981, a hearing was held by the Texas Railroad Commission (TRC). The conclusion of the hearing was that discharge of the produced water plus disposal of other trash by the public was degrading Petronilla Creek. The TRC initiated a joint committee (Texas Department of Water Resources, Texas Parks and Wildlife Department, and TRC) to establish the source of the trash, clean up

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[52] API comments in the Docket pertain to TX 31. API states that models show that "...rapid mixing in Bay waters results in no pollution to Bay waters as a whole from calcium ions or from the calcium-magnesium ratio."

[53] References for case cited: Toxic Effects of Calcium on the Atlantic Croaker: An Investigation of One Component of Oil Field Brine, by Kenneth N. Knudson and Charles E. Belaire, undated.

> trash from the creek, and conduct additional studies. After this work was completed, a second hearing was held in 1984. The creek was shown to contain high levels of chromium, barium, oil, grease, and EPA priority pollutants naphthalene and benzene. Oil operators stated that a no dumping order would put them out of business because oil production in this area is marginal. In 1986, the TRC ordered a halt to discharge of produced water into nontidal portions of Petronilla Creek. (TX 29)[54]

Although discharges are now prohibited in this creek, they are allowed in other tidally affected areas.

Long-term environmental impacts associated with this type of discharge are unknown, because of limited documentation and analysis. Bioaccumulation of heavy metals in the food chain of estuaries could potentially affect human health through consumption of crabs, clams, and other foods harvested off the Texas Gulf Coast.

Alternatives to coastal discharge do exist. They include underground injection of produced water and use of produced water tanks. While the Texas Railroad Commission has not stopped the practice of coastal discharge, it is currently evaluating the need to preclude this type of discharge by collecting data from new applications, and it is seeking delegation of the NPDES program under the Federal Clean Water Act. The TRC currently asks applicants for tidal discharge permits to analyze the produced water to be discharged for approximately 20 to 25 constituents.

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[54] References for case cited: The Effects of Brine Water Discharges on Petronilla Creek, Texas Parks and Wildlife Department, 1981. Texas Department of Water Resources interoffice memorandum documenting spills in Petronilla Creek from 1980 to 1983. The Influence of Oilfield Brine Water Discharges on Chemical and Biological Conditions in Petronilla Creek, by Frank Shipley, Texas Department of Water Resources, 1984. Letter from Dick Whittington, EPA, to Richard Lowerre, documenting absence of NPDES permits for discharge to Petronilla Creek. Final Order of TRC, banning discharge of produced water to Petronilla Creek, 6/23/86. Numerous letters, articles, legal documents, on Petronilla Creek case.

Leaching of Reserve Pit Constituents into Ground Water

Leaching of reserve pit constituents into ground water and soil is a problem in the Texas/Oklahoma zone. Reserve pit liners are generally not required in Texas and Oklahoma. When pits are constructed in permeable soil without liners, a higher potential exists for migration of reserve pit constituents into ground water and soil. Although pollutant migration may not always occur during the active life of the reserve pit, problems can occur after closure when dewatered drilling mud begins to leach into the surrounding soil. Pollutants may include chlorides, sodium, barium, chromium, and arsenic.

> On November 20, 1981, the Michigan-Wisconsin Pipe Line Company began drilling an oil and gas well on the property of Ralph and Judy Walker. Drilling was completed on March 27, 1982. Unlined reserve pits were used at the drill site. After 2 months of drilling, the water well used by the Walkers became polluted with elevated levels of chloride and barium (683 ppm and 1,750 ppb, respectively). The Walkers were forced to haul fresh water from Elk City for household use. The Walkers filed a complaint with the Oklahoma Corporation Commission (OCC), and an investigation was conducted. The Michigan-Wisconsin Pipe Line Co. was ordered to remove all drilling mud from the reserve pit.
>
> In the end, the Walkers retained a private attorney and sued Michigan-Wisconsin for damages sustained because of migration of reserve pit fluids into the freshwater aquifer from which they drew their domestic water supply. The Walkers won their case and received an award of $50,000.[55] (OK 08)[56]

Constructing a reserve pit over a fractured shale, as in this case, is a violation of OCC rules.

> In 1973, Horizon Oil and Gas drilled an oil well on the property of Dorothy Moore. As was the common practice, the reserve pit was dewatered, and the remaining mud was buried on site. In 1985-86, problems from the buried reserve pit waste began to appear. The reserve pit contents

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[55] API states that the Oklahoma Corporation Commission is in the process of developing regulations to prevent leaching of salt muds into ground water.

[56] References for case cited: Pretrial Order, Ralph Gail Walker and Judy Walker vs. Michigan-Wisconsin Pipe Line Company and Big Chief Drilling Company, U.S. District Court, Western District of Oklahoma, #CIV-82-1726-R. Direct Examination of Stephen G. McLin, Ph. D. Direct Examination of Robert Hall. Direct Examination of Laurence Alatshuler, M. D. Lab results from Walker water well.

> were seeping into a nearby creek and pond. The surrounding soil had very high chloride content as established by Dr. Billy Tucker, an agronomist and soil scientist. Extensive erosion around the reserve pit became evident, a common problem with high-salinity soil. Oil slicks were visible in the adjacent creek and pond. An irrigation well on the property was tested by Dr. Tucker and was found to have 3000 ppm chlorides; however, no monitoring wells had been drilled to test the ground water prior to the drilling of the oil well, and background levels of chlorides were not established. Dorothy Moore has filed civil suit against the operator for damages sustained during the oil and gas drilling activity. The case is pending.[57] (OK 02)[58]

Oklahoma performance standards prohibit leakage of reserve pits into ground water.

Chloride Contamination of Ground Water from Operation of Injection Wells

The Texas/Oklahoma zone contains a large number of injection wells used both for disposal of produced water and for enhanced or tertiary recovery projects. This large number of injection wells increases the potential for injection well casing leaks and the possibility of ground water contamination.

> The Devore #1, a saltwater injection well located on the property of Verl and Virginia Hentges, was drilled in 1947 as an exploratory well. Shortly afterwards, it was permitted by the Oklahoma Corporation Commission (OCC) as a saltwater injection well. The injection formation, the Layton, was known to be capable of accepting 80 barrels per hour at 150 psi. In 1984, George Kahn acquired the well and the OCC granted an exception to Rule 3-305, Operating Requirements for Enhanced Recovery Injection and Disposal Wells, and permitted the well to inject 2,000 barrels per day at 400 psi. Later in 1984, it appeared that there was saltwater migration from the intended injection zone of the Devore #1 to the surface.[59] The Hentges alleged that the migrating salt water had polluted the ground water used on their ranch.

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[57] API comments in the Docket pertain to OK 02. API states that "...there is no evidence that there has been any seepage whatsoever into surface water." API states that there are no irrigation wells on Mrs. Moore's farm. Further, it states that erosion has been occurring for years and is the "...result of natural conditions coupled with the failure of Mrs. Moore to repair terraces to prevent or limit such erosion." API has not provided supporting documentation.

[58] References for case cited: Extensive soil and water analysis results collected and interpreted by Dr. Billy Tucker, agronomist and soil scientist, Stillwater, Okla. Correspondence and conversation with Randall Wood, private attorney, Stack and Barnes, Oklahoma City, Okla.

[59] Comments by API in the Docket pertain to OK 06. API states that "...tests on the well pressure test and tracer logs indicate the injection well is not a source of salt water." API has not provided documentation with this statement.

> In addition, they alleged that the migrating salt water was finding its way to the surface and polluting Warren Creek, a freshwater stream used by downstream residents for domestic water. Salt water discharged to the surface had contaminated the soil and had caused vegetation kills. A report by the OCC concluded that "...the Devore #1 salt water disposal well operations are responsible for the contaminant plume in the adjacent alluvium and streams." The OCC required that a workover be done on the well. The workover was completed, and the operator continued to dispose of salt water in the well. The Hentges then sought private legal assistance and filed a lawsuit against George Kahn, the operator, for $300,000 in actual damages and $3,000,000 in punitive damages. The lawsuit is pending, scheduled for trial in October 1987.[60] (OK 06)[61]

Although at the time, the OCC permitted injection into the well at pressures that may have polluted the ground water, Oklahoma prohibits any contamination of drinking-water aquifers.

Illegal Disposal of Oil and Gas Wastes

Illegal disposal of oil and gas exploration and production wastes is a common problem in the Texas/Oklahoma zone. Illegal disposal can take many forms, including breaching of reserve pits, emptying of vacuum trucks into fields and ditches, and draining of produced water onto the land surface. Damage to surface soil, vegetation, and surface water may result as illustrated by the examples below.

> On May 16, 1984, Esenjay Petroleum Co. had completed the L.W. Bing #1 well at a depth of 9,900 feet and had hired T&L Lease Service to clean up the drill site. During cleanup, the reserve pit, containing high-chromium drilling mud, was breached by T&L Lease Service, allowing drilling mud to flow into a tributary of Hardy Sandy Creek. The drilling mud was up to 24 inches deep along the north bank of Hardy Sandy. Drilling mud had been pushed into the trees and brush adjacent to the drill site. The spill was reported to the operator and the Texas Railroad Commission (TRC). The TRC ordered cleanup, which began on May 20.

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[60] API states that the operator now believes old abandoned saltwater pits to be the source of contamination as the well now passes UIC tests.

[61] References for case cited: Remedial Action Plan for Aquifer Restoration within Section #2, Township 21 North, Range 2 West, Noble County, Oklahoma, by Stephen G. McLin, Ph. D. Surface Pollution at the De Vore #1 Saltwater Disposal Site, Oklahoma Corporation Commission, 1986. District Court of Noble County, Amended Petition, Verl E. Hentges and Virginia L. Hentges vs. George Kahn, #C-84-110, 7/25/85. Lab analysis records of De Vore well from Oklahoma Corporation Commission and Southwell Labs. Communication with Alan DeVore, plaintiffs' attorney.

Because of high levels of chromium contained in the drilling mud, warnings were issued by the Lavaca-Navidad River Authority to residents and landowners downstream of the spill as it represented a possible health hazard to cattle watering from the affected streams. The River Authority also advised against eating the fish from the affected waters because of the high chromium levels in the drilling mud. (TX 21)[62]

This discharge was a violation of State and Federal regulations.

On September 15, 1983, TXO Production Company began drilling its Dunn Lease Well No. B2 in Live Oak County. On October 5, 1983, employees of TXO broke the reserve pit levee and began spreading drilling mud downhill from the site, towards the fence line of property owned by the Dunns. By October 9, the mud had entered the draw that flows into two stock tanks on the Dunn property. On November 24 and 25, dead fish were observed in the stock tank. On December 17, Texas Parks and Wildlife documented over 700 fish killed in the stock tanks on the Dunn property. Despite repeated requests by the Dunns, TXO did not clean up the drilling mud and polluted water from the Dunn property.

Lab results from TRC and Texas Department of Health indicated that the spilled drilling mud was high in levels of arsenic, barium, chromium, lead, sulfates, other metals, and chlorides. In February 1984, the TRC stated that the stock tanks contained unacceptable levels of nitrogen, barium, chromium, and iron, and that the chemicals present were detrimental to both fish and livestock. (The Dunns water their cows at this same stock tank.) After further analysis, the TRC issued a memorandum stating that the fish had died because of a cold front moving through the area, in spite of the fact that the soil, sediment, and water in and around the stock pond contained harmful substances. Ultimately, TXO was fined $1,000 by the TRC, and TXO paid the Dunns a cash settlement for damages sustained.[63] (TX 22)[64]

This activity was in violation of Texas regulations.

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[62] References for case cited: Memorandum from Lavaca-Navidad River Authority documenting events of Esenjay reserve pit discharge, 6/27/84, signed by J. Henry Neason. Letter to TRC from Lavaca-Navidad River Authority thanking the TRC for taking action on the Esenjay case, "Thanks to your enforcement actions, we are slowly educating the operators in this area on how to work within the law." Agreed Order, Texas Railroad Commission, #2-83,043, 11/12/84, fining Esenjay $10,000 for deliberate discharge of drilling muds. Letter from U.S. EPA to TRC inviting TRC to attend meeting with Esenjay Petroleum to discuss discharge of reserve pit into Hardy Sandy Creek, 6/1/84, signed by Thomas G. Giesberg. Texas Railroad Commission spill report on Esenjay operations, 5/18/84.

[63] API states that the fish died from oxygen depletion of the water. The Texas Railroad Commission believes that the fish died from exposure to cold weather.

[64] References for case cited: Texas Railroad Commission Motion to Expand Scope of Hearing, #2-82,919, 6/29/84. Texas Railroad Commission Agreed Order, #2-82,919, 12/17/84. Analysis by Texas Veterinary Medical Diagnostic Laboratory System on dead fish in Dunn stock tank. Water and soil sample analysis from the Texas Railroad Commission. Water and soil samples from the Texas Department of Health. Letter from Wendell Taylor, TRC, to Jerry Mullican, TRC, stating that the fish kill was the result of cold weather, 7/13/84. Miscellaneous letters and memos.

NORTHERN MOUNTAIN

The Northern zone includes Idaho, Montana, and Wyoming. Idaho has no commercial production of oil or gas. Montana has moderate oil and gas production. Wyoming has substantial oil and gas production and accounts for all the damage cases discussed in this section.

Operations

Significant volumes of both oil and gas are produced in Wyoming. Activities range from small, marginal operations to major capital- and energy-intensive projects. Oil production comes both from mature fields producing high volumes of produced water and from newly discovered fields, where oil/water ratios are still relatively low. Gas production comes from mature fields as well as from very large new discoveries.

Although the average new well drilled in Wyoming in 1985 was about 7,150 feet, exploration in the State can be into strata as deep as 25,000 feet. In 1985, 1,332 new wells were completed in Wyoming, of which 541 were exploratory.

Types of Operators

Because of the capital-intensive nature of secondary and tertiary recovery projects and large-scale drilling projects, many operations in the State are conducted by the major oil companies. These companies are likely to implement environmental controls properly during drilling and completion and are generally responsible in carrying out their well abandonment obligations. Independents also operate in Wyoming, producing a significant amount of oil and gas in the State. Independent operators may be more vulnerable to fluctuating market conditions and may be more likely to maintain profitability at the expense of environmental protection.

Major Issues

Illegal Disposal of Oil and Gas Wastes

Wyoming Department of Environmental Quality officials believe that illegal disposal of wastes is the most pervasive environmental problem associated with oil and gas operations in Wyoming. Enforcement of State regulations is made difficult as resources are scarce and areas to be patrolled are large and remote. (See Table VII-7.)

> Altex Oil Company and its predecessors have operated an oil production field for several decades south of Rozet, Wyoming. (Altex purchased the property in 1984.) An access road runs through the area, which, according to Wyoming Department of Environmental Quality (WDEQ), for years was used as a drainage for produced water from the oil field operations.
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> In August of 1985, an official with WDEQ collected soil samples from the road ditch to ascertain chloride levels because it had been observed that trees and vegetation along the road were dead or dying. WDEQ analysis of the samples showed chloride levels as high as 130,000 ppm. The road was chained off in October of 1985 to preclude any further illegal disposal of produced water.[65] (WY 03)[66]
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> In early October 1985, Cities Service Oil Company had completed drilling at a site northeast of Cheyenne on Highway 85. The drilling contractor, Z&S Oil Construction Company, was suspected of illegally disposing of drilling fluids at a site over a mile away on the Pole Creek Ranch. An employee of Z&S had given an anonymous tip to a County detective. A stake-out of the

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[65] Comments in the Docket from the Wyoming Oil and Gas Conservation Commission (WOGCC) (Mr. Don Basko) pertain to WY 03. WOGCC states that "...not all water from Altex Oil producing wells... caused the contamination problem." Further, WOGCC states that "Illegal dumping, as well as a flow line break the previous winter, had caused a high level of chloride in the soil which probably contributed to the sagebrush and cottonwood trees dying."

[66] References for case cited: Analysis of site by the Wyoming Department of Environmental Quality (WDEQ), Quality Division Laboratory, File #ej52179, 12/6/85. Photographs of dead and dying cottonwood trees and sagebrush in and around site. Conversation with WDEQ officials.

illegal operation was made with law enforcement and WDEQ personnel. Stake-out personnel took samples and photos of the reserve pit and the dump site. During the stake-out, vacuum trucks were witnessed draining reserve pit contents down a slope and into a small pond on the Pole Creek Ranch. After sufficient evidence had been gathered, arrests were made by Wyoming law enforcement personnel, and the trucks were impounded. The State sued Z&S and won a total of $10,000. (WY 01)[67]

This activity was in violation of Wyoming regulations.

During the week of April 8, 1985, field personnel at the Byron/Garland field operated by Marathon Oil Company were cleaning up a storage yard used to store drums of oil field chemicals. Drums containing discarded production chemicals were punctured by the field employees and allowed to drain into a ditch adjacent to the yard. Approximately 200 drums containing 420 gallons of fluid were drained into the trench. The chemicals were demulsifiers, reverse demulsifiers, scale and corrosion inhibitors, and surfactants. Broken transformers containing PCBs were leaking into soil in a nearby area. Upon discovery of the condition of the yard, Wyoming Department of Environmental Quality (WDEQ) ordered Marathon to begin cleanup procedures. At the request of the WDEQ, ground-water monitors were installed, and monitoring of nearby Arnoldus Lake was begun. The State filed a civil suit against Marathon and won a $5000 fine and $3006 in expenses for lab work.[68] (WY 05)[69]

This activity was in direct violation of Wyoming regulations.

Reclamation Problems

Although Wyoming's mining industry has rules governing reclamation of sites, no such rules exist covering oil and gas operations. As a result, reclamation on privately owned land is often inadequate or entirely lacking, according to WDEQ officials. By contrast, reclamation on Federal lands is believed to be consistently more thorough, since Federal

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[67] References for case cited: WDEQ memorandum documenting chronology of events leading to arrest of Z&S employees and owners. Lab analysis of reserve pit mud and effluent, and mud and effluent found at dump site. Consent decree from District Court of First Judicial District, Laramie County, Wyoming, docket #108-493, The People of the State of Wyoming vs. Z&S Construction Company. Photographs of vacuum trucks dumping at Pole Creek Ranch.

[68] API states that the operator, thinking the drums had to be empty before transport offsite, turned the drums upside down and drained 420 gallons of chemicals into the trench.

[69] References for case cited: Summary of Byron-Garland case by Marathon employee J. C. Fowler. List of drums, contents, and field uses. Cross-section of disposal trench area. Several sets of lab analyses. Map of Garland field disposal yard. Newspaper articles on incident. District court consent decree, The People of the State of Wyoming vs. Marathon Oil Company, #108-87.

leases specify reclamation procedures to be used on specific sites. WDEQ officials state that this will be of growing concern as the State continues to be opened up to oil and gas development.[70]

WDEQ officials have photographs and letters from concerned landowners, regarding reclamation problems, but no developed cases. The Wyoming Oil and Gas Conservation Commission submitted photographs documenting comparable reclamation on both Federal and private lands. The issue is at least partially related to drilling waste management, since improper reclamation of sites often involves inadequate dewatering of reserve pits before closure. As a result of this inadequate dewatering, reserve pit constituents, usually chlorides, are alleged to migrate up and out of the pit, making revegetation difficult. The potential also exists for migration of reserve pit constituents into ground water.

Discharge of Produced Water into Surface Streams

Because much of the produced water in Wyoming is relatively low in chlorides, several operations under the beneficial use provision of the Federal NPDES permit program are allowed to discharge produced water directly into dry stream beds or live streams. The practice of chronic discharge of low-level pollutants may be harmful to aquatic communities in these streams, since residual hydrocarbons contained in produced water appear to suppress species diversity in live streams.

> A study was undertaken by the Columbia National Fisheries Research Laboratory of the U. S. Fish and Wildlife Service to determine the effect of continuous discharge of low-level oil effluent into a stream and the resulting effect on the aquatic community in the stream. The discharges to the stream contained 5.6 mg/L total hydrocarbons. Total hydrocarbons in the receiving sediment were 979 mg/L to 2,515 mg/L. During the study, samples were taken upstream

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[70] WOGCC disagrees with WDEQ on this statement.

> and downstream from the discharge. Species diversity and community structure were studied. Water analysis was done on upstream and downstream samples. The study found a decrease in species diversity of the macrobenthos community (fish) downstream from the discharge, further characterized by total elimination of some species and drastic alteration of community structure. The study found that the downstream community was characterized by only one dominant species, while the upstream community was dominated by three species. Total hydrocarbon concentrations in water and sediment increased 40 to 55 fold downstream from the discharge of produced water. The authors of the study stated that "...based on our findings, the fisheries and aquatic resources would be protected if discharge of oil into fresh water were regulated to prevent concentrations in receiving streams water and sediment that would alter structure of macrobenthos communities." (WY 07)[71]

These discharges are permitted under NPDES.

SOUTHERN MOUNTAIN

The Southern Mountain zone includes the States of Nevada, Utah, Arizona, Colorado, and New Mexico. All five States have some oil and gas production, but New Mexico's is the most significant. The discussion below is limited to New Mexico.

Operations

Although hydrocarbon production is scattered throughout New Mexico, most comes from two distinct areas within the State: the Permian Basin in the southeast corner and the San Juan Basin in the northwest corner.

Permian Basin production is primarily oil, and it is derived from several major fields. Numerous large capital- and energy-intensive enhanced recovery projects within the basin make extensive use of CO_2 flooding. The area also contains some small fields in which production

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[71] References for case cited: Petroleum Hydrocarbon Concentrations in a Salmonid Stream Contaminated by Oil Field Discharge Water and Effects on the Macrobenthos Community, by D.F. Woodward and R.G. Riley, U.S. Department of the Interior, Fish and Wildlife Service, Columbia National Fisheries Research Laboratory, Jackson, Wyoming, 1980; submitted to Transactions of the American Fisheries Society.

is derived from marginal stripper operations. This is a mature production area that is unlikely to see extensive exploration in the future. The Tucumcari Basin to the north of the Permian may, however, experience extensive future exploration if economic conditions are favorable.

The San Juan Basin is, for the most part, a large, mature field that produces primarily gas. Significant gas finds are still made, including many on Indian Reservation lands. As Indian lands are gradually opened to oil and gas development, exploration and development of the basin as a whole will continue and possibly increase.

Much of the State has yet to be explored for oil and gas. The average depth of new wells drilled in 1985 was 6,026 feet. The number of new wells drilled in 1985 was 1,734, of which 281 were exploratory.

Types of Operators

The capital- and energy-intensive enhanced recovery projects in the Permian Basin, as well as the exploratory activities under way around the State, are conducted by the major oil companies. Overall, however, the most numerous operators are small and medium-sized independents. Small independents dominate marginal stripper production in the Permian Basin. Production in the San Juan Basin is dominated by midsize independent operators.

Major Issues

Produced Water Pit and Oil Field Waste Pit Contents Leaching into Ground Water

New Mexico, unlike most other States, still permits the use of unlined pits for disposal of produced water. This practice has the potential for contamination of ground water.

> In July 1985, a study was undertaken in the Duncan Oil Field in the San Juan Basin by faculty members in the Department of Chemistry at New Mexico State University, to analyze the potential for unlined produced water pit contents, including hydrocarbons and aromatic hydrocarbons, to migrate into the ground water. The oil field is situated in a flood plain of the San Juan River. The site chosen for investigation by the study group was similar to at least 1,500 other nearby production sites in the flood plain. The study group dug test pits around the disposal pit on the chosen site. These test pits were placed abovegradient and downgradient of the disposal pit, at 25- and 50-meter intervals. A total of 9 test pits were dug to a depth of 2 meters, and soil and ground-water samples were obtained from each test pit. Upon analysis, the study group found volatile aromatic hydrocarbons were present in both the soil and water samples of test pits downgradient, demonstrating migration of unlined produced water pit contents into the ground water.
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> Environmental impact was summarized by the study group as contamination of shallow ground water with produced water pit contents due to leaching from an unlined produced water disposal pit. Benzene was found in concentrations of 0.10 ppb. New Mexico Water Quality Control Commission standard is 10 ppb. Concentrations of ethylbenzene, xylenes, and larger hydrocarbon molecules were found. No contamination was found in test pits placed abovegradient from the disposal pit. Physical signs of contamination were also present, downgradient from the disposal pit, including black, oily staining of sands above the water table and black, oily film on the water itself. Hydrocarbon odor was also present. (NM 02)[72]

It is now illegal to dispose of more than five barrels per day of produced water into unlined pits in this part of New Mexico.

As a result of this study, the use of unlined produced water pits was limited by the State to wells producing no more than five barrels per day of produced water. While this is a more stringent requirement than the previous rule, the potential for contamination of ground water with hydrocarbons and chlorides still exists. It is estimated by individuals familiar with the industry in the State that 20,000 unlined emergency

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[72] References for case cited: Hydrocarbons and Aromatic Hydrocarbons in Groundwater Surrounding an Earthen Waste Disposal Pit for Produced Water in the Duncan Oil Field of New Mexico, by G.A. Eiceman, J.T. McConnon, Masud Zaman, Chris Shuey, and Douglas Earp, 9/16/85. Polycyclic Aromatic Hydrocarbons in Soil at Groundwater Level Near an Earthen Pit for Produced Water in the Duncan Oil Field, by B. Davani, K. Lindley, and G.A. Eiceman, 1986. New Mexico Oil Conservation Commission hearing to define vulnerable aquifers, comments on the hearing record by Intervenor Chris Shuey, Case No. 8224.

produced water disposal pits are still in existence in the San Juan Basin area of New Mexico.[73]

New Mexico has experienced problems that may be due to centralized oil field waste disposal facilities:

> Lee Acres "modified" landfill (meaning refuse is covered weekly instead of daily as is done in a "sanitary" landfill) is located 4.5 miles E-SE of Farmington, New Mexico. It is owned by the U.S. Bureau of Land Management (BLM). The landfill is approximately 60 acres in size and includes four unlined liquid-waste lagoons or pits, three of which were actively used. Since 1981, a variety of liquid wastes associated with the oil and gas industry have been disposed of in the lagoons. The predominant portion of liquid wastes disposed of in the lagoons was produced water, which is known to contain aromatic volatile organic compounds (VOCs). According to the New Mexico Department of Health and Environment, Environmental Improvement Division, 75 to 90 percent of the produced water disposed of in the lagoons originated from Federal and Indian oil and gas leases managed by BLM. Water produced on these leases was hauled from as far away as Nageezi, which is 40 miles from the Lee Acres site. Disposal of produced water in these unlined pits was, according to New Mexico State officials, in direct violation of BLM's rule NTL-2B, which prohibits, without prior approval, disposal of produced waters into unlined pits, originating on Federally owned leases. The Department of the Interior states that disposal in the lagoons was "...specifically authorized by the State of New Mexico for disposal of produced water." The State of New Mexico states that "There is no truth whatsoever to the assertion that the landfill lagoons were specifically authorized by the State of New Mexico for disposal of produced water." Use of the pits ceased on 4/19/85; 8,800 cubic yards of waste were disposed of prior to closure.
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> New Mexico's Environmental Improvement Division (NMEID) asserts that leachate from the unlined waste lagoons that contain oil and gas wastes has contributed to the contamination of several water wells in the Lee Acres housing subdivision located downgradient from the lagoons and downgradient from a refinery operated by Giant, located nearby. NMEID has on file a soil gas survey that documents extensive contamination with chlorinated VOCs at the landfill site. High levels of sodium, chlorides, lead, chromium, benzene, toluene, xylenes, chloroethane, and trichloroethylene were found in the waste lagoons. An electromagnetic terrain survey of the Lee Acres landfill site and surrounding area, conducted by NMEID, located a plume of contaminated ground water extending from the landfill. This plume runs into a plume of contamination known to exist, emanating from the refinery. The plumes have become mixed and are the source of

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[73] Governor Carruthers refutes this and states that "Unlined pits in fresh water areas in Southeast New Mexico were banned beginning in 1956, with a general prohibition adopted in 1967." EPA notes that New Mexico still permits unlined pits to be used for disposal of produced water if the pit does not receive more than five barrels of produced water per day.

contamination of the ground water serving the Lee Acres housing subdivision.[74] One domestic well was sampled extensively by NMEID and was found to contain extremely high levels of chlorides and elevated levels of chlorinated VOCs, including trichloroethane. (Department of the Interior (DOI) states that it is unaware of any violations of New Mexico ground-water standards involved in this case. New Mexico states that State ground-water standards for chloride, total dissolved solids, benzene, xylenes, 1,1-dichloroethane, and ethylene dichloride have been violated as a result of the plume of contamination. In addition, the EPA Safe Drinking Water Standard for trichloroethylene has been violated.) New Mexico State officials state that "The landfill appears to be the principal source of chloride, total dissolved solids and most chlorinated VOCs, while the refinery appears to be the principal source of aromatic VOCs and ethylene dichloride."

During the period after disposal operations ceased and before the site was closed, access to the lagoons was essentially unrestricted. While NMEID believes that it is possible that non-oil and gas wastes illegally disposed of during this period may have contributed to the documented contamination, the primary source of ground-water contamination appears to be from oil and gas wastes.

The State has ordered BLM to provide public water to residents affected by the contamination, develop a ground-water monitoring system, and investigate the types of drilling, drilling procedures, and well construction methods that generated the waste accepted by the landfill. BLM submitted a motion-to-stay the order so as to include Giant Refining Company and El Paso Natural Gas in cleanup operations. The motion was denied. The case went into litigation. According to State officials, "The State of New Mexico agreed to dismiss its lawsuit only after the Bureau of Land Management agreed to conduct a somewhat detailed hydrogeologic investigation in a reasonably expeditious period of time. The lawsuit was not dismissed because of lack of evidence of contamination emanating from the landfill." The refinery company has completed an

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[74] In a letter dated 8/20/87, Giant Refining Company states that "Benzene, toluene and xylenes are naturally occurring compounds in crude oil, and are consequently in high concentrations in the produced water associated with that crude oil. The only gasoline additive used by Giant that has been found in the water of a residential well is DCA (ethylene dichloride) which has also been found in the landfill plume." Giant also notes that the refinery leaks in the last 2 years resulted in less than 30,000 gallons of diesel being released rather than the 100,000 gallons stated by the Department of Interior in a letter to EPA of 8/11/87.

extensive hydrogeologic investigation and has implemented containment and cleanup measures.[75] (NM 05)[76]

Current New Mexico regulations prohibit use of unlined commercial disposal pits.

Damage to Ground Water from Inadequately Maintained Injection Wells

As in other States, New Mexico has experienced problems with injection wells.

A saltwater injection well, the BO-3, operated by Texaco, is used for produced water disposal for the Moore-Devonian oil field in southeastern New Mexico. Injection occurs at about 10,000 ft. The Ogallala aquifer, overlying the oil production formation, is the sole source of potable ground water in much of southeastern New Mexico. Dr. Daniel B. Stephens, Associate Professor of Hydrology at the New Mexico Institute of Mining and Technology, concluded that injection well BO-3 has contributed to a saltwater plume of contamination in the Ogallala aquifer. The plume is nearly 1 mile long and contains chloride concentrations of up to 26,000 ppm.

A local rancher sustained damage to crops after irrigating with water contaminated by this saltwater plume. In 1973, an irrigation well was completed satisfactorily on the ranch of Mr. Paul Hamilton, and, in 1977, the well began producing water with chlorides of 1,200 ppm. Mr. Hamilton's crops were severely damaged, resulting in heavy economic losses, and his farm property was foreclosed on. There is no evidence of crop damage from irrigation prior to 1977. Mr. Hamilton initiated a private law suit against Texaco for damages sustained to his ranch. Texaco argued that the saltwater plume was the result of leachate of brines from unlined brine disposal pits, now banned in the area. Dr. Stephens proved that if old pits in the vicinity,

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[75] Comments in the Docket from BLM and the State of New Mexico pertain to NM 05. BLM states that the refinery upgradient from the subdivision is responsible for the contamination because of their "...extremely sloppy housekeeping practices..." which resulted in the loss of "...hundreds of thousands of gallons of refined product through leaks in their underground piping system." The Department of the Interior states that "There is, in fact, mounting evidence that the landfill and lagoons may have contributed little to the residential well contamination in the subdivisions." DOI states "...we strongly recommend that this case be deleted from the Damage Cases [Report to Congress]." "New Mexico states that "EID [Environmental Improvement Division] strongly believes that the Lee Acres Landfill has caused serious ground water contamination and is well worth inclusion in the Oil and Gas Damage Cases chapter of your [EPA] Report to Congress on Oil, Gas and Geothermal Wastes."

[76] References for case cited: State of New Mexico Administrative Order No. 1005; contains water analysis for open pits, monitor wells, and impacted domestic wells. Motion-to-stay Order No. 1005. Denial of motion to stay. Newspaper articles. Southwest Research and Information Center, Response to Hearing before Water Quality Control Commission, 12/2/86. Letter to Dan Derkics, EPA, from Department of the Interior, refuting Lee Acres damage case, 8/11/87. Letter to Dan Derkics, EPA, from NMEID, refuting Department of the Interior letter of 8/11/87, dated 8/18/87. Letter to Dan Derkics, EPA, from Giant Refining Company, 8/20/87.

previously used for saltwater disposal, had caused the contamination, high chloride levels would have been detected in the irrigation well prior to 1977. Dr. Stephens also demonstrated that the BO-3 injection well had leaked some 20 million gallons of brine into the fresh ground water, causing chloride contamination of the Ogallala aquifer from which Mr. Hamilton drew his irrigation water. Based on this evidence a jury awarded Mr. Hamilton a cash settlement from Texaco for damages sustained both by the leaking injection well and by the abandoned disposal pits. The well has had workovers and additional pressure tests since 1978. The well is still in operation, in compliance with UIC regulations. (NM 01)[77]

Current UIC regulations require mechanical integrity testing every 5 years for all Class II wells.

The well in the above case was tested for mechanical integrity several times during the course of the trial, during which the plaintiff's hydrologist, after contacting the Texas Railroad Commission, discovered that this injection well would have been classed as a failed well using criteria established by the State of Texas for such tests. However, at the time, the well did not fail the test using criteria established by the State of New Mexico. Both States have primacy under the UIC program.

WEST COAST

The West Coast zone includes Washington, Oregon, and California. Of the three states, California has the most significant hydrocarbon production; Washington and Oregon have only minor oil and gas activity. Damage cases were collected only in California.

Operations

California has a diverse oil and gas industry, ranging from stripper production in very mature fields to deep exploration and large enhanced recovery operations. Southern California and the San Joaquin Valley are dominated by large capital- and energy-intensive enhanced recovery

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[77] References for case cited: Oil-Field Brine Contamination - A Case Study, Lea Co. New Mexico, from Selected Papers on Water Quality and Pollution in New Mexico - 1984; proceedings of a symposium, New Mexico Bureau of Mines and Resources.

projects, while the coastal fields are experiencing active exploration. California's most mature production areas are in the lower San Joaquin Valley and the Sacramento Basin. The San Joaquin produces both oil and gas. The Sacramento Valley produces mostly gas.

The average depth of new wells drilled in California in 1985 was 4,176 feet. Some 3,413 new wells were completed in 1985, 166 of which were exploratory.

Types of Operators

Operators in California range from small independents to major producers. The majors dominate capital- and energy-intensive projects, such as coastal development and large enhanced recovery projects. Independents tend to operate in the mature production areas dominated by stripper production.

Major Issues

Discharge of Produced Water and Oily Wastes to Ephemeral Streams

In the San Joaquin Valley, the State has long allowed discharge of oily high-chloride produced water to ephemeral streams. After discharge to ephemeral streams, the produced water is diverted into central sumps for disposal through evaporation and percolation. Infiltration of produced water into aquifers is assumed to occur, but official opinion on its potential for damage is divided. Some officials take the position that the aquifers are naturally brackish and thus have no beneficial use for agriculture or human consumption. A report by the Water Resources Control Board, however, suggests that produced water may percolate into useable ground-water structures.

> For the purposes of this study conducted by Bean/Logan Consulting Geologists, ground water in the study area was categorized according to geotype and compared to produced water in sumps that came from production zones. Research was conducted on sumps in Cymric Valley, McKittrick Valley, Midway Valley, Elk Hills, Buena Vista Hills, and Buena Vista Valley production fields. While this recent research was not investigating ground-water damages per se, the study suggests obvious potential for damages relating to the ground water. The hydrogeologic analysis prepared for the California State Water Resources Control Board concludes that about 570,000 tons of salt from produced water were deposited in 1981 and that a total of 14.8 million tons have been deposited since 1900. The California Water Resources Board suspects that a portion of the salt has percolated into the ground water and has degraded it. In addition to suspected degradation of ground water, officers of the California Department of Fish and Game often find birds and animals entrapped in the oily deposits in the affected ephemeral streams. Exposure to the oily deposits often proves to be fatal to these birds and animals.[78] (CA 21)[79]

This is a permitted practice under current California regulations.

Aside from concerns over chronic degradation of ground water, this practice of discharge to ephemeral streams can cause damage to wildlife. The volume of wastes mixed with natural runoff sometimes exceeds the holding capacity of the ephemeral streams. The combined volume may then overflow the diversions to the sump areas and continue downstream, contaminating soil and endangering sensitive wildlife habitat. The oil and gas industry contends that it is rare for any wastes to pass the diversions set up to channel flow to the sumps, but the California Department of Fish and Game believes that it is a common occurrence.

> Produced water from the Crocker Canyon area flows downstream to where it is diverted into Valley Waste Disposal's large unlined evaporation/percolation sumps for oil recovery (cooperatively operated by local oil producers). In one instance, discovery by California Fish and Game officials of a significant spill was made over a month after it occurred. According to the California State Water Quality Board, the incident was probably caused by heavy rainfall, as a consequence of which the volume of rain and waste exceeded the containment capacity of the disposal facility. The sumps became eroded, allowing oily waste to flow down the valley and into a wildlife habitat occupied by several endangered species including blunt-nosed leopard lizards, San Joaquin kit foxes, and giant kangaroo rats.

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[78] API states that the California Regional Water Quality Board and EPA are presently deciding whether to promulgate additional permit requirements under the Clean Water Act and NPDES.

[79] References for case cited: Lower Westside Water Quality Investigation Kern County, and Lower Westside Water Quality Investigation Kern County: Supplementary Report, Bean/Logan Consulting Geologists, 11/83; prepared for California State Water Resources Control Board. Westside Groundwater Study, Michael R. Rector, Inc., 11/83; prepared for Western Oil and Gas Association.

> According to the State's report, there were 116 known wildlife losses including 11 giant kangaroo rats. The count of dead animals was estimated at only 20 percent of the actual number of animals destroyed because of the delay in finding the spill, allowing poisoned animals to leave the area before dying. Vegetation was covered with waste throughout the spill area. The California Department of Fish and Game does not believe this to be an isolated incident. The California Water Resources Control Board, during its investigation of the incident, noted "...deposits of older accumulated oil, thereby indicating that the same channel had been used for wastewater disposal conveyance in the past prior to the recent discharge. Cleanup activities conducted later revealed that buildup of older oil was significant." The companies implicated in this incident were fined $100,000 and were required to clean up the area. The companies denied responsibility for the discharge. (CA 08)[80]

This release was in violation of California regulations.

ALASKA

The Alaska zone includes Alaska and Hawaii. Hawaii has no oil or gas production. Alaska is second only to Texas in oil production.

Operations

Alaska's oil operations are divided into two entirely separate areas, the Kenai Peninsula (including the western shore of Cook Inlet) and the North Slope. Because of the areas' remoteness and harsh climate, operations in both areas are highly capital- and energy-intensive. For the purposes of damage case development, and indeed for most other types of analysis, operations in these two areas are distinct. Types of damages identified in the two areas have little in common.

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[80] References for case cited: Report of Oil Spill in Buena Vista Valley, by Mike Glinzak, California Division of Oil and Gas (DOG), 3/6/86; map of site and photos accompany the report. Letters to Sun Exploration and Production Co. from DOG, 3/12 and 3/31/86. Newspaper articles in Bakersfield Californian, 3/8/86, 3/11/86, and undated. California Water Quality Control Board, Administrative Civil Liability Complaint #ACL-016, 8/8/86. California Water Quality Control Board, internal memoranda, Smith to Pfister concerning cleanup of site, 5/27/86; Smith to Nevins concerning description of damage and investigation, including map, 8/12/86. California Department of Fish and Game, Dead Endangered Species in a California Oil Spill, by Capt. E.A Simons and Lt. M. Akin, undated. Fact Sheets: Buena Vista Creek Oil Spill, Kern County, 3/7/86, and Mammals Occurring on Elk Hills and Buena Vista Hills, undated. Letter from Lt. Akin to EPA contractor, 2/24/87.

Activities on the Kenai Peninsula have been in progress since the late 1950s, and gas is the primary product. Production levels are modest as compared to those on the North Slope.

North Slope operations occur primarily in the Prudhoe Bay area, with some smaller fields located nearby. Oil is the primary product. Production has been under way since the trans-Alaska pipeline was completed in the mid 1970s. Much of the oil recovery in this area is now in the secondary phase, and enhanced recovery through water flooding is on the increase.

There were 100 wells drilled in the State in 1985, all of them on the North Slope. In 1985, one exploratory well was drilled in the National Petroleum Reserve - Alaska (NPRA) and two development wells were drilled on the Kenai Peninsula.

Types of Operators

There are no small, independent oil or gas operators in Alaska because of the high capital requirements for all activities in the region. Operators in the Kenai Peninsula include Union Oil of California and other major companies. Major producers on the North Slope are ARCO and Standard Alaska Production Company.

Major Issues

Reserve Pits, North Slope

Reserve pits on the North Slope are usually unlined and made of permeable native sands and gravels. Very large amounts of water flow in this area during breakup each spring in the phenomenon known as "sheet flow." Some of this water may unavoidably flow into and out of the reserve pits; however, the pits are designed to keep wastes in and keep surface waters out. Discharge of excess liquids from the pits directly onto the tundra is permitted under regulations of the Alaska Department of Environmental Conservation (ADEC) if discharge standards are met. (See summary on State rules and regulations.)

Through the processes of breakup and discharge, ADEC estimates that 100 million gallons of supernatant are pumped onto the tundra and roadways each year,[81] potentially carrying with it reserve pit constituents such as chromium, barium, chlorides, and oil. Scientists who have studied the area believe this has the potential to lead to bioaccumulation of heavy metals and other contaminants in local wildlife, thus affecting the food chain. However, no published studies that demonstrate this possibility exist. Results from preliminary studies suggest that the possibility exists for adverse impact to Arctic wildlife because of discharge of reserve pit supernatant to the tundra:

> In 1983, a study of the effects of reserve pit discharges on water quality and the macroinvertebrate community of tundra ponds was undertaken by the U. S. Fish and Wildlife Service in the Prudhoe Bay oil production area of the North Slope. Discharge to the tundra ponds is a common disposal method for reserve pit fluid in this area. The study shows a clear difference in water quality and biological measures among reserve pits, ponds receiving discharges from reserve pits (receiving ponds), distant ponds affected by discharges through surface water flow, and control ponds not affected by discharges. Ponds directly receiving discharges had significantly greater concentrations of chromium, arsenic, cadmium, nickel, and barium than did control ponds, and distant ponds showed significantly higher levels of chromium than did control ponds. Chromium levels in reserve pits and in ponds adjacent to drill sites may have exceeded EPA chronic toxicity criteria for protection of aquatic life. (AK 06)[82]

These discharges were permitted by the State of Alaska. No NPDES permits have been issued for these discharges. New Alaska regulations have more stringent effluent limits.

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[81] Statement by Larry Dietrick to Carla Greathouse.

[82] References for case cited: The Effects of Prudhoe Bay Reserve Pit Fluids on the Water Quality and Macroinvertebrates of Tundra Ponds, by Robin L. West and Elaine Snyder-Conn, Fairbanks Fish and Wildlife Enhancement Office, U.S. Fish and Wildlife Service, Fairbanks, Alaska, 9/87.

In the summer of 1985, a field method was developed by the U. S. Fish and Wildlife Service to evaluate toxicity of reserve pit fluids discharged into tundra wetlands at Prudhoe Bay, Alaska. Results of the study document acute toxicity effects of reserve pit fluids on Daphnia. Acute toxicity in Daphnia was observed after 96 hours of exposure to liquid in five reserve pits. Daphnia exposed to liquid in receiving ponds also had significantly higher death/immobilization than did Daphnia exposed to liquid in control ponds after 96 hours. At Drill Site 1, after 96 hours, 100 percent of the Daphnia introduced to the reserve pit had been immobilized or were dead, as compared to a control pond which showed less than 5 percent immobilized or dead after 96 hours. At Drill Site 12, 80 percent of the Daphnia exposed to the reserve pit liquid were dead or immobilized after 96 hours and less than 1 percent of Daphnia exposed to the control pond were dead or immobilized.[83] (AK 07)[84]

In June 1985, five drill sites and three control sites were chosen for studying the effects of drilling fluids and their discharge on fish and waterfowl habitat on the North Slope of Alaska. Bioaccumulation analysis was done on fish tissue using water samples collected from the reserve pits. Fecundity and growth were reduced in daphnids exposed for 42 days to liquid composed of 2.5 percent and 25 percent drilling fluid from the selected drill sites. Bioaccumulation of barium, titanium, iron, copper, and molybdenum was documented in fish exposed to drilling fluids for as little as 96 hours. (AK 08)[85]

Erosion of reserve pits and subsequent discharge of reserve pit contents to the tundra constitute another potential environmental problem on the North Slope. If exploration drilling pits are not closed out at the end of a drilling season, they may breach during "breakup." Reserve pit contaminants are then released directly to the tundra. (As described in Chapter III, <u>production</u> reserve pits are different from <u>exploration</u> reserve pits. Production reserve pits are designed to last for as long as 20 years.) A reserve pit wall may be poorly constructed or suffer structural damage during use; the wall may be breached by the hydrostatic head on the walls due to accumulation of precipitation and produced fluids. New exploration reserve pits are generally constructed below-grade. Flow of gravel during a pit breach can choke or cut off tundra streams, severely damaging or eliminating aquatic habitat.

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[83] API comments in the Docket pertain to AK 07. API discusses the relevance of the Daphnia study to the damage cases.

[84] References for case cited: An In Situ Acute Toxicity Test with Daphnia: A Promising Screening Tool for Field Biologists? by Elaine Snyder-Conn, U.S. Fish and Wildlife Service, Fish and Wildlife Enhancement, Fairbanks, Alaska, 1985.

[85] References for case cited: Effects of Oil Drilling Fluids and Their Discharge on Fish and Waterfowl Habitat in Alaska, U.S. Fish and Wildlife Service, Columbia National Fishery Research Laboratory, Jackson Field Station, Jackson, Wyoming, February 1986.

> The Awuna Test Well No. 1, which is 11,200 feet deep, is in the National Petroleum Reserve in Alaska (NPRA) and was a site selected for cleanup of the NPRA by the U.S. Geological Survey (USGS) in 1984. The site is in the northern foothills of the Brooks Range. The well was spud on February 29, 1980, and operations were completed on April 20,1981. A side of the reserve pit berm washed out into the tundra during spring breakup, allowing reserve pit fluid to flow onto the tundra. As documented by the USGS cleanup team, high levels of chromium, oil, and grease have leached into the soil downgradient from the pit. Chromium was found at 2.2 to 3.0 mg/kg dry weight. The high levels of oil and grease may be from the use of Arctic Pack (85 percent diesel fuel) at the well over the winter of 1980. The cleanup team noted that the downslope soils were discolored and putrefied, particularly in the upper layers. The pad is located in a runoff area allowing for erosion of pad and pit into surrounding tundra. A vegetation kill area caused by reserve pit fluid exposure is approximately equal to half an acre. Areas of the drill pad may remain barren for many years because of contamination of soil with salt and hydrocarbons. The well site is in a caribou calving area.[86] (AK 12)[87]

This type of reserve pit construction is no longer permitted under current Alaska regulations.

Waste Disposal on the North Slope

Inspection of oil and gas activities and enforcement of State regulations on the North Slope is difficult, as illustrated by the following case:

> North Slope Salvage, Inc. (NSSI) operated a salvage business in Prudhoe Bay during 1982 and 1983. During this time, NSSI accepted delivery of various discarded materials from oil production companies on the North Slope, including more than 14,000 fifty-five gallon drums, 900 of which were full or held more than residual amounts of oils and chemicals used in the development and recovery of oil. The drums were stockpiled and managed by NSSI in a manner that allowed the discharge of hazardous substances. While the NSSI site may have stored chemicals and wastes from other operations that supported oil and gas exploration and production (e.g., vehicle maintenance materials), such storage would have constituted a very small percentage of NSSI's total inventory.

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[86] API states that exploratory reserve pits must now be closed 1 year after cessation of drilling operations. EPA notes that it is important to distinguish between exploratory and production reserve pits. Production reserve pits are permanent structures that remain open as long as the well or group of wells is producing. This may be as long as 20 years.

[87] References for case cited: Final Wellsite Cleanup on National Petroleum Reserve - Alaska, USGS, July 1986.

The situation was discovered by the Alaska Department of Environmental Conservation (ADEC) in June 1983. At this time, the State of Alaska requested Federal enforcement, but Federal action was never taken. An inadequate cleanup effort was mounted by NSSI after confrontation by ADEC. To preclude further discharges of hazardous substances, ARCO and Sohio paid for the cleanup because they were the primary contributors to the site. Cleanup was completed on August 5, 1983, after 58,000 gallons of chemicals and water were recovered. It is unknown how much of the hazardous substances was carried into the tundra. The discharge consisted of oil and a variety of organic substances known to be toxic, carcinogenic, mutagenic, or suspected of being carcinogenic or mutagenic.[88] (AK 10)[89]

Disposal of Drilling Wastes, Kenai Peninsula

Disposal of drilling wastes is the principal practice leading to potential environmental degradation on the Kenai Peninsula. The following cases involve centralized facilities, both commercial and privately run, for disposal of drilling wastes:

Operators of the Sterling Special Waste Site have had a long history of substandard monitoring, having failed during 1977 and 1978 to carry out any well sampling and otherwise having performed only irregular sampling. This was in violation of ADEC permit requirements to perform quarterly reports of water quality samples from the monitoring wells. An internal ADEC memo (L.G. Elphic to R.T. Williams, 2/25/76) noted "...we must not forget...that this is the State's first sanctioned hazardous waste site and as such must receive close observation during its initial operating period."[90]

A permit for the site was reissued by ADEC in 1979 despite knowledge by ADEC of lack of effective ground-water monitoring. In July of 1980, ADEC Engineer R. Williams visited the site and filed a report noting that the "...operation appears completely out of control." Monitoring well samples were analyzed by ADEC at this time and were found to be in excess of drinking water standards for iron, lead, cadmium, copper, zinc, arsenic, phenol, and oil and grease. One private water well in the vacinity showed 0.4 ppb 1,1,1-trichloroethane. The Sterling School well showed 2.1 g/L mercury. (Subsequent tests show mercury concentration below detection limits--0.001 mg/kg.) Both contamination incidents are alleged to be caused by the Sterling

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[88] Alaska Department of Environmental Conservation (ADEC) states that this case "...is an example of how the oil industry inappropriately considered the limits of the exemption [under RCRA Section 3001]."

[89] References for case cited: Report on the Occurrence, Discovery, and Cleanup of an Oil and Hazardous Substances Discharge at Lease Tract 57, Prudhoe Bay, Alaska, by Jeff Mach - ADEC, 1984. Letter to Dan Derkics, EPA, from Stan Hungerford, ADEC, 8/4/87.

[90] The term "hazardous waste site" as used in this memo does not refer to a "RCRA Subtitle C hazardous waste site."

Special Waste Site. Allegations are unconfirmed by the ADEC. (AK 03)[91]

Practices at the Sterling site were in violation of the permit.

This case involves a 45-acre gravel pit on Poppy Lane on the Kenai Peninsula used since the 1970s for disposal of wastes associated with gas development. The gravel pit contains barrels of unidentified wastes, drilling muds, gas condensate, gas condensate-contaminated peat, abandoned equipment, and soil contaminated with diesel and chemicals. The property belongs to Union Oil Co., which bought it around 1968. Dumping of wastes in this area is illegal; reports of last observed dumping were in October 1985, as witnessed by residents in the area. In this case, there has been demonstrated contamination of adjacent water wells with organic compounds related to gas condensate (ADEC laboratory reports from October 1986 and earlier). Alleged health effects on residents of neighboring properties include nausea, diarrhea, rashes, and elevated levels of metals (chromium, copper) in blood in two residents. Property values have been effectively reduced to zero for residential resale. A fire on the site on July 8, 1981, was attributed to combustion of petroleum-related products, and the fire department was unable to extinguish it. The fire was allegedly set by people illegally disposing of wastes in the pit. Fumes from organic liquids are noticeable in the breathing zone onsite. UNOCAL has been directed on several occasions to remove gas condensate in wastes from the site. Since June 19, 1972, disposal of wastes regulated as solid wastes has been illegal at this site. The case has been actively under review by the State since 1981. (AK 01)[92]

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[91] References for case cited: Dames and Moore well monitoring report, showing elevated metals referenced above, October 1976. Dowling Rice & Associates monitoring results, 1/15/80, and Mar Enterprises monitoring results, September 1980, provided by Walt Pederson, showing elevated levels of metals, oil, and grease in ground water. Detailed letter from Eric Meyers to Glen Aikens, Deputy Commissioner, ADEC, recounting permit history of site and failure to conduct proper monitoring, 1/22/82. Testimony and transcripts from Walt Pederson on public forums complaining about damage to drinking water and mismanagement of site. Transcripts of waste logs of site from 9/1/79 to 8/20/84, indicating only 264,436 bbl of muds received, during a period that should have generated much more waste. Letter from Howard Keiser to Union Oil, 12/7/81, indicating that "...drilling mud is being disposed of by methods other than at the Sterling Special Waste Site and by methods that could possibly cause contamination of the ground water."

[92] References for case cited: Photos showing illegal dumping in progress. Field investigations. State of Alaska Individual Fire Report on "petroleum dump," 7/12/81. File memo on site visit by Howard Keiser, ADEC Environmental Field Officer, in response to a complaint by State Forestry Officer, 7/21/81. Memo from Howard Keiser to Bob Martin on his objections to granting a permit to Union Oil for use of site as disposal site on basis of impairment of wildlife resources, 7/28/83. Letter, ADEC to Union Oil, objecting to lack of cleanup of site despite notification by ADEC on 10/3/84. Analytical reports by ADEC indicating gas condensate contamination on site, 8/14/84. EPA Potential Hazardous Waste Site Identification, indicating continued dumping as of 8/10/85. Citizens' complaint records. Blood test indicating elevated chromium for neighboring resident Jessica Black, 1/16/85. Letter to Mike Lucky of ADEC from Union Oil confirming cleanup steps, 2/12/85. Memo by Carl Reller, ADEC ecologist, indicating presence of significant toxics on site, 8/14/85. Minutes of Waste Disposal Commission meeting, 2/10/85. ADEC analytic reports indicating gas condensate at site, 10/10/85. Letters from four different real estate firms in area confirming inability to sell residential property in Poppy Lane area. Letter from Bill Lamoreaux, ADEC, to J. Black and R. Sizemore referencing high selenium/chromium in the ground water in the area. Miscellaneous technical documents. EPA Potential Hazardous Waste Site Preliminary Assessment, 2/12/87.

These activities are illegal under current Alaska regulations.

MISCELLANEOUS ISSUES

Improperly Abandoned and Improperly Plugged Wells

Degradation of ground water from improperly plugged and unplugged wells is known to occur in Kansas, Texas, and Louisiana. Improperly plugged and unplugged wells enable native brine to migrate up the wellbore and into freshwater aquifers. The damage sustained can be extensive.

Problems also occur when unidentified improperly plugged wells are present in areas being developed as secondary recovery projects. After the formation has been pressurized for secondary recovery, native brine can migrate up unplugged or improperly plugged wells, potentially causing extensive ground-water contamination with chlorides.

In 1961, Gulf and its predecessors began secondary recovery operations in the East Gladys Unit in Sedgwick County, Kansas. During secondary recovery, water is pumped into a target formation at high pressure, enhancing oil production. This pumping of water pressurizes the formation, which can at times result in brines being forced up to the surface through unplugged or improperly plugged abandoned wells. When Gulf began their secondary recovery in this area, it was with the knowledge that a number of abandoned wells existed and could lead to escape of salt water into fresh ground water.

Gerald Blood alleged that three improperly plugged wells in proximity to the Gladys unit were the source of fresh ground-water contamination on his property. Mr. Blood runs a peach orchard in the area. Apparently native brine had migrated from the nearby abandoned wells into the fresh ground water from which Mr. Blood draws water for domestic and irrigation purposes. Contamination of irrigation wells was first noted by Mr. Blood when, in 1970, one of his truck gardens was killed by irrigation with salty water. Brine migration contaminated two more irrigation wells in the mid-1970s. By 1980, brine had contaminated the irrigation wells used to irrigate a whole section of Mr. Blood's land. By this time, adjacent landowners also had contaminated wells. Mr. Blood lost a number of peach trees as a result of the contamination of his irrigation well; he also lost the use of his domestic well.

The Bloods sued Gulf Oil in civil court for damages sustained by their farm from chloride contamination of their irrigation and residential wells. The Bloods won their case and were awarded an undisclosed amount of money.[93] (KS 14)[94]

Current UIC regulations prohibit contamination of groundwater.

The potential for environmental damage through ground-water degradation is high, given the thousands of wells abandoned throughout the country prior to any State regulatory plugging requirements.

In West Texas, thousands of oil and gas wells have been drilled over the last several decades, many of which were never properly plugged. There exists in the subsurface of this area a geologic formation known as the Coleman Junction, which contains extremely salty native brine and possesses natural artesian properties. Since this formation is relatively shallow, most oil and gas wells penetrate this formation. If an abandoned well is not properly plugged, the brine contained in the Coleman Junction is under enough natural pressure to rise through the improperly plugged well and to the surface.

According to scientific data developed over several years, and presented by Mr. Ralph Hoelscher, the ground water in and around San Angelo, Texas, has been severely degraded by this seepage of native brine, and much of the agricultural land has absorbed enough salt as to be nonproductive. This situation has created a hardship for farmers in the area. The Texas Railroad Commission states that soil and ground water are contaminated with chlorides because of terracing and fertilizing of the land. According to Mr. Hoelscher, a long-time farmer in the area, little or no fertilizer is used in local agriculture. (TX 11)[95]

Improper abandonment of oil and gas wells is prohibited in the State of Texas.

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[93] API states that damage in this case was brought about by "old injection practices."

[94] References for case cited: U.S. District Court for the district of Kansas, Memorandum and Order, Blood vs. Gulf; Response to Defendants' Statement of Uncontroverted Facts; and Memorandum in Opposition to Motion for Summary Judgment. Means Laboratories, Inc., water sample results. Department of Health, District Office #14, water samples results. Extensive miscellaneous memoranda, letters, analysis.

[95] References for case cited: Water analysis of Ralph Hoelscher's domestic well. Soil Salinity Analysis, Texas Agricultural Extension Service - The Texas A&M University System, Soil Testing Laboratory, Lubbock, Texas 79401. Photographs. Conversation with Wayne Farrell, San Angelo Health Department. Conversation with Ralph Hoelscher, resident and farmer.

CHAPTER V

RISK MODELING

INTRODUCTION

This chapter summarizes the methods and results of a risk analysis of certain wastes associated with the onshore exploration, development, and production of crude oil and natural gas. The risk analysis relies heavily on the information developed by EPA on the types, amounts, and characteristics of wastes generated (summarized in Chapter II) and on waste management practices (summarized in Chapter III). In addition, this quantitative modeling analysis was intended to complement EPA's damage case assessment (Chapter IV). Because the scope of the model effort was limited, some of the types of damage cases reported in Chapter IV are not addressed here. On the other hand, the risk modeling of ground-water pathways covers the potential for certain more subtle or long-term risks that might not be evidenced in the contemporary damage case files. The methods and results of the risk analysis are documented in detail in a supporting EPA technical report (USEPA 1987a).

EPA's risk modeling study estimated releases of contaminants from selected oil and gas wastes into ground and surface waters, modeled fate and transport of these contaminants, and estimated potential exposures, health risks, and environmental impacts over a 200-year modeling period. The study was not designed to estimate absolute levels of national or regional risks, but rather to investigate and compare potential risks under a wide variety of conditions.

Objectives

The main objectives of the risk analysis were to (1) characterize and classify the major risk-influencing factors (e.g., waste types, waste management practices, environmental settings) associated with current operations at oil and gas facilities;[1] (2) estimate distributions of major risk-influencing factors across the population of oil and gas facilities within various geographic zones; (3) evaluate these factors in terms of their relative effect on risks; and (4) develop, for different geographic zones of the U.S., initial quantitative estimates of the possible range of baseline health and environmental risks for the variety of existing conditions.

Scope and Limitations

The major portion of this risk study involved a predictive quantitative modeling analysis focusing on large-volume exempt wastes managed according to generally prevailing industry practices. EPA also examined (but did not attempt quantitative assessment of) the potential effects of oil and gas wastes on the North Slope of Alaska, and reviewed the locations of oil and gas activities relative to certain environments of special interest, including endangered species habitats, wetlands, and public lands.

Specifically, the quantitative risk modeling analysis estimated long-term human health and environmental risks associated with the disposal of drilling wastes in onsite reserve pits, the deep well injection of produced water, and the direct discharge of produced water from stripper wells to surface waters. These wastes and waste management practices encompass the major waste streams and the most common management practices within the scope of this report, but they are not necessarily those giving rise to the most severe or largest number of damage cases of the types presented in Chapter IV. For risk modeling purposes, EPA generally assumed full compliance with applicable current State and

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[1] References in this chapter to oil and gas facilities, sites, or activities refer to exploration, development, and production operations.

Federal regulations for the practices studied. Risks were not modeled for a wide variety of conditions or situations, either permitted or illegal, that could give rise to damage incidents, such as waste spills, land application of pit or water wastes, discharge of produced salt water to evaporation/percolation pits, or migration of injected wastes through unplugged boreholes.

In this study, EPA analyzed the possible effects of selected waste streams and management practices by estimating risks for model scenarios. Model scenarios are defined as hypothetical (but realistic) combinations of variables representing waste streams, management practices, and environmental settings at oil and gas facilities. The scenarios used in this study were, to the extent possible, based on the range of conditions that exist at actual sites across the U.S. EPA developed and analyzed more than 3,000 model scenarios as part of this analysis.

EPA also estimated the geographic and waste practice frequencies of occurrence of the model scenarios to account for how well they represent actual industry conditions and to account for important variations in oil and gas operations across different geographic zones of the U.S.[2] These frequencies were used to weight the model results, that is, to account for the fact that some scenarios represent more sites than others. However, even the weighted risk estimates should not be interpreted as absolute risks for real facilities because certain major risk-influencing factors were not modeled as variables and because the frequency of occurrence of failure/release modes and concentrations of toxic constituents were not available.

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[2] The 12 zones used in the risk assessment are identical to the zones used as part of EPA's waste sampling and analysis study (see Chapter II), with one exception: zone 11 (Alaska) was divided into zone 11A representing the North Slope and zone 11B representing the Cook Inlet-Kenai Peninsula area.

A principal limitation of the risk analysis is that EPA had only a relatively small sample set of waste constituent concentration data for the waste streams under study. As a result, the Agency was unable to construct regional estimates of toxic constituent concentrations or a national frequency distribution of concentrations that could be directly related to other key geophysical or waste management variables in the study. Partly because of this data limitation, all model scenarios defined for this study were analyzed under two different sets of assumptions: a "best-estimate"[3] set of assumptions and a "conservative" set of assumptions. The best-estimate and conservative sets of assumptions are distinguished by different waste constituent concentrations, different timing for releases of drilling waste and produced water, and, in some cases, different release rates (see the later sections on model scenarios and model procedures for more detail). The best-estimate assumptions represent a set of conditions which, in EPA's judgment, best characterize the industry as a whole, while the conservative assumptions define higher-risk (but not worst-case) conditions. It is important to clarify that the best-estimate and conservative assumptions are not necessarily based on a comprehensive statistical analysis of the frequency of occurrence or absolute range of conditions that exist across the industry; instead, they reflect EPA's best judgment of a reasonable range of conditions based on available data analyzed for this study.

Another major limitation of the study is the general absence of empirical information on the frequency, extent, and duration of waste releases from the oil and gas field management practices under consideration. As described below, this study used available engineering judgments regarding the nature of a variety of failure/release mechanisms for waste pits and injection wells, but no assumptions were made

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[3] As used here, the term best estimate is different from the statistical concept of maximum likelihood (i.e., best) estimate.

regarding the relative frequency or probability of occurrence of such failures.

Although EPA believes that the scenarios analyzed are realistic and representative, the risk modeling for both sets of scenarios incorporated certain assumptions that tend to overestimate risk values. For example, for the health risk estimates it was assumed that individuals ingest untreated contaminated water over a lifetime, even if contaminant concentrations were to exceed concentrations at which an odor or taste is detectable. In addition, ingested concentrations were assumed to equal the estimated center line (i.e., highest) concentration in the contaminant plume.

Other features of the study tend to result in underestimation of risk. For example, the analysis focuses on risks associated with drilling or production at single oil or gas wells, rather than on the risks associated with multiple wells clustered in a field, which could result in greater risks and impacts because of overlapping effects. Also, the analysis does not account for natural or other source background levels of chemical constituents which, when combined with the contamination levels from oil and gas activities, could result in increased risk levels.

QUANTITATIVE RISK ASSESSMENT METHODOLOGY

EPA conducted the quantitative risk assessment through a four-step process (see Figure V-1). The first three steps--collection of input data, specification of model scenarios, and development of modeling procedures--are described in the following subsections. The last step, estimation of effects, is described in subsequent sections of this chapter that address the quantitative modeling results.

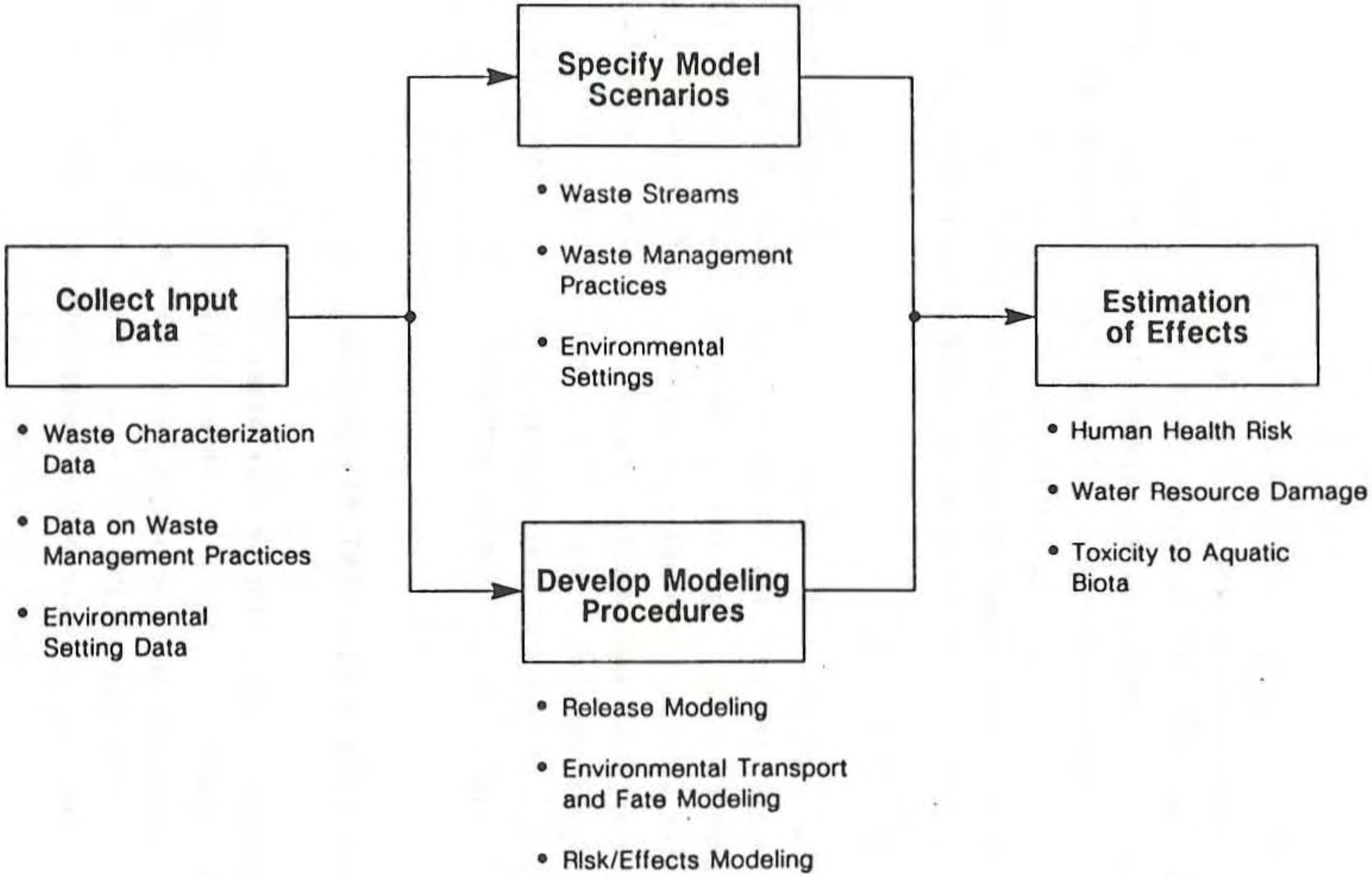

Figure V-1 Overview of Quantitative Risk Assessment Methodology

Input Data

EPA collected three main categories of input data for the quantitative modeling: data on waste volumes and constituents, waste management practices, and environmental settings. Data on waste volumes were obtained from EPA's own research on sources and volumes of wastes, supplemented by the results of a survey of oil and gas facilities conducted by the American Petroleum Institute (API) (see Chapter II). Data on waste constituents were obtained from EPA's waste stream chemical analysis study. The results of EPA's research on current waste management practices, supplemented by API's studies (see Chapter III), were the basis for defining necessary input parameters concerning waste management practices. Data needed to characterize environmental settings were obtained from an analysis of conditions at 266 actual drilling and production locations sampled from areas with high levels of oil and gas activity (see USEPA 1987a, Chapter 3, for more detail on the sample selection and analytical methods).

Model Scenarios

The model scenarios in this analysis are unique combinations of the variables used to define waste streams, waste management practices, and environmental settings at oil and gas facilities. Although the model scenarios are hypothetical, they were designed to be:

- Representative of actual industry conditions (they were developed using actual industry data, to the extent available);
- Broad in scope, covering prevalent industry characteristics but not necessarily all sets of conditions that occur in the industry; and
- Sensitive to major differences in environmental conditions (such as rainfall, depth to ground water, and ground-water flow rate) across various geographic zones of the U.S.

As illustrated in Figure V-2, EPA decided to focus the quantitative analysis on the human health and environmental risks associated with three types of environmental releases: leaching of drilling waste chemical constituents from onsite reserve pits to ground water below the pits (drilling sites); release of produced water chemical constituents from underground injection wells to surface aquifers[4] (production sites); and direct discharge of produced water chemical constituents to streams and rivers (stripper well production sites).

Chemical Constituents

EPA used its waste sampling and analysis data (described in Chapter II) to characterize drilling wastes and produced water for quantitative risk modeling. Based on the available data, EPA could not develop separate waste stream characterizations for various geographic zones; one set of waste characteristics was used to represent the nation. The model drilling waste represents only water-based drilling muds (not oil-based muds or wastes from air drilling), which are by far the most prevalent drilling mud type. Also, the model drilling waste does not represent one specific process waste, but rather the combined wastes associated with well drilling that generally are disposed of in reserve pits.

For both drilling wastes and produced water, EPA used a systematic methodology to select the chemical constituents of waste streams likely to dominate risk estimates (see USEPA 1987a, Chapter 3, for a detailed description of this methodology). The major factors considered in the chemical selection process were (1) median and maximum concentrations in

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[4] For the purpose of this report, a surface aquifer is defined as the geologic unit nearest the land surface that transmits sufficient quantities of ground water to be used as a source of drinking water. It is distinguished from aquifers at greater depths, which may be the injection zone for an underground injection well or are too deep to be generally used as a drinking water source.

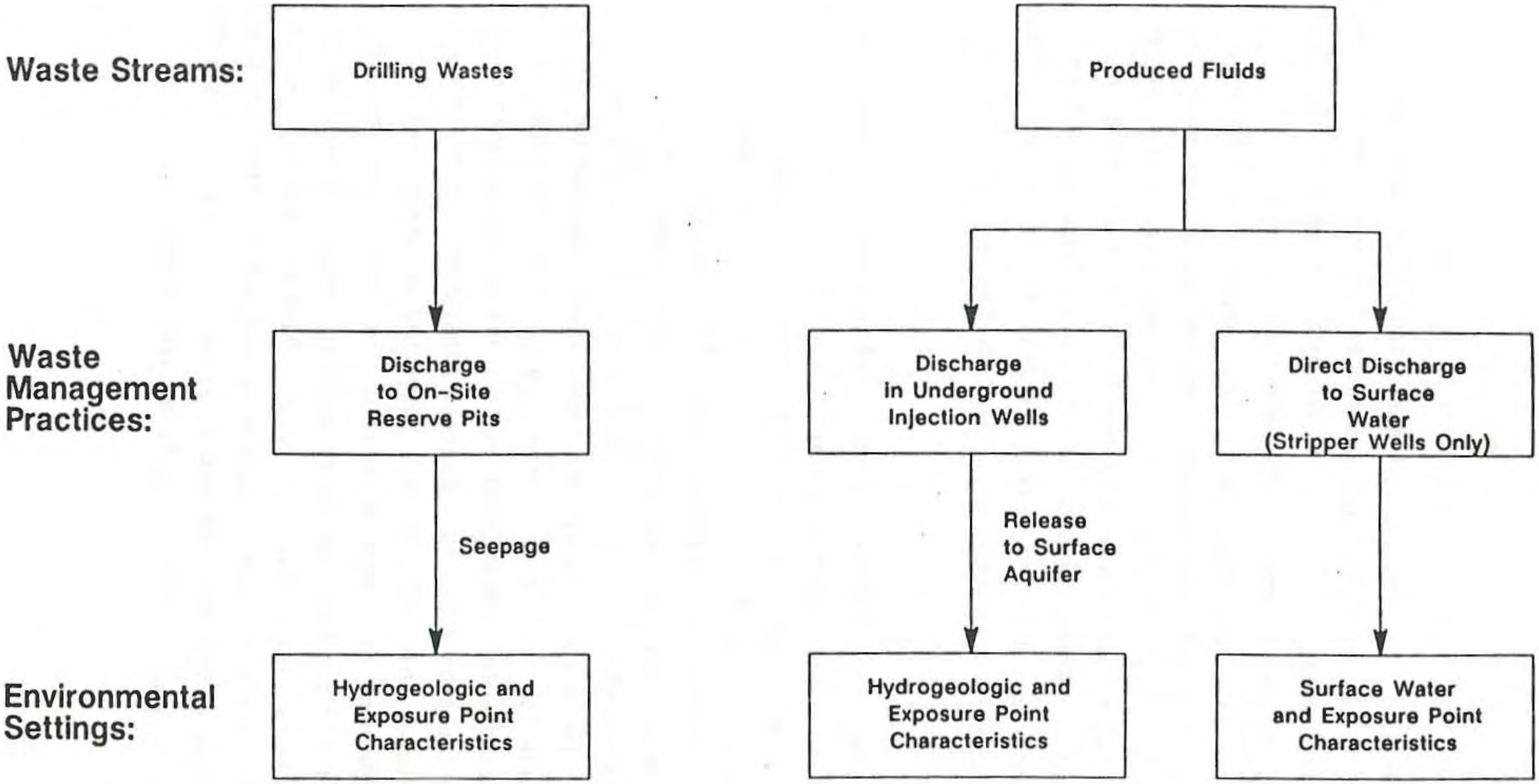

Figure V-2 Overview of Modeling Scenarios Considered in the Quantitative Risk Assessment the waste samples; (2) frequency of detection in the waste samples; (3) mobility in ground water; and (4) concentrations at which human health effects, aquatic toxicity, or resource damage start to occur. Through this screening process, EPA selected six chemicals for each waste type that were likely to dominate risk estimates in the scenarios modeled. For each selected chemical, two concentrations were determined from the waste characterization data. The 50th percentile (median) was used to set constituent concentrations for a "best-estimate" waste characterization, while the 90th percentile was used for a "conservative" waste characterization. The selected chemicals and concentrations, shown in Table V-1, served as model waste streams for the quantitative risk analysis.

Of the chemicals selected, arsenic and benzene were modeled as potential carcinogens. Both substances are rated as Group A in EPA's weight-of-evidence rating system (i.e., sufficient evidence of carcinogenicity in humans). Some scientists, however, believe that arsenic may not be carcinogenic and may be a necessary element at low levels. Sodium, cadmium, and chromium VI were modeled for noncarcinogenic effects. The critical (i.e., most sensitive) health effects for these constituents are hypertension for sodium and liver and kidney damage for cadmium and chromium VI. It is emphasized that the effect threshold for sodium used in this analysis was based on potential effects in the high-risk (not general) population. (The level used is slightly higher than EPA's 20 mg/L suggested guidance level for drinking water.) The high-risk population is defined to include individuals with a genetic predisposition for hypertension, pregnant women, and hypertensive patients. Finally, boron, chloride, sodium, cadmium, chromium VI, and total mobile ions were modeled for their potential aquatic toxicity and resource damage effects. Table V-2 lists the cancer potency factors and effects thresholds used in the study.

Table V-1 Model Constituents and Concentrations[a]

Produced water constituents	Concentrations Median (mg/L)	Upper 90% (mg/L)
Arsenic	0.02	1.7
Benzene	0.47	2.9
Boron	9.9	120
Sodium	9,400	67,000
Chloride	7,300	35,000
Mobile ions[b]	23,000	110,000

Drilling waste (water-based) constituents	Concentrations Pit liquids Median (mg/L)	Upper 90%	Pit solids/TCLP[c] Median (mg/L)	Upper 90%	Pit solids/direct Median (mg/kg)	Upper 90%
Arsenic	0.0	0.16	0.0	0.002[d]	0.0	0.010
Cadmium	0.056	1.4	0.011	0.29	2.0	5.4
Sodium	6,700	44,000	1,200[e]	4,400[e]	8,500	59,000
Chloride	3,500	39,000	2,000[f]	11,000[f]	17,000	88,000
Chromium VI	0.43	290	0	0.78	22	190
Mobile ions[b]	17,000	95,000	4,000	16,000	100,000	250,000

[a] The median constituent concentrations from the relevant samples in the EPA waste sampling/analysis study were used for a "best-estimate" waste characterization, and the 90th percentile concentrations were used for a "conservative" waste characterization (data source: USEPA 1987b).

[b] Mobile ions include chloride, sodium, potassium, calcium, magnesium, and sulfate.

[c] TCLP = toxicity characteristic leaching procedure.

[d] Upper 90th percentile arsenic values estimated based on detection limit.

[e] Preliminary examinations indicate that the sodium TCLP values may overestimate the actual leachable sodium concentrations in reserve pit samples. The accuracy of these concentrations is the subject of an ongoing evaluation.

[f] Chloride TCLP values are estimated based on sodium data.

Table V-2 Toxicity Parameters and Effects Thresholds[a]

Model constituent	Cancer potency factor $(mg/kd\text{-}d)^{-1}$	Human noncancer threshold (mg/kg-d)	Aquatic toxicity threshold (mg/L)	Resource damage threshold (mg/L)
Benzene	0.052	NA	NA[b]	NA
Arsenic	15	NA	NA	NA
Sodium	NA	0.66	83.4	NA
Cadmium	NA[c]	0.00029	0.00066	NA
Chromium VI	NA[c]	0.005	0.011	NA
Chloride	NA	NA	NA	250
Boron	NA	NA	NA	1
Total mobile ions[d]	NA	NA	NA	335[e] 500[f]

[a] See USEPA 1987a for detailed description and documentation.

[b] NA = not applicable; indicates that an effect type was not modeled for a specific chemical.

[c] Not considered carcinogenic by the oral exposure route.

[d] Represents total mass of ions mobile in ground water.

[e] For surface water only (assumes a background level of 65 mg/L and a threshold limit of 400 mg/L).

[f] For ground water only.

The chemicals selected for risk modeling differ from the constituents of potential concern identified in Chapter II for at least three important reasons. First, the analysis in Chapter II considers the hazards of the waste stream itself but, unlike the selection process used for this risk analysis, does not consider the potential for waste constituents to migrate through ground water and result in exposures at distant locations. Second, certain constituents were selected based on their potential to cause adverse environmental (as opposed to human health) effects, while the analysis in Chapter II considers only human health effects. Third, frequency of detection was considered in selecting constituents for the risk modeling but was not considered in the Chapter II analysis.

Waste Management Practices

Three general waste management practices were considered in this study: onsite reserve pits for drilling waste; underground injection wells for produced water; and direct discharge of produced water to rivers and streams (for stripper wells only).[5] EPA considered the underground injection of produced water in disposal wells and waterflooding wells.[6] The design characteristics and parameter values modeled for the different waste management practices are presented in Tables V-3 and V-4. These values were developed from an evaluation of EPA's and API's waste volume data (see Chapter II) and waste management practice survey results (see Chapter III) for the nation as a whole.

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[5] At present, there are no Federal effluent guidelines for stripper wells (i.e., oil wells producing less than ten barrels of crude oil per day), and, under Federal law, these wells are allowed to discharge directly to surface waters subject to certain restrictions. Most other onshore oil and gas facilities are subject to the Federal zero-discharge requirement.

[6] Waterflooding is a secondary recovery method in which treated fresh water, seawater, or produced water is injected into a petroleum-bearing formation to help maintain pressure and to displace a portion of the remaining crude oil toward production wells. Injection wells used for waterflooding may have different designs, operating practices, and economic considerations than those of disposal wells, which are used simply to dispose of unwanted fluid underground.

Table V-3 Drilling Pit Waste (Water-Based) Management Practices

Onsite pit size	Waste amount[a] (barrels)	Disposal practice	Pit dimensions(m) L	W	D
Large	26,000	Reserve pit-unlined	59	47	2.3[b]
		Reserve pit-lined, capped			
Medium	5,900	Reserve pit-unlined	32	25	2.0[b]
		Reserve pit-lined, capped			
Small	1,650	Reserve pit-unlined	17	14	1.9[b]
		Reserve pit-lined, capped			

[a] Per well drilled (includes solids and liquids).

[b] Waste depths for large, medium, and small pits were 1.5, 1.2, and 1.1 meters, respectively.

Table V-6 Definition of Best-Estimate and Conservative Release Assumptions

Release source	Release assumption	Constituent concentration in waste[a]	Failure/release timing	Release volume
Unlined Pits	Best-estimate	50th % (median)	Release begins in year 1	Calculated by release equations
	Conservative	90th %	Release begins in year 1	Calculated by release equations (same as best-estimate)
Lined Pits	Best-estimate	50th %	Liner failure begins in year 25	Calculated by release equations
	Conservative	90th %	Liner failure begins in year 5	Calculated by release equations (same as best-estimate)
Injection Wells/ Casing Failure	Best-estimate	50th %	One year release in year 1 for waterflood wells; constant annual releases during years 11-13 for disposal wells	0.2-96 bbl/d for waterflood wells; 0.05-38 bbl/d for disposal wells
	Conservative	90th %	Constant annual releases during years 11-15 for waterflood and disposal wells	Same as best-estimate
Injection Wells/ Grout Seal Failure	Best-estimate	50th %	Constant annual releases during years 11-15 for waterflood and disposal wells	0.00025-0.0025 bbl/d for waterflood wells; 0.00025-0.0075 bbl/d for disposal wells
	Conservative	90th %	Constant annual releases during years 1-20 for waterflood and disposal wells (immediate failure, no detection)	0.05-0.5 bbl/d for waterflood wells; 0.05-1.5 bbl/d for disposal wells

[a] See Table V-1.

the same layers considered during the active period. For unlined pits, release was assumed to begin immediately at the start of the modeling period. For lined pits, failure (i.e., increase in hydraulic conductivity of the liner) was assumed to occur either 5 or 25 years after the start of the modeling period. It was assumed that any liquids remaining in unlined reserve pits at the time of closure would be land applied adjacent to the pit. Liquids remaining in lined pits were assumed to be disposed offsite.

For modeling releases to surface aquifers from Class II injection wells, a 20-year injection well operating period was assumed, and two failure mechanisms were studied: (1) failure of the well casing (e.g., a corrosion hole) and (2) failure of the grout seal separating the injection zone from the surface aquifer. At this time, the Agency lacks the data necessary to estimate the probability of casing or grout seal failures occurring. A well casing failure assumes that injected fluids are exiting the well through a hole in the casing protecting the surface aquifer. In most cases, at least two strings of casing protect the surface aquifer and, in those cases, a release to this aquifer would be highly unlikely. The Agency has made exhaustive investigations of Class I well (i.e., hazardous waste disposal well) failures and has found no evidence of release of injected fluids through two strings of casing. However, the Agency is aware that some Class II wells were constructed with only one string of casing; therefore, the scenarios modeled fall within the realm of possible failures. Since integrity of the casing must be tested every 5 years under current EPA guidelines (more frequently by some States), EPA assumed for the conservative scenarios that a release would begin on the first day after the test and would last until the next test (i.e., 5 years). For the best-estimate scenarios, EPA assumed that the release lasted 1 year (the minimum feasible modeling period) in the case of waterflood wells and 3 years in the case of disposal wells, on the supposition that shorter release durations would be more likely for waterflooding where injection flow rates and volumes are important economic considerations for the operation. EPA also assumed here that the release flow from a failed well would remain constant over the duration of the failure. This simplifying assumption is more likely to hold in low-pressure wells than in the high-pressure wells more typical of waterflooding operations. In high-pressure wells the high flow rate would likely enlarge the casing holes more rapidly, resulting in more injection fluid escaping into the wrong horizon and a noticeable drop of pressure in the reservoir.

For the grout seal type of failure, EPA estimated for conservative modeling purposes that the failure could last for 20 years (i.e., as long as the well operates). This is not an unreasonable worst-case assumption because the current regulations allow the use of cementing records to determine adequacy of the cement job, rather than actual testing through the use of logs. If the cementing records were flawed at the outset, a cementing failure might remain undetected. As part of its review of the Underground Injection Control (UIC) regulations, the Agency is considering requiring more reliable testing of the cementing of wells, which would considerably lessen the likelihood of such scenarios. For an alternative best-estimate scenario, the Agency assumed a 5-year duration of failure as a more typical possibility.

Because of a lack of both data and adequate modeling methods, other potentially important migration pathways by which underground injection of waste could contaminate surface aquifers (e.g., upward contaminant migration from the injection zone through fractures/faults in confining layers or abandoned boreholes) were not modeled.

Chemical transport was modeled for ground water and surface water (rivers). Ground-water flow and mass transport were modeled using EPA's Liner Location Risk and Cost Analysis Model (LLM) (USEPA 1986). The LLM uses a series of predetermined flow field types to define ground-water conditions (see Table V-7); a transient-source, one-dimensional, wetting-front model to assess unsaturated zone transport; and a modified version of the Random Walk Solute Transport Model (Prickett et al. 1981) to predict ground-water flow and chemical transport in the saturated zone. All ground-water exposure and risk estimates presented in this report are for the downgradient center line plume concentration. Chemical transport in rivers was modeled using equations adapted from EPA (USEPA 1984a); these equations can account for dilution, dispersion, particulate adsorption, sedimentation, degradation (photolysis, hydrolysis, and biodegradation), and volatilization.

EPA used the LLM risk submodel to estimate cancer and chronic noncancer risks from the ingestion of contaminated ground and surface water. The measure used for cancer risk was the maximum (over the 200-year modeling period) lifetime excess[7] individual risk, assuming an individual ingested contaminated ground or surface water over an entire lifetime (assumed to be 70 years). These risk numbers represent the estimated probability of occurrence of cancer in an exposed individual. For example, a cancer risk estimate of 1×10^{-6} indicates that the chance of an individual getting cancer is approximately one in a million over a 70-year lifetime. The measure used for noncancer risk was the maximum (over the 200-year modeling period) ratio of the estimated chemical dose to the dose of the chemical at which health effects begin to occur (i.e., the threshold dose). Ratios exceeding 1.0 indicate the potential for adverse effects in some exposed individuals; ratios less than 1.0 indicate a very low likelihood of effect (assuming that background exposure is zero, as is done in this study). Although these ratios are <u>not</u> probabilities, higher ratios in general are cause for greater concern.

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[7] Excess refers to the risk increment attributable only to exposure resulting from the releases considered in this analysis. Background exposures were assumed to be zero.

Table V-7 Definition of Flow Fields Used in Ground-Water Transport Modeling

	Key variables defining flow field[a]	
Flow field	Aquifer configuration[b]	Horizontal ground-water velocity
A	Unconfined aquifer	1 m/yr
B	Unconfined aquifer	10 m/yr
C	Unconfined aquifer	100 m/yr
D	Unconfined aquifer	1,000 m/yr
E	Unconfined aquifer	10,000 m/yr
F	Confined aquifer	0.05 m/yr in the confining layer and 100 m/yr within the aquifer
K	Confined aquifer	0.05 m/yr in the confining layer and 10 m/yr within the aquifer

[a] Several other variables, such as porosity, distinguish the flow fields, but the variables listed here are the most important for the purpose of this presentation.

[b] In general, an aquifer is defined as a geological unit that can transmit significant quantities of water. An unconfined aquifer is one that is only partly filled with water, such that the upper surface of the saturated zone is free to rise and decline. A confined aquifer is one that is completely filled with water and that is overlain by a confining layer (a rock unit that restricts the movement of ground water).

As a means of assessing potential effects on aquatic organisms, EPA estimated, for each model scenario involving surface water, the volume contaminated above an aquatic effects threshold. EPA also estimated the volumes of ground and surface water contaminated above various resource damage thresholds (e.g., the secondary drinking water standard for chloride).

QUANTITATIVE RISK MODELING RESULTS: HUMAN HEALTH

This section summarizes the health risk modeling results for onsite reserve pits (drilling wastes), underground injection wells (produced water), and direct discharges to surface water (produced water, stripper well scenarios only). Cancer risk estimates are presented separately from noncancer risk estimates throughout. This section also summarizes EPA's preliminary estimates of the size of populations that could possibly be exposed through drinking water.

Onsite Reserve Pits--Drilling Wastes

Cancer and noncancer health risks were analyzed under both best-estimate and conservative modeling assumptions for 1,134 model scenarios[8] of onsite reserve pits. Arsenic was the only potential carcinogen among the constituents modeled for onsite reserve pits. Of the noncarcinogens, only sodium exceeded its effect threshold; neither cadmium nor chromium VI exceeded their thresholds in any model scenarios (in its highest risk scenario, cadmium was at 15 percent of threshold; chromium VI, less than 1 percent).

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[8] 1,134 = 9 infiltration/unsaturated zone types x 7 ground-water flow field types x 3 exposure distances x 3 size categories x 2 liner types.

Nationally Weighted Risk Distributions

Figure V-3 presents the nationally weighted frequency distributions of human health risk estimates associated with unlined onsite reserve pits. The figure includes best-estimate and conservative modeling results for both cancer (top) and noncancer (bottom) risks. Only the results for unlined reserve pits are given because the presence or absence of a liner had little influence on risk levels (see section on major factors affecting health risk). Many of the scenarios in the figure show zero risk because the nearest potential exposure well was estimated to be more than 2 kilometers away (roughly 61 percent of all scenarios).

Under best-estimate assumptions, there were no cancer risks from arsenic because arsenic was not included as a constituent of the modeled waste (i.e., the median arsenic concentration in the field sampling data was below detection limits; see Table V-1). Under conservative assumptions, nonzero cancer risks resulting from arsenic were estimated for 18 percent of the nationally weighted reserve pit scenarios, with roughly 2 percent of the scenarios having cancer risks greater than 1×10^{-7}. Even under conservative modeling assumptions, drilling waste pit scenarios produced maximum lifetime cancer risks of less than 1 in 100,000 for individuals drinking affected water.

A few threshold exceedances for sodium were estimated under both best-estimate and conservative assumptions. Under best-estimate assumptions, more than 99 percent of nationally weighted reserve pit scenarios posed no noncancer risk (i.e., they were below threshold). A few model scenarios had noncancer risks, but none exceeded 10 times the sodium threshold. Under conservative assumptions, 98 percent of nationally weighted reserve pit scenarios did not pose a noncancer risk. The remaining 2 percent of reserve pit scenarios had estimated exposure point sodium concentrations between up to 32 times the threshold.

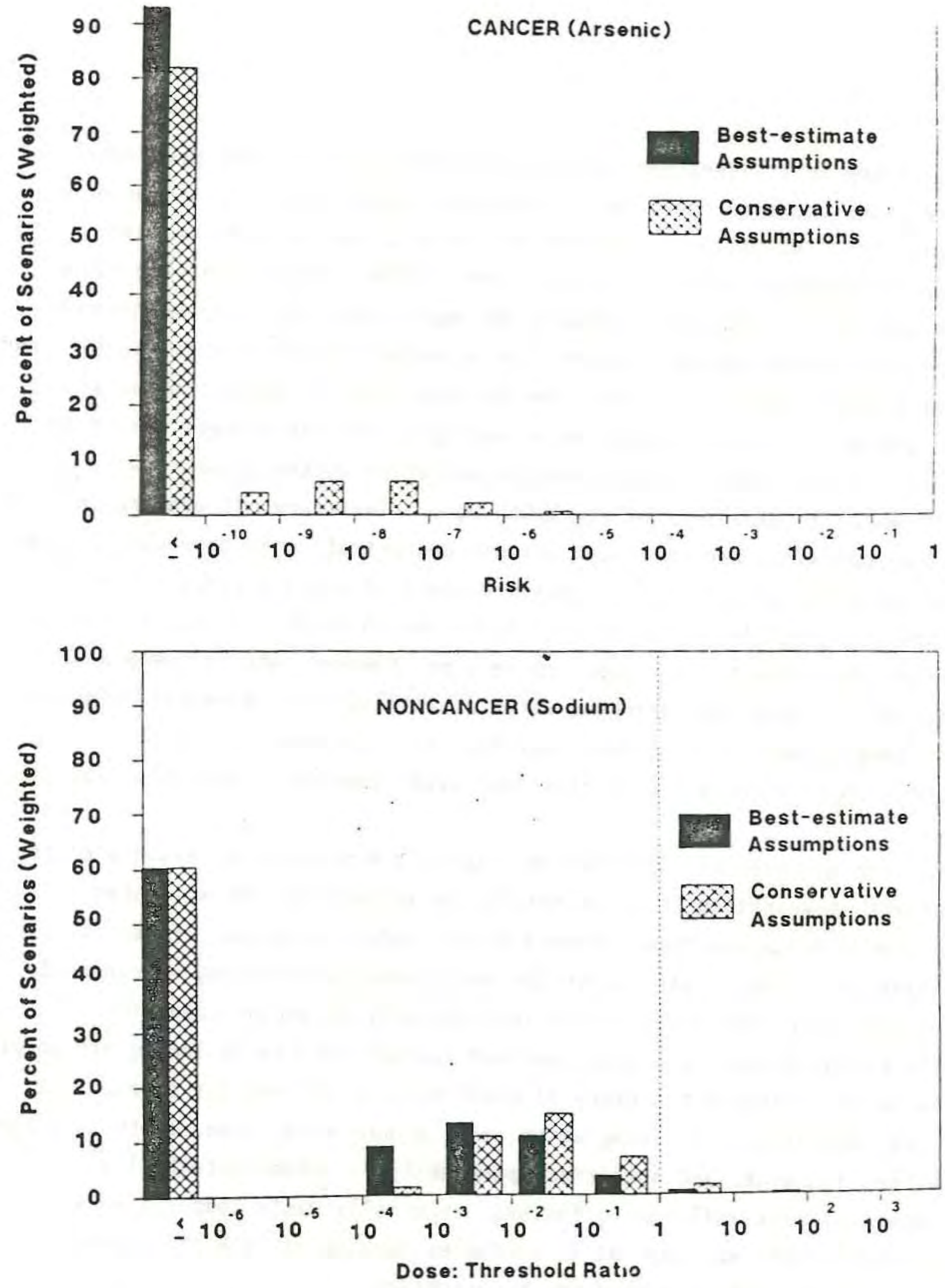


Figure V-3 Nationally Weighted Distribution of Health Risk Estimates. Unlined Reserve Pits

Based on a literature review conducted as part of the development of the Liner Location Model data base (USEPA 1986), chloride is the only model drilling waste constituent for which either a taste or odor threshold concentration is known. EPA (1984b) reports that the taste threshold for chloride is roughly 250 mg/L (i.e., this is the minimum chloride concentration in water that a person may be able to taste). For the highest cancer risk case, the maximum chloride concentration at the exposure well was estimated to be 400 mg/L; for the highest noncancer risk case, the maximum chloride concentration at the exposure well was estimated to be approximately 5,000 mg/L. Therefore, it appears that, if water contained a high enough arsenic concentration to pose cancer risks on the order of 1×10^{-5} or sodium concentrations 100 times the effect threshold, people may be able to taste the chloride that would also likely be present. The question remains, however, whether people would actually discontinue drinking water containing these elevated chloride concentrations. EPA (1984b) cautions that consumers may become accustomed to the taste of chloride levels somewhat higher than 250 mg/L.

For purposes of illustration, Figure V-4 provides an example of the effect of weighting the risk results to account for the estimated national frequency of occurrence of the model scenarios. Essentially, weighting allows risk results for more commonly occurring scenarios to "count" more than results from less commonly occurring scenarios. Weighting factors were developed and applied for the following variables, based on estimated frequency of occurrence at oil and gas sites: pit size, distance to drinking water well, ground-water type, depth to ground water, recharge, and subsurface permeability. Other potentially important risk-influencing factors, especially waste composition and strength, were not modeled as variables because of lack of information and thus are not accounted for by weighting.

In the example shown in Figure V-4 (conservative-estimate cancer risks for unlined onsite pits), weighting the risk results decreases the

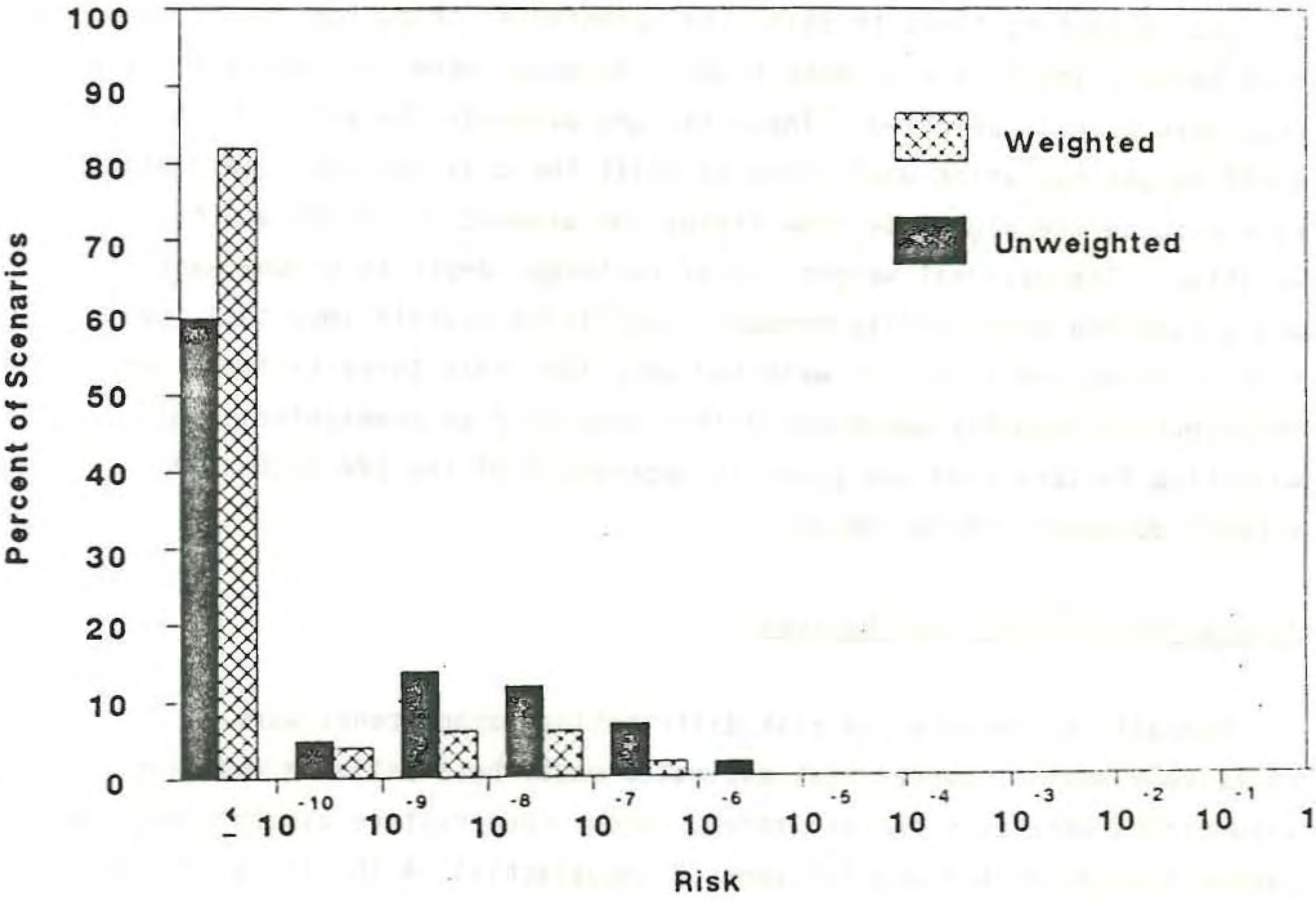


Figure V-4 Weighted vs. Unweighted Distribution of Cancer Risk Estimates. Unlined Reserve Pits. Conservative Modeling Assumptions risk (i.e., shifts the distribution toward lower risk). This happens primarily because close exposure distances (60 and 200 meters), which correspond to relatively high risks, occur less frequently and thus are less heavily weighted than greater distances. In addition, the effect of pit size weighting tends to shift the weighted distribution toward lower risk because small (i.e., lower risk) pits occur more frequently and are thus more heavily weighted. These factors override the effect of flow field weighting, which would tend to shift the distribution toward higher risk because the high-risk flow fields for arsenic (C and D) are heavily weighted. The national weightings of recharge, depth to ground water, and subsurface permeability probably had little overall impact on the risk distribution (i.e., if weighted only for these three factors, the distribution probably would not differ greatly from unweighted). All weighting factors used are given in Appendix B of the EPA technical support document (USEPA 1987a).

Zone-Weighted Risk Distributions

Overall, differences in risk distributions among zones were relatively small. Cancer risk estimates under best-estimate modeling assumptions were zero for all zones. Under conservative assumptions, the cancer risk distributions for zones 2 (Appalachia), 4 (Gulf), 6 (Plains), and 7 (Texas/Oklahoma) were slightly higher than the distribution for the nation as a whole. The cancer risk distributions for zones 5 (Midwest), 8 (Northern Mountain), 9 (Southern Mountain), 10 (West Coast), and 11B (Alaska, non-North Slope) were lower than the nationally weighted distribution; zones 10 and 11B were much lower. The risk distributions for individual zones generally varied from the national distribution by less than one order of magnitude.

Noncancer risk estimates under best-estimate modeling assumptions were extremely low for all zones. Under conservative assumptions, zones 2, 4, 5, 7, and 8 had a small percentage (1 to 10 percent) of weighted scenarios with threshold exceedances for sodium; other zones had less than 1 percent. There was little variability in the noncancer risk distributions across zones.

The reasons behind the differences in risks across zones are related to the zone-specific relative weightings of reserve pit size, distance to receptor populations, and/or environmental variables. For example, the main reason zone 10 has low risks relative to other zones is that 92 percent of drilling sites were estimated to be in an arid setting above a relatively low-risk ground-water flow field having an aquitard (flow field F). Zone 11B has zero risks because all potential exposure wells were estimated to be more than 2 kilometers away.

In summary, differences in cancer risks among the geographic zones were not great. Cancer risks were only prevalent in the faster aquifers (i.e., flow fields C, D, and E, with C having the highest cancer risks). Zone 4, with the highest cancer risks overall, also was assigned the highest weighting among the zones for flow field C. Noncancer risks caused by sodium were highest in zone 5. Noncancer risks occurred only in the more slow-moving flow fields (i.e., flow fields A, B, and K, with A having the highest noncancer risks); among the zones, zone 5 was assigned the highest weighting for flow field A. EPA considered the possible role of distributions of size and distance to exposure points, but determined that aquifer configuration and velocity probably contributed most strongly to observed zone differences in estimates of human health risks. The consistent lack of risk for zone 11B, however, is entirely because of the large distance to an exposure point. (See the section that follows on estimated population distributions.)

Evaluation of Major Factors Affecting Health Risk

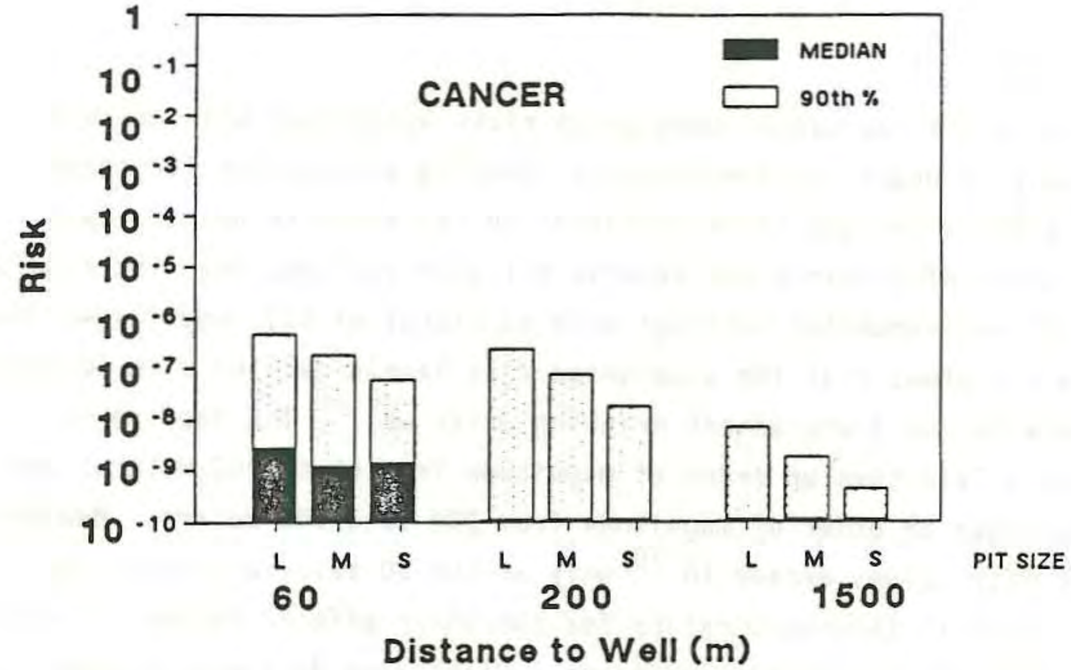
EPA examined the effect of several parameters related to pit design and environmental setting that were expected to influence the release and transport of contaminants leaking from onsite reserve pits. To assess the effect of each of these parameters in isolation, all other parameters were held constant for the comparisons. The results presented in this section are not weighted according to either national or zone-specific frequencies of occurrence. Instead, each model scenario is given equal weight. Thus, the following comparisons are not appropriate for drawing conclusions concerning levels of risk for the national population of onsite reserve pits. They are appropriate for examining the effect of selected parameters on estimates of human health risk.

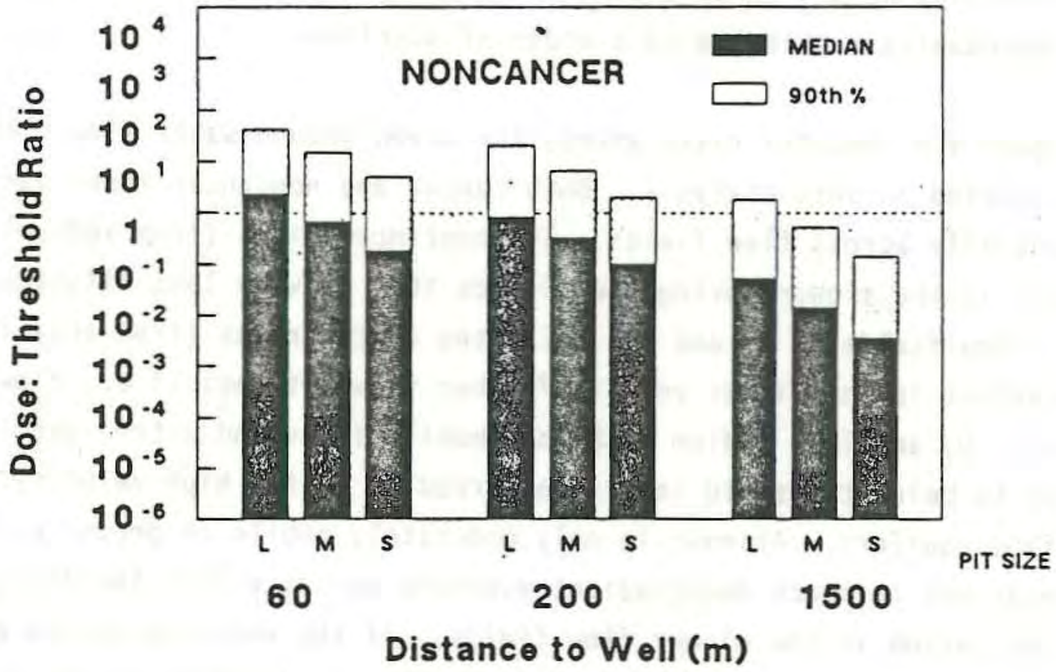
The presence or absence of a conventional, single synthetic liner underneath an onsite reserve pit had virtually no effect on the 200-year maximum health risk estimates. A liner does affect timing of exposures and risks, however, by reducing the amounts of leachate (and chemicals) released early in the modeling period. EPA's modeling assumed a single synthetic liner with no leak detection or leachate collection. (Note that this is significantly different from the required Subtitle C liner system design for hazardous waste land disposal units.) Furthermore, EPA assumed that such a liner would eventually degrade and fail, resulting in release of the contaminants that had been contained. Thus, over a long modeling period, mobile contaminants that do not degrade or degrade very slowly (such as the ones modeled here) will produce similar maximum risks whether they are disposed of in single-synthetic-lined or unlined pits (unless a significant amount of the contained chemical is removed, such as by dredging). This finding should not be interpreted to discount the benefit of liners in general. Measures of risk over time periods shorter than 200 years would likely be lower for lined pits than for unlined ones. Moreover, by delaying any release of contaminants, liners provide the opportunity for management actions (e.g., removal) to help prevent contaminant seepage and to mitigate seepage should it occur.

Figure V-5 represents unweighted risks associated with unlined reserve pits under the conservative modeling assumptions for three reserve pit sizes and three distances to the exposure point. Each combination of distance and reserve pit size includes the risk results from all environmental settings modeled (total of 63), equally weighted. Figure V-5 shows that the unweighted risk levels decline with increasing distance to the downgradient drinking water well. The decline is generally less than an order of magnitude from 60 to 200 meters, and greater than an order of magnitude from 200 to 1,500 meters. Median cancer risk values exceed 10^{-10} only at the 60-meter distance, and median dose-to-threshold ratios for noncancer effects exceed 1.0 only for large pits at the 60-meter distance. Risks also decrease as reserve pit size decreases at all three distances, although risks for small and large pits are usually within the same order of magnitude.

Figure V-6 compares risks across the seven ground-water flow field types modeled in this analysis. Both cancer and noncancer risks vary substantially across flow fields. The noncancer risks (from sodium) are greatest in the slower moving flow fields that provide less dilution (i.e., flow fields A, B, and K), while the cancer risks (from arsenic) are greatest in the higher velocity/higher flow settings (i.e., flow fields C, D, and E). Sodium is highly mobile in ground water, and it is diluted to below threshold levels more readily in the high-velocity/high-flow aquifers. Arsenic is only moderately mobile in ground water and tends not to reach downgradient exposure points within the 200-year modeling period in the slower flow fields. If the modeling period were extended, cancer risks resulting from arsenic would appear in the more slowly moving flow field scenarios.

As would be expected, both cancer and noncancer risks increased with increasing recharge rate and with increasing subsurface permeability. Risk differences were generally less than an order of magnitude. Depth to ground water had very little effect on the 200-year maximum risk,





L = Large, M = Medium, S = Small Reserve Pits

Figure V-5 Health Risk Estimates (Unweighted) as a Function of Size and Distance. Unlined Reserve Pits. Conservative Modeling Assumptions

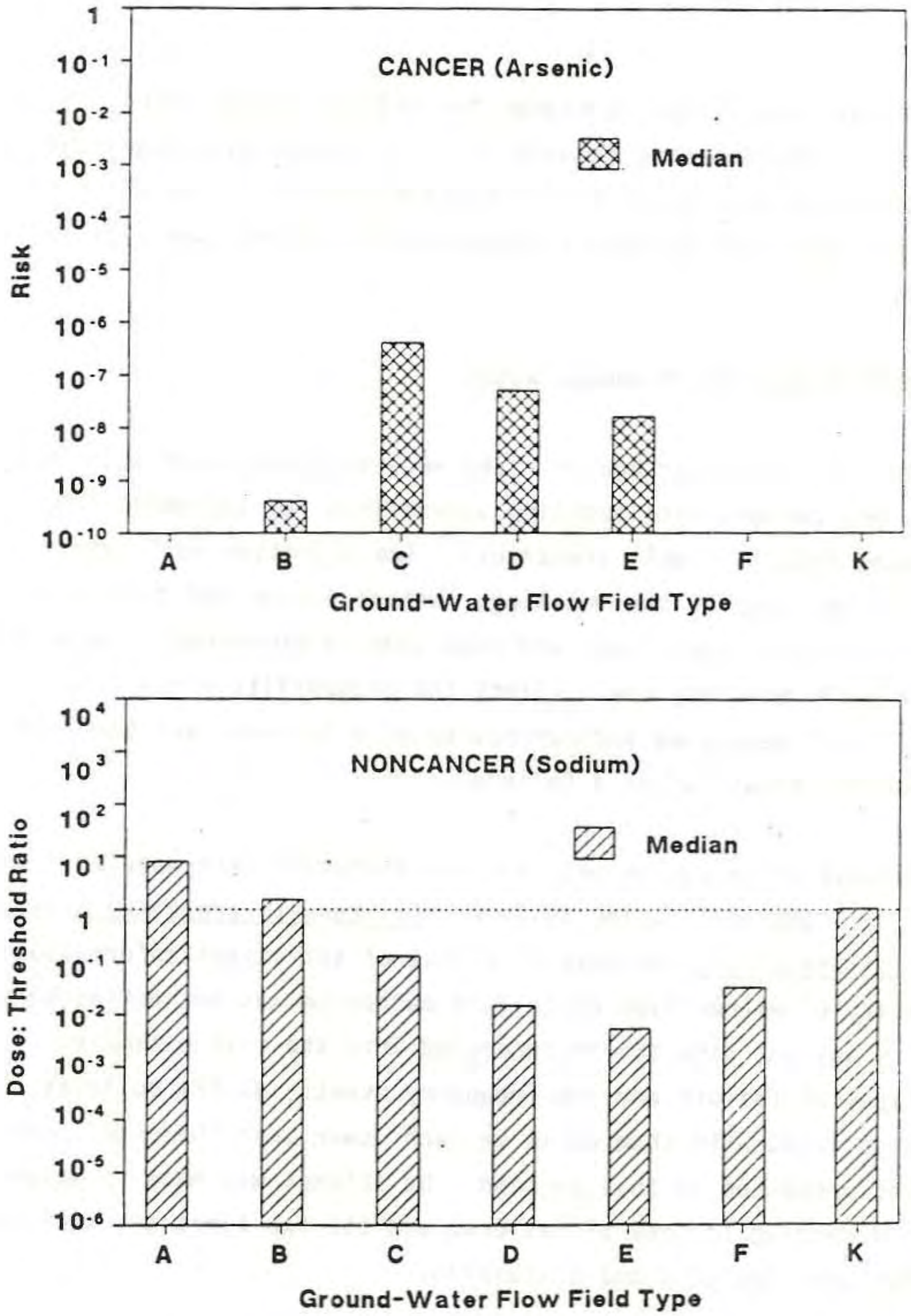


Figure V-6 Health Risk Estimates (Unweighted) as a Function of Ground-Water Type. Unlined Reserve Pits (Large). 60-Meter Exposure Distance. Conservative Modeling Assumptions although risks were slightly higher for shallow ground-water settings. This lack of effect occurs because the risk-producing contaminants are at least moderately mobile and do not degrade rapidly, if at all; thus, the main effect observed for deeper ground-water settings was a delay in exposures.

Underground Injection--Produced Water

Cancer and noncancer health risks were analyzed under both best-estimate and conservative modeling assumptions for 168 model Class II underground injection well scenarios.[9] Two injection well types were differentiated in the modeling: waterflooding and dedicated disposal. Design, operating, and regulatory differences between the two types of wells possibly could affect the probability of failure, the probability of detection and correction of a failure, and the likely magnitude of release given a failure.

Two types of injection well failure mechanism were modeled: grout seal failure and well casing failure. <u>All results presented here assume that a failure occurs</u>; because of a lack of sufficient information, the probability of either type of failure mechanism was not estimated and therefore was not directly incorporated into the risk estimates. If these types of failure are low-frequency events, as EPA believes, actual risks associated with them would be much lower than the conditional risk estimates presented in this section. No attempt was made to weight risk results according to type of failure, and the two types are kept separate throughout the analysis and discussion.

Nationally Weighted Risk Distributions

The risk estimates associated with injection well failures were weighted based on the estimated frequency of occurrence of the following

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[9] 168 = 7 ground-water flow field types x 3 exposure distances x 2 size categories x 2 well types x 2 failure mechanisms.

variables: injection well type, distance to nearest drinking water well, and ground-water flow field type. In addition, all risk results for grout seal failure were weighted based on injection rate. As for reserve pits, insufficient information was available to account for waste characteristics and other possibly important variables by weighting.

<u>Grout seal failure</u>: Best-estimate cancer risks, given a grout seal failure, were estimated to be zero for more than 85 percent of the model scenarios. The remaining scenarios had slightly higher risks but never did the best-estimate cancer risk exceed 1×10^{-7}. Under conservative assumptions, roughly 65 percent of the scenarios were estimated to have zero cancer risk, while the remaining 35 percent were estimated to have cancer risks ranging up to 4×10^{-4} (less than 1 percent of the scenarios had greater than 1×10^{4} risk). These modeled cancer risks were attributable to exposure to two produced water constituents, benzene and arsenic. Figure V-7 (top portion) provides a nationally weighted frequency distribution of the best-estimate and conservative-estimate cancer risks, given a grout seal failure. Figure V-7 shows the combined distribution for the two well types and two injection rates considered in the analysis, the three exposure distances, and the seven ground-water settings. As with drilling pits, many of the zero risk cases were because the nearest potential exposure well was estimated to be more than 2 kilometers away (roughly 64 percent of all scenarios).

Modeled noncancer risks, given a grout seal failure, are entirely attributable to exposures to sodium. There were no sodium threshold exceedances associated with grout seal failures under best-estimate conditions. Under conservative conditions, roughly 95 percent of the nationally weighted model scenarios also had no noncancer risk. The remaining 5 percent had estimated sodium concentrations at the exposure point that exceeded the effect threshold, with the maximum concentration exceeding the effect threshold by a factor of 70. The nationally

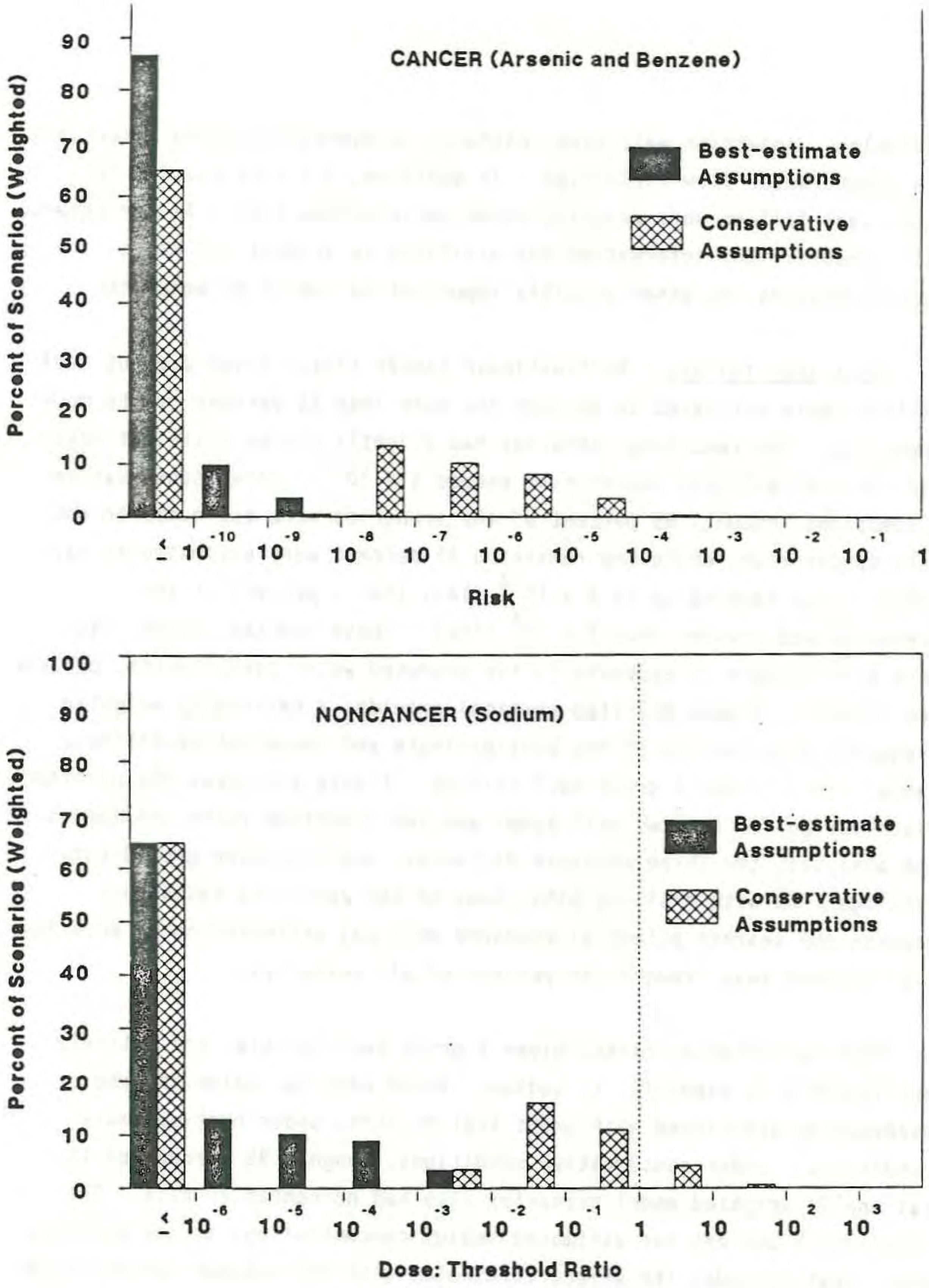


Figure V-7 Nationally Weighted Distribution of Health Risk Estimates. Underground Injection Wells: Grout Seal Failure Assumed weighted frequency distribution of the estimated dose/threshold ratios for sodium is shown in the bottom portion of Figure V-7.

Data are available on the taste and odor thresholds of two produced water model constituents: benzene and chloride. For the maximum cancer risk scenario assuming a grout seal failure, the estimated concentrations of benzene and chloride at the exposure well were below their respective taste and odor thresholds. However, for the maximum noncancer risk scenario assuming a grout seal failure, the estimated chloride concentration did exceed the taste threshold by roughly a factor of three. Therefore, people might be able to taste chloride in the highest noncancer risk scenarios, but it is questionable whether anybody would discontinue drinking water containing such a chloride concentration.

Well casing failure: The nationally weighted distributions of estimated cancer and noncancer risks, given an injection well casing failure, are presented in Figures V-8 and V-9. Figure V-8 gives the risk distributions for scenarios with high injection pressure, and Figure V-9 gives the risk distributions for scenarios with low injection pressure. (Because of a lack of adequate data to estimate the distribution of injection pressures, results for the high and low pressure categories were not weighted and therefore had to be kept separate.)

Best-estimate cancer risks, given a casing failure, were zero for approximately 65 percent of both the high and low pressure scenarios; the remaining scenarios had cancer risk estimates ranging up to 5×10^{-6} for high pressure and 1×10^{-6} for low pressure. The majority (65 percent) of both high and low pressure scenarios also had no cancer risks under the conservative assumptions, although approximately 5 percent of the high pressure scenarios and 1 percent of the low pressure scenarios had conservative-estimate cancer risks greater than 1×10^{-4} (maximum of 9×10^{4}). The rest of the scenarios had conservative-estimate cancer risks greater than zero and less than 1×10^{-4}.

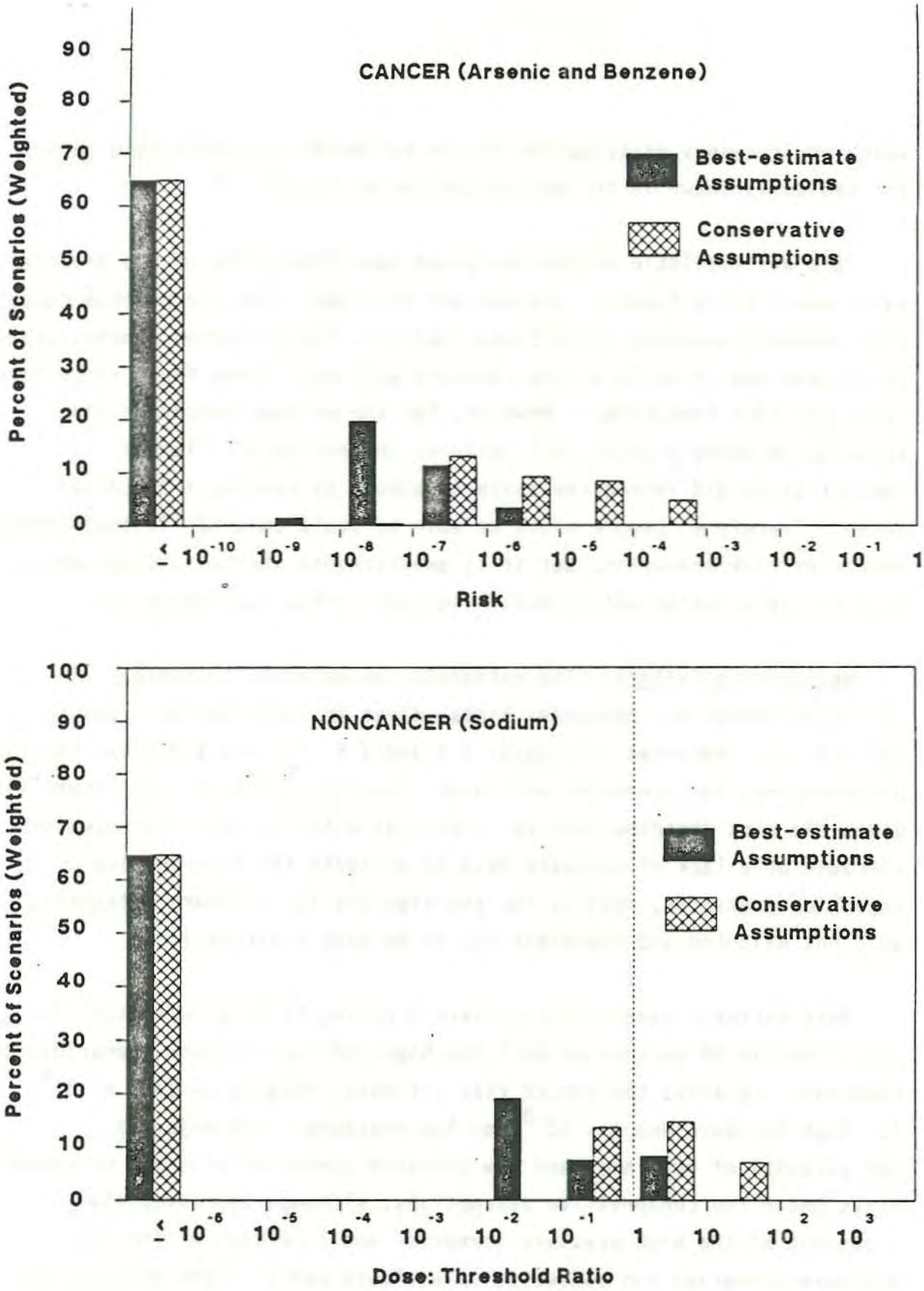


Figure V-8 Nationally Weighted Distribution of Health Risk Estimates. High Pressure Underground Injection Wells: Casing Failure Assumed

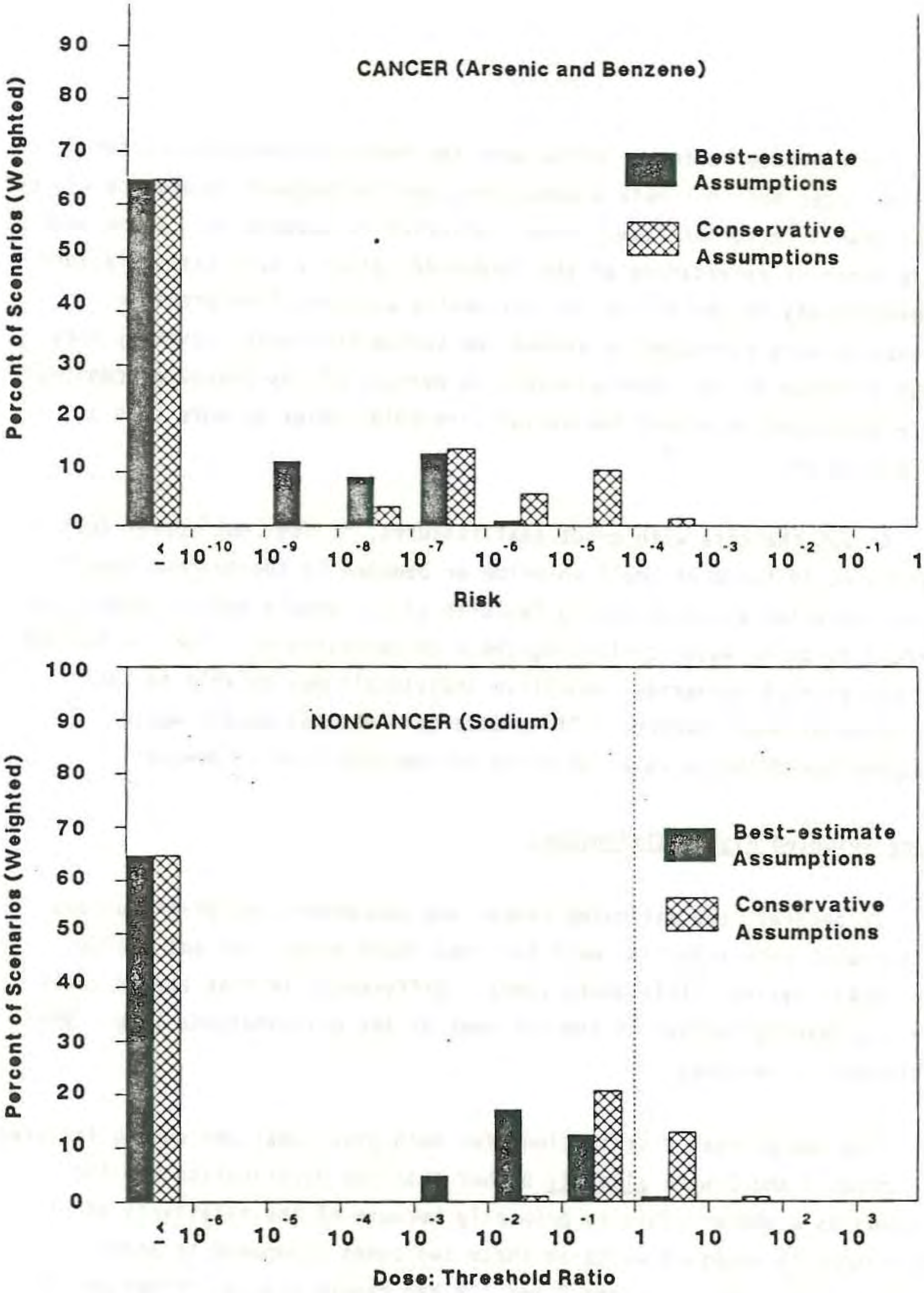


Figure V-9 Nationally Weighted Distribution of Health Risk Estimates. Low Pressure Underground Injection Wells: Casing Failure Assumed

For noncancer effects, there were few threshold exceedances for sodium under best-estimate assumptions, and the highest exceedance was by less than a factor of five. Under conservative assumptions, there were more numerous exceedances of the threshold, given a well casing failure. Approximately 22 percent of the nationally weighted high pressure scenarios were estimated to exceed the sodium threshold, never by more than a factor of 70. Approximately 14 percent of low pressure scenarios were estimated to exceed the sodium threshold, never by more than a factor of 35.

As was the case with grout seal failures, it does not appear that people would taste or smell chloride or benzene in the maximum cancer risk scenarios assuming casing failures (i.e., people would probably not refuse to drink water containing these concentrations). For the maximum noncancer risk scenarios, sensitive individuals may be able to taste chloride or smell benzene. It is uncertain whether people would discontinue drinking water at these contaminant levels, however.

Zone-Weighted Risk Distributions

In general, the estimated cancer and noncancer risk distributions associated with injection well failures (both grout seal and casing failures) varied little among zones. Differences in risk across zones were primarily limited to the extremes of the distributions (e.g., 90th percentile, maximum).

The cancer risk distributions for both grout seal and casing failures in zones 2 and 5 were slightly higher than the distribution for the nation as a whole. This is primarily because of the relatively short distances to exposure wells in these two zones (compared to other zones). In contrast, zones 8 and 11B had cancer risk distributions for injection well failures that were slightly lower than the national distribution. This difference is primarily because of the relatively long distance to exposure wells in these zones. (For almost 80 percent of production sites in both zones, it was estimated that the closest exposure well was more than 2 kilometers away.) A similar pattern of zone differences was observed for the noncancer risk results.

Evaluation of Major Factors Affecting Health Risk

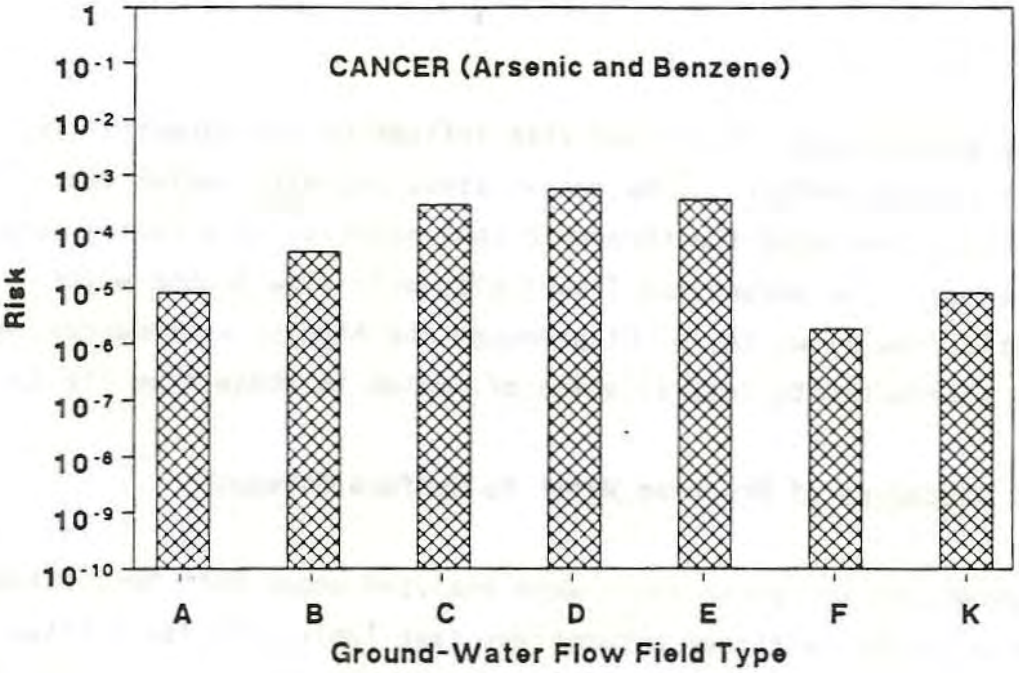
In general, estimated risks associated with well casing failure are from one to two orders of magnitude higher than risks associated with grout seal failure. This is because under most conditions modeled, well casing failures are estimated to release a greater waste volume, and thus a larger mass of contaminants, than grout seal failures.

The risks estimated for disposal and waterflood wells are generally similar in magnitude. For assumed casing failures, waterflood wells are estimated to cause slightly (no more than a factor of 2.5 times) higher risks than disposal wells. This pattern is the net result of two differences in the way waterflood and disposal wells were modeled. The release durations modeled for disposal wells are longer than those for waterflood wells, but the injection pressures modeled for waterflood wells are greater than those modeled for disposal wells. For assumed grout seal failures, disposal wells are estimated to cause slightly (no more than a factor of 3 times) higher risks than waterflood wells. This pattern results because the injection rates modeled for disposal wells are up to 3 times greater than those modeled for waterflood wells.

The distance to a potentially affected exposure well at an injection site is one of the most important indicators of risk potential. If all other parameters remain constant, carcinogenic risks decline slightly less than one order of magnitude between the 60-meter and 200-meter well distances; carcinogenic risks decline between one and two orders of magnitude from the 200-meter to the 1,500-meter well distances. The effect of well distance is a little less pronounced for noncarcinogenic risks. Sodium threshold exceedances drop by less than an order of magnitude between the 60-meter and 200-meter well distances and by approximately one order of magnitude between the 200-meter and 1,500-meter well distances. The reduction in exposure with increased distance from the well is attributable to three-dimensional dispersion of contaminants within the saturated zone. In addition, the 200-year modeling period limits risks resulting from less mobile constituents at greater distances (especially 1,500 meters). Degradation is not a factor because the constituents producing risk degrade very slowly (if at all) in the saturated zone.

Cancer and noncancer risk estimates decrease with decreasing injection rate/pressure. This relationship reflects the dependence of risk upon the total chemical mass released into the aquifer each year, which is proportional to either the assumed injection flow rate (grout seal failure) or pressure (casing failure).

Figure V-10 shows how the unweighted health risk estimates associated with injection well casing failures varied for the different ground-water flow fields. The figure includes only results for the conservative modeling assumptions, the high injection pressure, and the 60-meter modeling distance, because risk estimates under best-estimate assumptions and for other modeling conditions were substantially reduced and less varied. As shown, conservative-estimate carcinogenic risks ranged from roughly 2×10^{-6} (for flow field F) to approximately 6×10^{-4} (for flow field D). The difference in the risk estimates for these two flow fields is due primarily to their different aquifer configurations. Flow field D represents an unconfined aquifer, which is more susceptible to contamination than a confined aquifer setting represented by flow field F.



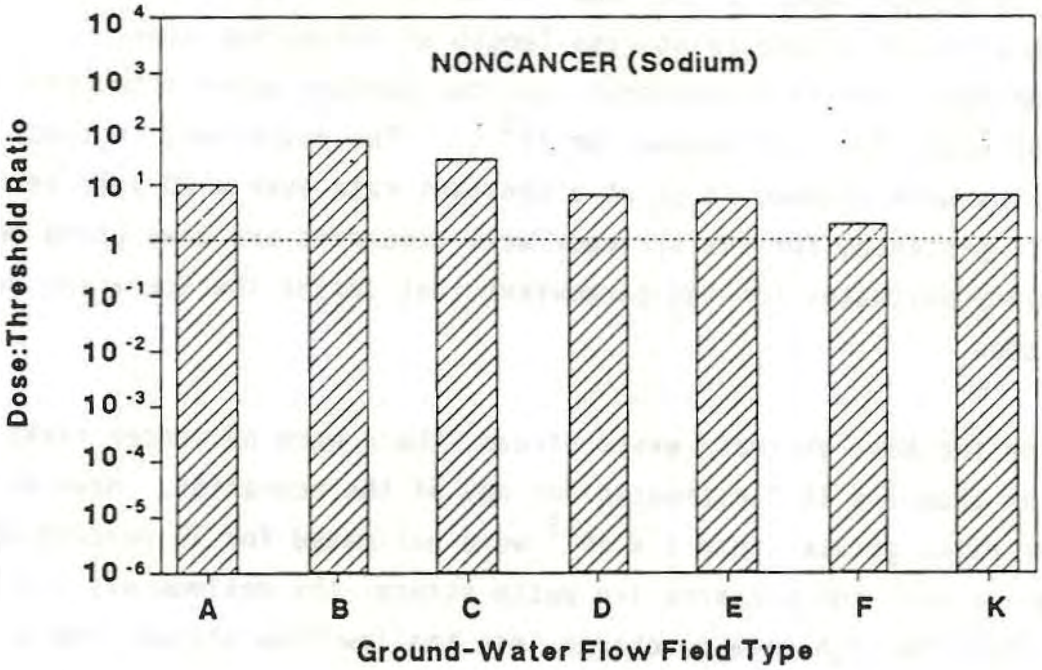


Figure V-10 Health Risk Estimates (Unweighted) as a Function of Ground-Water Type. High Pressure Underground Injection Wells: Casing Failure Assumed. 60-Meter Exposure Distance. Conservative Modeling Assumptions

The ground-water flow field also influenced the potential for noncarcinogenic effects. The conservative-estimate sodium concentrations at 60 meters exceeded the threshold concentration by a factor ranging up to 70 times. The unconfined flow fields with slow ground-water velocities/low flows (A, B, C) produced the highest exceedances, which can be attributed to less dilution of sodium in these flow fields.

Direct Discharge of Produced Water to Surface Streams

Cancer and noncancer risks were analyzed under both best-estimate and conservative waste stream assumptions (see Table V-1) for a total of 18 model scenarios of direct discharge of stripper well-produced fluids to surface waters. These scenarios included different combinations of three discharge rates (1, 10, and 100 barrels per day), three downstream distances to an intake point (the length of the mixing zone, 5 kilometers, and 50 kilometers), and two surface water flow rates (40 and 850 cubic feet per second, or ft^3/s). The discharges in these scenarios were assumed to be at a constant rate over a 20-year period. Results presented for the stripper well scenarios are unweighted because frequency estimates for the parameters that define the scenarios were not developed.

For the best-estimate waste stream, there were no cancer risks greater than 1×10^{-5} estimated for any of the scenarios. However, cancer risks greater than 1×10^{-5} were estimated for 17 percent of the scenarios with the conservative waste stream--the maximum was 3.5×10^{-5} (for the high-rate discharge into the low-flow stream, and a drinking water intake immediately downstream of the discharge point). These cancer risks were due primarily to exposure to arsenic, although benzene also contributed slightly. For noncancer risks, none of the scenarios had a threshold exceedance for sodium, regardless of whether the best-estimate or conservative waste stream was assumed.

EPA recognizes that the model surface water flow rates (40 and 850 ft^3/s) are relatively high and that discharges into streams or rivers with flow rates less than 40 ft^3/s could result in greater risks than are presented here. Therefore, to supplement the risk results for the model scenarios, EPA analyzed what a river or stream flow rate would have to be (given the model waste stream concentrations and discharges rates) in order for the contaminant concentration in the mixing zone (assuming instantaneous and complete mixing but no other removal processes) to be at certain levels.

The results of this analysis, presented in Table V-8, demonstrate that reference concentrations of benzene would be exceeded only in very low-flow streams (i.e., less than 5 ft^3/s) under all of the model conditions analyzed. It is unlikely that streams of this size would be used as drinking water sources for long periods of time. However, concentrations of arsenic and sodium under conservative modeling conditions could exceed reference levels in the mixing zone in relatively large streams, which might be used as drinking water sources. The concentrations would be reduced at downstream distances, although estimates of the surface water flow rates corresponding to reference concentrations at different distances have not been made.

Potentially Exposed Population

Preliminary estimates of the potentially exposed population were developed by estimating the number of individuals using private drinking water wells and public water supplies located downgradient from a sample of oil and gas wells. These estimates were based on data obtained from local water suppliers and 300 USGS topographic maps. One hundred of the maps were selected from areas containing high levels of drilling activity, and 200 were selected from areas containing high levels of production.

Table V-8 Surface Water Flow Rates At Which Concentrations of Waste Stream Constituents in the Mixing Zone Will Exceed Reference Levels[a]

		Waste stream discharge rate		
Constituent	Concentration in waste	High (100 BPD)	Medium (10 BPD)	Low (1 BPD)
Arsenic	Median	≤ 5 ft^3/s [b]	≤0.5 ft^3/s	≤ .05 ft^3/s
	90th %	≤ 470 ft^3/s	≤ 50 ft^3/s	≤ 5 ft^3/s
Benzene	Median	≤ 1 ft^3/s	≤ 0.1 ft^3/s	≤ 0.01 ft^3/s
	90th %	≤ 3 ft^3/s	≤ 0.3 ft^3/s	≤ 0.03 ft^3/s
Sodium	Median	≤ 3 ft^3/s	≤ 0.3 ft^3/s	≤ 0.03 ft^3/s
	90th %	≤ 20 ft^3/s	≤ 2 ft^3/s	≤ 0.2 ft^3/s

[a] The reference levels referred to are the arsenic and benzene concentrations that correspond to a 1×10^{-5} lifetime cancer risk level (assuming a 70-kg individual ingests 2 L/d) and EPA's suggested guidance level for sodium for the prevention of hypertension in high-risk individuals.

[b] Should be interpreted to mean that the concentration of arsenic in the mixing zone would exceed the 1×10^{-5} lifetime cancer risk level if the receiving stream or river was flowing at a rate of 5 ft^3/s or lower. If the stream or river was flowing at a higher rate, then the maximum concentration of arsenic would not exceed the 1×10^{-5} lifetime cancer risk level.

Table V-9 summarizes the sample results for the population potentially exposed through private drinking water wells. As shown in this table, over 60 percent of the oil and gas wells in both the drilling and production sample did not have private drinking water wells within 2,000 meters downgradient and only 2 percent of the oil and gas wells were estimated to have private drinking water wells within the 60-meter (i.e., higher-risk) distance category. Moreover, the numbers of potentially affected people per oil and gas well in the 60-meter distance category were relatively small. One other interesting finding demonstrated in Table V-9 is that fewer potentially affected individuals were estimated to be in the 1,500-meter distance category than in the 200-meter category. This situation is believed to occur because some residences located farther from oil and gas wells were on the other side of surface waters that appeared to be a point of ground-water discharge.

The sample results for the population potentially exposed through public water supplies are summarized in Table V-10. These results show a pattern similar to those for private drinking water wells; this is, most oil and gas wells do not have public water supply intakes within 2,000 meters and of those that do only a small fraction have public water supply intakes within the 60-meter distance category.

The results in Tables V-9 and V-10 are for the nation as a whole. Recognizing the limitations of the sample and of the analysis methods, EPA's data suggest that zone 2 (Appalachia) and zone 7 (Texas/Oklahoma) have the greatest relative number of potentially affected individuals per oil and gas well (i.e., potentially affected individuals are, on the average, closer to oil and gas wells in these zones relative to other zones). In addition, zone 4 (Gulf) has a relatively large number of individuals potentially affected through public water supplies. Zone 11 (Alaska) and zone 8 (Northern Mountain) appear to have relatively fewer potentially affected individuals per oil and gas well. Further

Table V-9 Population Potentially Exposed Through Private Drinking Water Wells at Sample Drilling and Production Areas

	Drilling sample results		Production sample results	
Distance category[a]	No. (%) of oil/gas wells with private drinking water wells within distance category	Maximum no. of potentially affected individuals per oil and gas well[b]	No. (%) of oil/gas wells with private drinking water wells within distance category	Maximum no. of potentially affected individuals per oil and gas well[b]
60 meters	561(2)	0.11	642(2)	0.17
200 meters	4,765(17)	0.44	5,139(16)	0.58
1,500 meters	5,606(20)	0.32	5,460(17)	0.36
>2,000 meters	17,096(61)	NA[c]	20,879(65)	NA

[a] Drinking water wells were counted as 60 meters downgradient if they were within 0 and 130 meters, were counted as 200 meters downgradient if they were within 130 and 800 meters, and were counted as 1,500 meters downgradient if they were within 800 and 2,000 meters.

[b] These ratios largely overestimate the number of people actually affected per oil and gas well (see text) and should be used to estimate the total number of people affected only with caution. The figures are intended simply to give a preliminary indication of the <u>potentially</u> exposed population and the distribution of that population in different distance categories.

[c] Not available; distances greater than 2,000 meters from oil and gas wells were not modeled.

Table V-10 Population Potentially Exposed Through Public Water Supplies at Sample Drilling and Production Areas

	Drilling sample results			Production sample results		
Distance category[a]	No. (%) of oil/gas wells with private drinking water wells within distance category		Maximum no. of potentially affected individuals per oil and gas well[b]	No. (%) of oil/gas wells with private drinking water wells within distance category		Maximum no. of potentially affected individuals per oil and gas well[b]
60 meters	87	(0.3)	3.6	54	(0.2)	96
200 meters	217	(0.8)	0.76	210	(0.7)	8.1
1,500 meters	232	(0.8)	0.55	617	(2)	3.9
>2,000 meters	27,492	(98)	NA[c]	31,239	(97)	NA[c]

[a] Public water supply intakes were counted as 60 meters downgradient if they were within 0 and 130 meters, were counted as 200 meters downgradient if they were within 130 and 800 meters, and were counted as 1,500 meters downgradient if they were within 800 and 2,000 meters.

[b] These ratios largely overestimate the number of people actually affected per oil and gas well (see text) and should be used to estimate the total number of people affected only with caution. The figures are intended simply to give a preliminary indication of the potentially exposed population and the distribution of that population in different distance categories.

[c] Not available; distances greater than 2,000 meters from oil and gas wells were not modeled.

discussion of the differences in population estimates across zones is provided in the supporting technical report (USEPA 1987a).

The number of potentially affected people per oil and gas well in Tables V-9 and V-10 represents the maximum number of people in the sample that could be affected if all the oil and gas wells in the sample resulted in ground-water contamination out to 2,000 meters. The number of persons actually affected is probably much smaller because ground water may not be contaminated at all (if any) of the sites, some of the individuals may rely on surface water or rainwater rather than on ground water, and some of the individuals and public water supplies may not have drinking water wells that are hydraulically connected to possible release sources. Also, the sample population potentially exposed through public water supplies is probably far less than estimated, because public water is frequently treated prior to consumption (possibly resulting in the removal of oil and gas waste contaminants) and because many supply systems utilize multiple sources of water, with water only at times being drawn from possibly contaminated sources. Therefore, these ratios largely overestimate the number of people actually exposed per oil and gas well and should be used to estimate the total number of people affected only with caution. The figures are intended simply to give a preliminary indication of the potentially exposed population and the distribution of that population in different distance categories.

QUANTITATIVE RISK MODELING RESULTS: RESOURCE DAMAGE

For the purposes of this study, resource damage is defined as the exceedance of pre-set threshold (i.e., "acceptable") concentrations for individual contaminants, based on levels associated with aquatic toxicity, taste and odor, or other adverse impacts. Potential ground-water and surface water damage was measured as the maximum (over the 200-year modeling time period) annual volume of contaminated water flowing past various points downgradient or downstream of the source. Only the volume of water that exceeded a damage threshold concentration was considered to be contaminated. This measure of potential ground-water and surface water damage was computed for each of three distances downgradient or downstream from a source: 60, 200, and 1,500 meters.

These estimates of resource damage supplement, but should be considered separate from, the damage cases described in Chapter IV. The resource damage results summarized here are strictly for the model scenarios considered in this analysis, which represent: (1) seepage of reserve pit wastes; (2) releases of produced water from injection well failures; and (3) direct discharge of produced water from stripper wells to streams and rivers. While these releases may be similar to some of the damage cases described in Chapter IV, no attempt was made to correlate the scenarios to any given damage case(s). In addition, Chapter IV describes damage cases from several types of releases (e.g., land application) that were not modeled as part of this quantitative risk analysis.

Potential Ground-Water Damage--Drilling Wastes

Two contaminants were modeled for ground-water resource damage associated with onsite reserve pits. These contaminants were chloride ions in concentrations above EPA's secondary maximum contaminant level and total mobile ions (TMI) in concentrations exceeding the level of total dissolved salts predicted to be injurious to sensitive and moderately sensitive crops. Chloride is highly mobile in ground water and the other ions were assumed to be equally mobile.

On a national basis, the risks of significant ground-water damage were very low for the model scenarios included in the analysis. Under the best-estimate modeling assumptions, only 2 percent of nationally weighted reserve pit scenarios were estimated to cause measurable ground-water damage at 60 meters resulting from TMI. Under the conservative modeling assumptions, less than 10 percent of reserve pits were associated with ground-water plumes contaminated by chloride and TMI at 60 meters and fewer than 2 percent at 200 meters. On a regional basis, the upper 90th percentile of the distributions for resource damage, under conservative modeling assumptions, were above zero for zones 2, 5, and 8. This zone pattern is similar to the zone pattern of noncancer human health risks from sodium. Flow field A was more heavily weighted for these three zones than for the remaining zones, and this flow field also was responsible for the highest downgradient concentrations of sodium of all the flow fields modeled.

The mobilities of chloride and total mobile salts in ground water were the same as the mobility of sodium, which was responsible for the noncancer human health risks. Thus, the effects of several pit design and environmental parameters on the volume of ground water contaminated above criteria concentrations followed trends very similar to those followed by the noncancer human health risks. These parameters included reserve pit size, net recharge, subsurface permeability, and depth to ground water. In contrast to the trend in noncancer human health risks, however, the magnitude of resource damage sometimes increased with increasing distance from the reserve pit. This is because contaminant concentrations (and thus health risks) decrease with distance traveled; however, the width of a contaminant plume (and thus the volume of contaminated water) increases up to a point with distance traveled. Eventually, however, the center line concentration of the plume falls below threshold, and the estimated volume of contaminated water at that distance falls to zero. Finally, as was the case with noncancer human health risks, only the slower aquifers were associated with significant estimates of resource damage.

Potential Ground-Water Damage--Produced Water

As they were for drilling wastes, chloride and total mobile ions were modeled to estimate ground-water resource damage associated with underground injection of produced water. Under best-estimate conditions, the risk of ground water becoming contaminated above the thresholds if injection well casing failures were to occur was negligible. Furthermore, in all but a few scenarios (approximately 1 percent of the nationally weighted scenarios), the resource damage estimates did not exceed zero under conservative assumptions. Estimated resource damage was almost entirely confined to the 60-meter modeling distance.

Grout seal failures were estimated to pose a slightly smaller risk of contaminating ground water above the chloride or TMI thresholds than injection well casing failures. In roughly 99 percent of the nationally weighted scenarios, grout seal failures never resulted in threshold exceedances, regardless of the set of conditions assumed (best-estimate vs. conservative) or the downgradient distance analyzed. Again, estimated resource damage was almost entirely confined to the 60-meter modeling distance.

In general, injection well failures were estimated to contaminate larger volumes of ground water above the damage criteria under conditions involving higher injection rates/pressures and lower ground-water velocities/flows (i.e., flow fields A, B, C, and K). The estimated TMI concentration exceeded its threshold for the low injection rate very rarely, and only out to a distance of 60 meters. Chloride and TMI threshold exceedances were limited almost exclusively to conditions involving the high injection rate or pressure. The slower velocity/lower flow ground-water settings permit less dilution (i.e., a higher probability of threshold exceedance) of constituents modeled for resource damage effects. In a trend similar to that observed for health risks, waterflood wells were estimated to contaminate larger volumes of ground water than disposal wells under conditions involving casing failures, but disposal wells were estimated to contaminate larger volumes under conditions involving grout seal failures. Finally, the resource damage estimates for injection well failures (and also for reserve pit leachate) indicate that TMI is a greater contributor to ground-water contamination than chloride. The reason for this difference is that the mobile salts concentration in the model produced water waste stream is more than three times the chloride concentration (see Table V-1), while the resource damage thresholds differ by a factor of two (see Table V-2).

Potential Surface Water Damage

EPA examined the potential for surface water damage resulting from the influx of ground water contaminated by reserve pit seepage and injection well failures, as well as surface water damage resulting from direct discharge of stripper well produced water. For all model scenarios, EPA estimated the average annual surface water concentrations of waste constituents to be below their respective thresholds at the point where they enter the surface water; that is, the threshold concentrations for various waste constituents were not exceeded even at the point of maximum concentration in surface waters. This is because the input chemical mass is diluted substantially upon entering the surface water. Surface water usually flows at a much higher rate than ground water and also allows for more complete mixing than ground water. Both of these factor suggest that there will be greater dilution in surface water than in ground water. One would expect, therefore, that the low concentrations in ground water estimated for reserve pit seepage and injection well failures would be diluted even further upon seeping into surface water.

These limited modeling results do not imply that resource damage could not occur from larger releases, either through these or other migration pathways or from releases to lower flow surface waters (i.e., streams with flows below 40 ft^3/s). In addition, surface water damages could occur during short periods (less than a year) of low stream flow or peak waste discharge, which were not modeled in this study.

EPA analyzed what a river or stream flow rate would have to be (given the model produced water concentrations and discharge rates from stripper wells) in order for contaminant concentrations in the mixing zone (assuming instantaneous and complete mixing but not other removal processes) to exceed resource damage criteria. The results of this analysis are summarized in Table V-11. As shown, the maximum concentrations of chloride, boron, sodium, and TMI in streams or rivers caused by the discharge of produced water from stripper wells would (under most modeling conditions) not exceed resource damage criteria unless the receiving stream or river was flowing at a rate below 1 ft^3/s. The exceptions are scenarios with a conservative waste stream concentration and high discharge rate. If produced water was discharged to streams or rivers under these conditions, the maximum concentrations of sodium and TMI could exceed resource damage criteria in surface waters flowing up to 5 ft^3/s. (The maximum concentrations in any surface water flowing at a greater rate would not exceed the criteria.)

The results suggest that, if produced waters from stripper wells are discharged to streams and rivers under conditions that are similar to those modeled, resource damage criteria would be exceeded only in very small streams.

ASSESSMENT OF WASTE DISPOSAL ON ALASKA'S NORTH SLOPE

In accordance with the scope of the study required by RCRA Section 8002(m), this assessment addresses only the potential impacts associated

Table V-11 Surface Water Flow Rates At Which Concentrations of Waste Stream Constituents in the Mixing Zone Will Exceed Aquatic Effects and Resource Damage Thresholds[a]

Constituent	Concentration in waste	Waste stream discharge rate		
		High (100 BPD)	Medium (10 BPD)	Low (1 BPD)
Sodium	Median	$\leq 0.7\ ft^3/s$[b]	$\leq 0.07\ ft^3/s$	$\leq 0.007\ ft^3/s$
	90th %	$\leq 5\ ft^3/s$	$\leq 0.5\ ft^3/s$	$\leq 0.05\ ft^3/s$
Chloride	Median	$\leq 0.2\ ft^3/s$	$\leq 0.02\ ft^3/s$	$\leq 0.002\ ft^3/s$
	90th %	$\leq 0.9\ ft^3/s$	$\leq 0.09\ ft^3/s$	$\leq 0.009\ ft^3/s$
Boron	Median	$\leq 0.06\ ft^3/s$	$\leq 0.006\ ft^3/s$	$\leq 0.0006\ ft^3/s$
	90th %	$\leq 0.8\ ft^3/s$	$\leq 0.08\ ft^3/s$	$\leq 0.008\ ft^3/s$
Total Mobile Ions	Median	$\leq 0.4\ ft^3/s$	$\leq 0.04\ ft^3/s$	$\leq 0.004\ ft^3/s$
	90th %	$\leq 2\ ft^3/s$	$\leq 0.2\ ft^3/s$	$\leq 0.02\ ft^3/s$

[a] The effect thresholds and effects considered in this analysis were as follows: Sodium-83 mg/L, which might result in toxic effects or osmoregulatory problems for freshwater aquatic organisms (note: while this threshold is based on toxicity data reported in the literature, it is dependent on several assumptions and is speculative); chloride--250 mg/L, which is EPA's secondary drinking water standard designed to prevent excess corrosion of pipes in hot water systems and to prevent objectionable tastes; boron--1 mg/L, which is a concentration in irrigation water that could damage sensitive crops (e.g., citrus trees; plum, pear, and apple trees; grapes; and avocados); and total mobile Ions--335 mg/L, which may be a tolerable level for freshwater species but would probably put them at a disadvantage in competing with brackish or marine organisms.

[b] Should be interpreted to mean that the concentration of sodium in the mixing zone would exceed the modeled effect threshold (described in footnote a) if the receiving stream or river was flowing at a rate of 0.7 ft^3/s or lower. If the stream or river was flowing at a higher rate, then the maximum concentration of sodium would not exceed the effect level.

with the management of exempt oil and gas wastes on Alaska's North Slope. It does not analyze risks or impacts from other activities, such as site development or road construction. The North Slope is addressed in a separate, qualitative assessment because readily available release and transport models for possible use in a quantitative assessment are not appropriate for many of the characteristics of the North Slope, such as the freeze-thaw cycle, the presence of permafrost, and the typical reserve pit designs.

Of the various wastes and waste management practices on the North Slope, it appears that the management of drilling waste in above-ground reserve pits has the greatest potential for adverse environmental effects. The potential for drilling wastes to cause adverse human health effects is small because the potential for human exposure is small. Virtually all produced water on the North Slope is reinjected approximately 6,000 to 9,000 feet below the land surface in accordance with discharge permits issued by the State of Alaska. The receiving formation is not an underground source of drinking water and is effectively sealed from the surface by permafrost. Consequently, the potential for environmental or human health impacts associated with produced fluids is very small under routine operating conditions.

During the summer thaw, reserve pit fluids are disposed of in underground injection wells, released directly onto the tundra or applied to roads if they meet quality restrictions specified in Alaska discharge permits, or stored in reserve pits. Underground injection of reserve pit fluids should have minor adverse effects for the same reasons as were noted above for produced waters. If reserve pit fluids are managed through the other approaches, however, there is much greater potential for adverse environmental effects.

Discharges of reserve pit fluids onto the tundra and roads are regulated by permits issued by the Alaska Department of Environmental Conservation (ADEC). In the past, reserve pit discharges have occasionally exceeded permit limitations for certain constituents. New permits, therefore, specify several pre-discharge requirements that must be met to help ensure that the discharge is carried out in an acceptable manner.

Only one U.S. Government study of the potential effects of reserve pit discharges on the North Slope is known to be complete. West and Snyder-Conn (1987), with the U.S. Fish and Wildlife Service, examined how reserve pit discharges in 1983 affected water quality and invertebrate communities in receiving tundra ponds and in hydrologically connected distant ponds. Although the nature of the data and the statistical analysis precluded a definitive determination of cause and effect, several constituents and characteristics (chromium, barium, arsenic, nickel, hardness, alkalinity, and turbidity) were found in elevated concentrations in receiving ponds when compared to control ponds. Also, alkalinity, chromium, and aliphatic hydrocarbons were elevated in hydrologically connected distant ponds when compared to controls. Accompanying these water quality variations was a decrease in invertebrate taxonomic richness, diversity, and abundance from control ponds to receiving ponds.

West and Snyder-Conn, however, cautioned that these results cannot be wholly extrapolated to present-day oil field practices on the North Slope because some industry practices have changed since 1983. For example, they state that "chrome lignosulfonate drill muds have been partly replaced by non-chrome lignosulfonates, and diesel oil has been largely replaced with less toxic mineral oil in drilling operations." Also, State regulations concerning reserve pit discharges have become increasingly stringent since the time the study was conducted. West and

Snyder-Conn additionally concluded that reserve pit discharges should be subject to standards for turbidity, alkalinity, chromium, arsenic, and barium to reduce the likelihood of biological impacts. ADEC's 1987 tundra discharge permit specifies effluent limitations for chromium, arsenic, barium, and several other inorganics, as well as an effluent limitation for settleable solids (which is related to turbidity). The 1987 permit requires monitoring for alkalinity, but does not specify an effluent limit for this parameter.

Reserve pits on the North Slope are frequently constructed above grade out of native soils and gravel. Below-grade structures are also built, generally at exploratory sites, and occasionally at newer production sites. Although the mud solids that settle at the bottom of the pits act as a barrier to fluid flow, fluids from above-ground reserve pits (when thawed) can seep through the pit walls and onto the tundra. No information was obtained on what percentage of the approximately 300 reserve pits on the North Slope are actually leaking; however, it has been documented that "some" pits do in fact seep (ARCO 1985, Standard Oil 1987). While such seepage is expected to be sufficiently concentrated to adversely affect soil, water, vegetation, and dependent fauna in areas surrounding the reserve pits, it is not known how large an area around the pits may be affected. Preliminary studies provided by industry sources indicate that seepage from North Slope reserve pits, designed and managed in accordance with existing State regulations, should not cause damage to vegetation more than 50 feet away from the pit walls (ARCO 1986, Standard Oil 1987). It is important to note that ADEC adopted regulations that should help to reduce the occurrence of reserve pit seepage and any impacts of drilling waste disposal. These regulations became effective in September 1987.

While some of the potentially toxic constituents in reserve pit liquids are known to bioaccumulate (i.e., be taken up by organisms low in the food chain with subsequent accumulation in organisms higher in the food chain), there is no evidence to conclude that bioaccumulation from reserve pit discharge or seepage is occurring. In general, bioaccumulation is expected to be small because each spring thaw brings a large onrush of water that may help flush residual contamination, and higher level consumers are generally migratory and should not be exposed for extended periods. It is recognized, however, that tundra invertebrates constitute the major food source for many bird species on the Arctic coastal plain, particularly during the breeding and rearing seasons, which coincide with the period that tundra and road discharges occur. The Fish and Wildlife Service is in the process of investigating the effects of reserve pit fluids on invertebrates and birds, and these and other studies need to be completed before conclusions can be reached with respect to the occurrence of bioaccumulation on the North Slope.

With regard to the pit solids, the walls of operating pits have slumped on rare occasions, allowing mud and cuttings to spill onto the surrounding tundra. As long as these releases are promptly cleaned up, the adverse effects to vegetation, soil, and wildlife should be temporary (Pollen 1986, McKendrick 1986).

ADEC's new reserve pit closure regulations for the North Slope contain strengthened requirements for reserve pit solids to be dewatered, covered with earth materials, graded, and vegetated. The new regulations also require owners of reserve pits to continue monitoring and to maintain the cover for a minimum of 5 years after closure. If the reserve pit is constructed below grade such that the solids at closure are at least 2 feet below the bottom of the soil layer that thaws each spring, the solids will be kept permanently frozen (a phenomenon referred to as freezeback). The solids in closed above-grade pits will also undergo freezeback if they are covered with a sufficient layer of earth material to provide insulation. In cases where the solids are kept permanently frozen, no leaching or erosion of the solid waste constituents should occur. However, ADEC's regulations do not require reserve pits to be closed in a manner that ensures freezeback. Therefore, some operators may choose to close their pits in a way that permits the solids to thaw during the spring. Even when the solids are not frozen, migration of the waste constituents will be inhibited by the reserve pit cover and the low rate of water infiltration through the solids. Nevertheless, in the long term, the cover could slump and allow increased snow accumulation in depressed areas. Melting of this snow could result in infiltration into the pit and subsequent leaching of the thawed solid waste contaminants. Also, for closed above-grade pits, long-term erosion of the cover could conceivably allow waste solids, if thawed, to migrate to surrounding areas. Periodic monitoring would forestall such possibilities.

LOCATIONS OF OIL AND GAS ACTIVITIES IN RELATION TO ENVIRONMENTS OF SPECIAL INTEREST

EPA analyzed the proximity of oil and gas activities to three categories of environments of special interest to the public: endangered and threatened species habitats, wetlands, and public lands. The results of this analysis are intended only to provide a rough approximation of the degree of and potential for overlap between oil and gas activities and these areas. The results should not be interpreted to mean that areas where oil and gas activities are located are necessarily adversely affected.

All of the 26 States having the highest levels of oil and gas activity are within the historical ranges of numerous endangered and threatened species habitats. However, of 190 counties across the U.S. identified as having high levels of exploration and production, only 13 (or 7 percent) have Federally designated critical habitats[10] within their boundaries. These 13 counties encompass the critical habitats for a total of 10 different species, or about 10 percent of the species for which critical habitats have been designated on the Federal level.

Wetlands create habitats for many forms of wildlife, purify natural waters by removing sediments and other contaminants, provide flood and storm damage protection, and afford a number of other benefits. In general, Alaska and Louisiana are the States with the most wetlands and oil and gas activity. Approximately 50 to 75 percent of the North Slope area consists of wetlands (Bergman et al. 1977). Wetlands are also abundant throughout Florida, but oil and gas activity is considerably less in that State and is concentrated primarily in the panhandle area. In addition, oil and gas activities in Illinois appear to be concentrated in areas with abundant wetlands. Other States with abundant wetlands (North Carolina, South Carolina, Georgia, New Jersey, Maine, and Minnesota) have very little onshore oil and gas activity.

For the purpose of this analysis, public lands are defined as the wide variety of land areas owned by the Federal Government and administered by the Bureau of Land Management (BLM), National Forest Service, or National Park Service. Any development on these lands must first pass through a formal environmental planning and review process. In many cases, these lands are not environmentally sensitive. National Forests, for example, are established for multiple uses, including timber development, mineral extraction, and the protection of environmental values. Public lands are included in this analysis, however, because they are considered "publicly sensitive," in the sense that they are commonly valued more highly by society than comparable areas outside

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[10] Critical habitats, which are much smaller and more rigorously defined than historical ranges, are areas containing physical or biological factors essential to the conservation of the species.

their boundaries. The study focuses only on lands within the National Forest and National Park Systems because of recent public interest in oil and gas development in these areas (e.g., see Sierra Club 1986; Wilderness Society 1987).

The National Forest System comprises 282 National Forests, National Grasslands, and other areas and includes a total area of approximately 191 million acres. Federal oil and gas leases, for either exploration or production, have been granted for about 25 million acres (roughly 27 percent) of the system. Actual oil and gas activity is occurring on a much smaller acreage distributed across 11 units in eight States. More than 90 percent of current production on all National Forest System lands takes place in two units: the Little Missouri National Grassland in North Dakota and the Thunder Basin National Grassland in Wyoming.

The National Park System contains almost 80 million acres made up by 337 units and 30 affiliated areas. These units include national parks, preserves, monuments, recreation areas, seashores, and other areas. All units have been closed to future leasing of Federal minerals except for four national recreation areas where mineral leasing has been authorized by Congress and permitted under regulation. If deemed acceptable from an environmental standpoint, however, nonfederally owned minerals within a unit's boundaries can be leased.[11] Ten units (approximately 3 percent of the total) currently have active oil and gas operations within their boundaries. Approximately 23 percent of the land area made up by these ten units is currently under lease (approximately 256,000 acres); however, 83 percent of the area within the ten units (almost one million acres) is leasable. The National Park Service also has identified 32 additional units that do not have active oil and gas operations at present, but do have the potential for such activities in the future.

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[11] Nonfederally owned minerals within National Park System units exist where the Federal Government does not own all the land within a unit's boundaries or does not possess the subsurface mineral rights.

Several of these units also have acres that are under lease for oil and gas exploration, development, and production. In total, approximately 334,700 acres within the National Park System (or roughly 4 percent of the total) are currently under lease for oil and gas.

CONCLUSIONS

EPA's major conclusions, along with a summary of the main findings on which they are based, are listed below. EPA recognizes that the conclusions are limited by the lack of complete data and the necessary risk modeling assumptions. In particular, the limited amount of waste sampling data and the lack of empirical evidence on the probability of injection well failures have made it impossible to estimate precisely the absolute nationwide or regional risks from current waste management practices for oil and gas wastes. Nevertheless, EPA believes that the risk analysis presented here has yielded many useful conclusions relating to the nature of potential risks and the circumstances under which they are likely to occur.

General Conclusions

- For the vast majority of model scenarios evaluated in this study, only very small to negligible risks would be expected to occur even if the toxic chemical(s) of concern were of relatively high concentration in the wastes <u>and</u> there was a release into ground water as was assumed in this analysis. Nonetheless, the model results also show that there are realistic combinations of measured chemical concentrations (at the 90th percentile level) and release scenarios that could be of substantial concern. EPA cautions that there are other release modes not considered in this analysis that could also contribute to risks. In addition, there are almost certainly toxic contaminants in the large unsampled population of reserve pits and produced fluids that could exceed concentration levels measured in the relatively small number of waste samples analyzed by EPA.

- EPA's modeling of resource damages to surface water--both in terms of ecological impact and of resource degradation--generally did not show significant risk. This was true both for ground-water seepage and direct surface water discharge (from stripper wells) pathways for drilling pit and produced water waste streams. This conclusion holds for the range of receiving water flow rates modeled, which included only moderate (40 ft^3/s) to large (850 ft^3/s) streams. It is clear that potential damages to smaller streams would be quite sensitive to relative discharge or ground-water seepage rates.

- Of the hundreds of chemical constituents detected in both reserve pits and produced water, only a few from either source appear to be of primary concern relative to health or environmental damages. Based on an analysis of toxicological data, the frequency and measured concentrations of waste constituents in the relatively small number of sampled waste streams, and the mobility of these constituents in ground water, EPA found a limited number of constituents to be of primary relevance in the assessment of risks via ground water. Based on current data and analysis, these constituents include arsenic, benzene, sodium, chloride, cadmium, chromium, boron, and mobile salts. All of these constituents were included in the quantitative risk modeling in this study. Cadmium, chromium, and boron did not produce risks or resource damages under the conditions modeled. Note: This conclusion is qualified by the small number of sampled sites for which waste composition could be evaluated.

- Both for reserve pit waste and produced water, there is a very wide (six or more orders of magnitude) variation in estimated health risks across scenarios, depending on the different combinations of key variables influencing the individual scenarios. These variables include concentrations of toxic chemicals in the waste, hydrogeologic parameters, waste amounts and management practices, and distance to exposure points.

Drilling Wastes Disposed of in Onsite Reserve Pits

- Most of the 1,134 onsite reserve pit scenarios had very small or no risks to human health via ground-water contamination of drinking water for the conditions modeled. Under the best-estimate assumptions, there were no carcinogenic waste constituents modeled (median concentrations for carcinogens in the EPA samples were zero or below detection), and more than 99 percent of the nationally weighted reserve pit scenarios resulted in exposure to noncarcinogens (sodium, cadmium, chromium) at concentration levels below health effect thresholds. Under more conservative assumptions, including toxic constituents at 90th percentile sample concentrations, no scenarios evaluated yielded lifetime cancer risks as high as 1 in 100,000 (1×10^{-5}),[12] and only 2 percent of the nationally weighted conservative scenarios showed cancer risks greater than 1×10^{-7}. Noncancer risks were estimated by threshold exceedances for only 2 percent of nationally weighted scenarios, even when the 90th percentile concentration of sodium in the waste stream was assumed. The maximum sodium concentration at drinking water wells was estimated to be roughly 32 times the threshold for hypertension. In general, these modeling results suggest that most onsite reserve pits will present very low risks to human health through ground-water exposure pathways.

- It appears that people may be able to taste chloride in the drinking water in those scenarios with the highest cancer and noncancer risks. It is questionable, however, whether people would actually discontinue drinking water containing these elevated chloride concentrations.

- Weighting the risk results to account for different distributions of hydrogeologic variables, pit size, and exposure distance across geographic zones resulted in limited variability in risks across zones. Risk distributions for individual zones generally did not differ from the national distribution by more than one order of magnitude, except for zones 10 (West Coast) and 11B (Alaska, non-North Slope), which usually were extremely low. Note: EPA was unable to develop geographical comparisons of toxic constituent concentrations in drilling pit wastes.

- Several factors were evaluated for their individual effects on risk. Of these factors, ground-water flow field type and exposure distance had the greatest influence (several orders of magnitude); recharge rate, subsurface permeability, and pit size had less, but measurable, influence (approximately one order of magnitude). Typically, the higher risk cases occur in the context of the largest unlined pits, the short (60-meter) exposure distance, and high subsurface permeability and infiltration. Depth to ground water and presence/absence of a single synthetic liner had virtually no measurable influence over the 200-year modeling period; however, risk estimated over shorter time periods, such as 50 years, would likely be lower for lined pits compared to unlined pits, and lower for deep ground water compared to shallow ground water.

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[12] A cancer risk estimate of 1×10^{-5} indicates that the chance of an individual contracting cancer over a 70-year average lifetime is approximately 1 in 100,000. The Agency establishes the cutoff between acceptable and unacceptable levels of cancer risk between 1×10^{-7} and 1×10^{-4}.

- Estimated ground-water resource damage (caused by exceedance of water quality thresholds for chloride and total mobile ions) was very limited and essentially confined to the closest modeling distance (60 meters). These resource damage estimates apply only to the pathway modeled (leaching through the bottom of onsite pits) and not to other mechanisms of potential ground-water contamination at drilling sites, such as spills or intentional surface releases.

- No surface water resource damage (caused by exceedance of thresholds for chloride, sodium, cadmium, chromium VI, or total mobile ions) was predicted for the seepage of leachate-contaminated ground water into flowing surface water. This finding, based on limited modeling, does not imply that resource damage could not occur from larger releases, either through this or other pathways of migration, or from releases to lower flow surface waters (below 40 ft^3/s).

Produced Water Disposal in Injection Wells

- All risk results for underground injection presented in this chapter assume that either a grout seal or well casing failure occurs. However, as anticipated under EPA's Underground Injection Control (UIC) regulatory program, these failures are probably low-frequency events, and the actual risks resulting from grout seal and casing failures are expected to be much lower than the conditional risks presented here. The results do not, however, reflect other possible release pathways such as migration through unplugged boreholes or fractures in confining layers, which also could be of concern.

- Only a very small minority of injection well scenarios resulted in meaningful risks to human health, due to either grout seal or casing failure modes of release of produced water to drinking water sources. In terms of carcinogenic risks, none of the best-estimate scenarios (median arsenic and benzene sample concentrations) yielded lifetime risks greater than 5 per 1,000,000 (5×10^{-6}) to the maximally exposed individual. When the 90th percentile benzene and arsenic concentrations were examined, a maximum of 35 percent of EPA's nationally weighted scenarios had risks greater than 1×10^{-7}, with up to 5 percent having cancer risks greater than 1×10^{-4} (the highest risk was 9×10^{-4}). The high cancer risk scenarios corresponded to a very short (60-meter) exposure distance combined with relatively high injection pressure/rates and a few specific ground-water flow fields (fields C and D in Table V-7).

- Noncancer health effects modeled were limited to hypertension in sensitive individuals caused by ingestion of sodium in drinking water. In the best-estimate scenarios, up to 8 percent of EPA's nationally weighted scenarios had threshold exceedances for sodium in ground-water supplies. In the conservative scenarios, where 90th percentile sodium concentrations were assumed in the injection waters, threshold exceedances in drinking water were predicted for a maximum of 22 percent of the nationally weighted scenarios. The highest sodium concentration predicted at exposure wells under conservative assumptions exceeded the threshold for hypertension by a factor of 70. The high noncancer risk scenarios corresponded to a very short (60-meter) exposure distance, high injection pressures/rates, and relatively slow ground-water velocities/low flows.

- It appears that people would not taste or smell chloride or benzene at the concentration levels estimated for the highest cancer risk scenarios, but sensitive individuals would be more likely to detect chloride or benzene tastes or odors in those scenarios with the highest noncancer risks. It is questionable, however, whether the detectable tastes or smells at these levels would generally be sufficient to discourage use of the water supply.

- As with the reserve pit risk modeling results, adjusting (weighting) the injection well results to account for differences among various geographic zones resulted in relatively small differences in risk distributions. Again, this lack of substantial variability in risk across zones may be the result of limitations of the study approach and the fact that geographic comparisons of toxic constituents in produced water was not possible.

- Of several factors evaluated for their effect on risk, exposure distance and ground-water flow field type had the greatest influence (two to three orders of magnitude). Flow rate/pressure had less, but measurable, influence (approximately one order of magnitude). Injection well type (i.e., waterflood vs. disposal) had moderate but contradictory effects on the risk results. For casing failures, high-pressure waterflood wells were estimated to cause health risks that were about 2 times higher than the risks from lower pressure disposal wells under otherwise similar conditions. However, for grout seal failures, the risks associated with disposal wells were estimated to be up to 3 times higher than the risks in similar circumstances associated with waterflood wells, caused by the higher injection rates for disposal.

- Estimated ground-water resource damage (resulting from exceedance of thresholds for chloride, boron, and total mobile ions) was extremely limited and was essentially confined to the 60-meter modeling distance. This conclusion applies only to releases from Class II injection wells, and not to other mechanisms of potential ground-water contamination at oil and gas production sites (e.g., seepage through abandoned boreholes or fractures in confining layers, leaching from brine pits, spills).

- No surface water resource damage (resulting from exceedance of thresholds for chloride, sodium, boron, and total mobile ions) was predicted for seepage into flowing surface water of ground water contaminated by direct releases from injection wells. This finding does not imply that resource damage could not occur via mechanisms and pathways not covered by this limited surface water modeling, or in extremely low flow streams.

Stripper Well Produced Water Discharged Directly into Surface Water

- Under conservative modeling assumptions, 17 percent of scenarios (unweighted) had cancer risks greater than 1×10^{-5} (the maximum cancer risk estimate was roughly 4×10^{-5}).[13] The maximum cancer risk under best-estimate waste stream assumptions was 4×10^{-7}. No exceedances of noncancer effect thresholds or surface water resource damage thresholds were predicted under any of the conditions modeled. The limited surface water modeling performed applies only to scenarios with moderate- to high-flow streams (40 to 850 ft^3/s). Preliminary analyses indicate, however, that resource damage criteria would generally be exceeded in only very small streams (i.e., those flowing at less than 5 ft^3/s), given the sampled waste stream chemical concentrations and discharge rates for stripper wells of up to 100 barrels per day.

Drilling and Production Wastes Managed on Alaska's North Slope

- Adverse effects to human health are expected to be negligible or nonexistent because the potential for human exposure to drilling waste and produced fluid contaminants on the North Slope is very small. The greatest potential for adverse environmental impacts is caused by discharge and seepage of reserve pit fluids containing toxic substances onto the tundra. A field study conducted in 1983 by the U.S. Fish and Wildlife Service indicates that tundra discharges of reserve pit fluids may adversely affect water quality and invertebrates in surrounding areas; however, the

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[13] These results are unweighted because the frequency of occurrence of the parameters that define the stripper well scenarios was not estimated.

results of this study cannot be wholly extrapolated to present-day practices on the North Slope because some industry practices have changed and State regulations concerning reserve pit discharges have become increasingly more stringent since 1983. Preliminary studies from industry sources indicate that seepage from operating above-ground reserve pits on the North Slope may damage vegetation within a radius of 50 feet. The Fish and Wildlife Service is in the process of studying the effects of reserve pit fluids on tundra organisms, and these studies need to be completed before more definitive conclusions can be made with respect to environmental impacts on the North Slope.

Locations of Oil and Gas Activities in Relation to Environments of Special Interest

- All of the top 26 States that have the highest levels of onshore oil and gas activity are within the historical ranges of numerous endangered and threatened species habitats; however, of 190 counties identified as having high levels of exploration and production, only 13 (or 7 percent) have federally designated critical habitats for endangered species within their boundaries. The greatest potential for overlap between onshore oil and gas activities and wetlands appears to be in Alaska (particularly the North Slope), Louisiana, and Illinois. Other States with abundant wetlands have very little onshore oil and gas activity. Any development on public lands must first pass through a formal environmental review process and some public lands, such as National Forests, are managed for multiple uses including oil and gas development. Federal oil and gas leases have been granted for approximately 25 million acres (roughly 27 percent) of the National Forest System. All units of the National Park System have been closed to future leasing of federally owned minerals except for 4 National Recreation Areas where mineral leasing has been authorized by Congress. If deemed acceptable from an environmental standpoint, however, nonfederally owned minerals within the park boundaries can be leased. In total, approximately 4 percent of the land area in the National Park System is currently under lease for oil and gas activity.

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CHAPTER VI

COSTS AND ECONOMIC IMPACTS OF ALTERNATIVE WASTE MANAGEMENT PRACTICES

OVERVIEW OF THE COST AND ECONOMIC IMPACT ANALYSIS

This chapter provides estimates of the cost and selected economic impacts of implementing alternative waste management practices by the oil and gas industry. The industry's current or "baseline" practices are described in Chapter III. In addition to current practices, a number of alternatives are available. Some of these offer the potential for higher levels of environmental control. Section 8002(m) of RCRA requires an assessment of the cost and impact of these alternatives on oil and gas exploration, development, and production.

This chapter begins by providing cost estimates for baseline and alternative waste management practices. The most prevalent current practices are reserve pit storage and disposal for drilling wastes and Class II deep well injection for produced water. In addition, several other waste management practices are included in the cost evaluation. The cost estimates for the baseline and alternative waste management practices are presented as the cost per unit of waste disposal (e.g., cost per barrel of drilling waste, cost per barrel of produced water). These unit cost estimates allow for a comparison among disposal methods and are used as input information for the economic impact analysis.

After establishing the cost of baseline and alternative practices on a unit-of-waste basis, the chapter expands its focus to assess the impact of higher waste management costs both on individual oil and gas projects and on the industry as a whole. For the purpose of this assessment, three hypothetical regulatory scenarios for waste management are defined. Each scenario specifies a distinct set of alternative environmentally protective waste management practices for oil and gas projects that generate potentially hazardous waste. Projects that do not generate hazardous waste may continue to use baseline practices under this approach.

After the three waste management scenarios have been defined, the remainder of the chapter provides estimates of their cost and economic impact. First, the impact of each scenario on the capital and operating cost and on the rate of return for representative new oil and gas projects is estimated. Using these cost estimates for individual projects as a basis, the chapter then presents regional- and national-level cost estimates for the waste management scenarios.

The chapter then describes the impact of the waste management scenarios on existing projects (i.e., projects that are already in production). It provides estimates of the number of wells and the amount of current production that would be shut down as a result of imposing alternative waste management practices under each scenario. Finally, the chapter provides estimates of the long-term decline in domestic production brought about by the costs of the waste management scenarios and estimates of the impact of that decline on the U.S. balance of payments, State and Federal revenues, and other selected economic aggregates.

The analysis presented in this chapter is based on the information available to EPA in November 1987. Although much new waste generation and waste management data was made available to this study, both by EPA and the American Petroleum Institute, certain data limitations did restrict the level of analysis and results. In particular, data on waste generation, management practices, and other important economic parameters were generally available only in terms of statewide or nationwide averages. Largely because of this, the cost study was conducted using "average regional projects" as the basic production unit of analysis. This lack of desired detail could obscure special attributes of both marginal and above average projects, thus biasing certain impact effects, such as the number of well closures.

The scope of the study was also somewhat limited in other respects. For example, not all potential costs of alternative waste management under the RCRA amendments could be evaluated, most notably the land ban and corrective action regulations currently under development. The Agency recognizes that this could substantially understate potential costs of some of the regulatory scenarios studied. The analysis was able to distinguish separately between underground injection of produced water for disposal purposes and injection for waterflooding as a secondary or enhanced energy recovery method. However, it was not possible during the course of preparing this report to evaluate the costs or impacts of alternative waste management regulations on tertiary (chemical, thermal, and other advanced EOR) recovery, which is becoming an increasingly important feature of future U.S. oil and gas production.

COST OF BASELINE AND ALTERNATIVE WASTE MANAGEMENT PRACTICES

Identification of Waste Management Practices

The predominant waste management practices currently employed by the oil and gas industry are described in Chapter III of this report. For drilling operations, wastes are typically stored in an unlined surface impoundment during drilling. After drilling, the wastes are dewatered, either by evaporation or vacuum truck, and buried onsite. Where vacuum trucks are used for dewatering, the fluids are removed for offsite disposal, typically in a Class II injection well. For production operations, the predominant disposal options are injection into a Class II onsite well or transportation to an offsite Class II disposal facility. Where onsite injection is used, the Class II well may be used for disposal only or it may be used to maintain pressure in the reservoir for enhanced oil recovery.

In addition to the above disposal options, a number of additional practices are considered here. Some of these options are fairly common (Table VI-1). For example, 37 percent of current drill sites use a lined disposal pit; 12 percent of production sites in the lower 48 States (Lower 48) discharge their produced water to the surface. Other disposal options considered here (e.g., incineration) are not employed to any significant extent at present.

For drilling waste disposal, nine alternative practices were reviewed for the purpose of estimating comparative unit costs and evaluating subsequent cost-effectiveness in complying with alternative regulatory options:

1. Onsite unlined surface impoundment;
2. Onsite single-synthetic-liner surface impoundment;
3. Offsite single-synthetic-liner surface impoundment;
4. Offsite synthetic composite liner with leachate collection (SCLC), Subtitle C design;
5. Landfarming consistent with current State oil and gas field regulations;
6. Landfarming consistent with RCRA Subtitle C requirements;
7. Waste solidification;
8. Incineration; and
9. Volume reduction.

Table VI-1 Summary of Baseline Disposal Practices, by Zone, 1985

	Drilling waste disposal (percent of drill sites)		Produced water disposition (percent of produced waters)		
				Class II Injection	
Zone	Unlined facilities	Lined facilities	Surface discharge	EOR	Disposal
Appalachian	23	77	50	25	25
Gulf	89	11	34	11	55
Midwest	47	53	0	91	9
Plains	49	51	0	38	62
Texas/ Oklahoma	60	40	4	69	27
Northern Mountain	65	35	12	45	42
Southern Mountain	50	50	0	84	16
West Coast	99	1	23	54	23
Alaska	67	33	0	71	29
Total U.S.	63	37	11	59	28
Lower 48 States	63	37	12	60	28

Sources: Drilling waste and produced water disposal information from API, 1987a except for produced water disposal percents for the Appalachian zone, which are based on personal communications with regional industry sources.

NOTE: Produced water disposition percents for total U.S. and Lower 48 are based on survey sample weights. Weighting by oil production results in a figure of 9 percent discharge in the Lower 48 (API 1987b).

In addition to these disposal options, costs were also estimated for ground-water monitoring and general site management for waste disposal sites. These latter practices can be necessary adjunct requirements for various final disposal options to enhance environmental protection.

For produced water, two alternative practices were considered in the cost analysis: Class I injection wells and Class II injection wells. Both classes may be used for water disposal or for enhanced energy recovery waterflooding. They may be located either onsite or, in the case of disposal wells, offsite. To depict the variation in use patterns of these wells, cost estimates were developed for a wide range of injection capacities.

Cost of Waste Management Practices

For each waste disposal option, engineering design parameters of representative waste management facilities were established for the purpose of costing (Table VI-2). For the baseline disposal methods, parameters were selected to typify current practices. For waste management practices that achieve a higher level of environmental control than the most common baseline practices, parameters were selected to typify the best (i.e., most environmentally protective) current design practices. For waste management practices that would be acceptable for hazardous waste under Subtitle C of RCRA, parameters were selected to represent compliance with these regulations as they existed in early 1987.

Capital and operating and maintenance (O&M) costs were estimated for each waste management practice based on previous EPA engineering cost documents and tailored computer model runs, original contractor engineering cost estimates, vendor quotations, and other sources.[1] Capital costs were annualized using an 8 percent discount rate, the

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[1] See footnotes to Tables VI-3 and VI-4 and Eastern Research Group 1987 for a detailed source list.

Table VI-2 Summary of Engineering Design Elements for Baseline and Alternative Waste Management Practices

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Unlined pit	• Pit excavation (0.25 acre) • Clearing and grubbing • Contingency • Contractor fee	• Negligible	• Pit burial (earth fill only) • Contingency • Contractor fee	
One-liner pit (waste buried on site)	• Clearing and grubbing • Pit excavation (0.25 acre) • Berm construction (gravel and vegetation) • 30-mil synthetic liner • Liner protection (geotextile subliner) • Engineering, contractor, and inspection fee • Contingency	• Negligible	• Pit burial (earth fill) • Capping - 30-mil PVC synthetic membrane - topsoil • Revegetation • Engineering, contractor, and inspection fee • Contingency	
Offsite one-liner facility	• Pit excavation (15 acres) • Same costs as onsite one-liner pit with addition of: - land cost - utility site work - pumps - spare parts - dredging equipment - inlet/outlet structures - construction and field expense	• Operating labor - clerical staff - foremen • Maintenance labor and supplies • Utilities • Plant overhead • Dredging	• Same costs as onsite one-liner pit • Solidification • Free liquid removal and treatment	

Table VI-2 (continued)

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Offsite SCLC facility	• Pit excavation (15 acres) • Same costs as commercial one-liner pit with the addition of: - additional pit liners - clay liner replaces geotextile subliner	• Same costs as commercial one-liner pit	•Same costs as onsite one-liner pit with addition of synthetic cap • Equipment decontamination	(See ground-water monitoring and site management)
Ground water monitoring and site management	• Ground-water monitoring wells • Leachate collection system - drainage tiles - leachate collection layer (sand or gravel) for single-liner case only - leachate collection liner for single-liner case only • Signs/fencing • RCRA permitting (for RCRA scenario)	• Ground-water monitoring wells sampling and laboratory fees • Leachate treatment	• Soil poisoning (to prevent disruption by long-rooted plants) • Cover drainage tile - collection layer (sand or gravel) - geotextile filter fabric in one-liner pit • Monitoring • Certification, supervision	• Monitoring well sampling • Leachate treatment • Notice to local authorities • Notation on property deed • Facility inspection • Maintenance and repair • Cover replacement • Engineering and inspection fees • Contingency
Offsite, multiple-application landfarming	• Land cost • Land clearing cost • Building cost • Lysimeter cost (RCRA scenario) • Cluster wells (RCRA scenario)	• Labor • Ground-water monitoring • Soil core cost • Maintenance • Utilities • Insurance, taxes, and G & A	• Revegetation • Testing	• Land authority and property deed cost • Ground-water monitoring cost • Soil core cost • Erosion control cost • Vegetative cover cost

Table VI-2 (continued)

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Offsite, multiple-application landfarming (continued)	• Wind dispersal control (RCRA scenario) • Storage tanks • Engineering and inspection • Contingency • Retention pond (RCRA scenario) • Berms (RCRA scenario)			• Engineering and inspection costs • Contingency
Volume reduction	• Equipment rental - mechanical or vacuum separation equipment • Tanks	• Chemicals • Labor		
Injection (Class II)	• Convert existing well to disposal well - completion rig contract - drilling fluids - cementing - logging and perforating - stimulation - liner and tubing • Site work/building • Holding tanks • Skim tanks • Filters and pumps • Pipelines	• Labor • Chemicals • Electricity • Filters • Disposal of filtrates • Pump maintenance • Pressure tests • Liability costs	• Plug and abandon	

Table VI-2 (continued)

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Injection (Class I)	• Drill new well - drilling rig contract - completion rig contract - cementing - logging and perforating - site preparation - casing - liner - tubing • Storage tanks • Annular fluid tank • Filters • Pumps • Pipelines • Site work/buildings • RCRA permit cost (RCRA scenario)	• Same costs as Class II wells with addition of: - tracer survey - cement bond log - pipe evaluation - disposal of filtrate in hazardous waste facility	• Plug and abandon	

approximate after-tax real cost of capital for this industry. Annualized capital costs were then added to O&M costs to compute the total annual costs for typical waste management unit operations. Annual costs were divided by annual waste-handling capacity (in barrels) to provide a cost per barrel of waste disposal. Both produced water disposal costs and drilling waste (i.e., muds and cuttings) disposal costs are expressed on a dollars-per-barrel basis.

The average engineering unit cost estimates for drilling wastes are presented in Table VI-3 for each region and for a composite of the Lower 48. Regional cost variations were estimated based on varying land, construction, and labor costs among regions. The costs for the Lower 48 composite are estimated by weighting regional cost estimates by the proportion of production occurring in each region. (Throughout the discussion that follows, the Lower 48 composite will be referenced to illustrate the costs and impacts in question.)

For the Lower 48 composite, the drilling waste disposal cost estimates presented in Table VI-3 range from $2.04 per barrel for onsite, unlined pit disposal to $157.50 per barrel for incineration. Costs for the disposal options are significantly higher for Alaska because of the extreme weather conditions, long transportation distances from population and material centers to drill sites, high labor costs, and other unique features of this region.

Costs for produced water are presented in Table VI-4. Disposal costs include injection costs, as well as transport, loading, and unloading charges, where appropriate. Injection for EOR purposes occurs onsite in either Class II or Class I wells. Class II disposal occurs onsite in all zones except Appalachia. Class I disposal occurs offsite except for the Northern Mountain and Alaska zones. Well capacities and transport distances vary regionally depending on the volume of water production and the area under production.

Table VI-3 Unit Costs of Drilling Waste Disposal Options, by Zone (Dollars per Barrel of Waste, 1985 Basis)

	Zone									
Disposal option	Appalachian	Gulf	Midwest	Plains	Texas/ Oklahoma	Northern Mountain	Southern Mountain	West Coast	Alaska	Lower 48
Surface impoundment[a]										
Unlined (0.25 acre)	$ 2.09	$ 1.98	$ 2.00	$ 1.98	$ 2.10	$ 2.00	$ 2.00	$ 2.04	$ 2.69	$ 2.04
Single-liner (0.25 acre)	4.62	4.32	4.35	4.29	4.63	4.35	4.35	4.46	6.16	4.46
SCLC (15 acres)	18.26	12.41	25.61	19.54	11.66	19.73	20.69	27.54	20.27	15.52
Landfarming[b]										
Current	13.21	12.06	12.41	15.91	17.01	16.14	15.99	16.42	N.E.	15.47
Subtitle C	30.23	31.58	28.94	39.14	40.31	36.45	36.38	38.45	N.E.	37.12
Solidification[c]	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	N.E.	8.00
Incineration[d]	157.50	157.50	157.50	157.50	157.50	157.50	157.50	157.50	N.E.	157.50
Volume reduction and offsite single-liner disposal[e]	15.16	3.18	17.24	9.50	5.83	5.40	6.15	21.87	5.67	6.74
Volume reduction and offsite SCLC disposal[e]	19.27	7.94	25.50	15.94	9.91	11.90	12.93	30.71	12.57	11.95

N.E. = Not estimated; disposal method not practical and/or information not available for Alaska.

[a] Source: Pope Reid Associates 1985a, 1985b, 1987a; costs for SCLC disposal include transportation charges.

[b] Source: Pope Reid Associates 1987b.

[c] Source: Erlandson 1986; Webster 1987; Tesar 1986; Camp, Dresser & McKee 1986; Hanson and Jones 1986; Cullinane et al. 1986; North American Environmental Service 1985.

[d] Source: USEPA 1986.

[e] Source: Slaughter 1987; Rafferty 1987. Costs include equipment rental and transport and disposal of reduced volume of waste. All costs are allocated over the original volume of waste so that per-barrel costs of waste disposal are comparable to the other cost estimates in the table.

Table VI-4 Unit Costs of Underground Injection of Produced Water, by Zone (Dollars per Barrel of Water)

Zone	Class II injection		Class I injection[a]	
	Disposal	EOR	Disposal	EOR
Appalachian[b]	$1.26-1.33	$0.75	$2.45	$6.12
Gulf	0.10	0.23	0.84	1.35
Midwest	0.29	0.13	1.14	0.84
Plains	0.14	0.19	0.86	1.21
Texas/Oklahoma	0.11	0.14	0.96	0.76
Northern Mountain	0.01	0.14	0.40	0.58
Southern Mountain	0.07	0.14	1.05	0.67
West Coast	0.04	0.05	0.72	0.25
Alaska	0.05	0.41	1.28	2.15
Lower 48 States	0.10	0.14	0.92	0.78

[a] Disposal costs for Class I injection include transportation and loading/unloading charges except for the Northern Mountain zone and Alaska, where onsite disposal is expected to occur.

[b] Class II disposal costs for Appalachian zone includes transport and loading/unloading charges. Lower estimate is for intermediate scenarios; higher estimate is for baseline practice due to change in transport distances. For all other zones, Class II disposal is assumed to occur onsite.

Sources: Tilden 1987a, 1987b.

NOTE: Base year for costs is 1985.

Produced water disposal costs range from $0.01 to $1.33 per barrel for Class II disposal and EOR injection and from $0.40 to $6.12 per barrel for Class I disposal and EOR injection. Costs for Class I facilities are substantially higher because of the increased drilling completion, monitoring, and surface equipment costs associated with waste management facilities that accept hazardous waste.

The transportation of waste represents an additional waste management cost for some facilities. Transportation of drilling or production waste for offsite centralized or commercial disposal is practiced now by some companies and has been included as a potential disposal option in the waste management scenarios. Drilling waste transport costs range from $0.02 per barrel/mile for nonhazardous waste to $0.06 per barrel/mile for hazardous waste. Produced water transport costs range from $0.01 per barrel/mile (nonhazardous) to $0.04 per barrel/mile (hazardous). Distances to disposal facilities were estimated based on the volume of wastes produced, facility capacities, and the area served by each facility. Waste transportation also involves costs for loading and unloading.

WASTE MANAGEMENT SCENARIOS AND APPLICABLE WASTE MANAGEMENT PRACTICES

In order to determine the potential costs and impacts of changes in oil and gas waste disposal requirements, three waste management scenarios have been defined. The scenarios have been designed to illustrate the cost and impact of two hypothetical additional levels of environmental control in relation to current baseline practices. EPA has not yet identified, defined, or evaluated its regulatory options for the oil and gas industry; therefore, it should be noted that these scenarios <u>do not</u> represent regulatory determinations by EPA. A regulatory determination will be made by EPA following the Report to Congress.

Baseline Scenario

The Baseline Scenario represents the current situation. It encompasses the principal waste management practices now permitted under State and Federal regulations. Several key features of current practice for both drilling waste and produced water were summarized in Table VI-1, and the distribution of disposal practices shown in Table VI-1 is the baseline assumption for this analysis.

Intermediate Scenario

The Intermediate Scenario depicts a higher level of control. Operators generating wastes designated as hazardous are subject to requirements more stringent than those in the Baseline Scenario. An exact definition of "hazardous" has not been formulated for this scenario. Further, even if a definition were posited (e.g., failure of the E.P. toxicity test), available data are insufficient to determine the proportion of the industry's wastes that would fail any given test. Pending an exact regulatory definition of "hazardous" and the development of better analytical data, a range of alternative assumptions has been employed in the analysis. In the Intermediate 10% Scenario, the Agency assumed, for the purpose of costing, that 10 percent of oil and gas projects generate hazardous waste and in the Intermediate 70% Scenario that 70 percent of oil and gas projects generate hazardous waste.

For drilling wastes designated hazardous, operators would be required to use a single-synthetic-liner facility, landfarming with site management (as defined in Table VI-2), solidification, or incineration. Operators would select from these available compliance measures on the basis of lowest cost. Since a substantial number of operators now employ a single synthetic liner in drilling pits, only those sites not using a liner would be potentially affected by the drilling waste requirements of the Intermediate Scenario.

For produced waters, the Intermediate Scenario assumes injection into Class II facilities for any produced water that is designated hazardous. Operators now discharging waste directly to water or land (approximately 9 to 12 percent of all water) would be required to use a Class II facility if their wastes were determined to be hazardous.

"Affected operations" under a given scenario are those oil and gas projects that would have to alter their waste management practices and incur costs to comply with the requirements of the scenario. For example, in the Intermediate 10% Scenario, it is assumed that only 10 percent of oil and gas projects generate hazardous waste. For drilling, an estimated 63 percent of oil and gas projects now use unlined facilities and are therefore potentially affected by the requirements of the scenario. Since 10 percent of these projects are assumed to generate hazardous waste, an estimated 6.3 percent of the projects are affected operations, which are subject to higher disposal costs.

The Subtitle C Scenario

In the Subtitle C Scenario, wastes designated as hazardous are subject to pollution control requirements consistent with Subtitle C of RCRA. For drilling wastes, those wastes that are defined as hazardous must be disposed of in a synthetic composite liner with leachate collection (SCLC) facility employing site management and ground-water monitoring practices consistent with RCRA Subtitle C, a landfarming facility employing Subtitle C site management practices, or a hazardous waste incinerator. In estimating compliance costs EPA estimated that a combination of volume reduction and offsite dedicated SCLC disposal would be the least-cost method for disposal of drilling waste. For production wastes, those defined as hazardous must be injected into Class I disposal or EOR injection wells.

Since virtually no drilling or production operations currently use Subtitle C facilities or Class I injection wells in the baseline, all projects that generate produced water are potentially affected. In the Subtitle C 10% Scenario, 10 percent of these projects are assumed to be affected; in the Subtitle C 70% Scenario, 70 percent of these projects are affected. The Subtitle C Scenario, like the Intermediate Scenario, does not establish a formal definition of "hazardous"; nor does it attempt to estimate the proportion of wastes that would be hazardous under the scenario. As with the Intermediate Scenario, two assumptions (10 percent hazardous, 70 percent hazardous) are employed, and a range of costs and impacts is presented.

This Subtitle C Scenario does not, however, impose all possible technological requirements of the Solid Waste Act Amendments, such as the land ban and corrective action requirements of the Hazardous Solid Waste Amendments (HSWA), for which regulatory proposals are currently under development in the Office of Solid Waste. Although the specific regulatory requirements and their possible applications to oil and gas field practices, especially deep well injection practices, were not sufficiently developed to provide sufficient guidelines for cost evaluation in this report, the Agency recognizes that the full application of these future regulations could substantially increase the costs and impacts estimated for the Subtitle C Scenario.

The Subtitle C-1 Scenario

The Subtitle C-1 Scenario is exactly the same as the Subtitle C Scenario, except that produced water used in waterfloods is considered part of a production process and is therefore exempt from more stringent (i.e., Class I) control requirements, even if the water is hazardous. As shown in Table VI-1, approximately 60 percent of all produced water is used in waterfloods. Thus, only about 40 percent of produced water is potentially affected under the Subtitle C-1 Scenario. The requirements of the Subtitle C-1 Scenario for drilling wastes are exactly the same as those of the Subtitle C Scenario. As with the other scenarios, alternative assumptions of 10 and 70 percent hazardous are employed in the Subtitle C-1 Scenario.

Summary of Waste Management Scenarios

Table VI-5 summarizes the major features of all the waste management scenarios. It identifies acceptable disposal practices under each scenario and the percent of wastes affected under each scenario. The Subtitle C 70% Scenario enforces the highest level of environmental control in waste management practices, and it affects the largest percent of facilities.

COST AND IMPACT OF THE WASTE MANAGEMENT SCENARIOS FOR TYPICAL NEW OIL AND GAS PROJECTS

Economic Models

An economic simulation model, developed by Eastern Research Group (ERG) and detailed in the Technical Background Document (ERG 1987), was employed to analyze the impact of waste management costs on new oil and gas projects. The economic model simulates the performance and measures the profitability of oil and gas exploration and development projects both before and after the implementation of the waste management scenarios. For the purposes of this report, a "project" is defined as a single successful development well and the leasing and exploration activities associated with that well. The costs for the model project include the costs of both the unsuccessful and the successful leasing and exploratory and development drilling required, on average, to achieve one successful producing well.

Table VI-5 Assumed Waste Management Practices for Alternative Waste Management Scenarios

Waste management scenario	Drilling wastes		Produced waters	
	Disposal method	Potentially affected operations	Disposal method	Potentially affected operations
Baseline	Unlined surface impoundment Lined surface impoundment	N.A.	Class II injection Surface discharge	N.A.
Intermediate	Baseline practices for nonhazardous wastes For hazardous wastes: - Lined surface impoundment - Landfarming with site management - Solidification - Incineration	Facilities not now using liners: approximately 63% of total[a]	Baseline practices for nonhazardous wastes Class II injection for hazardous wastes	Facilities not now using Class II injection: approximately 20% of total[d]
Subtitle C	Baseline practices for nonhazardous wastes For hazardous wastes: - SCLC impoundment with Subtitle C site management - Landfarming with Subtitle C site management - Hazardous waste incineration	All facilities[b]	Baseline practices for nonhazardous wastes Class I injection for hazardous wastes	All facilities[e]
Subtitle C-1	Same as Subtitle C scenario	Same as Subtitle C scenario[c]	Baseline practices for nonhazardous wastes For hazardous wastes: - Class I injection for nonwaterfloods - Class II injection for waterfloods	Facilities not now waterflooding: approximately 40% of total[f]

[a] In the Intermediate 10% Scenario, 10% of the 63%, or 6.3%, are assumed to be hazardous; in the Intermediate 70% Scenario, 70% of the 63%, or 44.1%, are assumed to be hazardous.

[b] In the Subtitle C 10% Scenario, 10% of the 100%, or 10.0%, are assumed to be hazardous; in the Subtitle C 70% Scenario, 70% of the 100%, or 70.0%, are assumed to be hazardous.

[c] In the Subtitle C-1 10% Scenario, 10% of the 100%, or 10.0%, are assumed to be hazardous; in the Subtitle C-1 70% Scenario, 70% of the 100%, or 70.0%, are assumed to be hazardous.

[d] In the Intermediate 10% Scenario, 10% of the 20%, or 2.0%, are assumed to be hazardous; in the Intermediate 70% Scenario, 70% of the 20%, or 14.0%, are assumed to be hazardous.

[e] In the Subtitle C 10% Scenario, 10% of the 100%, or 10.0%, are assumed to be hazardous; in the Subtitle C 70% Scenario, 70% of the 100%, or 70.0%, are assumed to be hazardous.

[f] In the Subtitle C-1 10% Scenario, 10% of the 40%, or 4.0%, are hazardous and not exempt because of waterflooding. In the Subtitle C-1 70% Scenario, 70% of the 40%, or 28.0%, are hazardous and not exempt because of waterflooding.

For this study, model projects were defined for oil wells (with associated casinghead gas) in the nine active oil and gas zones and for a Lower 48 composite. Model gas projects were defined for the two most active gas-producing zones (the Gulf and Texas/Oklahoma zones). Thus, 12 model projects have been analyzed. The Technical Background Document for the Report to Congress provides a detailed description of the assumptions and data sources underlying the model projects.

A distinct set of economic parameter values is estimated for each of the model projects, providing a complete economic description of each project. The following categories of parameters are specified for each project:

1. Lease Cost: initial payments to Federal or State governments or to private individuals for the rights to explore for and to produce oil and gas.
2. Geological and Geophysical Cost: cost of analytic work prior to drilling.
3. Drilling Cost per Well.
4. Cost of Production Equipment.
5. Discovery Efficiency: the number of wells drilled for one successful well.
6. Production Rates: initial production rates of oil and gas and production decline rates.
7. Operation and Maintenance Costs.
8. Tax Rates: Rates for Federal and State income taxes, severance taxes, royalty payments, depreciation, and depletion.
9. Price: wellhead selling price of oil and gas (also called the "first purchase price" of the product).
10. Cost of Capital: real after-tax rate of return on equity and borrowed investment capital for the industry.
11. Timing: length of time required for each project phase (i.e., leasing, exploration, development, and production).

The actual parameter values for the 12 model projects are summarized in Table VI-6.

For each of the 12 model projects, the economic performance is estimated before (i.e., baseline) and after each waste management scenario has been implemented. Two measures of economic performance are employed in the impact assessment presented here. One is the after-tax rate of return. The other is the cost of production per barrel of oil (here defined as the cost of the resources used in production, including profit to the owners of capital, excluding transfer payments such as royalties and taxes). A number of other economic output parameters are described in the Technical Background Document.

Quantities of Wastes Generated by the Model Projects

To calculate the waste management costs for each representative project, it was necessary to develop estimates of the quantities of drilling and production wastes generated by these facilities. These estimates, based on a recent API survey, are provided in Table VI-7. Drilling wastes are shown on the basis of barrels of waste per well. Production wastes are provided on the basis of barrels of waste per barrel of oil.

For the Lower 48 composite, an estimated 5,170 barrels of waste are generated for each well drilled. For producing wells, approximately 10 barrels of water are generated for every barrel of oil. This latter statistic includes waterflood projects, some of which operate at very high water-to-oil ratios.

Model Project Waste Management Costs

Model project waste management costs are estimated for the baseline and for each waste management scenario using the cost data presented in

Table VI-6 Economic Parameters of Model Projects for U.S. Producing Zones
(All Costs in Thousands of 1985 Dollars, Other Units as Noted)

Parameter	Appalachian	Gulf	Gulf	Midwest	Plains	Texas/ Oklahoma	Texas/ Oklahoma	Northern Mountain	Southern Mountain	West Coast	Alaska	Lower 48 States
Production	Oil/Gas	Oil/Gas	Gas	Oil/Gas	Oil/Gas	Oil/Gas	Gas	Oil/Gas	Oil/Gas	Oil/Gas	Oil/Gas	Oil/Gas
Yr of first prod.	1	1	1	1	1	1	1	2	1	1	10	1
Lease cost	1.146	19.296	154.368	2.509	2.080	11.200	22.400	4.992	2.251	33.178	161.056	14.877
G & G expense	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%
Well cost	63.911	244.276	640.146	122.138	186.347	246.324	727.636	421.142	492.053	160.995	3,207.388	248.607
Disc. efficiency	85%	59%	59%	51%	52%	71%	71%	55%q	72%	90%	88%	69%
Infrastructure cost	45.000	73.189	35.297	60.788	81.855	86.820	39.824	102.662	109.357	82.560	45,998.400	83.952
O & M costs (per yr)	4.500	13.349	18.486	11.807	14.529	15.114	21.048	17.015	17.781	13.370	690.900	14.463
Initial prod. rates												
Oil (bbl/day)	4	60	0	16	26	37	0	53	32	35	3700	41
Gas (Mcf/day)	16	82	1295	15	34	69	1038	72	69	0	686	57
Prod. decline rates	9%	19%	19%	17%	19%	12%	12%	13%	13%	7%	9%	12%
Federal corp. tax	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%
State corp. tax	0%	8%	8%	4%	6.75%	5%	5%	0%	6%	9.35%	9.40%	6.14%
Royalty rate	18.75%	18.75%	18.75%	12.50%	12.50%	20.00%	20.00%	12.50%	16.00%	18.75%	14.30%	18.24%
Severance tax												
Oil	0.5%	12.5%	12.5%	0%	8%	7%	7%	6%	4%	0.14%	a	6.67%
Gas	1.5%	4.25%	4.25%	4.84%	0%	8%	7%	7%	6%	4%	0.14%	a
Wellhead price												
Oil ($/bbl)	$20.90	$21.65	$21.65	$22.11	$21.14	$22.03	$22.03	$20.74	$21.16	$18.38	$16.37	$20.00
Gas ($/Mcf)	$ 2.00	$ 1.99	$ 1.99	$ 2.03	$ 1.43	$ 1.58	$ 1.58	$ 1.77	$ 1.98	$ 2.21	$ 0.49	$ 1.65

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[a] Tax based on formula in tax code, not a flat percentage.

Source: ERG 1987.

Table VI-7 Average Quantities of Waste Generated, by Zone

Model project/ zone	Drilling waste barrels/well	Produced water (barrels/barrel of oil)
Appalachian	2,344	2.41
Gulf	10,987	8.42
Midwest	1,853	23.61
Plains	3,623	9.11
Texas/Oklahoma	5,555	10.62
Northern Mountain	8,569	12.30
Southern Mountain	7,153	7.31
West Coast	1,414	8.05
Alaska	7,504	0.15
Lower 48 States	5,170	9.98
Gulf (gas only)	10,987	17.17[a]
Texas/Oklahoma (gas only)	5,555	17.17[a]

[a] Barrels of water per million cubic feet of natural gas.

Sources: API 1987a; Flannery and Lannan 1987.

Tables VI-3 and VI-4 and the waste quantity data shown in Table VI-7. For each model project, waste management costs are calculated for each waste management scenario.

For each model project and scenario, the available compliance methods were identified (Table VI-5). Cost estimates for all available compliance methods, including transportation costs for offsite methods, were developed based on the unit cost factors (Tables VI-2 and VI-3) and the waste quantity estimates (Table VI-7). Each model facility was assumed to have selected the lowest cost compliance method. Based on compliance cost comparisons, presented in more detail in the Technical Background Document, the following compliance methods are employed by affected facilities under the waste management scenarios:

Intermediate Scenario

1. Drilling wastes - single-liner onsite facility; volume reduction and transport to offsite single-liner facility if cost-effective.
2. Production wastes - Class II onsite facility.

Subtitle C Scenario

1. Drilling wastes - transport to offsite SCLC facility with site management and with volume reduction if cost-effective.
2. Production wastes - for waterfloods, onsite injection in Class I facility; for nonwaterfloods, transport and disposal in offsite Class I facility.

Subtitle C-1 Scenario

1. Drilling wastes - transport to offsite SCLS facility with site management and with volume reduction if cost-effective.
2. Production wastes - waterfloods exempt; for nonwaterfloods, transport and injection in offsite Class I facility.

For each model facility under each scenario, the least-cost compliance method was assumed to represent the cost of affected projects. Costs for unaffected projects were estimated based on the cost of baseline practices. Weighted average costs for each model under each scenario (shown in Tables VI-8 and VI-9) incorporate both affected and unaffected projects. For example, in the Subtitle C 70% Scenario, while 70 percent of projects must dispose of drilling wastes in Subtitle C facilities, the other 30 percent can continue to use baseline practices. The weighted average cost is calculated as follows:

Project category	Percentage of projects	Drilling waste disposal cost	Weighted cost
Affected operations	70%	$61,782	$43,248
Unaffected operations	30%	$15,176	$ 4,552
Weighted average			$47,800

For drilling wastes, the weighted average costs range from $15,176 per well in the Baseline to $47,800 per well in the RCRA Subtitle C 70% case. Thus, the economic analysis assumes that each well incurs an additional $32,624 under the RCRA Subtitle C 70% Scenario. For produced water, costs per barrel of water disposed of range from $0.11 in the Baseline to $0.62 in the RCRA Subtitle C 70% Scenario. Thus, there is an additional cost of $0.51 per barrel of water under this scenario.

Impact of Waste Management Costs on Representative Projects

The new oil and gas projects incur additional costs under the alternative waste management scenarios for both drilling and production waste management. By incorporating these costs into the economic model simulations, the impact of these costs on financial performance of typical new oil and gas projects is assessed. These impacts are presented in Tables VI-10 and VI-11.

As shown in Table VI-10, the internal rate of return can be substantially affected by waste management costs, particularly in the Subtitle C 70% Scenario. From a base case level of 28.9 percent, model

Table VI-8 Weighted Average Regional Costs of Drilling Waste Management for Model Projects Under Alternative Waste Management Scenarios (Dollars per Well)

Model project/ zone	Baseline	Intermediate		Subtitle C 10% and Subtitle C-1 10%	Subtitle C 70% and Subtitle C-1 70%
		10%	70%		
Appalachian	$ 9,465	$ 9,602	$10,420	$12,799	$ 32,801
Gulf	24,582	25,756	32,796	30,848	68,440
Midwest	6,014	6,219	7,447	10,138	34,880
Plains	11,442	11,852	14,312	16,073	43,858
Texas/Oklahoma	17,398	18,258	23,418	21,163	43,755
Northern Mountain	24,186	25,495	33,348	31,965	78,636
Southern Mountain	22,711	23,511	28,594	29,689	71,555
West Coast	2,919	3,258	5,290	6,521	28,135
Alaska	28,779	30,277	39,266	35,333	74,661
Lower 48 States	15,176	15,964	20,964	19,837	47,800

NOTE: Costs in 1985 dollars, based on 1985 cost factors.

Source: ERG estimates.

Table VI-9 Weighted Average Unit Costs of Produced Water Management for Model Projects under Alternative Waste Management Scenarios (Dollars per Barrel of Water)

Model project/ zone	Baseline	Intermediate		Subtitle C		Subtitle C-1	
		10%	70%	10%	70%	10%	70%
Appalachian	$0.52	$0.57	$0.94	$0.80	$2.51	$0.67	$1.57
Gulf	0.08	0.06	0.10	0.16	0.65	0.15	0.57
Midwest	0.14	0.14	0.14	0.22	0.65	0.15	0.20
Plains	0.16	0.16	0.16	0.24	0.74	0.20	0.47
Texas/Oklahoma	0.13	0.13	0.13	0.20	0.61	0.15	0.31
Northern Mountain	0.07	0.07	0.07	0.11	0.36	0.09	0.22
Southern Mountain	0.13	0.13	0.13	0.19	0.55	0.14	0.24
West Coast	0.04	0.04	0.04	0.08	0.34	0.07	0.26
Alaska	0.31	0.31	0.31	0.46	1.42	0.34	0.56
Lower 48 States	0.11	0.11	0.12	0.18	0.62	0.15	0.35

NOTE: Waste management costs applied to both oil and gas production wastes. Costs in 1985 dollars.

Source: ERG estimates.

Table VI-10 Impact of Waste Management Costs on Model Projects: Comparisons of After-Tax Internal Rate of Return [a]
(%)

Model project/ zone	Baseline	Alternative waste management scenarios					
		Intermediate		Subtitle C		Subtitle C-1	
		10%	70%	10%	70%	10%	70%
Appalachian	10.3%	10.2%	8.9%	8.9%	0.9%	9.2%	3.6%
Gulf-gas	22.9	22.8	22.5	22.5	20.7	22.6	20.7
Gulf-oil	36.4	36.2	34.5	33.2	15.6	33.5	17.9
Midwest	12.1	12.1	11.8	8.2	-19.4	10.9	5.1
Plains	9.0	9.0	8.6	6.9	-5.6	7.7	0.0
Texas/Oklahoma-gas	19.6	19.5	19.3	19.4	18.3	19.4	18.5
Texas/Oklahoma-oil	29.6	29.5	28.9	27.4	14.6	28.4	22.1
Northern Mountain	19.6	19.5	19.0	18.2	10.1	18.6	13.1
Southern Mountain	9.2	9.2	9.0	8.3	3.3	8.7	6.3
West Coast	35.0	35.0	34.5	33.6	25.4	33.8	26.9
Alaska	10.9	10.9	10.9	10.8	10.6	10.9	10.8
Lower 48 States	28.9	28.8	28.0	26.6	13.0	27.6	19.7

NOTE: Both drilling and production wastes regulated.

[a] Internal rate of return defined as return after corporate taxes, to total invested capital including both equity and debt.

Source: ERG estimates.

Table VI-11 Impact of Waste Management Costs on Model Projects:
Increase in Total Cost of Production[a]
(Dollars per Barrel of Oil Produced)

Model project/ zone	Total baseline cost	Increase in cost under alternative waste management scenarios					
		Intermediate		Subtitle C		Subtitle C-1	
		10%	70%	10%	70%	10%	70%
Appalachian	$16.22	$ 0.05	$ 0.44	$ 0.45	$ 3.24	$ 0.33	$ 2.35
Gulf-gas	9.45	0.01	0.03	0.03	0.20	0.03	0.20
Gulf-oil	15.65	0.01	0.17	0.40	2.85	0.36	2.48
Midwest	19.45	0.01	0.07	1.11	8.31	0.34	2.12
Plains	18.46	0.02	0.09	0.51	3.69	0.33	2.46
Texas/Oklahoma-gas	7.61	0.01	0.02	0.02	0.11	0.02	0.09
Texas/Oklahoma-oil	14.86	0.01	0.07	0.40	1.24	0.20	2.74
Northern Mountain	15.51	0.02	0.12	0.36	2.56	0.23	1.65
Southern Mountain	18.05	0.01	0.08	0.29	2.01	0.16	0.99
West Coast	13.19	0.00	0.07	0.23	1.68	0.18	1.34
Alaska	15.02	0.00	0.00	0.01	0.10	0.00	0.03
Lower 48 States	14.11	0.01	0.11	0.40	2.88	0.20	1.55

[a] Total cost of production defined to include capital costs, operating costs, lease bonus costs, and pollution control costs, as well as transfer payments such as Federal income taxes, royalties, and State severance taxes.

Source: ERG estimates.

project after-tax internal rates of return decline under the waste management scenarios to the 13.0 to 28.8 percent range for the Lower 48 average.

The after-tax cost of producing hydrocarbons can also increase substantially. As Table VI-11 shows, these costs can increase by up to $2.98 per barrel of oil equivalent (BOE), a 20 percent increase over baseline costs. The impacts of these cost increases on a national level are described further below.

REGIONAL- AND NATIONAL-LEVEL COMPLIANCE COSTS OF THE WASTE MANAGEMENT SCENARIOS

The cost of waste management for the typical projects under each waste management scenario (see Tables VI-8 and VI-9) were used in conjunction with annual drilling (API 1986) and production levels (API 1987c) to estimate the regional- and national-level annual costs of the waste management scenarios. These costs, which include both drilling and production waste disposal costs, are presented in Table VI-12. National-level costs range from $49 million in the Intermediate 10% Scenario to more than $12.1 billion in the Subtitle C 70% Scenario.

The costs presented in Table VI-12 do not include the effects of closures. They are based on 1985 drilling and production levels, assuming that no activities are curtailed because of the requirements of the waste management scenarios. In reality, each of the waste management scenarios would result in both the early closure of existing projects and the cancellation of new projects. To the extent that the level of oil and gas activity declines, total aggregate compliance costs incurred under each waste management scenario will be lower, but there will be other costs to the national economy caused by lower levels of oil production. These effects are described more fully below.

Table VI-12 Annual Regional and National RCRA Compliance Cost of Alternative Waste Management Scenarios
(Millions of Dollars)

Model project/ zone	Waste management scenarios					
	Intermediate		Subtitle C		Subtitle C-1	
	10%	70%	10%	70%	10%	70%
Appalachian	$5	$43	$57	$403	$47	$328
Gulf	8	94	200	1,417	180	1,239
Midwest	1	6	120	870	31	185
Plains	2	17	126	907	77	576
Texas/Oklahoma	26	181	879	6,156	442	2,873
Northern Mountains	3	19	94	677	55	404
Southern Mountains	3	21	92	643	47	297
West Coast	1	36	126	936	97	736
Alaska	0	2	17	118	5	34
Lower 48 States	49	418	1,693	12,007	975	6,637
National Total	49	420	1,710	12,125	980	6,671

NOTE: Figures represent before-tax total annual increase in waste management cost over baseline costs at 1985 levels of drilling and production, without adjusting for decreases in industry activity caused by higher production costs at affected sites. Column totals may differ because of independent rounding. Base year for all costs is 1985.

CLOSURE ANALYSIS FOR EXISTING WELLS

The potential of the waste management scenarios to shut down existing producing wells was estimated using the model facility approach. The model facility simulations for existing projects, however, do not include the initial capital cost of leasing and drilling the production well. For the analysis of existing projects, it is assumed that these costs have already been incurred. The projects are simulated for their operating years. If operating revenues exceed operating costs, the projects remain in production.

Closures of existing wells are estimated by using a variable called the economic limit (i.e., a level of production below which the project cannot continue to operate profitably). Under the waste management scenarios, produced water disposal costs are higher and, therefore, the economic limit is higher. Some projects that have production levels that exceed the baseline economic limit would fall below the economic limit under the alternative waste management scenarios. Those projects not meeting this higher level of production can be predicted to close. This analysis was conducted only with respect to stripper wells. To the extent that certain high-volume, low-margin wells may also be affected, the analysis may understate short-term project closures.

The economic limit analysis requires information on the distribution of current production levels across wells. Because of the lack of data for most States, the economic limit analysis is presented here only for Texas and on a national level. The 1985 distribution of production by volume size class for Texas and for the Nation as a whole is shown in Table VI-13.

Table VI-14 displays the results of the economic limit analysis. Under baseline assumptions, the representative Lower 48 project requires 2.40 barrels per day to remain in operation. The economic limit for

Table VI-13 Distribution of Oil Production Across Existing Projects, 1985

Region	Production Interval (BOPD) bbl/d	Number of Wells	Total Oil Production 1000 bb/d
National			
	0 - 1	112,000	71
	1 - 2	112,000	165
	2 - 3	78,000	206
	3 - 4	65,000	231
	4 - 5	20,000	92
	5 - 6	27,000	154
	6 - 7	21,000	142
	7 - 8	16,000	119
	8 - 9	15,000	129
	9 - 10	9,000	63
Total		475,000	1,371
Texas	<1	42,831	21
	1.0 - 1.5	15,018	19
	1.6 - 2.5	20,856	43
	2.6 - 3.5	14,018	43
	3.6 - 4.5	11,303	46
	4.6 - 5.5	9,665	49
	5.6 - 6.5	7,638	46
	6.6 - 7.5	6,201	44
	7.6 - 8.6	5,420	44
	9.6 - 1.05	4,441	45
Total			142,743
446			

Sources: :The Effect of Lower Oil Prices on Production From Proved U.S. Oil Reserves," Energy and Environmental Analysis, Inc., February 1987, taken from Figure 2-2. Indicators: A Monthly Data Review-April 1986, Railroad Commission of Teas, April 1986.

Table VI-14 Impact of Waste Management Cost on Existing Production

			Lower-range effects				Upper-range effects			
			Well closures		Lost production		Well closures		Lost production	
Region	Scenario	Economic limit (bbl/d)	Number of wells	Percent of wells	1000 bbl/d	Percent of production	Number of wells	Percent of wells	1000s bbl/d	Percent of production
Texas										
	Baseline[a]	2.30								
	Intermediate 10%	2.32	42	0.02	0.09	0.00	6,562	3.29	5.60	0.24
	Intermediate 70%	2.32	292	0.15	0.60	0.03	45,931	23.05	33.22	1.67
	Subtitle C 10%	3.89	2,260	1.13	6.92	0.30	8,780	4.41	12.00	0.53
	Subtitle C 70%	3.89	15,818	7.94	48.41	2.07	61,457	30.84	87.04	3.71
	Subtitle C-1 10%	2.73	740	0.37	1.84	0.08	7,259	3.64	7.36	0.31
	Subtitle C-1 70%	2.73	5,177	2.60	12.87	0.55	50,816	25.50	51.49	2.20
National:	Lower 48 States									
	Baseline[b]	2.40								
	Intermediate 10%	2.42	156	0.03	0.41	0.00	20,652	3.33	21.00	0.25
	Intermediate 70%	2.42	1,092	0.18	2.88	0.03	144,564	23.31	148.45	1.75
	Subtitle C 10%	4.20	11,580	1.87	37.32	0.44	32,076	5.17	58.00	0.68
	Subtitle C 70%	4.20	81,060	13.07	261.23	3.07	224,532	36.20	406.79	4.79
	Subtitle C-1 10%	3.01	4,745	0.77	13.00	0.15	25,241	4.07	33.00	0.39
	Subtitle C-1 70%	3.01	33,215	5.36	88.14	1.04	176,687	28.49	233.70	2.75

[a] Baseline production level is 2.3 million bbl/d; baseline well total is 199,000.

[b] Baseline production level is 8.6 million bbl/d; baseline well total is 620,000.

Source: ERG estimates.

affected operations rises to 3.01 to 4.20 barrels per day under the waste management scenarios. The increase in the economic limit results in closures of from 0.03 percent to 36.20 percent of all producing wells.

The "lower-range effects" in Table VI-14 assume that only affected wells (i.e., wells generating hazardous produced waters) producing at levels <u>between</u> the baseline economic limit and the economic limit under the waste management scenarios will be closed. The "upper-range effects" assume that all affected wells producing at levels below the economic limit under the waste management scenarios will be closed, and are adjusted to account for the change in oil prices from 1985 to 1986.

Under the lower-range effects case, production losses are estimated at between 0.00 and 3.07 percent of total production. Under the upper-range effects assumptions, production closures range from 0.25 to 4.79 percent of the total. These results are indicative of the immediate, short-term impact of the waste management scenarios caused by well closures.

The results of the Texas simulation mirror those of the national-level analysis. This would be expected, since nearly 30 percent of all stripper wells are in Texas, and the State is, therefore, reflected disproportionately in the national-level analysis. Under the lower-range effects assumptions, Texas production declines between 0.00 and 2.07 percent. Under the upper-range effects assumptions, Texas production declines between 0.24 and 3.71 percent.

THE INTERMEDIATE AND LONG-TERM EFFECTS OF THE WASTE MANAGEMENT SCENARIOS

Production Effects of Compliance Costs

The intermediate and long-term effects of the waste management scenarios will exceed the short-term effects for two principal reasons.

First, the increases in drilling waste management cost, which do not affect existing producers, can influence new project decisions. Second, the higher operating costs due to produced water disposal requirements may result in some project cancellations because of the expectation of reduced profitability during operating years. Although such projects might be expected to generate profits in their operating years (and therefore might be expected to operate if drilled), the reduced operating profits would not justify the initial investment.

The intermediate and long-term production effects were estimated using Department of Energy (DOE) production forecasting models. As described above, an economic simulation model was used to calculate the increase in the cost of resource extraction under each waste management scenario. These costs were used in conjunction with the DOE FOSSIL2 model (DOE 1985) and the DOE PROLOG model (DOE 1982) to generate estimates of intermediate and long-term production effects of the waste management scenarios.

For the FOSSIL2 model, an estimate of the increase in resource extraction costs for each waste management scenario, based on model project analysis, was provided as an input. Simulations were performed to measure the impact of this cost increase on the baseline level of production.

For the PROLOG model, no new simulations were performed. Instead, results of previous PROLOG modeling were used to calculate the elasticity of supply with respect to price in the PROLOG model. The model project simulation results were used to calculate an oil price decline that would have the same impact as the cost increase occurring under each alternative waste management scenario. These price increases were used in conjunction with an estimate of the price elasticity of supply from the PROLOG model to estimate an expected decline in production for each waste management scenario.

Table VI-15 shows the results of this analysis. The long-term impacts of the waste management scenarios range from levels that are below the detection limits of the modeling system to declines in production ranging up to 32 percent in the year 2000, based on the PROLOG analysis. For the FOSSIL2 simulations, production declines were estimated to range from "not detectable" to 18 percent in the year 2000 and from "not detectable" to 29 percent in the year 2010.

Additional Impacts of Compliance Costs

The decline in U.S. oil production brought about by the cost of the waste management scenarios would have wide-ranging effects on the U.S. economy. Domestic production declines would lead to increased oil imports, a deterioration in the U.S. balance of trade, a strengthening of OPEC's position in world markets, and an increase in world oil prices. Federal and State revenues from leasing and from production and income taxes would decline. Jobs would be lost in the oil and gas drilling, servicing, and other supporting industries; jobs would be created in the waste management industries (e.g., contractors who drill and complete Class I injection wells).

It is beyond the scope of this report to fully analyze all of these and other macroeconomic effects. To illustrate the magnitude of some of these effects, however, five categories of impacts were defined and quantified (oil imports, balance of trade, oil price, Federal leasing revenues, and State production taxes). These are presented in Table VI-16. Measurable effects are evident for all but the lowest cost (Intermediate 10% Scenario).

The impacts of the waste management scenarios on the U.S. economy were analyzed utilizing the DOE FOSSIL2/WOIL modeling system. Cost increases for U.S. oil producers create a slight decrease in the world oil supply curve (i.e., the amount of oil that would be brought to market at any oil price declines). The model simulates the impact of this shift on the world petroleum supply, demand, and price.

Table VI-15 Long-Term Impacts on Production of Cost Increases under Waste Management Scenarios

(%)	Estimated resource extraction cost increase (%)	Decline of domestic oil production in lower 48 States				
		Year 1990		Year 2000		Year 2010
Scenario		FOSSIL2	PROLOG	FOSSIL2	PROLOG	FOSSIL2
Intermediate 10%	0.16	No detectable change	No detectable change	No detectable change	No detectable change	No detectable change
Intermediate 70%	2.49	No detectable change	No detectable change	1.4%	No detectable change to 0.4%	1.6%
Subtitle C 10%	9.51	No detectable change	0.3% to 0.4%	4.2%	1.6% to 3.5%	6.3%
Subtitle C 70%	68.84	3.2%	6.9% to 7.8%	18.1%	19.1% to 32.4%	28.6%
Subtitle C-1 10%	4.73	No detectable change	No detectable change	1.4%	0.3% to 1.4%	3.2%
Subtitle C-1 70%	36.51	2.1%	3.7% to 4.3%	12.5%	10.7% to 18.5%	19.0%

Source: ERG estimates for extraction cost increase and for PROLOG impacts. Applied Energy Services of Arlington, Virginia, (Wood 1987) for FOSSIL2 results, based on specific runs of U.S. Department of Energy FOSSIL2 Model for alternative scenario cost increases. Department of Energy baseline crude oil price per barrel assumptions in FOSSIL2 were $20.24 in 1990, $33.44 in 2000, and $52.85 in 2010.

Table VI-16 Effect of Domestic Production Decline on Selected Economic Parameters in the Year 2000

Waste management scenario	Projected decline in lower 48 production (%)[a]	Increase in petroleum imports (millions of barrels per day)	Increase in U.S. balance of trade deficit ($ billions per year)	Increase in world oil price (dollars per barrel)[a]	Annual cost to consumers of the oil price increase ($ billions per year)	Decrease in Federal leasing revenues ($ millions per year)	Decrease in State tax revenues ($ millions per year)
Intermediate 10%	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Intermediate 70%	1.4%	N.D.	$0.2	$0.06	$0.4	$19.1	$71.0
Subtitle C 10%	4.2%	0.2	$3.2	$0.21	$1.2	$53.6	$208.9
Subtitle C 70%	18.1%	1.1	$17.5	$1.08	$6.4	$279.8	$903.2
Subtitle C-1 10%	1.4%	0.1	$1.6	$0.12	$0.7	$20.9	$60.7
Subtitle C-1 70%	12.5%	0.7	$11.3	$0.76	$4.5	$176.2	$616.1

N.D. - Not detectable using the FOSSIL2/WOIL modeling system.

[a] Revised baseline values for year 2000 in the FOSSIL2 modeling system include (1) lower 48 States crude oil production of 7.2 million barrels per day; (2) U.S. imports of 9.2 million barrels per day; and (3) world crude oil price of $33.44 per barrel.

Source: Results based on U.S. Department of Energy's FOSSIL2/WOIL energy modeling system, with special model runs for individual waste management scenario production costs effects conducted by Applied Energy Services of Arlington, Virginia (Wood 1987). ERG estimates based on FOSSIL2 results.

A new equilibrium shows the following effects:

- A lower level of domestic supply (previously depicted in Table VI-15);
- A higher world oil price (see Table VI-16);
- A decrease in U.S. oil consumption caused by the higher world oil price; and
- An increase in U.S. imports to partially substitute for the decline in domestic supply (also shown in Table VI-16).

The first numerical column in Table VI-16 shows the decline in U.S. production associated with each waste management scenario. These projections, derived from simulations of the FOSSIL2/WOIL modeling system, were previously shown in Table VI-15. The second column in Table VI-16 provides FOSSIL2/WOIL projections of the increase in petroleum imports necessary to replace the lost domestic supplies. The projections range from "not detectable" to 1.1 million barrels per day, equal to 1.4 to 18.1 percent of current imports of approximately 6.1 million barrels per day.

The third column in Table VI-16 shows the increase in the U.S. balance of trade deficit resulting from the increase in imports and the increase in the world oil price. The increase in the U.S. balance of trade deficit ranges from $0.2 to $17.5 billion under the waste management scenarios. The projected increase in petroleum imports under the most restrictive regulatory scenarios could be a matter for some concern in terms of U.S. energy security perspectives, making the country somewhat more vulnerable to import disruptions and/or world oil price fluctuations. In the maximum case estimated (Subtitle C 70% Scenario), import dependence would increase from 56 percent of U.S. crude oil requirements in the base case to 64 percent in the year 2000.

The fourth column shows the crude petroleum price increase projected under each of the waste management scenarios by the FOSSIL2/WOIL modeling system. This increase ranges from $0.06 to $1.08 per barrel of oil (a 0.2 to 3 percent increase). This increase in oil price translates into an increase in costs to the consumer of $0.4 to $6.4 billion in the year 2000 (column five). These estimates are derived by multiplying FOSSIL2-projected U.S. crude oil consumption in the year 2000 by the projected price increase. The estimates assume that the price increase is fully passed through to the consumer with no additional downstream markups.

Federal leasing revenues will also decline under the waste management scenarios. These revenues consist of lease bonus payments (i.e., initial payments for the right to explore Federal lands) and royalties (i.e., payments to the Federal government based on the value of production on Federal lands). Both of these revenue sources will decline because of the production declines associated with the waste management scenarios. If the revenue sources are combined, there will be a reduction of $19 to $280 million in Federal revenues in the year 2000.

State governments generally charge a tax on crude oil production in the form of severance taxes, set as a percentage of the selling price. On a national basis, the tax rate currently averages approximately 6.7 percent. Applying this tax rate, the seventh column in Table VI-16 shows the projected decline in State tax revenues resulting from the waste management scenarios. These estimates range from about $60 million to $900 million per year.

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CHAPTER VII

CURRENT REGULATORY PROGRAMS

INTRODUCTION

A variety of programs exist at the State and Federal levels to control the environmental impacts of waste management related to the oil and gas industry. This chapter provides a brief overview of the requirements of these programs. It also presents summary statistics on the implementation of these programs, contrasting the numbers of wells and other operations regulated by these programs with resources available to implement regulatory requirements.

State programs have been in effect for many years, and many have evolved significantly over the last decade. The material presented here provides only a general introduction to these complex programs and does not attempt to cover the details of State statutes and current State implementation policy. Additional material on State regulatory programs can be found in Appendix A. Federal programs are administered both by the Environmental Protection Agency and by the Bureau of Land Management within the U.S. Department of the Interior.

STATE PROGRAMS

The tables on the following pages compare the principal functional requirements of the regulatory control programs in the principal oil- and gas-producing States that have been the focus of most of the analysis of this study. These States are Alaska, Arkansas, California, Colorado, Kansas, Louisiana, Michigan, New Mexico, Ohio, Oklahoma, Texas, West Virginia, and Wyoming.

Table VII-1 covers requirements for reserve pit design, construction, and operation; Table VII-2 covers reserve pit closure and waste removal. Table VII-3 presents requirements for produced water pit design and construction, while Table VII-4 compares requirements for the produced water surface discharge limits. Table VII-5 deals with produced water injection well construction; these requirements fall under the general Federal Underground Injection Control program, which is discussed separately below under Federal programs. Finally, Table VII-6 discusses requirements for well abandonment and plugging.

FEDERAL PROGRAMS--EPA

Federal programs discussed in this section include the Underground Injection Control (UIC) program and the Effluent Limitations Guidelines program administered by the EPA.

Underground Injection Control

The Underground Injection Control (UIC) program was established under Part C of the Safe Drinking Water Act (SDWA) to protect underground sources of drinking water (USDWs) from endangerment by subsurface emplacement of fluids through wells. Part C of the SDWA requires EPA to:

1. Identify the States for which UIC programs may be necessary--EPA listed all States and jurisdictions;
2. Promulgate regulations establishing minimum requirements for State programs which:
    - prohibit underground injection that has not been authorized by permit or by rule;
    - require applicants for permits to demonstrate that underground injection will not endanger USDWs;
    - include inspection, monitoring, record-keeping, and reporting requirements.

These minimum requirements are contained in 40 CFR Parts 144 and 146, and were promulgated in June 1980.

3. Prescribe by regulation a program applicable to the States, in cases where States cannot or will not assume primary enforcement responsibility. These direct implementation (DI) programs were codified in 40 CFR Part 147.

The regulations promulgated in 1980 set minimum requirements for 5 classes of wells including Class II wells--wells associated with oil and gas production and hydrocarbon storage. In December 1980, Congress amended the SDWA to allow States to demonstrate the effectiveness of their in-place regulatory programs for Class II wells, in lieu of demonstrating that they met the minimum requirements specified in the UIC regulations. In order to be deemed effective, State Class II programs had to meet the same statutory requirements as the other classes of wells, including prohibition of unauthorized injection and protection of underground sources of drinking water. (§1425 SDWA). Because of the large number of Class II wells, the regulations allow for authorization by rule for existing enhanced recovery wells (i.e., wells that were injecting at the time a State program was approved or prescribed by EPA). In DI States, these wells are subject to requirements specified in Part 147 for authorization by rule, which are very similar to requirements applicable to permitted wells, with some relief available from casing and cementing requirements as long as the wells do not endanger USDWs. In reviewing State programs where the intent was to "grandfather" existing wells as long as they met existing requirements, EPA satisfied itself that these requirements were sufficient to protect USDWs. In addition, all States adopted the minimum requirements of §146.08 for demonstrating mechanical integrity of the wells (ensuring that the well was not leaking or allowing fluid movement in the borehole), at least every 5 years. This requirement was deemed by EPA to be absolutely necessary in order to prevent endangerment of USDWs. In addition, EPA and the States have been conducting file reviews of all wells whether grandfathered or subject to new authorization-by-rule requirements. File reviews are assessments of the technical issues that would normally be part of a permit decision, including mechanical integrity testing, construction, casing and cementing, operational history, and monitoring records. The intent of the file review is to ensure that injection wells not subject to permitting are technically adequate and will not endanger underground sources of drinking water.

Because of §1425 and the mandate applicable to Federal programs not to interfere with or impede underground injection related to oil and gas production, to avoid unnecessary disruption of State programs and to consider varying geologic, hydrologic, and historical conditions in different States, EPA has accepted more variability in this program than in many of its other regulatory programs. Now that the program has been in place for several years, the Agency is starting to look at the adequacy of the current requirements and may eventually require more specificity and less variation among States.

Effluent Limitations Guidelines

On October 30, 1976, the Interim Final BPT Effluent Limitations Guidelines for the Onshore Segment of the Oil and Gas Extraction Point Source Category were promulgated as 41 FR (44942). The rulemaking also proposed Best Available Technology Economically Achievable (BAT) and New Source Performance Standards.

On April 13, 1979, BPT Effluent Limitations Guidelines were promulgated for the Onshore Subcategory, Coastal Subcategory, and Agricultural and Wildlife Water Use Subcategory of the Oil and Gas Extraction Industry (44 FR 22069). Effluent limitations were reserved for the Stripper Subcategory because of insufficient technical data.

The 1979 BPT regulation established a zero discharge limitation for all wastes under the Onshore Subcategory. Zero discharge Agricultural and Wildlife Subcategory limitations were established, except for produced water, which has a 35-mg/L oil and grease limitation.

The American Petroleum Institute (API) challenged the 1979 regulation (including the BPT regulations for the Offshore Subcategory) (661 F.2D.340(1981)). The court remanded EPA's decision transferring 1,700 wells from the Coastal to the Onshore Subcategory (47 FR 31554). The court also directed EPA to consider special discharge limits for gas wells.

Summary of Major Regulatory Activity Related to Onshore Oil and Gas

October 13, 1976 - Interim Final BPT Effluent Limitations Guidelines and Proposed (and Reserved) BAT Effluent Limitations Guidelines and New Source Performance Standards for the Onshore Segment of the Oil and Gas Extraction Point Source Category

April 13, 1979 - Final Rules

- BPT Final Rules for the Onshore, Coastal, and Wildlife and Agricultural Water Use Subcategories
- Stripper Oil Subcategory reserved
- BAT and NSPS never promulgated

July 21, 1982 - Response to American Petroleum Institute vs. EPA Court Decision

- Recategorization of 1,700 "onshore" wells to Coastal Subcategory
- Suspension of regulations for Santa Maria Basin, California
- Planned reexamination of marginal gas wells for separate regulations

Onshore Segment Subcategories

Onshore

- BPT Limitation

  -- Zero discharge

- Defined: NO discharge of wastewater pollutants into navigable waters from ANY source associated with production, field exploration, drilling, well completion, or well treatment (i.e., produced water, drilling muds, drill cuttings, and produced sand).

Stripper (Oil Wells)[1]

- Category reserved

- Defined: TEN barrels per well per calendar day or less of crude oil.

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[1] This subcategory does not include marginal gas wells.

Coastal

- BPT Limitations

  -- No discharge of free oil (no sheen)

  -- Oil and grease: 72 mg/L (daily)
  48 mg/L (average monthly)
  (produced waters)

- Defined: Any body of water landward of the territorial seas or any wetlands adjacent to such waters.

Wildlife and Agriculture Use

- BPT Limitations

  -- Oil and Grease: 35 mg/L (produced waters)
  -- Zero Discharge: ANY waste pollutants

- Defined: That produced water is of good enough quality to be used for wildlife or livestock watering or other agricultural uses west of the 98th meridian.

FEDERAL PROGRAMS--BUREAU OF LAND MANAGEMENT

Federal programs under the Bureau of Land Management (BLM) within the U.S. Department of the Interior are discussed in this section.

Introduction

Exploration, development, drilling, and production of onshore oil and gas on Federal and Indian lands are regulated separately from non-Federal lands. This separation of authority is significant for western States where oil and gas activity on Federal and Indian lands is a large proportion of statewide activity.

Regulatory Agencies

The U.S. Department of the Interior exercises authority under 43 CFR 3160 for regulation of onshore oil and gas practices on Federal and Indian lands. The Department of the Interior administers its regulatory program through BLM offices in the producing States. These offices generally have procedures in place for coordination with State agencies on regulatory requirements. Where written agreements are not in place, BLM usually works cooperatively with the respective State agencies. Generally, where State requirements are more stringent than those of BLM, operators must comply with the State requirements. Where State requirements are less stringent, operators must meet the BLM requirements.

The Bureau works closely with the U.S. Forest Service for surface stipulations in Federal forests or Federal grasslands. This cooperative arrangement is specifically provided for in the Federal regulations.

Rules and Regulations

BLM has authority over oil and gas activities on Federal lands. The authority includes leasing, bonding, royalty arrangements, construction and well spacing regulations, waste handling, most waste disposal, site reclamation, and site maintenance.

Historically, BLM has controlled oil and gas activities through Notices to Lessees (NTLs) and through the issuance of permits. The Bureau is working to revise all notices into Oil and Gas Orders, which will be Federally promulgated. To date, Oil and Gas Order No. 1 has been issued.

While the regulations, NTLs, and orders provide the general basis for regulation of oil and gas activities on Federal and Indian lands, there are variations in actual application of some of the requirements among BLM districts. In many cases, the variations are in response to specific geographical or geological characteristics of particular areas.

For example, in middle and southern Florida, the water table is near the surface. As a result, BLM requires the use of tanks instead of mud pits for oil and gas drilling activities on Federal lands in this area. In southeast New Mexico, there is simultaneous development of potash resources and oil and gas resources, and drilling and development requirements are imposed to accommodate the joint development activities. In general, more stringent controls of wastes and of disposal activities are required for oil and gas activities that could affect ground-water aquifers used for drinking water.

Drilling

Before beginning to drill on Federal land, operators must receive a permit to drill from BLM. The permit application must include a narrative description of waste handling and waste disposal methods planned for the well. Any plans to line the reserve pit must be detailed.

The lease is required to be covered by a bond prior to beginning drilling of the well. But the bonds may be for multiple wells, on a lease basis, statewide basis, or nationwide basis. The current bond requirement for wells on a single lease is $10,000. Statewide bonds are $25,000, but bonds must be provided separately for wells on public land and wells on Federally acquired land. The requirement for a nationwide bond is $150,000.

BLM considers reserve pits, and some other types of pits, as temporary. Except in special circumstances, reserve pits do not have to be lined. NTL-2B contains the following provisions for "Temporary Use of Surface Pits":

> Unlined surface pits may be used for handling or storage of fluids used in drilling, redrilling, reworking, deepening, or plugging of a well provided that such facilities are promptly and properly emptied and restored upon completion of the operations. Mud or other fluids contained in such pits shall not be disposed of by cutting the pit walls without the prior authorization of the authorized officer.
>
> Unlined pits may be retained as emergency pits, if approved by the authorized officer, when a well goes into production.
>
> Landspreading of drilling and reworking wastes by breaching pit walls is allowed when approved by the authorized officer.

Production

Produced waters may be disposed of by underground injection, by disposal into lined pits, or "by other acceptable methods." An application to dispose of produced water must specify the proposed method and provide information that will justify the method selected. One application may be submitted for the use of one disposal method for produced water from wells and leases located in a single field, where the water is produced from the same formation or is of similar quality.

Disposal in Pits: A number of general requirements apply to disposal into permanent surface disposal pits, whether lined or unlined. The pits must:

1. Have adequate storage capacity to safely contain all produced water even in those months when evaporation rates are at a minimum;
2. Be constructed, maintained, and operated to prevent unauthorized surface discharges of water; unless surface discharge is authorized, no siphon, except between pits, will be permitted;
3. Be fenced to prevent livestock or wildlife entry to the pit, when required by an authorized officer;
4. Be kept reasonably free from surface accumulations of liquid hydrocarbons by use of approved skimmer pits, settling tanks, or other suitable equipment; and
5. Be located away from the established drainage patterns in the area and be constructed so as to prevent the entrance of surface water.

Approval of disposal of produced water into unlined pits will be considered only if one or more of the following applies:

- The water is of equal or better quality than potentially affected ground water or surface waters, or contains less than 5,000 ppm total dissolved solids (annual average) and no objectionable levels of other toxic constituents;

- A substantial proportion of the produced water is being used for beneficial purposes, such as irrigation or livestock or wildlife watering;
- The volume of water disposed of does not exceed a monthly average of 5 barrels/day/facility; and
- A National Pollutant Discharge Elimination System (NPDES) permit has been granted for the specific disposal method.

Operators using unlined pits are required to provide information regarding the sources and quantities of produced water, topographic map, evaporation rates, estimated soil percolation rates, and "depth and extent of all usable water aquifers in the area."

Unlined pits may be used for temporary containment of fluids in emergency circumstances as well as for disposal of produced water. The pit must be emptied and the fluids appropriately disposed of within 48 hours after the emergency.

Where disposal in lined pits is allowed, the linings of the pits must be impervious and must not deteriorate in the presence of hydrocarbons, acids, or alkalis. Leak detection is required for all lined produced water disposal pits. The recommended detection system is an "underlying gravel-filled sump and lateral system." Other systems and methods may be considered acceptable upon application and evaluation. The authorized officer must be given the opportunity to examine the leak detection system before installation of the pit liner.

When applying for approval of surface disposal into a lined pit, the operator must provide information including the lining material and leak detection method for the pit, the pit's size and location, its net evaporation rate, the method for disposal of precipitated solids, and an analysis of the produced water. The water analysis must include concentrations of chlorides, sulfates, and other (unspecified) constituents that could be toxic to animal, plant, or aquatic life.

Injection: Produced waters may be disposed of into the subsurface, either for enhanced recovery of hydrocarbon resources or for disposal. Since the establishment of EPA's underground injection control program for Class II injection wells, BLM no longer directly regulates the use of injection wells on Federal or Indian lands. Instead, it defers to either EPA or the State, where the State has received primacy for its program, for all issues related to ground-water or drinking water protection. Operators must obtain their underground injection permits from either EPA or the State.

BLM still retains responsibility for making determinations on injection wells with respect to lease status, protection of potential oil and gas production zones, and the adequacy of pressure-control and other safety systems. It also requires monthly reports on volumes of water injected.

Plugging/Abandonment

When a well is a dry hole, plugging must take place before removal of the drilling equipment. The mud pits may be allowed to dry before abandonment of the site. No abandonment procedures may be started without the approval of an authorized BLM representative. Final approval of abandonment requires the satisfactory completion of all surface reclamation work called for in the approved drilling permit.

Within 90 days after a producing well ceases production, the operator may request approval to temporarily abandon the well. Thereafter, reapproval for continuing status as temporarily abandoned may be required every 1 or 2 years. Exact requirements depend on the District Office and on such factors as whether there are other producing wells on the lease. The well may simply be defined as shut-in if equipment is left in place.

Plugging requirements for wells are determined by the BLM District Office. Typically, these will include such requirements as a 100-foot cement plug over the shoe of the surface casing (half above, half below), a 20- to 50-foot plug at the top of the hole, and plugs (usually 100 feet across) above and below all hydrocarbon or freshwater zones.

IMPLEMENTATION OF STATE AND FEDERAL PROGRAMS

Table VII-7 presents preliminary summary statistics on the resources of State oil and gas regulatory programs for the 13 States for which State regulatory programs have been summarized in Tables VII-1 through VII-6. Topics covered include rates of gas and oil production, the number of gas and oil wells, the number of injection wells, the number of new wells, the responsible State agency involved, and the number of total field staff in enforcement positions.

Table VII-8 presents similar statistics covering activities of the Bureau of Land Management. Since offices in one State often have responsibilities for other States, each office is listed separately along with the related States with which it is involved. Statistics presented include the number of oil and gas producing leases, the number of nonproducing oil and gas leases, and the number of enforcement personnel available to oversee producing leases.

Table VII- 1 Reserve Pit Design, Construction and Operation

State	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/ oversight
Alaska	The pits must be rendered impervious.	Whether reserve pit requires lining (and what kind of lining) depends on proximity to surface water and populations, whether the pit is above permafrost, and what kind of pit management strategy is used; visual monitoring required, and ground water monitoring usually required.	Fluid mgmt provision entails use of dewatering practices to keep to a minimum the hydrostatic head in a containment structure to reduce the potential for seepage and to prevent overflow during spring thaw.	Reserve pit "drilling wastes" defined as including "drilling muds, cuttings, hydrocarbons, brine, acid, sand, and emulsions or mixtures of fluids produced from and unique to the operation or maintenance of a well."	Individual permit for active and new pits.
Arkansas (revisions due in '88)	Oil & Gas Commission (OGC); no specific regulations governing construction or management of reserve pits. Dept. of Pollution Control & Ecology (DPCE) incorporates specific requirements in letters of authorizataion serving as informal permits, but regulatory basis and legal enforceability not supported by OGC.	OGC: No regulatory requirement. DPCE: 20-mil synthetic or 18-24 inch thick liner (per authorization letter).	1-ft freeboard (DPCE: 2-ft per authorization letter).	DPCE only: no high TDS completion fluids (per authorization letter).	OGC: No separate permit for reserve pit. DPCE: Terms of permitting for reserve pits incorporated in letter of authorization.
California	No degradation of ground-water quality; if waste is hazardous, detailed standards apply to the pits as "surface	Liners may or may not be required, depending on location and local regulations; in limited cases where fluids		Use of nonapproved additives and fluids renders the waste subject to regulation as a hazardous waste.	Regional Water Quality Control Boards (RWQCBs) have authority to permit, oversee management.

Table VII-1 (continued)

State	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/ oversight
California (continued)	impoundments"; if non-hazardous, the waste "shall be disposed of in such a manner as not to cause damage to life, health, property, fresh water aquifers or surface waters, or natural resources, or be a menace to public safety."	contain hazardous materials, double liners required			
Colorado	Prevent pollution (broadly defined) of State waters; prevent exceeding of stream standards.	Liners and leak detection systems generally reqd for pits with a capacity greater than 100 bbl/d and a TDS content greater than 5,000 ppm; liners also reqd in designated areas overlying domestic water supplies.		No prohibition on commingling of drilling muds and initial water production, but disposal of greater than 5 bbl/d produced water renders the reserve pit subject to regulations for pits receiving produced water; no wells drilled with oil-based muds.	Individual permit if pit receives more than 5 barrels fluid per day.
Kansas	Specific delineation of areas requiring liners (proposed)	No general requirement; liners may be required in geologically or hydrologically sensitive areas (e.g., over sandy soils); Commission may require observation trenches, holes, or monitoring wells.	1-ft freeboard (proposed regs).		General permits for pits operating for less than 1 year (extensions granted); individual permits granted unless denied within 10 days of application (proposed regs.).

Table VII-1 (continued)

State	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/ oversight
Louisiana	Prevent contamination of aquifers, including USDWs, and protect surface water.	Liners not required for onsite reserve pits; liners (10^{-7} cm/sec) reqd for offsite commercial facilities.	2-ft freeboard, protection of surface water by levees, walls, and drainage ditches.	No produced water or waste oil at onsite facilities	More stringent reqts. (including financial respons.) for commercial facilities.
Michigan		Liners required when drilling with salt water-based drilling fluids; or when drilling through salt or brine-containing formations; in other areas, exceptions may be granted, but rarely are requested; liners must be 20 mil virgin PVC or its equivalent.		No salt cuttings as solids, oil, refuse, completion or test fluids.	Individual permit bond, and environmental assessment reqd.
New Mexico	Prevent contamination of surface and subsurface water.	Liners not required for onsite reserve pits; in the Northwest, liners may be required for commercial facilities.			Permits are reqd for centralized facilities with some exceptions.
Ohio	Prevent escape of produced water; prevent contamination of land, surface water, and ground water.	No requirement for liners, except where required on a site-specific basis in hydrogeologically sensitive areas.			

Table VII-1 (continued)

States	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/oversight
Oklahoma	Prevent pollution of surface and subsurface water, commercial pits must be sealed with an impervious material.	No liner requirement for reserve pits for wells using freshwater drilling muds, 30-mil liners (or metal tanks) reqd for pits containing "deleterious fluids other than freshwater drilling muds." 12-inch, 10^{-7} cm/sec soil liner for commercial pits; commercial pits must be at least 25 feet above highest aquifer, site-specific reqt for coml pits containing deleterious fluids.	18-inch freeboard and run-on controls; 36 inches for commercial pits.	More stringent reqts (i.e., liners) for fluids other than water-based muds provide an incentive to manage these wastes separately.	Permit not reqd for on-site pits; notification reqd for emergency and burn pits.
Texas	May not cause or allow pollution of surface or subsurface water.	Liners not required.		Use of reserve pits and mud circulation pits is restricted to drilling fluids, drill cuttings, sands, silts, wash water, drill stem test fluids, and blowout preventer test fluids.	Reserve pits and mud circulation pits are authorized by rule without permits; individual permit reqd for coml facilities, drilling fluid storage pits (other than mud circulation pits), and drilling fluid disposal pits (other than reserve pits).

Table VII-1 (continued)

States	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/ oversight
W. Virginia	Prevent seepage, leakage, or overflow and maintain pit integrity.	Liners not reqd, except where soil is not suitable to prevent seepage or leakage.	Adequate freeboard	No produced water, unused fracturing fluid or acid, compressor oil, refuse, diesel, kerosene, halogenated phenol, etc.	General permit, offsite discharge of fluids requires an individual permit.
Wyoming	Prevent pollution of streams and underground water and unreasonable damage to the land.	Liners not reqd except where the potential for communication between the pit contents and surface water or shallow ground water is high.		No chemicals that reduce the pit's fluid seal.	Individual permit reqd except for workover and completion pits containing oil and/or water; more stringent design reqts for commercial pits.

Table VII-2 Reserve Pit Closure/Waste Removal

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Annular injection
Alaska	Must be operated with a fluid management plan and must be closed within 1 year after final disposal of drilling wastes in pit; or must be designed for 2 years' disposal and closed in that time period; numerous performance reqts added.	General permit for discharge of fluids to tundra; prior written approval reqd; specs and effluent monitoring for metals and conventional pollutants; only pits eligible are those that have received no drilling wastes since previous summer (last freeze-thaw cycle), to allow precipitation of contaminants.	Individual permit; compliance point is edge of the road for same specs as for land application (except pH); no requirement for freeze-thaw cycle.	See land application; specs same as AK WQS (except TDS) pending study to determine effect on wildlife.	General permit for N. Slope; prior written approval reqd; discharge must occur below the permafrost into a zone containing greater than 3,000 ppm TDS.
Arkansas (revisions due in '88)	OGC: No specific regulatory requirements. DPCE: within 60 days of rig's removal, reclaim to grade and reseed; fluids must be consigned to state-permitted disposal service (per authorization letter).	DPCE only: waste analysis and landowner's consent reqd for land application (per authorization letter).		Prohibited.	DPCE: prior approval reqd (per authorization letter).
California	When drilling operations cease, remove either (1) all wastes or (2) all free liquids and hazardous residuals.	Offsite disposal reqts depend on whether waste is "hazardous" (double liners), "designated" (single liner) or nonhazardous.		Permit reqd from RWQCB; disposal may not cause damage to surface water.	
Colorado	For dry and abandoned wells, within 6 months of a well's closure, decant the fluids, backfill and reclaim.	Dewatered sediment may be tilled into the ground.		Permits for discharge may be issued if effluent meets stream's classification standard.	

Table VII-2 (continued)

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Annular injection
Kansas	As soon as practical, evaporate or dewater and backfill; 365 days, or sooner if specifically required by Commission (proposed).	Landfarming is prohibited; in-situ disposal may be prohibited in sensitive areas.	If approved by Kansas Department of Health and Environment.		Prohibited.
Louisiana	Within 6 months of completion of drilling or workover activities, fluids must be analyzed for pH, O&G, metals and salinity, and then removed; exemption for wells less than 5,000 ft deep if native mud used.	Onsite land treatment or trenching of fluids and land treatment, burial or solidification of nonfluids allowed provided specs are met (including pH, electrical conductivity, and certain metals).		Permits issued for discharge of wastewater from treated drilling site reserve pits, so long as limitations for oil and grease, TSS, metals, chlorides, pH are met. Dilution allowed to meet chloride limits.	Surface casing must be at least 200 ft below the lowest USDW.
Michigan	At closure, all free liquids must be removed and the residue encapsulated onsite or disposed of offsite.	In-situ encapsulation requires a 10-mil PVC cap 4 ft below grade; offsite disposal must be in a lined landfill with leachate collection and ground-water monitoring	Prohibited.	Prohibited.	Well must have production casing and injected fluid must be isolated below freshwater horizons; exception granted if, among other things, pressure gradient is less than 0.7 psi.
New Mexico		Pits are evaporated and residue generally buried onsite.		Prohibited.	

Table VII 2 (continued)

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Annular injection
Ohio	Within 5 months of the commencement of drilling, backfill and remove concrete bases and drilling equipment, within 9 months, grade and revegetate area not reqd for production.	Drilling fluids may be disposed of by land application; pit solids may be buried onsite, except where history of ground-water problems		Permit reqd.	Standard well treatment fluids can be injected; same reqts as for annular produced water disposal; permit generally reqd
Oklahoma	Within 12 months of drilling operation's cessation, dewater and leave; 6-month extension for good cause; only 60 days allowed for circulating and fracture pits.	Landfarming of water-based muds is allowed; permit reqd; siting and rate application reqts, waste analysis, revegetation within 120 days		Prohibited.	Onsite injection allowed, approval reqd; surface casing must be set at least 200 ft below treatable water; limits on pressure so that vertical fractures will not extend to base of treatable water.
Texas	Within 30 days to 1 year from when drilling ceases (depending on the fluid's Cl content) dewater, backfill, and compact.	Landfarming prohibited for water-based drilling fluids having greater than 3,000 mg/L Cl and oil-based wastes; onsite burial prohibited for oil-based drilling fluids (but burial of solids obtained while using oil-based drilling fluid allowed).		Minor permit required for discharge of fluid fraction from treated reserve pits; prior notif. and 24-hour bioassay test reqd; discharge may not violate TX WQS or haz. metals limits; specs include O&G (15 mg/L), Cl (1,000 mg/L coastal, 500 mg/L in-land); TSS (50 mg/L), COD (200 mg/L), TDS (3000 mg/L)	One-time annular injection allowed; "minor permit" required; limits on surface injection pressure; casing set such that usable quality water protected to depth recommended by TWC.

Table VII-2 (continued)

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Annular injection
W. Virginia	Within 6 months from when drilling ceases.	Cuttings may be buried onsite; after physical treatment, fluids meeting specs can be applied to the land; specs include oil (no visible sheen on land) and Cl (25,000 mg/L), monitoring reqd for other parameters.			
Wyoming	Within 1 year of use, remove liquids and reclaim pit; reclamation bond released after pit closure inspected and approved.	Permit reqd for land application; discharge must meet water quality limits, including O&G (2,000 or 20,000 lb/acre, depending on whether soil incorporated), Cl (1,500 mg/L).	Permit reqd for road application; location and application reqts imposed through DEQ memorandum.	Prohibited, except where DEQ determines discharge will not cause sig. envir damage or contaminate public water supplies; application must include complete analysis, volume, location, and name of receiving stream.	One-time injection allowed under some conditions as in UIC permit.

Table VII-3 Produced Water Pit Design and Construction

State	General statement of objective/purpose	Liners	Exemptions	Permitting/oversight
Alaska	Produced water is a "drilling waste" and is subject to the same reqts as in Table VII-1.			
Arkansas (revisions due in '88)	No discharge into any water of the State (including ground water).	Pits must be lined or underlaid by tight soil; pits prohibited over porous soil; (DPCE authorization letter requires tanks).		Individual permit; application reqd within 30 days of producing waste.
California	Nondegradation of State waters; pits not permitted in natural drainage channels or where they may be in communication with freshwater-bearing aquifers.	Liners reqd where necessary to comply with the State's nondegradation policy; specific standards for construction/operation may be established by RWQCBs.		Subject to permitting authority of Regional WQCB.
Colorado	Prevent pollution (broadly defined) of State waters; prevent exceeding of stream standards.	Same as for reserve pits (for pits receiving more than 5 bbl/d 90% of the pits are lined; 2/3 clay, 1/3 synthetic)	Exemptions from liner requirement for pits overlying impermeable materials or receiving water with less than 5,000 ppm TDS.	Individual permit.
Kansas	Consideration of protection of soil and water resources from pollution.	Strict liner and seal requirements in conjunction with hydrogeologic investigation.		No permits issued for unlined pits.
Louisiana		All pits must be lined such that the hydraulic conductivity is less than 10^{-7} cm/sec.	Pits in certain coastal areas, provided they are part of a treatment train for oil and grease removal.	

State	General statement of objective/purpose	Liners	Exemptions	Permitting/oversight
Michigan	Brine cannot be run to earthen reservoirs or ponds.			
New Mexico		In the southeast, 30-mil liners with leak detection are reqd; in the northwest, liners are reqd over specified vulnerable aquifers.	Small-volume pits and pits in specified areas that are already saline and in areas without fresh water.	If liner required, individual permit after hearing.
Ohio	Pits must be liquid tight; waste cannot be stored for more than 180 days; pits may not be used for ultimate disposal.			Produced water disposal plan must be submitted.
Oklahoma	Pits must be sealed with an impervious material; in addition, offsite pits must contain fluids with less than 3,500 ppm Cl.	12-inch, 10^{-7} cm/sec soil liner for coml pits; site-specific liner reqt if coml pit contains deleterious fluids		Individual permits required.
Texas	Permit for unlined pit denied unless operator conclusively shows pit will not pollute agricultural land, surface or subsurface water; emergency pits generally exempted.	Generally, all pits other than emergency pits require liners unless (1) there is no surface or subsurface water in the area, or (2) the pit is underlaid by a naturally occurring impervious barrier; liners required for emergency pits in sensitive areas.		Individual permit.
W. Virginia	Same as for reserve pits.	Same as for reserve pits.		Same as for reserve pits.
Wyoming		Liners not reqd except where the potential for communication between the pit contents and surface water or shallow ground water is high.		Individual permit reqd if pit receives more than 5 bbl/day produced water; area-wide permits also granted; individual permits and more stringent terms for commercial pits.

Table VII-4 Produced Water Surface Discharge Limits

State	Onshore	Coastal/tidal	Beneficial use	Permitting/oversight
Alaska				Produced water is subject to the discharge reqts for reserve pit fluids in Table VII-1.
Arkansas	Prohibited.	Not applicable.		
California	In some cases, produced waters ultimately disposed of in sumps are allowed to first be discharged into canals or ephemeral streams that carry the salt water to the sumps.	Policy for enclosed bays and estuaries prohibits discharge of materials of petroleum origin in sufficient quantities to be visible or in violation of waste discharge reqts; Ocean Plan sets limits for O&G, arsenic, total chromium, etc.	Discharge allowed to canals, ditches, and ephemeral streams before reuse; specs issued by one RWQCB include O&G (35 mg/L) and Cl (200 mg/L).	Permit reqd from RWQCB for beneficial use.
Colorado	Discharge must not cause pollution (broadly defined) of any waters of the state; must not cause exceeding of stream standards.	N/A	Specs for wildlife and agricultural use include O&G (10 mg/L) and TDS (5,000 mg/L, 30-day average).	Permit reqd from Water Quality Control Division of Department of Health.
Kansas	Prohibited.	N/A		Road application requires approval by Dept. of Health and Environment.
Louisiana	Discharges allowed into lower distributaries of Mississippi and Atchafalaya Rivers; discharges into waters of the State require a permit after 11/20/86; facility deemed in compliance except where an investigation or a complaint has been filed.	Discharge allowed if treated to remove residual O&G.		Individual permits for surface discharges required after 11/20/86.

Table VII-4 (continued)

State	Onshore	Coastal/tidal	Beneficial use	Permitting/oversight
Michigan	Prohibited.	Prohibited.	Specs for dust control, 3-yr study to determine if practice should be continued.	
New Mexico	Prohibited except in emergencies or for construction, application reqd.	N/A	Use as drinking water for cattle and in construction, no contaminant levels specified.	State approval for cattle watering and construction reqd.
Ohio	Discharge must not cause pollution of any waters of the State.	N/A	Reqts for road spreading include a 12-ft buffer zone to prevent damage to water bodies.	Road or land spreading must be authorized by city/municipal resolution; NPDES permit reqd for onshore discharges.
Oklahoma	Prohibited.	N/A		
Texas	Prohibited, unless fresh.	Discharges allowed, but skimming required to prevent oil in tidal waters; testing for oil every 30-40 days.		Individual permit.
W. Virginia	No discharge of salt water or other water unfit for domestic livestock into waters of State.	N/A	Road application allowed pending study.	NPDES permit reqd for onshore discharges; general permit for stripper wells expected mid-1987.
Wyoming	Specs include O&G (10 mg/l) and Cl (2,000 mg/L); no discharge of toxic substances at conc. toxic to humans, animals, or aquatic life.	N/A		NPDES permit reqd for surface discharges.

Table VII-5 Produced Water Injection Well Construction

State	Casing	MIT pressure and duration	MIT frequency	Abandoned wells
Alaska	Safe and appropriate casing, cemented to protect oil, gas, and fresh water; detailed casing specs.	30 min at 1,500 psi or 0.25 psi/ft times vertical depth of casing shoe, whichever is greater; max. pressure decline 10%.	Before operation; thereafter monthly reporting of casing-tubing annulus pressure.	1/4-mile area of review.
Arkansas	Well must be cased and cemented so as not to damage oil, gas, or fresh water.	Determined by AOGC on a case-by-case basis.	Before operation; thereafter every 5 years.	1/2-mile area of review.
California	Safe and appropriate casing; cementing specs.	From hydrostatic to the pressure reqd to fracture the injection zone or the proposed injection pressure, whichever occurs first; step rate test may be waived.	Within 3 months after injection commences and annually thereafter, after any anomalous rate or pressure change, or as requested by DOG.	1/4-mile fixed radius in combination with radial flow equation and documented geological features are used to define area of review.
Colorado	Safe and adequate casing or tubing to prevent leakage, and cemented so as not to damage oil, gas, or fresh water.	15 min at 300 psi or the minimum injection pressure, whichever is greater; max. variance 10%.	Before operation, thereafter every 5 years; exceptions for wells monitoring annulus pressure monthly.	1/4-mile area of review; notice to surface and working interest owners within 1 mile.
Kansas	Well must be cased and cemented to prevent damage to hydrocarbon sources or fresh and usable water.	For old wells, 100 psi; for new wells, 100 psi or the authorized pressure, whichever is greater; alternative tests allowed; 30-minute test.	Before operation; thereafter every 5 years	1/4-mile area of review.
Louisiana	Casing must be set through the deepest USDW and cemented to the surface.	For new wells, 30 min at 300 psi, or max. allowable pressure, whichever is greater; for converted wells, the lesser of 1,000 psi or max. allowable pressure, but no lower than 300 psi; max. variance of 5 psi.	Before operation; thereafter every 5 years.	1/4-mile area of review.

Table VII-5 (continued)

State	Casing	MIT pressure and duration	MIT frequency	Abandoned wells
Michigan	Casing and seal to prevent the loss of produced water into an unapproved formation.	30 min at 300 psi, 3% allowable bleedoff.	As scheduled by RA (Federally administered)	State program to plug abandoned wells.
New Mexico	Casing or tubing to prevent leakage and fluid movement from the injection zone.	15-30 min at 250-300 psi; max. variance 10%	Before operation, thereafter every 5 years; special test can be reqd more often; annulus monitoring required monthly.	State program to plug abandoned wells; 2 1/2-mile area of review, variance allowing no less than 1/4 mile; corrective action reqd to prevent migration through conduits.
Ohio	In addition to use of injection wells, annular disposal of produced water is allowed; max annular disposal 5-10 bbl/d; use only force of gravity; systems must be airtight.			
	Casing must be set at least 50 ft below the deepest USDW and must be cemented to the surface.	15 min at 300 psi, or max. allowable pressure, whichever is greater; max. decline 5%; alternative tests allowed.	Before operation; thereafter every 5 years.	1/4- to 1/2-mile area of review, depending on volume injected; well plugging fund.
Oklahoma	Casing must be set at least 90 ft below the surface or 50 ft below treatable water, whichever is lower, and must be cemented to the surface.	Same as Louisiana, except maximum bleedoff of 10%.	Before operation; thereafter every 5 years; exception for wells monitoring pressure monthly and reporting annually.	1/2-mile area of review; well plugging fund.
Texas	Surface casing cemented to surface; tubing and cemented casing string to isolate injection zone.	Test at 500 psig, or max. allowable pressure, whichever is less, but at least 200 psig; max. decline of 10%; once pressure stabilizes, 30 minutes with no variation.	Before injection, after workover, and thereafter every 5 years (exception for wells monitoring annulus pressure monthly and rpt'g annually, or for other viable alternative test).	1/4-mile area of review; notice to surface owners and offset operators; well plugging fund (main source: $100 drilling permit fee).

Table VII-5 (continued)

State	Casing	MIT pressure[a] and duration	MIT frequency	Abandoned wells
W. Virginia		20 min at 1.5 to 2 times the injection pressure; max. variance 5%.	Every 5 years.	
Wyoming	Surface casing must be set below freshwater sources; casing cemented to the surface.	Same as Louisiana.	Before injection, thereafter every 5 years.	Notice to landowners and operators within 1/2 mile, 1/4-mile area of review.

Table VII-6 Well Abandonment/Plugging

States	Plugging deadline	Plugging oversight
Alaska	1 year following end of operator's activity within the field; if well not completed, must be abandoned or suspended before removal of drilling equipment; bridge plugs reqd for suspended wells.	Plugging method must be approved before beginning work; indemnity bond released after approval of well abandonment.
Arkansas	If not completed, must be abandoned/plugged before drilling equip. is released form the drilling operation; no time limit for temporary abandonment of properly cased well.	Plugging permit; onsite supervision by AOGC official; bond or other evidence of finanacial responsibility reqd, and released only after plugging/abandonment completed.
California	6 months after drilling activity ceases or 2 years after drilling equipment is removed; unless temp. abandonment of properly cased well.	Indemnity bond released after proper abandonment or completion is ensured.
Colorado	Generally, 6 months after production ceases; extensions require semi-annual status report.	Plugging method must be approved; COGC must have opportunity to witness; blanket or individual bond reqd.
Kansas	90 days after operations cease; where temporary abandonment, annual extensions require notice and status reports.	Plugging plan reqd before beginning work; report reqd after completion.
Louisiana	Within 90 days of notice in "Inactive Well Report" unless a plan is submitted describing the well's future use.	
Michigan	Within 60 days after cessation of drilling activities; within 1 year after cessation of production (with extensions, if sufficient reason to retain well).	Plugging method must be approved.

Table VII-6 (continued)

State	Plugging deadline	Plugging oversight
New Mexico	Generally, 6 months; extensions granted for up to 2 yr at a time	Well plugging plan must be approved; plugging bond released after inspection and Director approval.
Ohio	Immediately upon abandonment of a dry hole, without undue delay after prod ceases, extensions provided for 6 months.	Before plugging, approval reqd, after plugging, report reqd including identity of witnesses, liability insurance reqd; surety bond forfeited if noncompliance with regs
Oklahoma	Where prod. casing has been run, 1 year after cessation of drilling (numerous exceptions); less time where no, or only surface, casing run, special rules for temporary abandonment.	Plugging must be supervised by an authorized rep. of the Conservation Division; plugging report reqd; proof of financial ability to comply with plugging reqt
Texas	Within 90 days after drilling or operations cease, except where cessation occurred in '66 or '67 (1 year); extensions at Director's discretion (if no pollution hazard) with plugging bond or letter of credit or plan to use for enhanced recovery.	Before plugging, notification and approval reqd, after plugging, report reqd; operator must be present during plugging.
W. Virginia	Prompt plugging reqd if dry holes and wells not in use for 12 mo; extensions for good cause.	Plugging bond and notif. to the Director and nearby coal operators reqd.
Wyoming	Approval from the State reqd if well is "temporarily abandoned" for more than 1 year.	Before plugging, approval reqd; after plugging, report reqd; well plugging bond released after the State inspection.

Table VII-7 State Enforcement Matrix

State	Gas Production	Oil Production	Gas wells	Oil wells	Injection wells	New wells	Agency	Personnel*
Alaska	316,000 Mmcf 1986	681,309,821 bbl 1986	104	1,191	472 Class II 425 EOR 47 Disposal	100 new onshore wells completed in 1985	Oil and Gas Conservation Commission Department of Environmental Conservation	8 enforcement positions 8 enforcement positions
Arkansas	194,483 Mmcf 1985	19,715,691 bbl 1985	2,492	9,490	1,211 Class II 239 EOR 972 Disposal	1,055 new wells completed in 1985	Arkansas Oil and Gas Commission Department of Pollution Control and Ecology	7 enforcement positions 2 enforcement positions
California	493,000 Mmcf 1985	423,900,000 bbl 1985	1,566	55,079	11,066 Class II 10,047 EOR 1,019 Disposal	3,413 new wells completed in 1985	Conservation Dept., Division of Oil and Gas Department of Fish and Game	31 enforcement positions
Kansas	466,600 Mmcf 1984	75,723,000 bbl 1984	12,680	57,633	14,902 Class II 9,366 EOR 5,536 Disposal	6,025 new wells completed in 1985	Kansas Corporation Commission	30 enforcement positions
Louisiana	5,867,000 Mmcf 1984	449,545,000 bbl 1984	14,436	25,823	4,436 Class II 1,283 EOR 3,153 Disposal	5,447 new onshore wells completed 1985	Department of Environmental Quality Office of Conservation - Injection and Mining	32 enforcement positions 36 enforcement positions
New Mexico	893,300 Mmcf 1985	78,500,000 bbl 1985	18,308	21,986	3,871 Class II 3,508 EOR 363 Disposal	1,747 new wells completed in 1985	Energy and Minerals Department, Oil Conservation Division	10 enforcement positions
Ohio	182,200 Mmcf 1985	14,987,592 bbl 1985	31,343	29,210	3,956 Class II 127 EOR 3,829 Disposal	6,297 new wells completed in 1985	Ohio Department of Natural Resources, Division of Oil and Gas	66 enforcement positions
Oklahoma	1,996,000 Mmcf 1984	153,250,000 bbl 1984	23,647	99,030	22,803 Class II 14,901 EOR 7,902 Disposal	9,176 new wells completed in 1985	Oklahoma Corporation Commission	52 enforcement positions
Pennsylvania	166,000 Mmcf 1984	4,825,000 bbl 1984	24,050	20,739	6,183 Class II 4,315 EOR 1,868 Disposal	4,627 new wells completed in 1985	Department of Environmental Resources, Bureau of Oil and Gas Management	34 enforcement positions
Texas	5,805,000 Mmcf 1985	830,000,000 bbl 1985	68,811	210,000	53,141 Class II 45,223 EOR 7,918 Disposal	25,721 new wells completed in 1985	Texas Railroad Commission	120 enforcement positions
West Virginia	142,500 Mmcf 1986	3,600,000 bbl 1986	32,500	15,895	761 Class II 687 EOR 74 Disposal	1,839 new wells completed in 1985	West Virginia Department of Energy	15 enforcement positions
Wyoming	597,896 Mmcf 1985	130,984,917 bbl 1985	2,220	12,218	5,880 Class II 5,257 EOR 623 Disposal	1,735 new wells completed in 1985	Oil and Gas Conservation Commission Department of Environmental Quality	7 enforcement positions 4.5 enforcement positions

*Only field staff are included in total enforcement positions.

Table VII-8 BLM Enforcement Matrix*

Office location	Other States for which office is responsible	Producing oil and gas leases	Nonproducing oil and gas leases**	Personnel (for producing leases only)
Alaska		43	8,443	1 enforcement position
California		305	1,383	7 enforcement positions
Colorado		3,973	4,463	10 enforcement positions
Idaho		0	471	0 enforcement positions
Mississippi		116	1,519	3 enforcement positions
	Alabama	12	567	
	Arkansas	161	1,099	
	Florida	1	0	
	Kentucky	13	65	
	Louisiana	121	487	
	Virginia	1	523	
	Total	425	4,260	
Montana		958	4,721	12 enforcement positions
	North Dakota	456	1,991	
	South Dakota	98	572	
	Total	1,512	7,284	
Nevada		43	3,045	1 enforcement position
New Mexico		5,725	9,306	43 enforcement positions
	Arizona	10	386	
	Kansas	150	227	
	Oklahoma	2,767	2,754	
	Texas	61	279	
	Total	8,713	12,952	
Oregon		0	1,513	0
Utah		1,654	7,222	10 enforcement positions
Wisconsin		0	0	1 enforcement position
	Maryland	2	11	
	Michigan	28	603	
	Missouri	1	6	
	Ohio	33	69	
	Pennsylania	6	1	
	West Virginia	46	54	
	Total	116	844	
Wyoming		5,037	28,044	27 enforcement positions
	Nebraska	42	582	
	Total	5,079	28,626	
	Total	22,037	102,251	115 enforcement positions

* Oil and gas inspectors working in the field as of March 30, 1987. At that time there were eight vacancies nationwide.

** Includes leases that have never been drilled, have been drilled and abandoned, or are producing wells that have been temporarily shut down.

REFERENCES

43 CFR 3100 (entire group).

U.S. Bureau of Land Management. (Not dated.) Federal Onshore Oil and Gas Leasing and Operating Regulations.

U.S. Bureau of Land Management. NTL-2B.

U.S. Department of the Interior - Geological Survey Division. (Not dated.) Notice to Lessees and Operators of Federal and Indian Oil and Gas Leases (NTL-2B).

Personal communication with Mr. Steve Spector, September 23, 1986.

CHAPTER VIII

CONCLUSIONS

From the analysis conducted for this report, it is possible to draw a number of general conclusions concerning the management of oil and gas wastes. These conclusions are presented below.

Available waste management practices vary in their environmental performance.

Based on its review of current and alternative waste management practices, EPA concludes that the environmental performance of existing waste management practices and technologies varies significantly. The reliability of waste management practices will depend largely on the environmental setting. However, some methods will generally be less reliable than others because of more direct routes of potential exposure to contaminants, lower maintenance and operational requirements, inferiority of design, or other factors. Dependence on less reliable methods can in certain vulnerable locations increase the potential for environmental damage related to malfunctions and improper maintenance. Examples of technologies or practices that are less reliable in locations vulnerable to environmental damage include:

- Annular disposal of produced water (see damage case OH 38, page IV-16);
- Landspreading or roadspreading of reserve pit contents (see damage case WV 13, page IV-24);
- Use of produced water storage pits (see damage case AR 10, page IV-36); and

- Surface discharges of drilling waste and produced water to sensitive systems such as estuaries or ephemeral streams (see damage cases TX 55, page IV-49; TX 31, page IV-50; TX 29, page IV-51; WY 07, page IV-60; and CA 21, page IV-68).

Any program to improve management of oil and gas wastes in the near term will be based largely on technologies and practices in current use.

Current technologies and practices for the management of wastes from oil and gas operations are well established, and their environmental performance is generally understood. Improvements in State regulatory requirements over the past several years are tending to increase use of more desirable technologies and practices and reduce reliance on others. Examples include increased use of closed systems and underground injection and reduced reliance on produced water storage and disposal pits.

Long-term improvements in waste management need not rely, however, purely on increasing the use of better existing technology. The Agency does foresee the possibility of significant technical improvements in future technologies and practices. Examples include incineration and other thermal treatment processes for drilling fluids; conservation, recycling, reuse, and other waste minimization techniques; and wet air oxidation and other proven technologies that have not yet been applied to oil and gas operations.

Because of Alaska's unique and sensitive tundra environment, there has been special concern about the environmental performance of waste management practices on the North Slope. Although there are limited and preliminary data that indicate some environmental impacts may occur, these data and EPA's initial analysis do not indicate the need to curtail current or future oil exploration, development, and production operations on the North Slope. However, there is a need for more environmental data on the performance of existing technology to provide assurance that future operations can proceed with minimal possible adverse impacts on this sensitive and unique environment. The State of Alaska has recently enacted new regulations which will provide additional data on these practices.

EPA is concerned in particular about the environmental desirability of two waste management practices used in Alaska: discharge of reserve pit supernatant onto tundra and road application of reserve pit contents as a dust suppressant. Available data suggest that applicable discharge limits have sometimes been exceeded. This, coupled with preliminary biological data on wildlife impacts and tundra and surface water impairment, suggests the need for further examination of these two practices with respect to current and future operations. The new regulations recently enacted by the State of Alaska should significantly reduce the potential for tundra and wildlife impacts.

Increased segregation of waste may help improve management of oil and gas wastes.

The scope of the exemption, as interpreted by EPA in Chapter II of this report, excludes certain relatively low-volume but possibly high-toxicity wastes, such as unused pipe dope, motor oil, and similar materials. Because some such wastes could be hazardous and could be segregated from the large-volume wastes, it may be appropriate to require that they be segregated and that some of these low-volume wastes be managed in accordance with hazardous waste regulations. While the Agency recognizes that small amounts of these materials may necessarily become mixed with exempt wastes through normal operations, it seeks to avoid any deliberate and unnecessary use of reserve pits as a disposal mechanism. Segregation of these wastes from high-volume exempt wastes appears to be desirable and should be encouraged where practical.

Although this issue is not explicitly covered in Chapter VII, EPA is aware that some States do require segregation of certain of these low-volume wastes. EPA does not have adequate data on which to judge whether these State requirements are adequate in coverage, are enforceable, are environmentally effective, or could be extended to general operations across the country. The Agency concludes that further study of this issue is desirable.

Stripper operations constitute a special subcategory of the oil and gas industry.

Strippers cumulatively contribute approximately 14 percent of total domestic oil production. As such, they represent an economically important component of the U.S. petroleum industry. Two aspects of the stripper industry raise issues of consequence to this study.

First, generation of production wastes by strippers is more significant than their total petroleum production would indicate. Some stripper wells yield more than 100 barrels of produced water for each barrel of oil, far higher on a percentage production basis than a typical new well, which may produce little or no water for each barrel of oil.

Second, stripper operations as a rule are highly sensitive to small fluctuations in market prices and cannot easily absorb additional costs for waste management.

Because of these two factors--inherently high waste-production rates coupled with economic vulnerability--EPA concludes that stripper operations constitute a special subcategory of the oil and gas industry that should be considered independently when developing recommendations for possible improvements in the management of oil and gas wastes. In the event that additional Federal regulatory action is contemplated, such special consideration could indicate the need for separate regulatory actions specifically tailored to stripper operations.

Documented damage cases and quantitative modeling results indicate that, when managed in accordance with State and Federal requirements, exempted oil and gas wastes rarely pose significant threats to human health and the environment.

Generalized modeling of human health risks from current waste management practices suggests that risks from properly managed operations are low. The damage cases researched in the course of this project, however, indicate that exempt wastes from oil and gas exploration, development, and production can endanger human health and cause environmental damage when managed in violation of existing State requirements.

Damage Cases

In a large portion of the cases developed for this study, the types of mismanagement that lead to such damages are illegal under current State regulations although a few were legal under State programs at the time when the damage originally occurred. Evidence suggests that violations of regulations do lead to damages. It is not possible to determine from available data how frequently violations occur or whether violations would be less frequent if new Federal regulations were imposed.

Documented damages suggest that all major types of wastes and waste management practices have been associated to some degree with endangerment of human health and damage to the environment. The principal types of wastes responsible for the damage cases include general reserve pit wastes (primarily drilling fluids and drill cuttings, but also miscellaneous wastes such as pipe dope, rigwash, diesel fuel, and crude oil); fracturing fluids; production chemicals; waste crude oil; produced water; and a variety of miscellaneous wastes associated with exploration, development, or production. The principal types of damage sometimes caused by these wastes include contamination of drinking-water aquifers and foods above levels considered safe for consumption, chemical contamination of livestock, reduction of property values, damage to native vegetation, destruction of wetlands, and endangerment of wildlife and impairment of wildlife habitat.

Risk Modeling

The results of the risk modeling suggest that of the hundreds of chemical constituents detected in both reserve pits and produced fluids, only a few from either source appear to be of concern to human health and the environment via ground-water and surface water pathways. The principal constituents of potential concern, based on an analysis of their toxicological data, their frequency of occurrence, and their mobility in ground water, include arsenic, benzene, sodium, chloride, boron, cadmium, chromium, and mobile salts. All of these constituents were included in the quantitative risk modeling; however, boron, cadmium, and chromium did not produce risks or resource damages under the conditions modeled.

For these constituents of potential concern, the quantitative risk modeling indicates that risks to human health and the environment are very small to negligible when wastes are properly managed. However, although the risk modeling employed several conservative assumptions, it was based on a relatively small sample of sites and was limited in scope to the management of drilling waste in reserve pits, the underground injection of produced water, and the surface water discharge of produced water from stripper wells. Also, the risk analysis did not consider migration of produced water contaminants through fractures or unplugged or improperly plugged and abandoned wells. Nevertheless, the relatively low risks calculated by the risk modeling effort suggest that complete adherence to existing State requirements would preclude most types of damages.

Damages may occur in some instances even where wastes are managed in accordance with currently applicable State and Federal requirements.

There appear to be some instances in which endangerment of human health and damage to the environment may occur even where operations are in compliance with currently applicable State and Federal requirements.

Damage Cases

Some documented damage cases illustrate the potential for human health endangerment or environmental damage from such legal practices as discharge to ephemeral streams, surface water discharges in estuaries in the Gulf Coast region, road application of reserve pit contents and discharge to tundra in the Arctic, annular disposal of produced waters, and landspreading of reserve pit contents.

Risk Modeling

For the constituents of potential concern, the quantitative evaluation did indicate some situations (less than 5 percent of those studied) with carcinogenic risks to maximally exposed individuals higher then 1 in 10,000 ($1x10^{-4}$) and sodium levels in excess of interim limits for public drinking water supplies. Although these higher risks resulted only under conservative modeling assumptions, including high (90th percentile) concentration levels for the toxic constituents, they do indicate potential for health or environmental impairment even under the general assumption of compliance with standard waste management procedures and applicable State and Federal requirements. Quantitative risk modeling indicates that there is an extremely wide variation (six or more orders of magnitude) in health and environmental damage potential among different sites and locations, depending on waste volumes, wide differences in measured toxic constituent concentrations, management practices, local hydrogeological conditions, and distances to exposure points.

Unplugged and improperly plugged abandoned wells can pose significant environmental problems.

Documentation assembled for the damage cases and contacts with State officials indicate that ground-water damages associated with unplugged and improperly plugged abandoned wells are a significant concern. Abandoned disposal wells may leak disposed wastes back to the surface or to usable ground water. Abandoned production wells may leak native brine, potentially leading to contamination of usable subsurface strata or surface waters.

Many older wells, drilled and abandoned prior to current improved requirements on well closure, have never been properly plugged. Many States have adequate regulations currently in place; however, even under some States' current regulations, wells are abandoned every year without being properly plugged.

Occasionally companies may file for bankruptcy prior to implementing correct plugging procedures and neglect to plug wells. Even when wells are correctly plugged, they may eventually leak in some circumstances in the presence of corrosive produced waters. The potential for environmental damage occurs wherever a well can act as a conduit between usable ground-water supplies and strata containing water with high chloride levels. This may occur when the high-chloride strata are pressurized naturally or are pressurized artificially by disposal or enhanced recovery operations, thereby allowing the chloride-rich waters to migrate easily into usable ground water.

Discharges of drilling muds and produced waters to surface waters have caused locally significant environmental damage where discharges are not in compliance with State and Federal statutes and regulations or where NPDES permits have not been issued.

Damage cases indicate that surface water discharges of wastes from exploration, development, and production operations have caused damage or danger to lakes, ephemeral streams, estuaries, and sensitive environments when such discharges are not carried out properly under applicable Federal and State programs and regulations. This is particularly an issue in areas where operations have not yet received permits under the Federal NPDES program, particularly along the Gulf Coast, where permit applications have been received but permits have not yet been issued, and on the Alaskan North Slope, where no NPDES permits have been issued.

For the Nation as a whole, Rrgulation of all oil and gas field wastes under unmodified Subtitle C of RCRA would have a substantial impact on the U.S. economy.

The most costly hypothetical hazardous waste management program evaluated by EPA could reduce total domestic oil production by as much as 18 percent by the year 2000. Because of attendant world price increases, this would result in an annual direct cost passed on to consumers of over $6 billion per year. This scenario assumes that 70 percent of all drilling and production wastes would be subject to the current requirements of Subtitle C of RCRA. If only 10 percent of drilling wastes and produced waters were found to be hazardous, Subtitle C regulation would result in a decline of 4 percent in U.S. production and a $1.2 billion cost increase to consumers, compared with baseline costs, in the year 2000.

EPA also examined the cost of a Subtitle C scenario in which produced waters injected for the purpose of enhanced oil recovery would be exempt from Subtitle C requirements. This scenario yielded production declines ranging from about 1.4 to 12 percent and costs passed on to consumers ranging from $0.7 to $4.5 billion per year, depending on whether 10 percent or 70 percent of the wastes (excluding produced waters injected for enhanced oil recovery) were regulated as hazardous wastes.

These Subtitle C estimates do not, however, factor in all of the Hazardous and Solid Waste Act Amendments relating to Subtitle C land disposal restrictions and corrective action requirements currently under regulatory development. If these two requirements were to apply to oil and gas field wastes, the impacts of Subtitle C regulation would be substantially increased.

The Agency also evaluated compliance costs and economic impacts for an intermediate regulatory scenario in which moderately toxic drilling wastes and produced waters would be subject to special RCRA requirements less stringent than those of Subtitle C. Under this scenario, affected drilling wastes would be managed in pits with synthetic liners, caps, and ground-water monitoring programs and regulated produced waters would continue to be injected into Class II wells (with no surface discharges allowed for produced waters exceeding prescribed constituent concentration limits). This scenario would result in a domestic production decline, and a cost passed on to consumers in the year 2000, of 1.4 percent and $400 million per year, respectively, if 70 percent of the wastes were regulated. If only 10 percent of the wastes were subject to regulation, this intermediate scenario would result in a production decline of less than 1 percent and an increased cost to consumers of under $100 million per year.

The economic impact analysis also estimates affects on U.S. foreign trade and State tax revenues. By the year 2000, based on U.S. Department of Energy models, the EPA cost results projected an increase in national petroleum imports ranging from less than 100 thousand to 1.1 million barrels per day and a corresponding increase in the U.S. balance of payments deficit ranging from less than $100 thousand to $18 billion annually, depending on differences in regulatory scenarios evaluated. Because of the decline in domestic production, aggregated State tax revenues would be depressed by an annual amount ranging from a few million to almost a billion dollars, depending on regulatory assumptions.

Regulation of all exempt wastes under full, unmodified RCRA Subtitle C appears unnecessary and impractical at this time.

There appears to be no need for the imposition of full, unmodified RCRA Subtitle C regulation of hazardous waste for all high-volume exempt oil and gas wastes. Based on knowledge of the size and diversity of the industry, such regulations could be logistically difficult to enforce and could pose a substantial financial burden on the oil and gas industry, particularly on small producers and stripper operations. Nevertheless, elements of the Subtitle C regulatory program may be appropriate in select circumstances. Reasons for the above tentative conclusion are described below.

The Agency considers imposition of full, unmodified Subtitle C regulations for all oil and gas exploration, development, and production wastes to be <u>unnecessary</u> because of factors such as the following.

- Damages and risks posed by oil and gas operations appear to be linked, in the majority of cases, to violations of existing State and Federal regulations. This suggests that implementation and enforcement of existing authorities are critical to proper management of these wastes. Significant additional environmental protection could be achieved through a program to enhance compliance with existing requirements.

- State programs exist to regulate the management of oil and gas wastes. Although improvements may be needed in some areas of design, implementation, or enforcement of these programs, EPA believes that these deficiencies are correctable.

- Existing Federal programs to control underground injection and surface water discharges provide sufficient legal authority to handle most problems posed by oil and gas wastes within their purview.

The Agency considers the imposition of full Subtitle C regulations for all oil and gas exploration, development, and production wastes to be impractical because of factors such as the following:

- EPA estimates that the economic impacts of imposition of full Subtitle C regulations (excluding the corrective action and land disposal restriction requirements), as they would apply without modification, would significantly reduce U.S. oil and gas production, possibly by as much as 22 percent.

- If reserve pits were considered to be hazardous waste management facilities, requiring permitting as Subtitle C land disposal facilities, the administrative procedures and lengthy application processes necessary to issue these permits would have a drastic impact on development and production.

- Adding oil and gas operations to the universe of hazardous waste generators would potentially add hundreds of thousands of sites to the universe of hazardous waste generators, with many thousands of units being added and subtracted annually.

- Manifesting of all drilling fluids and produced waters offsite to RCRA Subtitle C disposal facilities would pose difficult logistical and administrative problems, especially for stripper operations, because of the large number of wells now in operation.

States have adopted variable approaches to waste management.

State regulations governing proper management of Federally exempt oil and gas wastes vary to some extent to accommodate important regional differences in geological and climatic conditions, but these regional environmental variations do not fully explain significant variations in the content, specificity, and coverage of State regulations. For example, State well-plugging requirements for abandoned production wells range from a requirement to plug within 6 months of shutdown of operations to no time limit on plugging prior to abandonment.

Implementation of existing State and Federal requirements is a central issue in formulating recommendations in response to Section 8002(m).

A preliminary review of State and Federal programs indicates that most States have adequate regulations to control the management of oil and gas wastes. Generally, these State programs are improving. Alaska, for example, has just promulgated new regulations. It would be desirable, however, to enhance the implementation of, and compliance with, certain waste management requirements.

Regulations exist in most States to prohibit the use of improper waste management practices that have been shown by the damage cases to lead to environmental damages and endangerment of human health. Nevertheless, the extent to which these regulations are implemented and enforced must be one of the key factors in forming recommendations to Congress on appropriate Federal and non-Federal actions.

CHAPTER IX

RECOMMENDATIONS

Following public hearings on this report, EPA will draw more specific conclusions and make final recommendations to Congress regarding whether there is a need for new Federal regulations or other actions. These recommendations will be made to Congress and the public within 6 months of the publication of this report.

Use of Subtitle D and other Federal and State authorities should be explored as a means for implementing any necessary additional controls on oil and gas wastes.

EPA has concluded that imposition of full, unmodified RCRA Subtitle C regulation of hazardous waste for all exempt oil and gas wastes may be neither desirable nor feasible. The Agency believes, however, that further review of the current and potential additional future use of other Federal and State authorities (such as Subtitle D authority under RCRA and authorities under the Clean Water Act and the Safe Drinking Water Act) is desirable. These authorities could be appropriate for improved management of both exempt and nonexempt, high-volume or low-volume oil and gas wastes.

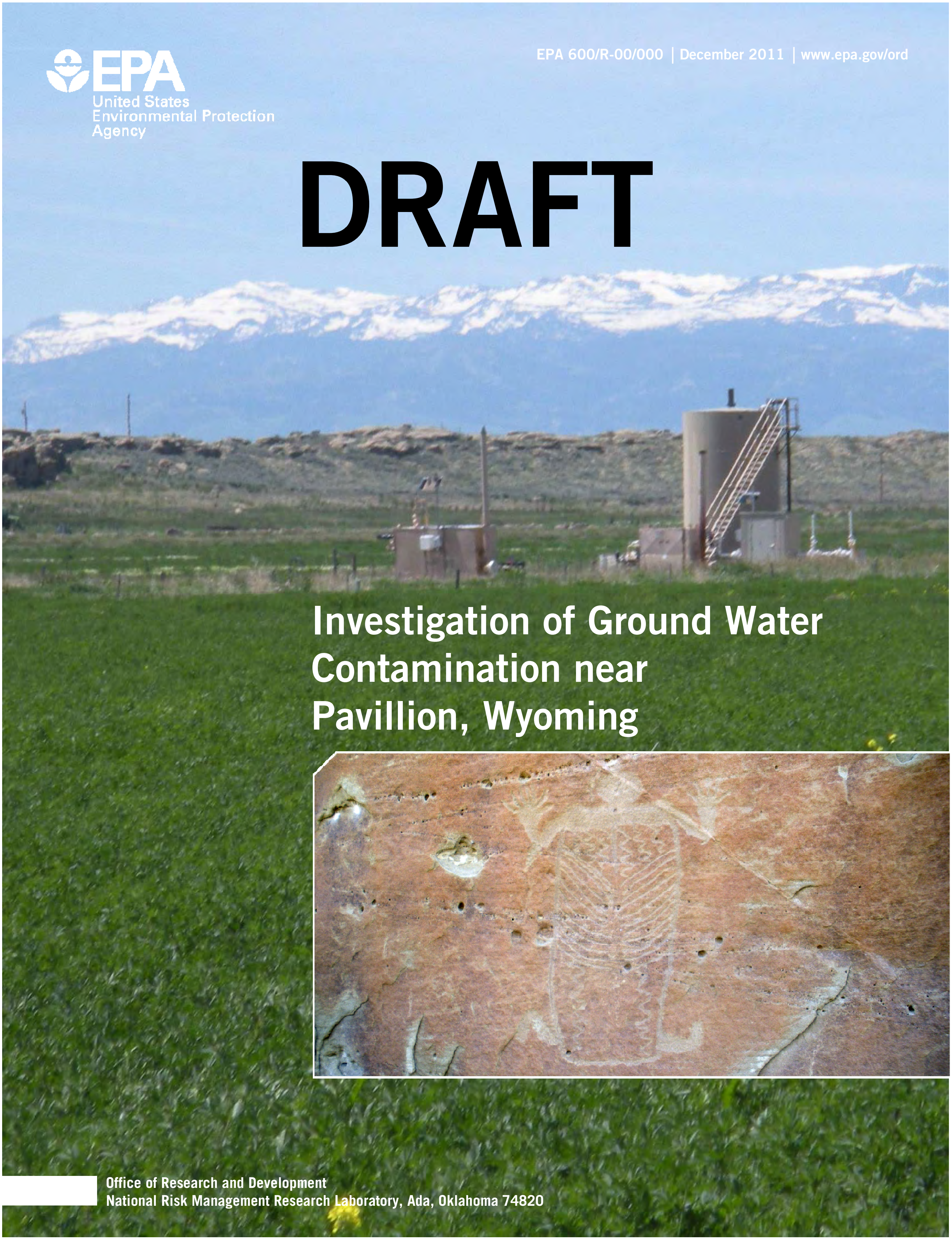
EPA may consider undertaking cooperative efforts with States to review and improve the design, implementation, and enforcement of existing State and Federal programs to manage oil and gas wastes.

EPA has concluded that most States have adequate regulations to control most impacts associated with the management of oil and gas wastes, but it would be desirable to enhance the implementation of, and compliance with, existing waste management requirements. EPA has also concluded that variations among States in the design and implementation of regulatory programs warrant review to identify successful measures in some States that might be attractive to other States. For example, EPA may want to explore whether changes in State regulatory reporting requirements would make enforcement easier or more effective. EPA therefore recommends additional work, in cooperation with the States, to explore these issues and to develop improvements in the design, implementation, and enforcement of State programs.

During this review, EPA and the States should also explore nonregulatory approaches to support current programs. These might include development of training standards, inspector training and certification programs, or technical assistance efforts. They might also involve development of interstate commissions or other organizational approaches to address waste management issues common to operations in major geological regions (such as the Gulf Coast, Appalachia, or the Southwest). Such commissions might serve as a forum for discussion of regional waste management efforts and provide a focus for development and delivery of nonregulatory programs.

The industry should explore the potential use of waste minimization, recycling, waste treatment, innovative technologies, and materials substitution as long-term improvements in the management of oil and gas wastes.

Although in the near term it appears that no new technologies are available for making significant technical improvements in the management of exempt wastes from oil and gas operations, over the long term various innovative technologies and practices may emerge. The industry should explore the use of innovative approaches, which might include conservation and waste minimization techniques for reducing generation of drilling fluid wastes, use of incineration or other treatment technologies, and substitution of less toxic compounds wherever possible in oil and gas operations generally.



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Investigation of Ground Water Contamination near Pavillion, Wyoming

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Notice

Foreword

The U.S. Environmental Protection Agency (EPA) is charged by Congress with protecting the Nation's land, air, and water resources. Under a mandate of national environmental laws, the Agency strives to formulate and implement actions leading to a compatible balance between human activities and the ability of natural systems to support and nurture life. The scientific arm of EPA, the Office of Research and Development (ORD), conducts leading-edge research that helps provide the solid underpinning of science and technology for the Agency. The work at ORD laboratories, research centers, and offices across the country helps improve the quality of air, water, soil, and the way we use resources. The research described in this report was designed and conducted by ORD's National Risk Management Research Laboratory in Ada, Oklahoma, working in close collaboration with scientists from EPA Region 8 in Denver, Colorado.

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Extended Abstract

In response to complaints by domestic well owners regarding objectionable taste and odor problems in well water, the U.S. Environmental Protection Agency initiated a ground water investigation near the town of Pavillion, Wyoming under authority of the Comprehensive Environmental Response, Compensation, and Liability Act. The Wind River Formation is the principal source of domestic, municipal, and stock (ranch, agricultural) water in the area of Pavillion and meets the Agency's definition of an Underground Source of Drinking Water. Domestic wells in the area of investigation overlie the Pavillion gas field which consists of 169 production wells which extract gas from the lower Wind River Formation and underlying Fort Union Formation. Hydraulic fracturing in gas production wells occurred as shallow as 372 meters below ground surface with associated surface casing as shallow as 110 meters below ground surface. Domestic and stock wells in the area are screened as deep as 244 meters below ground surface. With the exception of two production wells, surface casing of gas production wells do not extend below the maximum depth of domestic wells in the area of investigation. At least 33 surface pits previously used for the storage/disposal of drilling wastes and produced and flowback waters are present in the area. The objective of the Agency's investigation was to determine the presence, not extent, of ground water contamination in the formation and if possible to differentiate shallow source terms (pits, septic systems, agricultural and domestic practices) from deeper source terms (gas production wells).

The Agency conducted four sampling events (Phase I - IV) beginning in March 2009 and ending in April, 2011. Ground water samples were collected from domestic wells and two municipal wells in the town of Pavillion in Phase I. Detection of methane and dissolved hydrocarbons in several domestic wells prompted collection of a second round of samples in January, 2010 (Phase II). During this phase, EPA collected additional ground water samples from domestic and stock wells and ground water samples from 3 shallow monitoring wells and soil samples near the perimeter of three known pit locations. Detection of elevated levels of methane and diesel range organics (DRO) in deep domestic wells prompted the Agency to install 2 deep monitoring wells screened at 233 - 239 meters (MW01) and 293 - 299 meters (MW02) below ground surface, respectively, in June 2010 to better evaluate to deeper sources of contamination. The expense of drilling deep wells while utilizing blowout prevention was the primary limiting factor in the number of monitoring wells installed. In September 2010 (Phase III), EPA collected gas samples from well casing from MW01 and MW02. In October 2010, EPA collected ground water samples from MW01 and MW02 in addition to a number of domestic wells. In April 2011 (Phase IV), EPA resampled the 2 deep monitoring wells to compare previous findings and to expand the analyte list to include glycols, alcohols, and low molecular weight acids.

Detection of high concentrations of benzene, xylenes, gasoline range organics, diesel range organics, and total purgeable hydrocarbons in ground water samples from shallow monitoring wells near pits indicates that pits are a source of shallow ground water contamination in the area of investigation. When considered separately, pits represent potential source terms for localized ground water plumes of unknown extent. When considered as whole they represent potential broader contamination of shallow ground water. A number of stock and domestic wells in the area of investigation are fairly shallow (e.g., < 30 meters below ground surface) representing potential receptor pathways.

Determination of the sources of inorganic and organic geochemical anomalies in deeper ground water was considerably more complex than determination of sources in shallow media necessitating the use of mulitiple

lines of reasoning approach common to complex scientific investigations. pH values in MW01 and MW01 are highly alkaline (11.2-12.0) with up to 94% of the total alkalinity contributed by hydroxide suggesting addition of a strong base as the causative factor. Reaction path modeling indicates that sodium-sulfate composition of ground water typical of deeper portions of the Wind River Formation provides little resistance to elevation of pH with small addition of potassium hydroxide. Potassium hydroxide was used in a crosslinker and in a solvent at this site.

The inorganic geochemistry of ground water from the deep monitoring wells is distinctive from that in the domestic wells and expected composition in the Wind River formation. Potassium concentration in MW02 (43.6 milligrams per liter) and MW01 (54.9 milligrams per liter) is between 14.5 and 18.3 times values in domestic wells and expected values in the formation. Chloride concentration in monitoring well MW02 (466 milligrams per liter) is 18 times the mean chloride concentration (25.6 milligrams per liter) observed in ground water from domestic wells and expected in the formation. Chloride enrichment in this well is significant because regional anion trends show decreasing chloride concentration with depth. In addition, the monitoring wells show low calcium, sodium, and sulfate concentrations compared to the general trend observed in domestic well waters. The formulation of fracture fluid provided for carbon dioxide foam hydraulic fracturing jobs typically consisted of 6% potassium chloride. Potassium metaborate was used in crosslinkers. Potassium hydroxide was used in a crosslinker and in a solvent. Ammonium chloride was used in crosslinker.

A number of synthetic organic compounds were detected in MW01 and MW02. Isopropanol was detected in MW01 and MW02 at 212 and 581 micrograms per liter, respectively. Diethylene glycol was detected in MW01 and MW02 at 226 and 1570 micrograms per liter, respectively. Triethylene glycol was detected in MW01 and MW02 at 46 and 310 micrograms per liter, respectively. Another synthetic compound, *tert*-butyl alcohol, was detected in MW02 at a concentration of 4470 micrograms per liter. Isopropanol was used in a biocide, in a surfactant, in breakers, and in foaming agents. Diethylene glycol was used in a foaming agent and in a solvent. Triethylene glycol was used in a solvent. *Tert*-butyl alcohol is a known breakdown product of methyl *tert*-butyl ether (a fuel additive) and *tert*-butyl hydroperoxide (a gel breaker used in hydraulic fracturing). Material Safety Data Sheets do not indicate that fuel or tert-butyl hydroperoxide were used in the Pavillion gas field. However, Material Safety Data Sheets do not contain proprietary information and the chemical ingredients of many additives. The source of *tert*-butyl alcohol remains unresolved. However, *tert*-butyl alcohol is not expected to occur naturally in ground water.

Benzene, toluene, ethylbenzene, and xylenes (BTEX) were detected in MW02 at concentrations of 246, 617, 67, and 750 micrograms per liter, respectively. Trimethylbenzenes were detected in MW02 at 105 micrograms per liter. Gasoline range organics were detected in MW01 and MW02 at 592 and 3710 micrograms per liter. Diesel range organics were detected in MW01 and MW02 at 924 and 4050 micrograms per liter, respectively. Aromatic solvent (typically BTEX mixture) was used in a breaker. Diesel oil (mixture of saturated and aromatic hydrocarbons including naphthalenes and alkylbenzenes) was used in a guar polymer slurry/liquid gel concentrate and in a solvent. Petroleum raffinates (mixture of paraffinic, cycloparaffinic, olefinic, and aromatic hydrocarbons) were used in a breaker. Heavy aromatic petroleum naphtha (mixture of paraffinic, cycloparaffinic and aromatic hydrocarbons) was used in surfactants and in a solvent. Toluene and xylene were used in flow enhancers and a breaker.

Detections of organic chemicals were more numerous and exhibited higher concentrations in the deeper of the two monitoring wells. Natural breakdown products of organic contaminants like BTEX and glycols include acetate and benzoic acid. These breakdown products are more enriched in the shallower of the two monitoring wells, suggesting upward/lateral migration with natural degradation and accumulation of daughter products. Hydraulic gradients are currently undefined in the area of investigation. However, there are flowing conditions in a number of deep stock wells suggesting that upward gradients exist in the area of investigation.

Alternative explanations were carefully considered to explain individual sets of data. However, when considered together with other lines of evidence, the data indicates likely impact to ground water that can be explained by hydraulic fracturing. A review of well completion reports and cement bond/variable density logs in the area around MW01 and MW02 indicates instances of sporadic bonding outside production casing directly above intervals of hydraulic fracturing. Also, there is little lateral and vertical continuity of hydraulically fractured tight sandstones and no lithologic barrier (laterally continuous shale units) to stop upward vertical migration of aqueous constituents of hydraulic fracturing in the event of excursion from fractures. In the event of excursion from sandstone units, vertical migration of fluids could also occur via nearby wellbores. For instance, at one production well, the cement bond/variable density log indicates no cement until 671 m below ground surface. Hydraulic fracturing occurred above this depth at nearby production wells.

A similar lines of reasoning approach was utilized to evaluate the presence of gas in monitoring and domestic wells. A comparison of gas composition and stable carbon isotope values indicate that gas in production and monitoring wells is of similar thermogenic origin and has undergone little or no degradation. A similar evaluation in domestic wells suggests the presence of gas of thermogenic origin undergoing biodegradation. This observation is consistent with a pattern of dispersion and degradation with upward migration observed for organic compounds.

Elevated levels of dissolved methane in domestic wells generally increase in those wells in proximity to gas production wells. Near surface concentrations of methane appear highest in the area encompassing MW01. Ground water is saturated with methane at MW01 which is screened at a depth (239 meters below ground surface) typical of deeper domestic wells in the area. A blowout occurred during drilling of a domestic well at a depth of only 159 meters below ground surface close to MW01. A mud-gas log conducted in 1980 (prior to intensive gas production well installation) located only 300 m from the location of the blowout does not indicate a gas show (distinctive peaks on a gas chromatograph) within 300 meters of the surface. Again, with the exception of two production wells, surface casing of gas production wells do not extend below the maximum depth of domestic wells in the area of investigation. A number of production wells in the vicinity of MW01 have sporadic bonding or no cement over large vertical instances. Again, alternate explanations of data have been considered. Although some natural migration of gas would be expected above a gas field such as Pavillion, data suggest that enhanced migration of gas has occurred within ground water at depths used for domestic water supply and to domestic wells. Further investigation would be needed to determine the extent of gas migration and the fate and transport processes influencing migration to domestic wells.

1.0

Site Background

In early 2008, the U.S. Environmental Protection Agency (EPA) received complaints from several domestic well owners near the town of Pavillion, Wyoming regarding sustained objectionable taste and odor problems in well water following hydraulic fracturing at nearby gas production wells. In response to these complaints, EPA initiated a comprehensive ground water investigation in September 2008 under authority of the Comprehensive Environmental Response, Compensation, and Liability Act. The area of investigation is a sparsely populated rural area in west-central Wyoming directly east of the town of Pavillion. Land use by residents consists primarily of ranching (horse and cattle) and alfalfa hay production for use by ranchers and commercial sale. Fields are periodically flooded using water obtained from canals and laterals.

Domestic wells in the area of investigation overlie the Pavillion gas field which is one of several gas fields within the Wind River Basin - a large, complex, structural, asymmetric, deep sedimentary basin covering much of central Wyoming (**Figure 1**). Oil and gas exploration wells were drilled in the 1950s. Commercial natural gas extraction in the field commenced in 1960 (Single 1969) with gas production well installation activity intensifying in the late 1990s through 2006 (**Figure 2**). The field currently consists of approximately 169 vertical production wells. Ninety-seven production wells are designated as "Tribal Pavillion" and are regulated by the U.S. Bureau of Land Management (BLM). The remaining wells are designated as "Pavillion Fee" and are regulated by Wyoming Oil and Gas Conservation Commission (WOGCC).

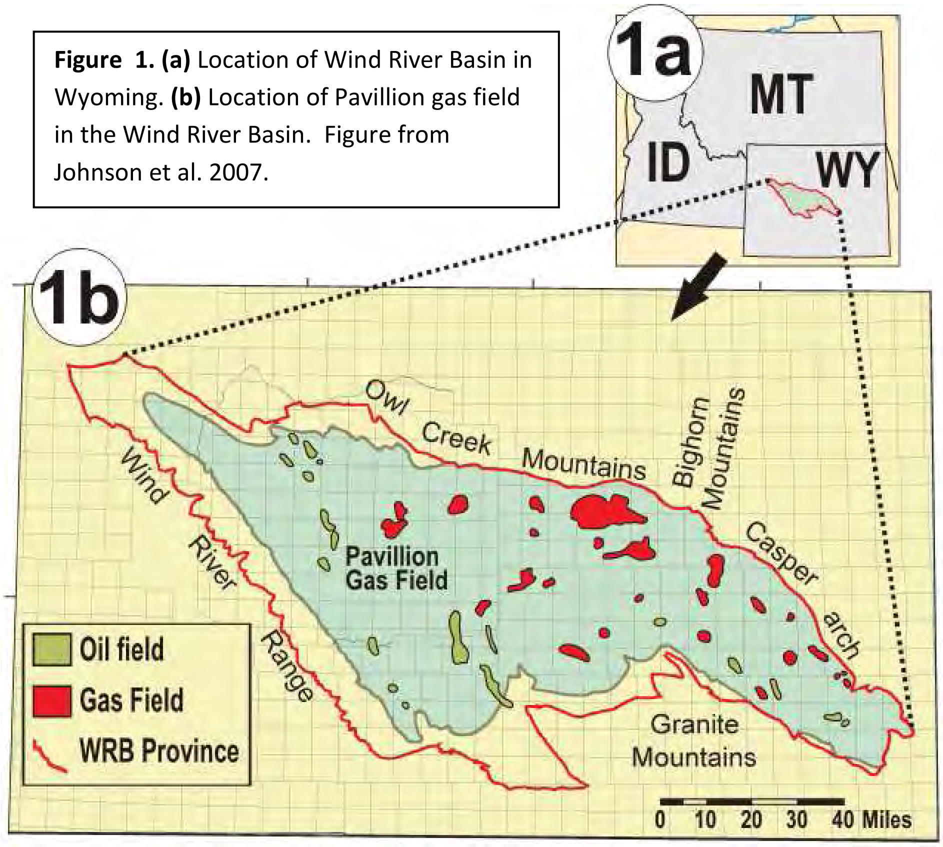

Figure 1. (a) Location of Wind River Basin in Wyoming. **(b)** Location of Pavillion gas field in the Wind River Basin. Figure from Johnson et al. 2007.

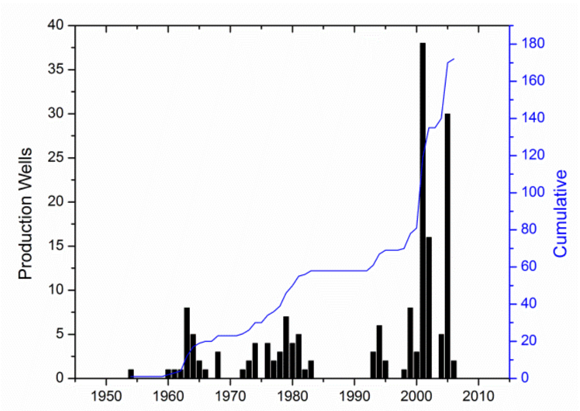

Figure 2. Chronology of production well completion at the Pavillion gas field.

A review of production well records obtained on line from WOGCC indicates that hydraulic fracturing in gas production wells occurred as shallow as 372 m (1220 ft) below ground surface (bgs) with associated surface casing in production wells as shallow as 110 m (361 ft) bgs. Information obtained from the Wyoming State Engineer's Office and homeowners indicates that domestic wells (including stock wells) in the area of investigation are screened as deep as 244 m (800 ft) bgs. With the exception of two production wells, surface casings of gas production wells do not extend below the maximum depth of domestic wells in the area of investigation (**Figure 3**).

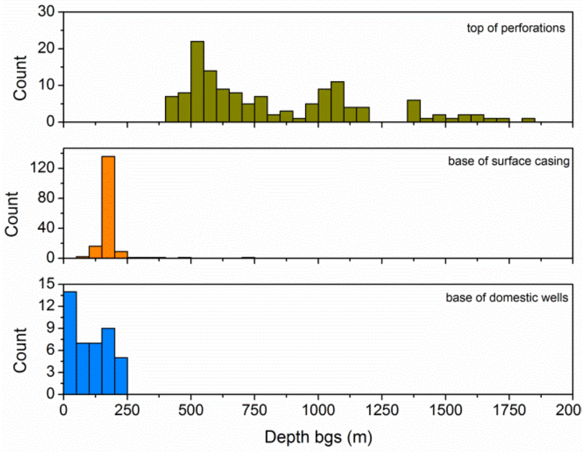

Figure 3. Histograms summarizing depths of top of perforation interval of production wells, base of surface casing of production wells, and base of screened interval of domestic wells.

Gas extraction occurs from both the lower Eocene Wind River Formation and underlying Paleocene Fort Union Formation (**Figure 4**). The Wind River Formation consists of interbedded layers of sandstones and shale with coarse-grained meandering stream channel deposits (Osiensky et al. 1984) and extends from the surface to approximately 1036 m (3400 ft) bgs. The Fort Union Formation ranges in thickness from 762 to 914 m (2500 to 3000 ft) in the area (Flores and Keighin 1993). The Waltman Shale Member in the Fort Union Formation is absent below the Pavillion Gas Field. The most productive zone of gas extraction in the Wind River Formation occurs at its base and is often targeted for gas extraction (Single 1969). Gas trapping in the lower Wind River and Fort Union Formations occurs in localized stratigraphic sandstone pinchouts on the crest and along flanks of a broad dome (Mueller 1989, Keefer and Johnson 1993).

There is substantial vertical and lateral stratigraphic variation over short distances in both formations (Single 1969, Flores and Keighin 1993). Individual productive sandstones in the two formations generally vary in thickness from 1 to 21 m with permeability varying from 0.1 to 300 millidarcies and porosity ranging from 4 to 28 percent (Single 1969). Gas from the Fort Union and lower Wind River Formations varies little in $\delta^{13}C$ for methane, ethane, and propane with depth from the lower Eocene Wind River Formation to deeper mature and post-mature Upper Cretaceous source rocks (**Figure 4**) suggesting upward gas migration (Johnson and Rice 1993, Johnson and Keighin 1998) from deep source rocks. $\delta^{13}C$ is defined as

$$\delta^{13}C(‰) = \left[\frac{\left({}^{13}C/{}^{12}C\right)\text{sample}}{\left({}^{13}C/{}^{12}C\right)\text{standard}} - 1 \right] x1000$$

where the standard is the Pee Dee Belemnite (PDB) reference standard. Stable isotope ratios are reported as the relative difference in the ratio of the less abundant heavier isotope to the more abundant lighter isotope of the sample with respect to a

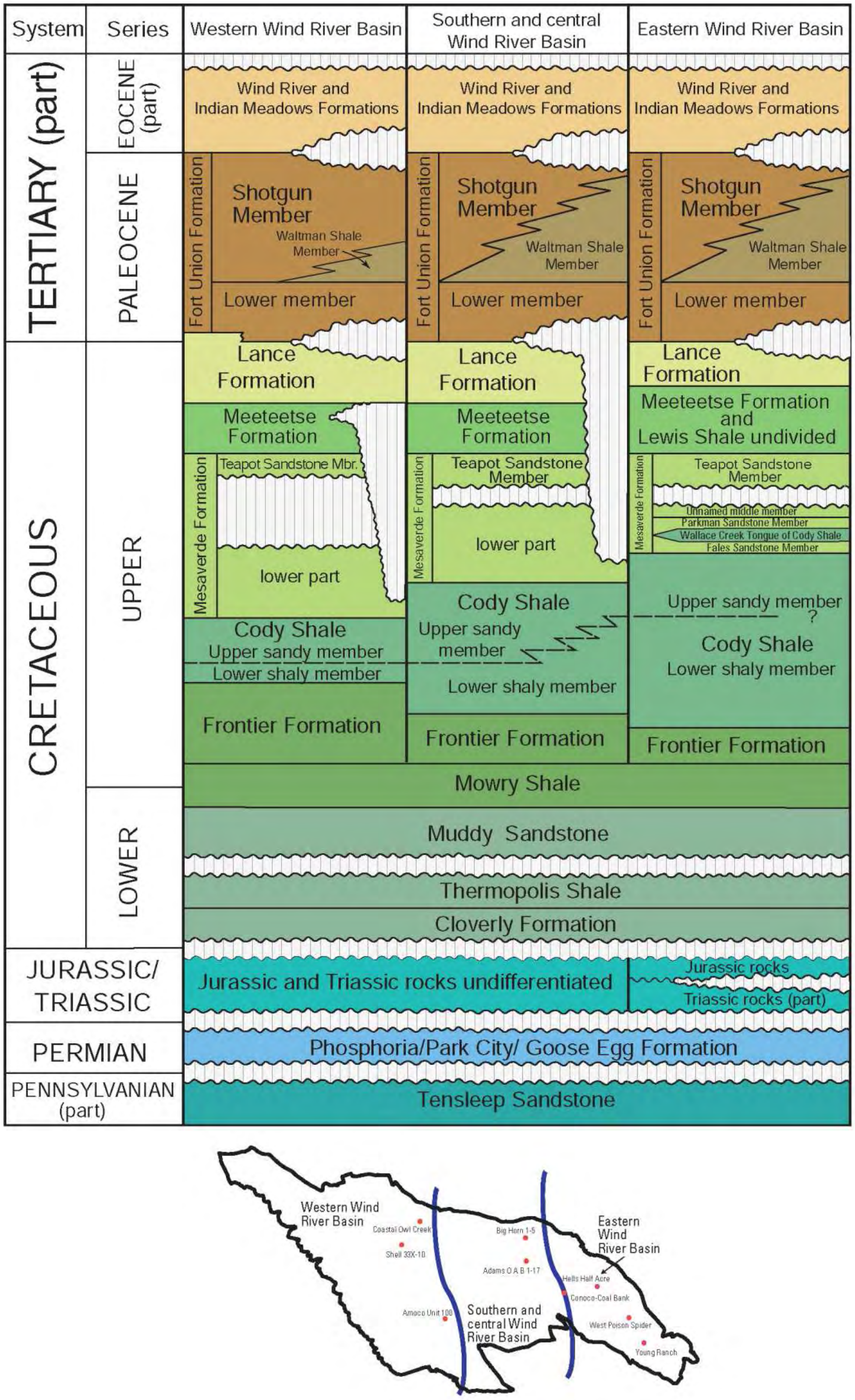

Figure 4. Generalized stratigraphic columns and correlations of Mississippian through Eocene strata in the Wind River Basin, Wyoming. The Pavillion Gas Field is located in the Western Wind River Basin. Figure from Johnson et al. 2007.

reference standard. Ratios are expressed in parts per thousand or permil (‰). A substantial amount of additional compositional and isotopic data is available on the Wind River and Fort Union Formations but is classified as Confidential Business Information by the gas field operator.

Ground water from the upper Wind River Formation is the principal source of domestic, municipal, and stock (ranching, agriculture) water in the Pavillion area (WY State Water Plan 2003). The Wind River Formation meets the definition of an Underground Source of Drinking Water (USDW) under the United States Code of Federal Regulations, Title 40, Section 144.3. Water yields from wells in the upper Wind River Formation range up to 11,300 L/min with total dissolved-solids (TDS) concentrations ranging from 100 to 5,110 mg/L (WY State Water Plan 2003, Daddow 1996). The town of Pavillion has five municipal wells screened at depths ranging from 122 to 158 m bgs with average daily use estimated at 60,000 L/day (WY State Water Plan 2003). Fluids used for hydraulic fracturing were injected directly into the Wind River Formation.

2.0
Methods

Sampling Chronology

Four sampling events (Phase I - IV) were conducted commencing in March 2009 and ending in April 2011. In March 2009 (Phase I), EPA collected aqueous samples from 35 domestic wells (including two samples from post reverse osmosis systems) in the area of investigation and 2 municipal wells in the town of Pavillion. Detection of methane and dissolved hydrocarbons in several domestic wells prompted collection of a second round of samples in January 2010 (Phase II). During this phase, EPA collected: (1) ground water samples from 17 domestic wells (10 previously sampled), 4 stock wells, and 2 municipal wells; (2) a filter sample from a reverse osmosis system; (3) surface-water and sediment samples from 5 locations along Five-Mile Creek (a creek traversing the area of investigation); (4) gas and produced water/condensate samples (organic compounds only) from 5 production wells; and (5) ground water samples from 3 shallow monitoring wells and soil samples near the perimeter of three known pit locations.

Detection of elevated levels of methane and diesel range organics (DRO) in deep domestic wells prompted EPA to install 2 deep monitoring wells in June 2010 to differentiate potential deep (e.g., gas production related) versus shallow (e.g., pits) sources of ground water contamination. Monitoring wells MW01 and MW02 were screened at 233 - 239 m (765 – 785 ft) and 293 - 299 m (960 – 980 ft) bgs, respectively. The expense of drilling deep wells while utilizing blowout prevention was the primary limiting factor in the number of monitoring wells installed. In September 2010 (Phase III), EPA collected gas samples from well casing from MW01 and MW02. In October 2010, EPA collected ground water samples from MW01 and MW02 in addition to a previously unsampled domestic well and two previously sampled domestic wells. In April 2011 (Phase IV), EPA resampled the 2 deep monitoring wells to compare previous findings and expand the analyte list to include glycols, alcohols, and low molecular weight acids. Eight previously sampled domestic wells and three previously sampled stock/irrigation wells were also sampled at this time. Sampling chronology and analytical methods for all sampling events are summarized in **Table A1**. The location of production wells, monitoring wells, and sampled domestic wells is illustrated in **Figure 5**.

Deep Monitoring Well Installation

EPA installed two deep monitoring wells (designated as MW01 and MW02) using air (0 - 6 m bgs) and mud rotary (6 m bgs to target depth). Mud rotary was selected for installation of deep monitoring wells because it allowed the use of blowout prevention (BOP). Use of mud rotary with BOP was necessary given that a blowout occurred during installation of a domestic well at only 159 m (522 ft) bgs in December 2005 in the vicinity of MW01. Both deep monitoring wells were located away from gas production wells, known locations of pits, and areas of domestic waste disposal (abandoned machinery). There were no incidents of fuel spillage used to power pumps and generators.

Mud rotary required the use of drilling mud to remove cuttings and additives to avoid heaving of shale during drilling and well placement. Jet Lube Well Guard hydrocarbon free lubricant was used for outside threads for drillstem and submersible pipe connections. Mud composition consisted of formation water, municipal drinking water from Riverton, WY (transported on site by water truck), Quik-Gel high yield bentonite and additives listed on **Table 1**. Municipal water was mixed with bentonite to create drilling mud. The pH of mud during drilling varied between pH 8 - 9. Aqua-Clear (Halliburton) was used during well development to facilitate removal of mud. Drilling additives were extracted in water (1:20 to 1:100 dilution) and analyzed for pH, inorganics, organics, glycols, and alcohols. Despite the highly concentrated nature of these solutions (not

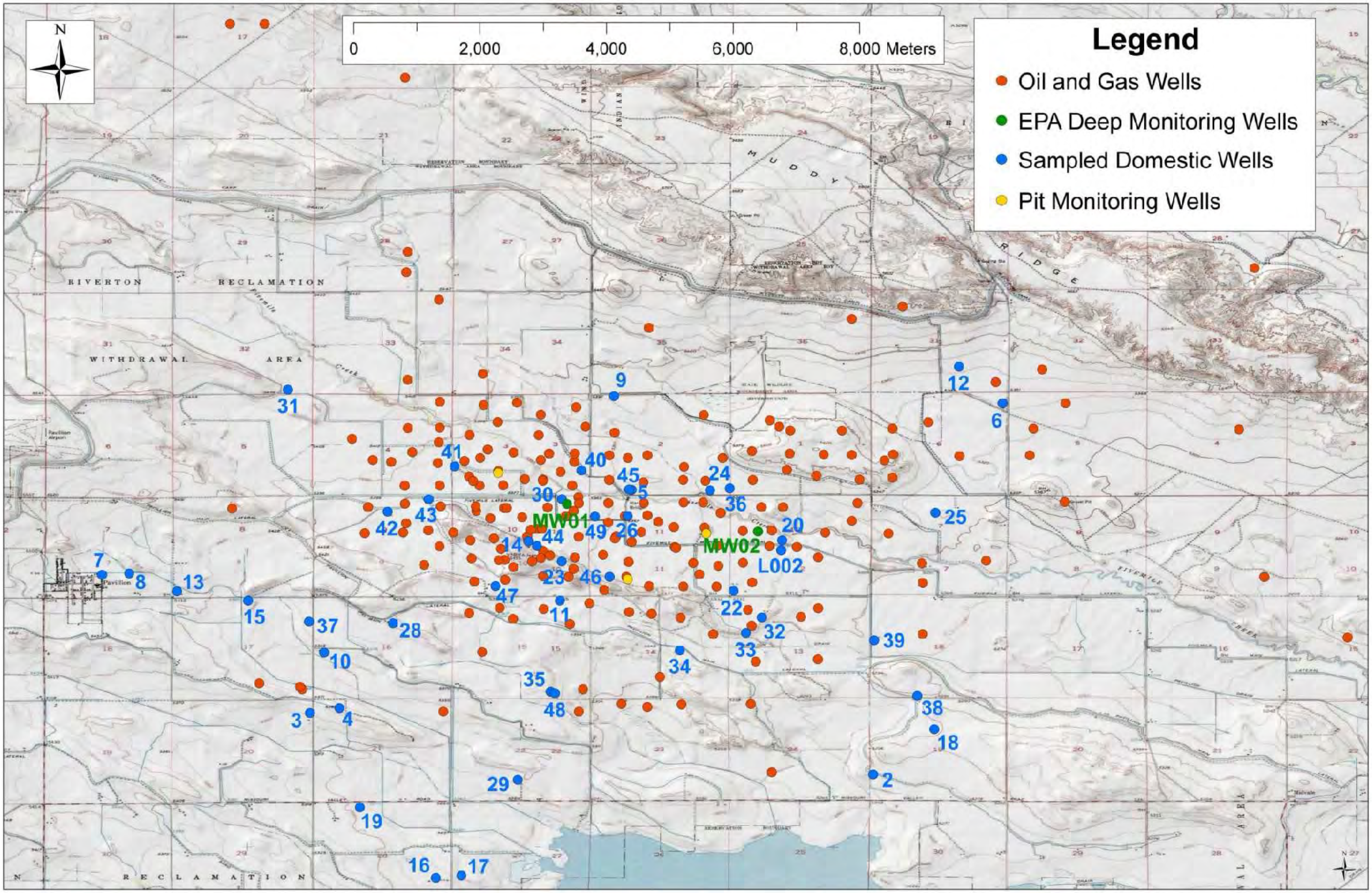

Figure 5. Map illustrating location of oil and gas production wells, sampled PGDWxx series domestic wells (only numbers shown to conserve space), two deep monitoring wells, and three shallow monitoring wells near pits. PGDW07 and PGDW08 are municipal wells in the town of Pavillion.

Table 1. Drilling additives, properties and product use recommendations

Ingredient	Manufacturer	Purpose	Composition from MSDS	Specific gravity	Recommended mixture with water (wt/wt)	pH	Properties
Aqua-Clear PFD	Halliburton	Dispersant/ mud removal	anionic polyacrylamide (30-60%)	1.2-1.4	1:2500	neat 6.5 to 7.5	liquid
Penetrol	Halliburton	Non-ionic wetting agent	diethanolamine (1-5%) and coco diethanolamide (10-30%)	0.98	1:400 to 1:100	1% solution 9.5	liquid
EZ-Mud Gold	Halliburton	Clay/shale stabilizer	"no hazardous substances"	0.8-1	1:1400 to 1:350	1% solution 7.75	solid
Dense Soda Ash	OCI Chemical Corp	Improve bentonite	Sodium carbonate (100%)	2.5	1:100 to 1:50	5% solution 11.5	solid
Quik-Gel	Halliburton	Viscosifier/ bentonite	bentonite (60%), crystalline silica quartz (1-5%), crystalline silica cristobalite (0-1%), crystalline silica tridymite (0-1%).	2.6	1:60 to 1:30	3% solution 8.9	solid
Quik-Trol Gold	Halliburton	Ease of mixing and improved filtration	cellulose derivative (polysaccharide) (60-100%)	0.6 - 0.9	1:3500 to 1:200	1% solution 6 -8 (listed)	solid

representative of significantly lower levels in drilling mud, see recommended product use mixture listed in **Table 1**), the pH of samples varied between 6.6 to 11.2, potassium varied between 0.1 to 1.2 mg/L, chloride varied between not detected to 214 mg/L, ethanol and isopropanol detections were less than 90 µg/L, and acetone, *tert*-butyl alcohol (TBA), benzene, toluene, ethylbenzene, xylenes (BTEX), trimethylbenzenes, and glycols were not detected (**Table 2**). Organics were not analyzed in the dense soda ash and Quik-Gel because dissolved organic carbon concentrations were low and because of difficulties in analyzing the viscous gel (Quik-Gel). Since inorganic and organic concentration patterns measured in the drilling additives do not match patterns observed in the deep monitoring wells and because large volumes of ground water were extracted from the wells during development and prior to sampling, it is unlikely that ground water chemistry was impacted by drilling additives.

Composite samples of cuttings were collected and sent to TestAmerica Laboratories in Denver, Colorado for Toxic Characteristic Leaching Procedure (TCLP). Samples were analyzed for TCLP volatile organic compounds using gas chromatography-mass spectrometry (GC-MS) in accordance with EPA SW-846 Methods 1311/8260B, and for TCLP semivolatile organic compounds (GC-MS) in accordance with EPA SW-846 Methods 1311/8270C, for TCLP metals in accordance with EPA SW-846 Methods 1311/ 6010B, for TCLP mercury in accordance with EPA SW-846 Methods 1311/7470A. Acetone, toluene, and m & p-xylene were detected in one sample at 6.9, 0.63, and 1.0 µg/L, respectively. Cuttings were disposed offsite in a landfill.

A photographic log of drilling, mud circulation, examination of cuttings, screen placement, and well development is provided in **Appendix C**. Well construction schematics are provided for MW01 and

Table 2. Analytical results of additives (compounds listed are those detected in ground water)

	Aqua-Clear PFD	Penetrol	EZ-Mud Gold	Dense Soda Ash	Quik-Gel	Blank
Extraction ratio (wt/wt)	1:20	1:20	1:100	1:100	1:100	-----
pH measured	7.96	8.51	6.64	11.2	8.35	-----
Specific Conductance (mS/cm)	13.3	0.47	0.24	15.5	0.20	-----
Dissolved Organic Carbon (ppm)	1640 (1650) †	1500	388	0.58	2.11	0.28
Cl (ppm)	214 (230) †	85	2.22	7.03	nd	nd
SO4 (ppm)	121 (117) †	597	nd	nd	3.53	nd
K (ppm)	0.40 (0.40) †	0.63	1.16	0.12	0.09	0.07*
Acetone (µg/L)	nd	nd	nd	-----	-----	nd
Tert-butyl alcohol (µg/L)	nd	nd	nd	-----	-----	nd
Isopropanol (µg/L)	85 (87)†*	43*	27*	-----	-----	nd
Ethanol (µg/L)	59 (62) †*	58*	nd	-----	-----	nd
Benzene (µg/L)	nd	nd	nd	-----	-----	nd
Toluene (µg/L)	nd	nd	nd	-----	-----	nd
Ethylbenzene (µg/L)	nd	nd	nd	-----	-----	nd
Xylene (µg/L)	nd	nd	nd	-----	-----	nd
Trimethylbenzenes (µg/L)	nd	nd	nd	-----	-----	nd
Naphthalene	nd	2.00	nd	-----	-----	nd
Ethylene glycol (µg/L)	nd	nd	nd	-----	-----	nd
Diethylene glycol (µg/L)	nd	nd	nd	-----	-----	nd

nd – not detected. ----- not measured. Drilling additives were extracted at the specified weight ratio into deionized water. † - Duplicate analysis. Blank sample is analysis of water used for the extraction of drilling additives. * Concentration above minimum detection limit, but below the level of quantification.

MW02 in **Figures 6a** and **6b**, respectively. During installation of MW02, cuttings were allowed to settle at the cessation of drilling and form a 5 m (17 ft) base for placement of the screen. Cuttings were never added to the borehole. Since a significant vertical distance existed between the depth of drilling and screen placement at MW01, cement grout was utilized to form the base for screen placement. No lubricants were used to attach sections of casing or casing to screens. Well screens, sections of casing and tremie pipe were mounted above ground (never touched soil) and power washed (no detergents used) prior to (deployment. Locations of both MW01 and MW02 were in fields used for alfalfa hay production away from production wells, pads, and pits.

Cuttings were continuously examined during drilling by manually washing drilling mud from rock fragments with observations recorded as a function of depth in borehole logs. At the cessation of drilling, open-hole geophysical logging (caliper, density, resistivity, spontaneous potential, natural gamma) was conducted by Colog Inc., prior to placement of well

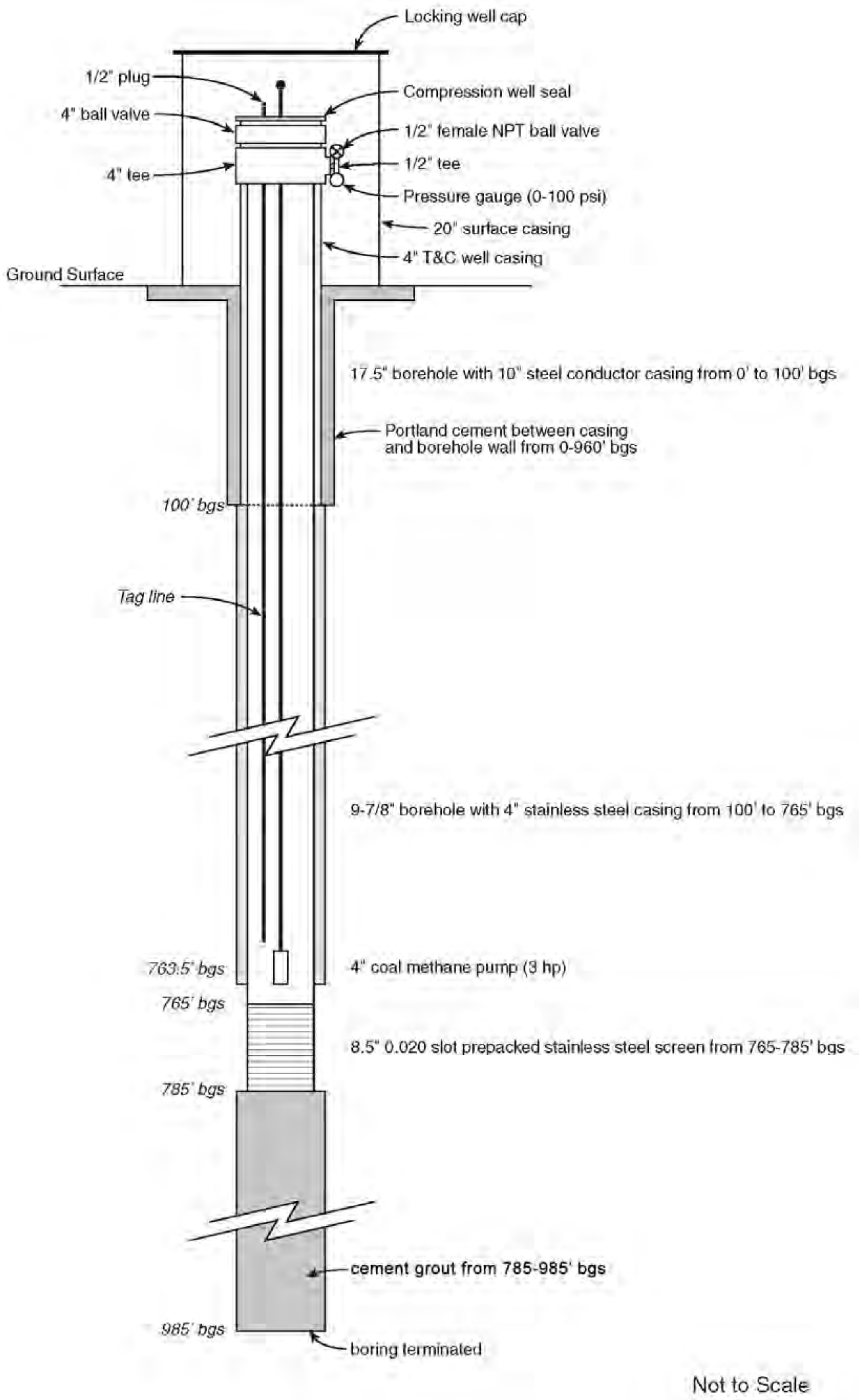

Figure 6a. Schematic illustrating construction of MW01.

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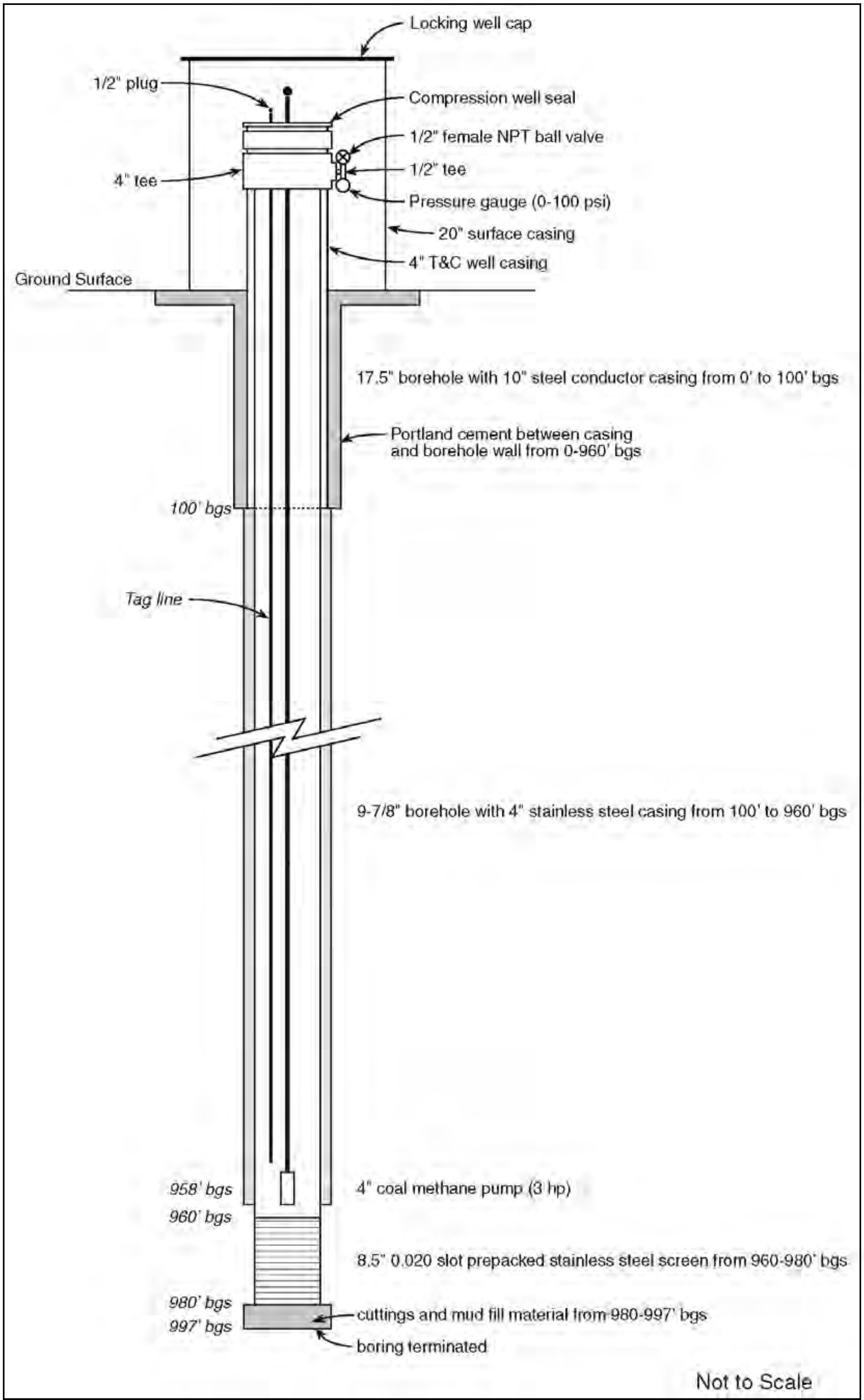

Figure 6b. Schematic illustrating construction of MW02.

construction materials. Examination of resistivity and cuttings indicated elevated resistivity at depths where white coarse-grained sandstone was observed. This relationship was utilized to place screens at both deep monitoring wells at the deepest observed interval of white coarse-grained sand (**Figure 7**). White coarse-grained sandstones in the area of investigation contain little or no shale and are targeted by local well drillers for domestic well installation. During drilling, mud and cuttings were monitored in an open atmosphere with a TVA-1000B Thermo-Scientific portable flame- and photo-ionization detector (FID/PID) for health and safety monitoring. Comparison of FID and PID readings (PID readings remained at background and are not sensitive to methane) indicates the presence of methane at various intervals from ground surface in MW01 (**Figure 7**).

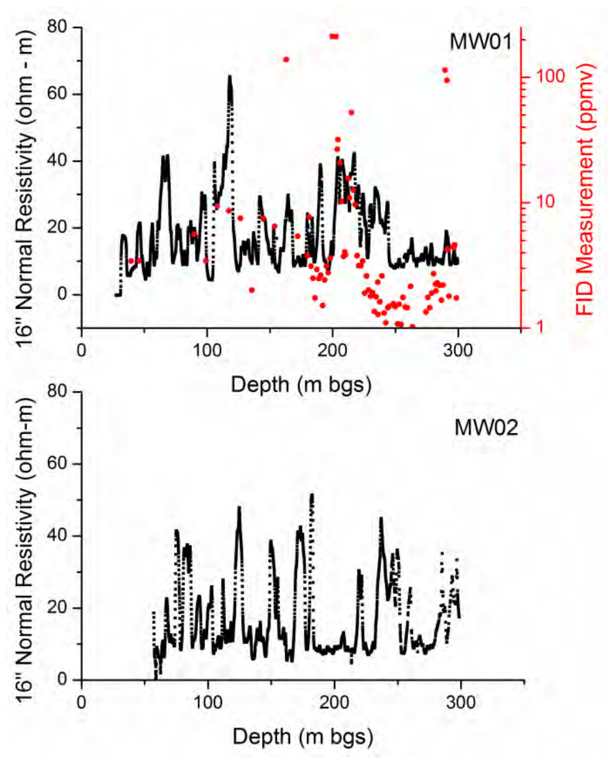

Figure 7. Resistivity as a function of depth in MW01 and MW02. MW01 and MW02 were screened at 233 - 239 m and 293 - 299 m bgs, respectively, corresponding to elevated resistivity and presence of coarse-grained sandstone. FID readings in MW01 denote detections of methane during open air logging of mud. FID monitoring at MW02 was sporadic and is not illustrated here.

Ground Water Sampling of Deep Monitoring Wells in Phase III and IV

Ground water in deep monitoring wells was sampled using dedicated explosion proof submersible pumps (10-cm Franklin Electric 3HP). Wells were purged at a flow rate of approximately 5 to 30 L/min. The rate of pumping was measured using a Model TM0050 in-line turbine flow meter with associated Model FM0208 flow monitor manufactured by Turbines, Inc. Drawdown during pumping was measured with a sonic water level sensor obtained from Eno Scientific, Inc. (Model WS2010 PRO). The flow was split, with one portion going to waste and the other portion going to a flow-cell equipped with a YSI 5600 multiparameter probe to track stabilization of pH (<0.02 standard units per minute), oxidation-reduction potential (<2 mV per minute), specific conductance (<1% per minute), dissolved oxygen (DO), and temperature. Purge volumes prior to sampling ranged from about 200 to 450 L (Phase III) and 1100 to 1250 L (Phase IV). Lower purge volumes in Phase III sampling were due to initial gas invasion into the screened intervals that caused cavitation and concern about prolonged pump operation. By the time of Phase IV sampling, disruptive gas invasion was no longer observed and extended purging was possible. Turbidity ranged from 1.7 to 29.7 Nephelometric Turbidity Units (NTUs) in domestic wells (Phase III and IV). Turbidity in MW01 was 7.5 NTUs in Phase III and 7.9 NTUs in Phase IV. Turbidity in MW02 was 28.8 NTUs in Phase III and 24.0 NTUs in Phase IV. Turbidity measurements in MW01 and MW02 could be impacted by gas exsolution. A photographic log of deep monitoring and domestic well sampling is provided in **Appendix D**.

In April 2011, the static water level in MW01 prior to purging was 61.2 m (200.8 ft) below the top of the casing (BTOC) measured using the Well Sounder 2010. The initial pumping rate was approximately 27.6 L/min. The pumping rate declined during purging to approximately 24.2 L/min as a result of the increasing depth to water. At approximately 30 min after the start of purging, the pumping rate was reduced using an in-line valve to 7.6 L/min. This resulted in approximately 18.2 m (60 ft) of rebound in the water level within the well at the start of sampling (**Figure 8**). Given that the screen length is only 6.1 m (20 ft) and that the pump was set approximately 0.6 m (2 ft) above the screen, this indicates that ground water obtained during sampling was derived from the formation with no component of casing storage. The total volume of water purged at the start of sampling was approximately 1117 L. The static water level in MW02 prior to purging was 80.5 m (264.2 ft) BTOC measured using the Well Sounder 2010 (April 2011). The initial pumping rate was approximately 18.9 L/min. The Eno Scientific well sounder was unable to measure the depth to water during most of the purging cycle perhaps due to a more rapid rate of decline in the water level in the casing. Sampling was initiated after approximately 1249 L of water were removed. The pump cavitated after approximately 1287 L were purged. The pump was subsequently stopped, allowed to cool, and restarted approximately 10 min later to complete the sampling.

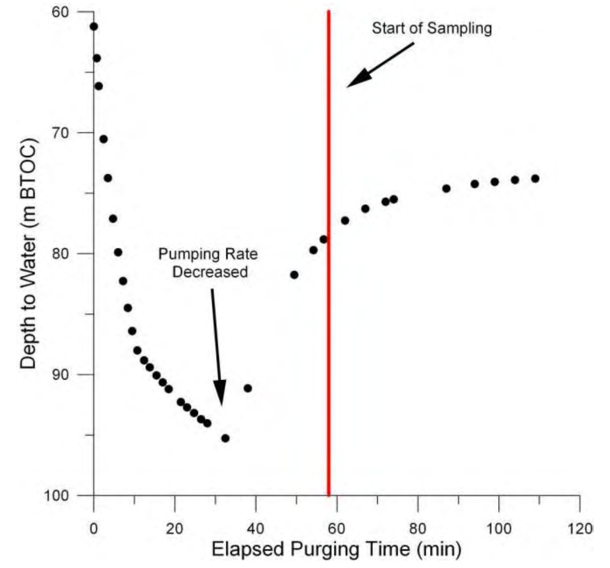

Figure 8. Variation of water level as a function of time in MW01 during Phase IV well purging. The initial pumping rate was 24.2 L/min. After approximately 30 minutes of purging, the flow rate was decreased to 7.6 L/min. This reduced flow rate caused partial recovery of the water level and confirmation that formation water was being accessed.

An example of flow-cell readings through the purging of well MW02 is shown in **Figure 9**. The electrode readings show fairly rapid equilibration of pH and dissolved oxygen. Oxidation-reduction potential steadily decreased with the rate of change falling into the desired range (<2 mV per minute) by the end of purging. Specific conductance readings were typically variable, likely due to continuous off-gassing and bubble formation within the conductivity sensor. After field measurements stabilized, ground water was collected into sample bottles as summarized in **Table B1**. Samples were collected for a wide range of inorganic, organic, and stable isotope analyses. A 500 mL sample was collected for field determinations of alkalinity, turbidity, ferrous iron, and dissolved sulfide. Alkalinity was determined onsite by incremental titration of ground water with sulfuric acid. Turbidity measurements were made with a portable meter (Hach 2100Q). Measurements were made for dissolved sulfide and ferrous iron using the methylene blue and 1,10-phenanthroline colorimetric methods, respectively (APHA 1998a,b). Samples collected for dissolved gases, volatile organic compounds, semi-volatile organic compounds, diesel-range organics, gasoline-range organics, glycols, low molecular weight acids, and $\delta^{13}C/\delta D$ of methane were not filtered. δD is defined as

$$\delta D(‰) = \left[\frac{\left({}^{2}H/{}^{1}H\right)\text{sample}}{\left({}^{2}H/{}^{1}H\right)\text{standard}} - 1\right] \text{x1000}$$

where the standard is the Vienna Standard Mean Ocean Water Standard (VSMOW). Samples collected for metals, anions, nutrients, dissolved organic carbon, dissolved inorganic carbon (DIC), $\delta^{13}C$ of dissolved inorganic carbon, and $\delta^{18}O/\delta D$ of water were filtered onsite using 0.45-micron pore-size, disposable-capsule filters. $\delta^{18}O$ is defined as

$$\delta^{18}O(‰) = \left[\frac{\left({}^{18}O/{}^{16}O\right)\text{sample}}{\left({}^{18}O/{}^{16}O\right)\text{standard}} - 1\right] \text{x1000}$$

where the standard is the VSMOW.

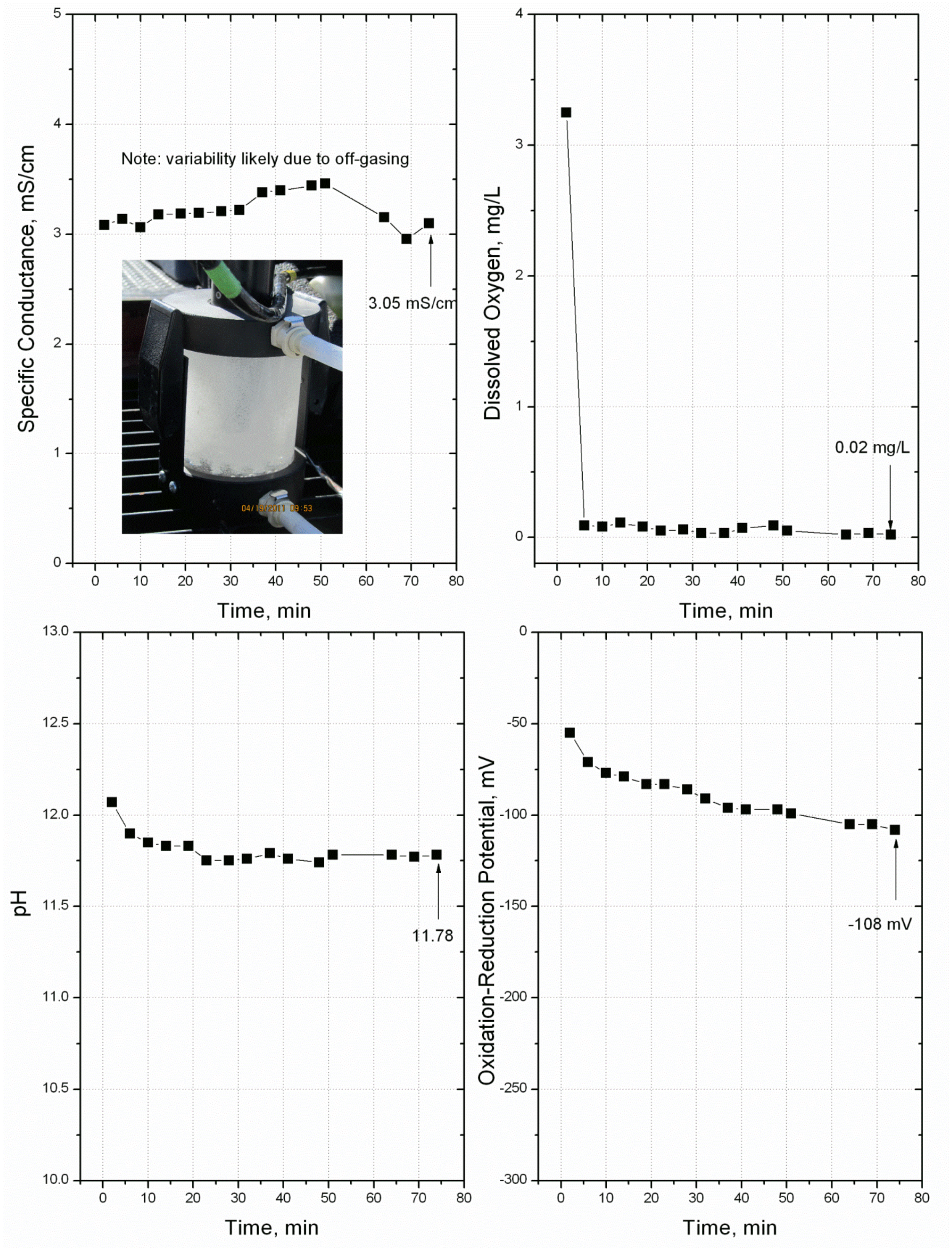

Figure 9. Flow-cell readings as a function of time for specific conductance, dissolved oxygen, pH, and oxidation-reduction potential (well MW02, Phase IV sampling).

Sample preservation and holding time criteria are listed in **Table B1**. Field quality control (QC) samples are summarized in **Table B2**. These included several types of blanks, duplicate samples, and field matrix-spike samples. All of these QC sample types were collected, preserved, and analyzed using identical methodologies as used for the water samples collected in the field (**Table B1**). Quality assurance/quality control (QA/QC) requirements for analysis of metals and major ions are summarized in **Table B3**. QA/QC requirements for analysis of dissolved gases, DIC/DOC, VOCs, low molecular weight acids and stable isotopes of water are summarized in **Table B4**. QA/QC requirements for analysis of semivolatile organic compounds (SVOCs), GRO, and DRO are summarized in **Table B5**. QA/QC requirements for analysis of glycols are summarized in **Table B6**. Results of Phase III and Phase IV blank samples are provided in **Tables B7** to **B12.** Detections observed in the blank samples were generally very low-level and generally much lower than concentrations measured in the deep monitoring wells. Some blank samples showed detections of acetone (1 µg/L), m,p-xylene (up to 0.7 µg/L), toluene (up to 0.5 µg/L), benzoic acid (3 µg/L), and tetraethylene glycol (3 µg/L). Concentrations of these analytes in MW01 and MW02 in Phase III and Phase IV sampling ranged from: 80 to 641 µg/L (acetone), non-detect to 750 µg/L (total xylenes), 0.6 to 617 µg/L (toluene), 209 to 457 µg/L (benzoic acid), and 7 to 27 µg/L (tetraethylene glycol). Detected concentrations of toluene (Phase III), xylene (Phase IV), and tetraethylene glycol (Phase IV) in MW01 are within about 2 times the detected levels of these chemicals in some of the applicable blank samples. Consequently, reported detections and concentrations of these chemicals in MW01 were used cautiously in this study. In one of the six blank samples collected for DRO, an elevated concentration of 135 µg/L or 6 times the reporting limit was observed (**Table B12**); all other DRO blank samples were non-detects (<20 µg/L). Concentrations of DRO in the deep monitoring wells ranged from 634 to 4050 µg/L.

Duplicate samples were collected in three locations during Phase III and Phase IV sampling activities. Results for the duplicate analyses are presented **Tables B13** and **B14**. Relative percent differences (RPDs) were generally less than 10% for most inorganic constituents indicating very good precision. RPD is defined as

$$\mathrm{RPD} = \left[\frac{x1 - x2}{(x1 + x2)/2}\right] x1000$$

where x1 = sample and x2 = sample duplicate. RPDs for methane, volatile organic compounds, and semi-volatile organic compounds were generally less than 25% (**Table B14**). The lower reproducibility for these compounds detetected in MW02 is likely due to difficulties in sampling and preserving water that is oversaturated in gas.

Major ions were quality checked by calculating ion balances. The AqQA (v.1.1.1) software package was used to evaluate cation/anion balance, which ranged from <0.1 to 17.2% with 90% of the calculated balances better than 5%.

Geochemical equilibria in ground water were evaluated with the Geochemist's Workbench package (version 8; Bethke 1996). Speciation and mineral equilibria calculations were made by entering the concentrations of major cations (Na^+, K^+, Ca^{2+}, Mg^{2+}), anions (Cl^-, SO_4^{2-}, HCO_3^-), pH, and temperature. For domestic well samples, bicarbonate concentrations were determined from alkalinity measurements. For the deep monitoring wells, because alkalinity included a significant contribution from hydroxide, concentrations of dissolved inorganic carbon were used for bicarbonate/carbonate input. Activity corrections were made using the Debye-Hückel equation. The LLNL (EQ3/6) thermodynamic database was selected for use in the calculations (Delany and Lundeen 1990). Model simulations were also conducted by tracing alkaline-addition titration paths. In order to do this, an additional entry was made to the thermodynamic database describing the solubility of KOH (log K= 24.9; $KOH_{(s)} + H^+ = K^+_{(aq)} + H_2O_{(l)}$).

Audits of Data Quality (ADQs) were conducted by a contractor (independent of this investigation) or an EPA QA Manager for all analyses conducted outside EPA's Contract Laboratory Program (CLP) with the exception of data collected during Phase I, which is till in progress. This included data from EPA's Region VIII laboratory in Golden, Colorado, EPA's Region III laboratory in Fort Mead, MD, EPA's Office of Research and Development Laboratory in Ada, Oklahoma, and Isotech Laboratories in Champaign, Illinois. A technical systems audit of Isotech Laboratories included an on-site visit by the independent contractor and EPA QA Manager. Two on-site field technical system audits were also conducted by the independent contractor and the EPA QA Manager to ensure compliance with the Category I (highest of four levels in EPA) Quality Assurance Project Plan established for this site for ground water and gas sample collection.

Gas Sampling from Casing of Deep Monitoring Wells in Phase III and IV

Gas samples were collected from casing of deep monitoring wells by connecting a 12.7 mm NPT stainless-steel Swagelok quick-connect body and a Swagelok single-end shutoff stem to a 12.7 mm brass ball valve. The stem was connected to 6.35 mm internal diameter Tygon Masterflex tubing and a 0.5 liter Cali-5 Bond gas sampling bag equipped with a Leur-Fit Valve^{TM} and a Leur-taper Quick-Mate^{TM} connector. A Masterflex E/S portable peristaltic pump was used to extract gas at 1 L/min. Samples were collected after stabilization (± 1%) of O_2, CO_2, and CH_4 readings on a GEM-2000 Plus CES-LANDTEC portable gas analyzer.

Domestic Well Sampling for Methane Using a Closed System in Phase IV

During the Phase IV sample event, water from domestic wells was screened using a Thermo-Scientific TVA-1000B portable FID/PID and a 10 L Plexiglas sparge cell **(Figure 10)**. Samples from domestic wells were routed through a closed (no contact with the atmosphere to avoid offgassing) sample train and collected in 0.5 L Cali-5 Bond gas sample bags. Ultrapure N_2 gas was introduced into the bags and placed on a rotary shaker for one hour prior to headspace analysis on site using a portable GC equipped with a thermal conductivity detector. Portable FID readings provided an immediate indication of methane in well water prior to GC analysis. Samples were also submitted to EPA's Office of Research and Development (ORD) laboratory in Ada, Oklahoma for analysis of dissolved gases.

Review of Borehole Geophysical Logs

Borehole geophysical logs available on line from WOGCC were utilized to map lithology in the area of investigation. Depending upon the specific well, various combinations of natural gamma, resistivity, self-potential, density, and neutron porosity logs were utilized. Log resolution was sufficient to discern distinct layers of shale 1 m or greater in thickness but not sufficient to differentiate coarse-, medium-, and fine-grained sandstones nor sandstones containing various proportions of shale. Descriptions of cuttings logged during installation of deep monitoring wells and domestic wells obtained from a local driller were used for near surface description. Neither grain size nor proportions of shale in sandstone were differentiated in near surface sandstones to maintain consistency with descriptions from geophysical logs. Lithology in the area of investigation is highly variable and difficult to correlate from borehole to borehole, even for boreholes in close proximity to one another consistent with other observations in the Wind River Formation (Osiensky 1984). Sandstone and shale layers appeared thin and of limited lateral extent, again consistent with previous observations of lithology in the Wind River Formation (Single 1969, Flores and Keighin 1993).

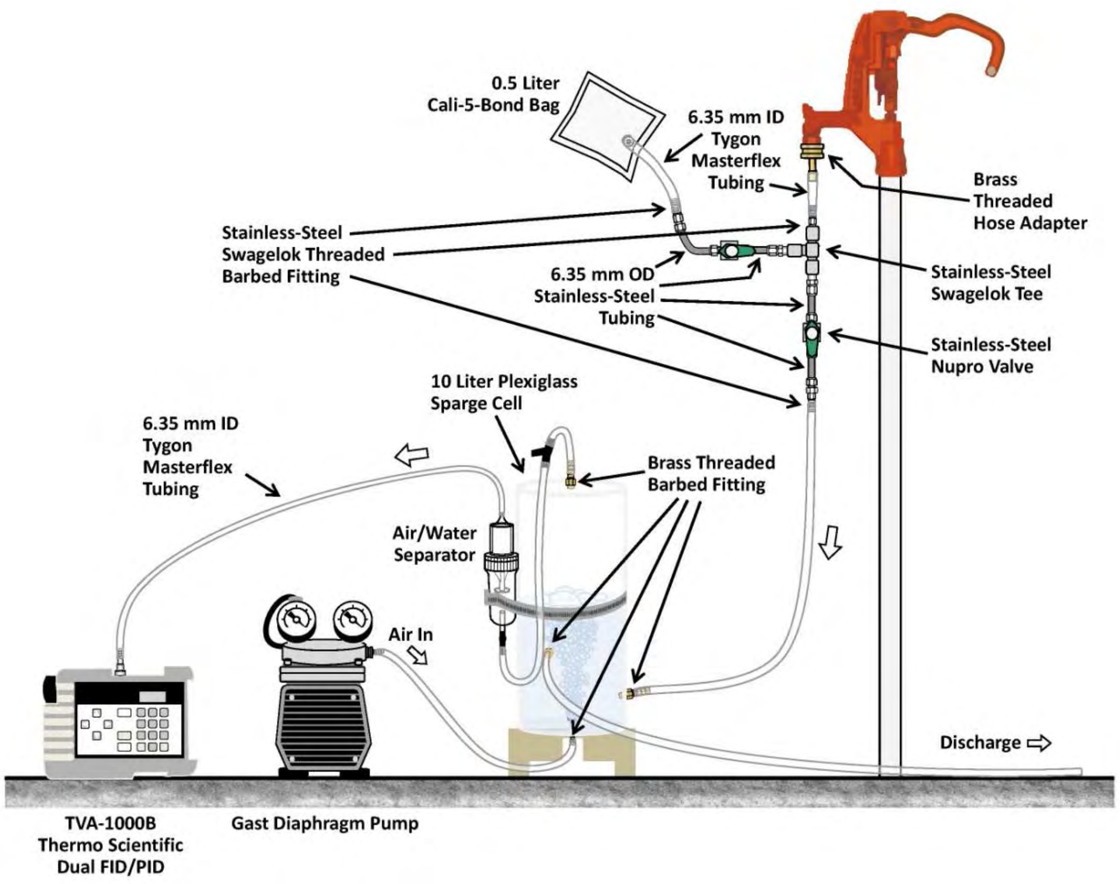

Figure 10. Schematic of closed (no contact to atmosphere) sampling train for domestic wells. Water flow from domestic well and into sparge cell was approximately 5 and 1 L/min respectively. Excess water bled through valve used for sampling prior to sample collection. Gas flow into sparge cell and portable FID/PID sparge cell was approximately 20 and 1 L/min. Excess air was bled through splitter above sparge cell.

Review of Cement Bond/Variable Density Logs

Cement bond/variable density (CBL/VDL) logs, available for less than half of production wells, were obtained online from WOGCC to evaluate well integrity. Sporadic bonding is defined as an interval having an amplitude (mV) greater than A_{80} (EPA 1994) where

$$A_{80} = 10^{0.2\log A_0 + 0.8\log A_{100}}$$

and A_{80}, A_0, and A_{100} = amplitude at 80%, 0%, and 100% bond respectively. A_0 typically corresponds to amplitude in free pipe whereas A_{100} corresponds to the best-bonded interval on the CBL. Examples of "no cement", "sporadic bonding", and "good bonding" are provided in **Appendix E**.

CBL/VDLs provide an average volumetric assessment of the cement in the casing-to-formation annular space and are considered low resolution tools compared to ultrasonic imaging tool logs which provide a high-resolution 360° scan of the condition of the casing-to-cement bond (Bybee 2007). Acoustic imaging tools do not directly measure cement seal. Communication of fluids between intervals has been observed to occur despite indication of "good to excellent" cement bond on acoustic logs (Boyd et al. 2006). All CBL/VDLs available from WOGCC reflect pre-hydraulic fracturing conditions.

3.0

Results and Discussion

Ground Water and Soil Sample Results Near Three Pits

There are at least 33 pits previously used for storage/disposal of drilling wastes, produced water, and flowback fluids in the area of investigation. Discussions are ongoing with stakeholders to determine the location, delineate the boundaries, and extent (areal and vertical) of contamination associated with these pits. The operator has initiated remediation of selected pit areas. Concentrations of DRO, gasoline range organics (GRO), and total purgeable hydrocarbons (TPH) detected in soil samples adjacent to three pits investigated in Phase II were as high as 5010, 1760, and 6600 mg/kg, respectively (EPA 2010). Concentrations of GRO, DRO, and TPH in ground water samples from shallow (4.6 m bgs) monitoring wells were as high as 2.4, 39, and 3.8 mg/L, respectively (EPA 2010). A wide variety of organic compounds including benzene and m, p-xylene were detected at concentrations up to 390 and 150 µg/L, respectively (EPA 2010), indicating pits as a source of shallow ground water contamination in the area of investigation. EPA's maximum concentration level (MCL) for benzene is 5 µg/L.

Inorganic Geochemistry

Inorganic geochemical results for ground water (all phases) are summarized in **Table A2a and Figure 11**. Major ion chemistry of ground water in the Pavillion area varies as a function of aquifer depth. Shallow ground waters (< 31 m bgs) collected from drinking water wells and stock wells are near-neutral (pH 7.7 ± 0.4, n = 19) (**Figure 12**) and display calcium-bicarbonate composition. With increasing depth, ground water becomes moderately alkaline (pH 9.0 ± 1.0, n = 55) (**Figure 12**), and with only one exception (MW02), is dominated by sodium and sulfate as the major cation/anion pair (**Figures 11** and **12**, **Table A2a**). This gradient in pH and water chemistry likely arises from the wide-scale surface application of irrigation water from the Wind River to support

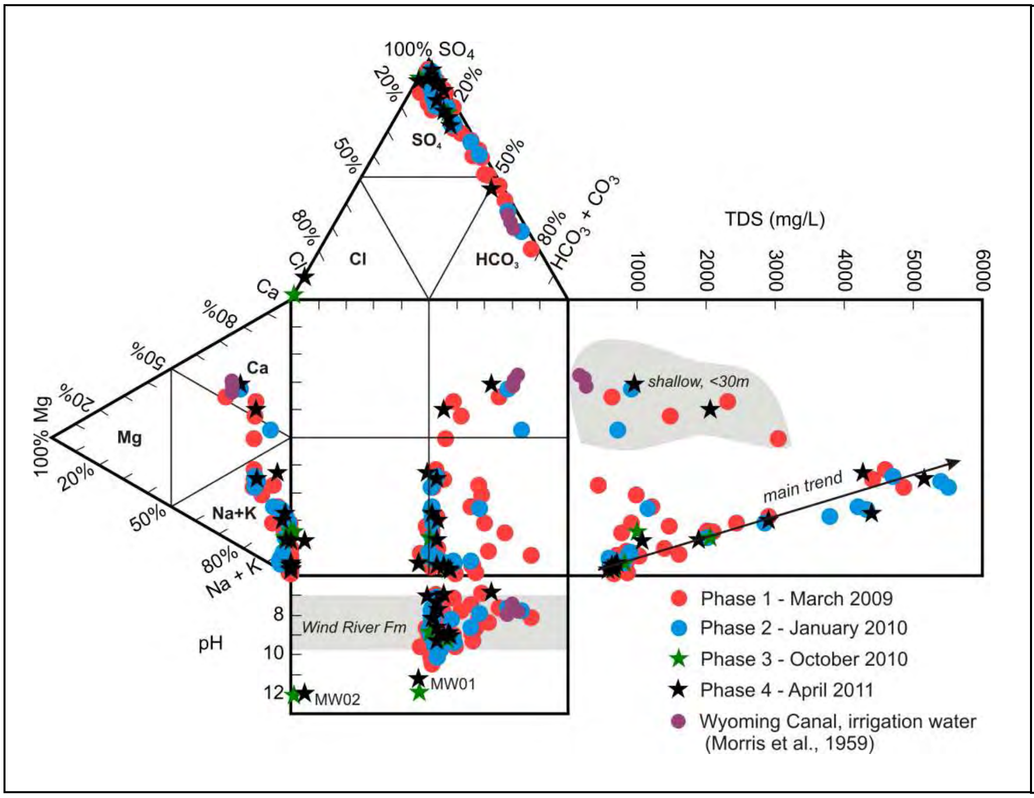

Figure 11. Durov diagram showing ground water chemistry trends obtained in Phase I - IV sampling events and the composition of irrigation water.

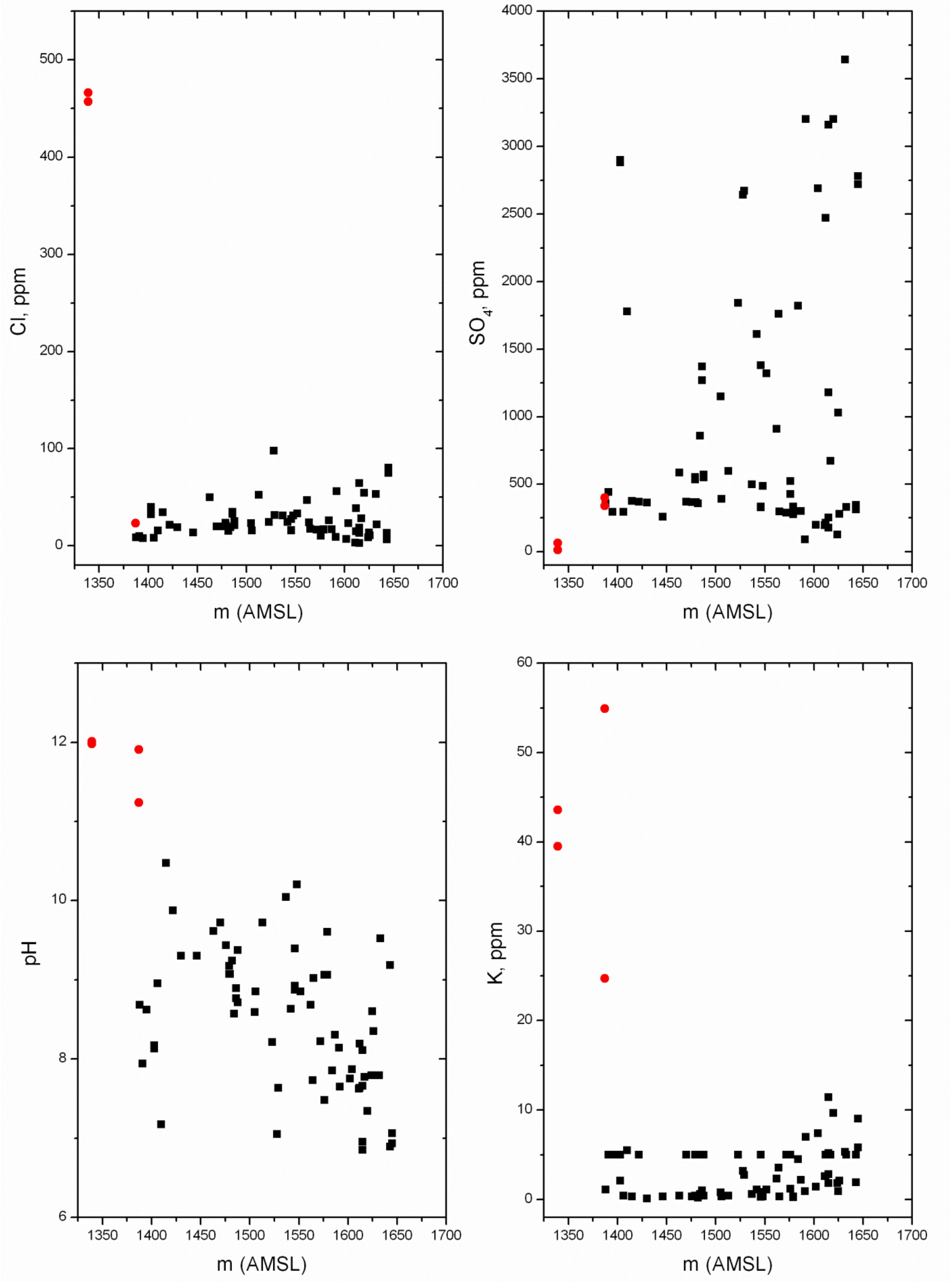

Figure 12. Depth trends of chloride, pH, sulfate, and potassium (filled black squares = domestic wells, filled red circles = monitoring wells).

crop growth since irrigation water appears to represent an endmember composition (**Figure 11**). The chemical alteration from bicarbonate-type recharge water to sulfate-type ground water involves multiple water-rock interactions, including salt dissolution, carbonate mineralization, and exchange of divalent cations for sodium (Morris et al. 1959). Total dissolved solids concentrations are <6000 mg/L in all ground water samples collected to depths up to 296 m (**Figure 11**).

Saturation indices of gypsum ($CaSO_4 \cdot 2H_2O$) and calcite ($CaCO_3$), plotted against sulfate and calcium concentrations, are shown in **Figure 13**. The trend for gypsum saturation suggests that sulfate concentrations in the aquifer are limited by the solubility of gypsum. Ground water is also close to equilibrium with calcite which likely is an important control on pH and concentrations of calcium and bicarbonate. Some residents have described the development of particulates in ground water samples collected and stored in glass jars. Precipitates that formed from PGDW05 ground water were analyzed by powder X-ray diffraction and found to be dominantly calcite. Because calcite has retrograde solubility, precipitation of calcite is possibly triggered by warming calcite-saturated ground water to ambient conditions.

The geochemistry of ground water from the deep monitoring wells is distinctive from that in the domestic wells. Chloride enrichment in monitoring well MW02 is 18 times the mean chloride concentration (25.6 mg/L) observed in ground water from domestic wells. Chloride enrichment in this well is significant because regional anion trends tend to show decreasing Cl concentrations with depth. The mean potassium concentration in domestic wells

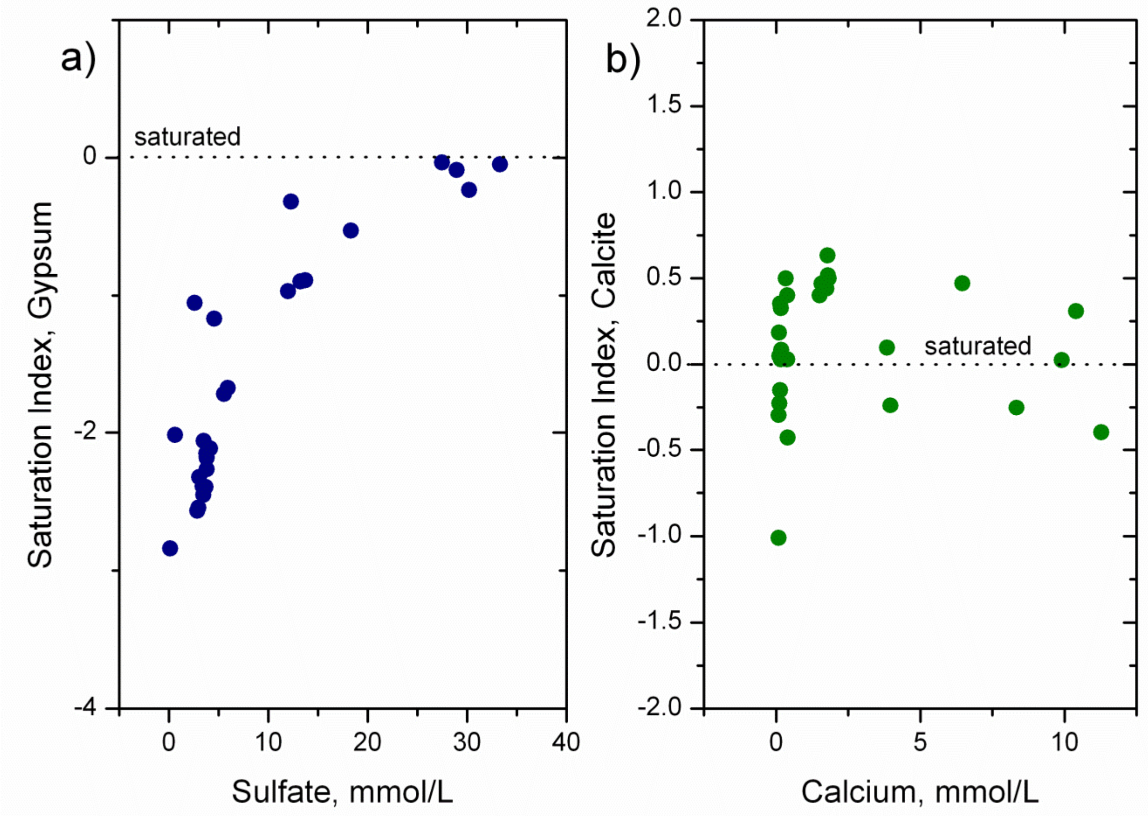

Figure 13. Saturation indices for **(a)** gypsum versus sulfate concentration and **(b)** calcite versus calcium concentration. Saturation Index is equal to the logarithm of the ratio of the ion activity product to the mineral solubility product. A Saturation Index of 0 corresponds to chemical equilibrium; values less than 0 and greater than 0 correspond to undersaturated and oversaturated conditions, respectively.

screened to 244 m bgs is 3 mg/L, with 99% of values <10 mg/L. Potassium enrichment in MW01 and MW02 is between 8.2 and 18.3 times the mean value of domestic wells (**Table A2a**). pH values in MW01 and MW02 are highly alkaline (11.2-12.0), above the pH range observed in domestic wells (6.9-10), and above the pH range previously reported for the Wind River Formation (Plafcan et al. 1995, Daddow 1996). In the deep monitoring wells, up to 94% of the total alkalinity is contributed by hydroxide. In addition, the monitoring wells show low calcium, sodium, and sulfate concentrations compared to the general trend observed in domestic well waters (**Figure 14)**.

The high pH measured in the deep monitoring wells was unusual and unexpected. Although ground water pH in these wells was >11, total alkalinity was not particularly high (<500 mg/kg), and as already noted up to 94% of the total alkalinity was present as hydroxide (see charge balance calculations, **Table A2b**). Alkalinity contributed by carbonate/bicarbonate was less than the hydroxide component. In fact, inorganic carbon concentrations were so low in MW02 as to prevent the measurement of $\delta^{13}C$ of dissolved inorganic carbon. Presence of hydroxide alkalinity suggests strong base addition as the causative factor for elevated pH in the deep monitoring wells. The possibility of cement/grout intrusion into the screened intervals was considered as a possibility for both monitoring wells, although precautions were taken to prevent downward migration of cement during well construction. Cement intrusion typically leads to pH values between 10 and 11, lower than the pH values measured in the deep monitoring wells (Gibb et al. 1987). Prolonged purging did not show decreasing pH trends (e.g., **Figure 9**) and water chemistry results indicate that ground water from the wells was highly undersaturated with respect to cement phases (e.g., portlandite), suggesting that cement was not the cause of elevated pH.

In order to gain additional insight, reaction path modeling was conducted to evaluate pH response to addition of strong base (potassium hydroxide, KOH). Geochemical modeling was carried out by using ground water compositions for PGDW49, PGDW20, and PGDW32 (initial pH 7.3, 8.9, and 9.9, respectively). Modeled titration results are shown in **Figure 15a**; pH is plotted versus the mass of KOH added per kg of solution. Model titration results vary as a function of ground water composition. Samples PGDW20 and PGDW32 have Na-SO_4-type compositions typical of deeper portions of the aquifer. In both of these cases, attainment of pH values between 11.2 and 12.0 requires small quantities of KOH addition (<250 mg KOH per kg of solution). Sample PGDW49 is elevated in Ca^{2+} and Mg^{2+}, lower in pH, and typical of shallower ground water compositions. In this case, significantly more KOH addition is required to attain pH values observed in the monitoring wells. The first derivative of the titration curve, or buffer intensity, is shown in **Figure 15b**. The buffer intensity indicates that ground water compositions like PGDW20 and PGDW32 inherently have little resistance to pH change up to about pH 12, at which point increased KOH additions are necessary to further increase pH. PGDW49 shows a broad peak on the buffer intensity diagram (pH 10 to 11) which reflects precipitation reactions to form calcium carbonate and magnesium hydroxide, reactions that consume hydroxide and therefore limit pH increases, until divalent cations are completely consumed. The model results clearly show that ground water typical of the Pavillion aquifer below 100 m depth (Na-SO_4-type composition) is especially vulnerable to the addition of strong base, with small KOH additions driving significant upward pH changes.

Paired values of $\delta^{18}O$ and $\delta^{2}H$ in ground water samples plot below the Global Meteoric Water Line (**Figure 16**; -16.6 to -12.4‰ $\delta^{18}O$ and -129.2 to -97.4‰ $\delta^{2}H$). Shallow ground water samples generally tend to be depleted in ^{18}O and ^{2}H compared to deeper ground water samples and may be more reflective of local recharge. Ground water isotope data from the deep monitoring wells (red circles, **Figure 16**) follow along the same $\delta^{18}O$ versus $\delta^{2}H$ trajectory established by the domestic well data, suggesting similar recharge and evolutional paths (e.g., Bartos et al. 2008).

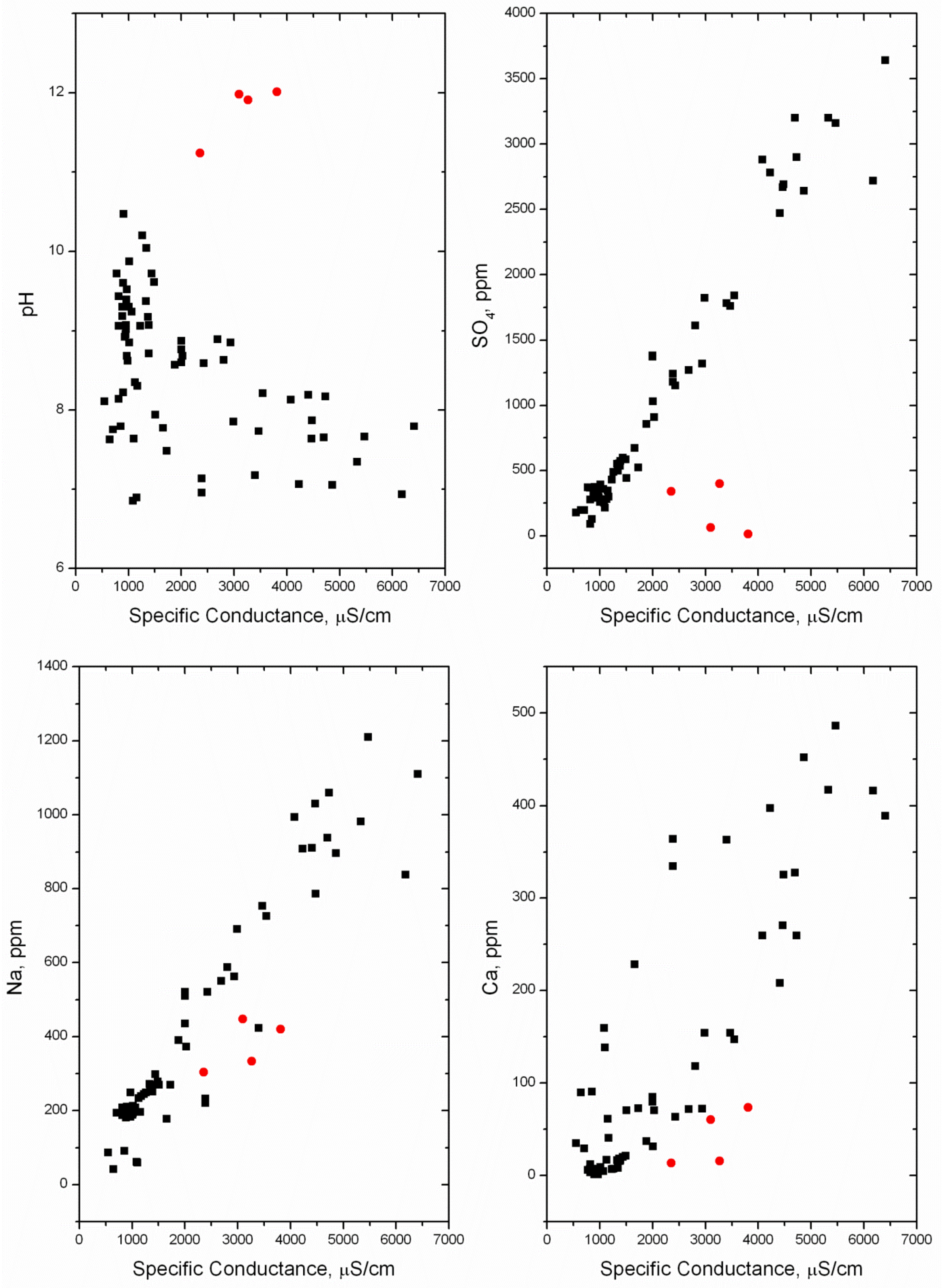

Figure 14. Concentration trends versus specific conductivity. Note the monitoring wells show high pH and low sulfate, calcium, and sodium relative to the general trend observed in the domestic wells (filled black squares = domestic wells, filled red circles = monitoring wells).

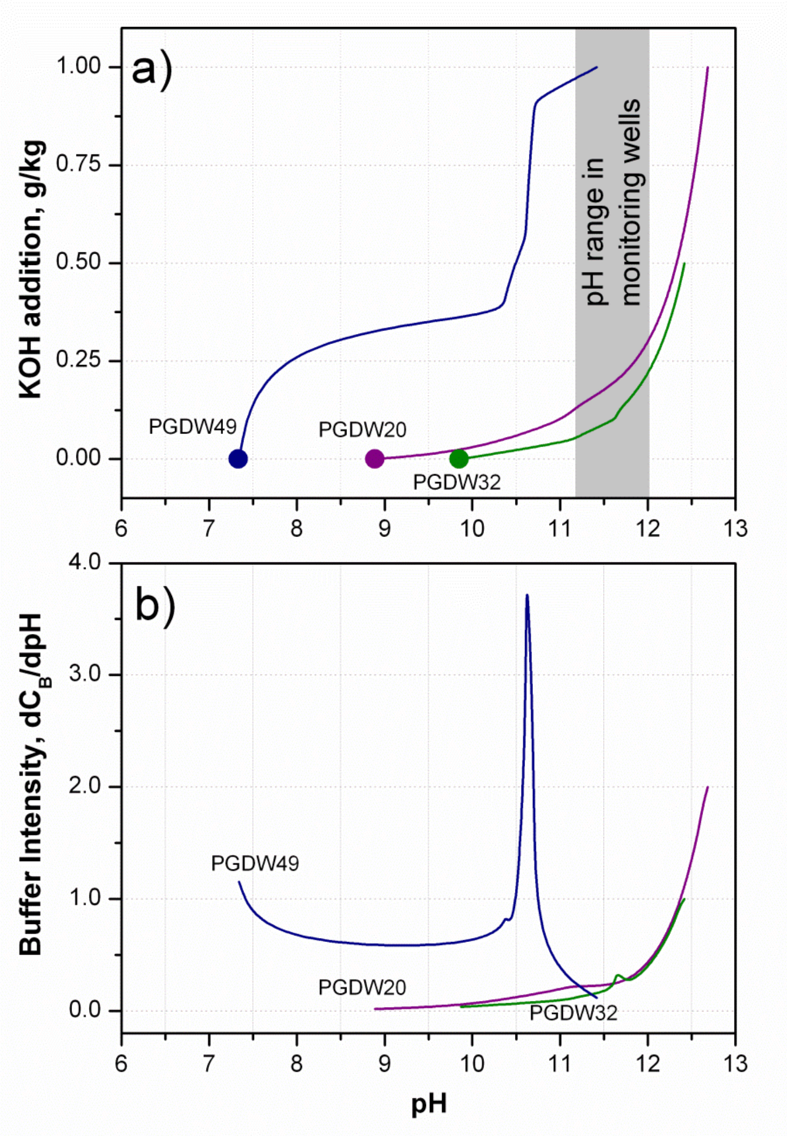

Figure 15. (a) Results of KOH titration models plotted as pH versus grams of KOH added per kilogram of solution. Initial water compositions are from PGDW49, PGDW20, and PGDW32. Model accounts for reactions taking place in solution as KOH is added and equilibrated. pH range in deep monitoring wells shown for reference; **(b)** Buffer Intensity plot or first derivative of titration plot, pH versus change in concentration of base (C_B) per change in pH.

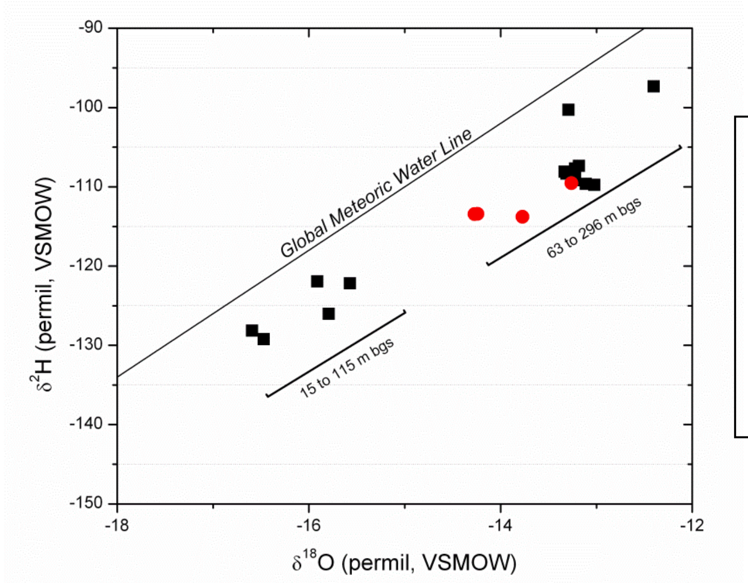

Figure 16. Hydrogen and oxygen isotope values (permil, Vienna Standard Mean Ocean Water, VSMOW) for ground water samples (black squares=domestic wells; red circles=deep monitoring wells) relative to the Global Meteoric Water Line from Craig (1961).

Organic Geochemistry

Organic and inorganic geochemical impacts in deep ground water monitoring wells (Phase III and IV) are summarized in **Table 3**. The monitoring wells produce ground water near-saturated in methane at ambient pressure, with concentrations up to 19.0 mg/L. Gas exsolution was observed while sampling at both MW01 and MW02. A wide variety of organic chemicals was detected in the monitoring wells including: GRO, DRO, BTEX, trimethylbenzenes, phenols, naphthalenes, acetone, isopropanol, TBA, 2-butoxyethanol, 2-butanone, diethylene glycol, triethylene glycol, and tetraethylene glycol (**Figure 17**; **Table 3**). Concentrations of these chemicals range from µg/L to mg/L levels. Concentrations of benzene in MW02 exceed EPA's MCL in drinking by a factor of 49 times. Detections of organic chemicals are more numerous and exhibit higher concentrations in the deeper of the two monitoring wells (**Figure 17**, **Table 3**). This observation, along with trends in methane, potassium, chloride, and pH, suggest a deep source (>299 m bgs) of contamination. Natural breakdown products of organic contaminants like BTEX and glycols include acetate and benzoic acid; these breakdown products are more enriched in the shallower of the two monitoring wells, suggesting upward/lateral migration with natural degradation and accumulation of daughter products (Corseuil et al. 2011, Caldwell and Suflita 2000, Dwyer and Tiedje 1983). Other trace-level detections of semi-volatile organic compounds included: bis(2-ethylhexyl) phthalate (MW01 and MW02, Phase III and IV), bis(2-chloroethyl) ether, bis(2-ethylhexyl) adipate (MW01, Phase IV), butyl benzyl phthalate, and 4-methyl-2-pentanone (MW02, Phase IV).

Well completion reports obtained online from WOGCC and Material Safety and Data Sheets (MSDSs) obtained from the operator were reviewed to examine inorganic and organic compounds in additives used for hydraulic fracturing and similarity with detected elements and compounds in ground water. Well completion reports were limited to a subset of production wells and included dates of injection, injection depths, pressure, flow, and volume for slickwater and carbon dioxide foam fracture jobs. Some MSDSs list chemical formulation as proprietary (e.g., proprietary alcohols) or list a chemical family (e.g., blend of organic surfactants) rendering identification of constituents impossible. This review is summarized in **Table 4**. Inorganic additives are potential sources of elevated K, Cl, and OH in deep monitoring wells.

Detection of compounds associated with petroleum-based additives in ground water samples using analytical methods employed in this investigation would be manifested as GRO, DRO, BTEX, naphthalenes, and trimethylbenzenes observed in deep monitoring wells.

TBA was detected in MW02 during Phase 4 sampling at a concentration of 4470 µg/L. Two possible formation pathways for TBA are: 1) biodegradation of methyl *tert*-butyl ether (MTBE, synthetic chemical used as a fuel additive) under methanogenic conditions (e.g., Mormile et al. 1994, Bradley et al. 2001); and 2) breakdown of *tert*-butyl hydroperoxide (a gel breaker used in hydraulic fracturing; e.g., Hiatt et al. 1964). TBA biodegradation is generally slow compared to the degradation of MTBE; this suggests that TBA could be present and persist even after complete MTBE removal from ground water impacted by fuel releases (Wilson et al. 2005). MTBE was not detected in either of the deep monitoring wells. A second pathway of TBA production is from the decomposition of the gel breaker *tert*-butyl hydroperoxide. Hiatt et al. (1964) found that decomposition of *tert*-butyl hydroperoxide yielded a 10-fold molar quantity of TBA, oxygen, *di*-*tert*-butyl peroxide, and acetone. Acetone was detected in MW02 during Phase 4 sampling at a concentration of 641 µg/L. This breaker is used in hydraulic fracturing formulations; however, the MSDSs made available to EPA do not indicate whether *tert*-butyl hydroperoxide was used in the Pavillion gas field for well stimulation. Elevated concentrations of TBA are not expected in unimpacted aquifers and its presence in MW02 remains unresolved. Additional insight about the occurrence of TBA (and other organic compounds) might be obtained by conducting compound-specific isotope analyses.

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Table 3. Geochemical impacts in deep ground-water monitoring wells

Compound	MW01 Phase 3 10/6/2010	MW02 Phase 3 10/6/2010	MW01 Phase 4 4/20/2011	MW02 Phase 4 4/19/2011
pH	11.9	12.0	11.2	11.8
K, mg/L	54.9	39.5	24.7	43.6
Cl, mg/L	23.3	466	23.1	457
CH_4, mg/L	16.0	19.0	17.9	18.8
Benzene †	nd	246	nd	139
Toluene	0.75 [d]	617	0.56	336
Ethylbenzene	nd	67	nd	21.5
Xylenes (total)	nd	750	0.89 [d]	362
1,2,4 Trimethylbenzene	nd	69.2	nd	18.5
1,3,5 Trimethylbenzene	nd	35.5	nd	nd
Diesel Range Organics	634	1440	924	4050
Gasoline Range Organics	389	3710	592	2800
Phenol [a]	11.1	56.1	20.9	64.9
Naphthalene [b]	nd	6.06	nd	6.10
Isopropanol	-----	-----	212	581
Tert-Butyl Alcohol	-----	-----	nd	4470
2-Butanone	-----	-----	nd	120
Diethylene Glycol	-----	-----	226	1570
Triethylene Glycol	-----	-----	46	310
Tetraethylene Glycol	-----	-----	7.3 [c, d]	27.2
2-Butoxyethanol *	-----	-----	nd	nd
2-Butoxyethanol **	nd	nd	12.7	nd
Acetone	-----	-----	79.5	641
Benzoic Acid	212	244	457	209
Acetate	-----	-----	8050	4310
Formate	-----	-----	112	558
Lactate	-----	-----	69	213
Propionate	-----	-----	309	803

† All values in µg/L unless otherwise noted.
----- not analyzed.
nd - not detected.
[a] Includes phenol, 2,4-dimethylphenol, 2-methylphenol, 3&4 methylphenol.
[b] Includes naphthalene, 1-methylnaphthalene, and 2-methylnaphthalene.
[c] Value below quantitation limit of 10 µg/L.
[d] Chemical detected in a blank sample at a similar level
* 2-Butoxyethanol determined by HPLC-MS-MS.
** 2-Butoxyethanol determined by GC-MS.

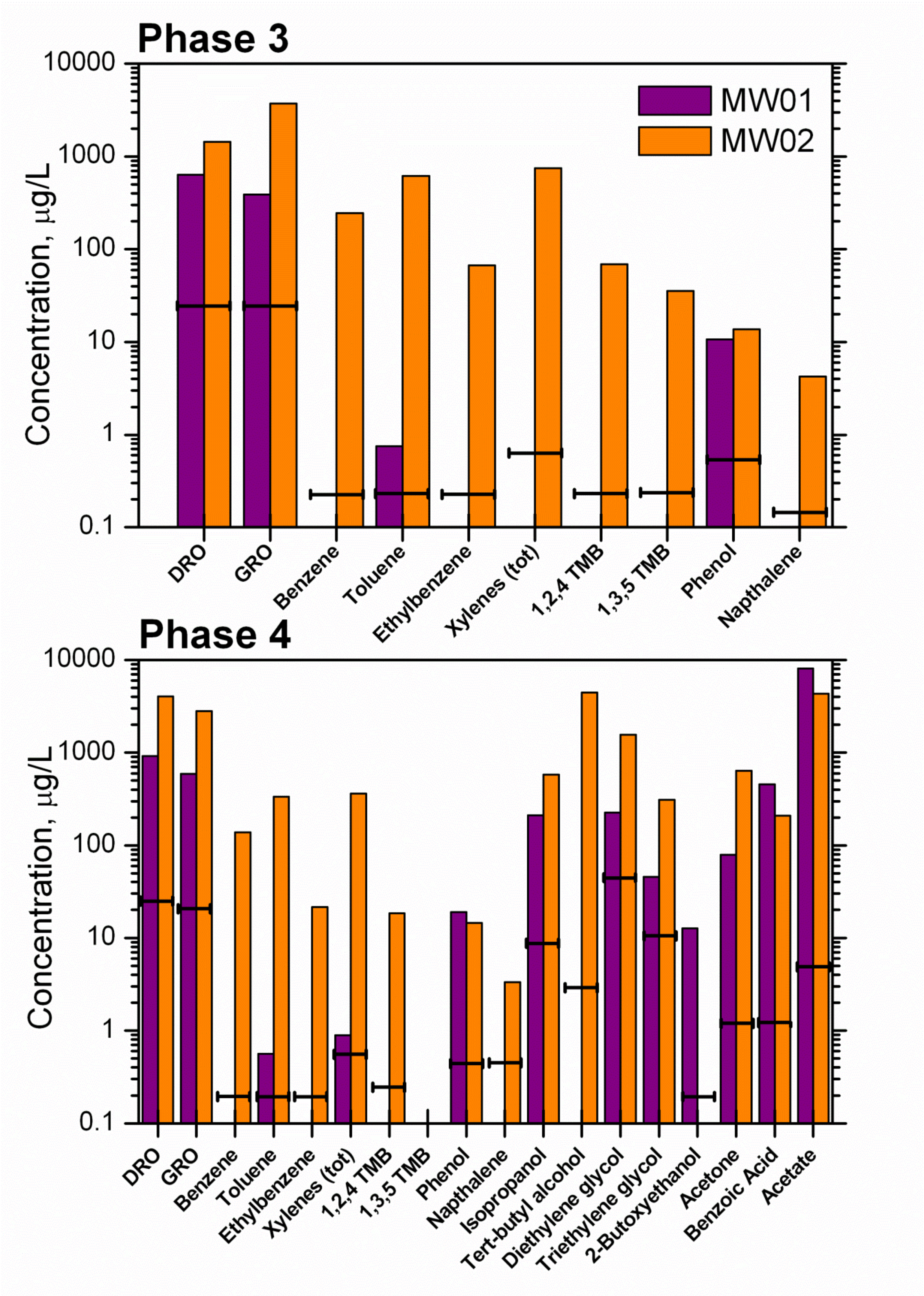

Figure 17. Organic compounds detected in deep monitoring wells MW01 and MW02 during Phase III and IV sampling events. Horizontal bars show method reporting limits for the individual analytes.

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Table 4. Association of inorganic and organic anomalies with compounds used for hydraulic fracturing

Compound/ Compound Class	Information from MSDSs and Well Completion Reports
pH	KOH was used in a crosslinker (<5%) and in a solvent (85-100%).
K, Cl	The formulation of fracture fluid provided for foam jobs typically consisted of CO_2, 6% KCl, 10% methanol, and "clean" fluid and "additives." Potassium metaborate was used in crosslinkers (5-10%, 30-60%). KOH was used in a crosslinker (<5%) and in a solvent (85-100%).
Cl	Ammonium chloride was used in crosslinker (1-27%).
BTEX	Aromatic solvent (typically BTEX mixture) was used in a breaker (<75%). Diesel oil (mixture of saturated and aromatic hydrocarbons including naphthalenes and alkylbenzenes) was used in a guar polymer slurry/liquid gel concentrate (30-60%) and in a solvent (60-100%). Petroleum raffinates (mixture of paraffinic, cycloparaffinic, olefinic, and aromatic hydrocarbons) was used in a breaker (<30-60%). Heavy aromatic petroleum naptha (mixture of paraffinic, cycloparaffinic and aromatic hydrocarbons) was used in surfactants (5-10%, 10-30%, 30-60%) and in a solvent (10-50%). Toluene was used in a flow enhancer (3-7%). Xylenes were used in a flow enhancer (40-70%) and a breaker (confidential percentage).
Trimethylbenzenes	1,2,4-trimethylbenzene was used in surfactants (0-1%). Diesel oil (mixture of saturated and aromatic hydrocarbons including naphthalenes and alkylbenzenes) was used in a guar polymer slurry/liquid gel concentrate (30-60%) and in a solvent (60-100%). Petroleum raffinates (mixture of paraffinic, cycloparaffinic, olefinic, and aromatic hydrocarbons) was used in a breaker (<30-60%). Heavy aromatic petroleum naptha (mixture of paraffinic, cycloparaffinic and aromatic hydrocarbons) was used in surfactants (5-10%, 10-30%, 30-60%) and in a solvent (10-50%).
DRO and GRO	Diesel oil (mixture of saturated and aromatic hydrocarbons including naphthalenes and alkylbenzenes) was used in a guar polymer slurry/liquid gel concentrate (30-60%) and in a solvent (60-100%). Petroleum raffinates (mixture of paraffinic, cycloparaffinic, olefinic, and aromatic hydrocarbons) was used in a breaker (<30-60%). Heavy aromatic petroleum naptha (mixture of paraffinic, cycloparaffinic and aromatic hydrocarbons) was used in surfactants (5-10%, 10-30%, 30-60%) and in a solvent (10-50%).
Naphthalene	Naphthalene was used in surfactants (0-1, 5-10%) and a breaker (confidential percentage). Hydrotreated light petroleum distillates (mixture of C10-C14 naphthenes, iso- and n-paraffins) were used in a guar polymer slurry/liquid gel concentrate (40-60%). Diesel oil (mixture of saturated and aromatic hydrocarbons including naphthalenes and alkylbenzenes) was used in a guar polymer slurry/liquid gel concentrate (30-60%) and in a solvent (60-100%).
Isopropanol	Isopropanol was used in a biocide (20-40%), in a surfactant (30-60%), in breakers (<1%, 10-30%), and in foaming agents (<3%, 1-5%, 10-30%).
Tert-Butyl Alcohol	No MSDS listing. Breakdown product of methyl *tert*-butyl ether and *tert*-butyl hydroperoxide - found in gel breakers. See discussion.
Glycols	Diethylene glycol was used in a foaming agent (5-10%) and in a solvent (0.1-5%). Triethylene glycol was used in a solvent (95-100%).
2-Butoxyethanol	2-butoxyethanol was used in a surfactant (10-30%), in foaming agents (<10%, <11%, <12%, 1-10%, 10-30%) and in solvents (15-40%, 60-100%).
Acetone	Breakdown product of *tert*-butyl hydroperoxide - found in gel breakers. See discussion.
Benzoic Acid, Acetate, Formate, Lactate, Propionate, 2-Butanone, Phenols	Natural breakdown products of organic contaminants (e.g., BTEX, glycols, etc.).

Natural gas condensates are composed primarily of aliphatic hydrocarbons; however, condensates may contain low quantities of aromatic compounds, such as BTEX. Gas from the Fort Union and lower Wind River Formations is generally dry (C_1/C_1-C_5 = 0.95 - 0.96 where methane = C_1, ethane = C_2, propane = C_3, butane = C_4, pentane = C_5) (Johnson and Rice 1993) and unlikely to yield liquid condensates at ground water pressure and temperature conditions. In addition, a condensate origin for BTEX compounds in ground water is doubtful because dissolved gas compositions and concentrations are similar between the two deep monitoring wells and therefore would yield similar liquid condensates, yet the compositions and concentrations of organic compounds detected in these wells are quite different (**Figure 17**) further suggesting a deep source of BTEX in MW02. The presence of synthetic compounds such as glycol ethers, along with enrichments in K, Cl, pH, and the assortment of other organic components is explained as the result of direct mixing of hydraulic fracturing fluids with ground water in the Pavillion gas field.

As noted previously, this investigation was prompted by homeowner complaints over perceived changes in water quality. Domestic well results showed: the presence of DRO and GRO (in 23 of 28 samples), and trace levels of exotic organic compounds in some domestic wells including adamantanes, 2-butoxyethanol phosphate, phenols, naphthalene, and toluene (EPA 2009*,* EPA 2010). Methane was detected in 10 of 28 samples at concentration levels below 0.8 mg/L. Foul odors associated with some domestic wells correlate with detections of GRO and DRO. Anomalous trends in inorganic constituents observed in the deep monitoring wells (e.g., K, Cl, pH) were not revealed in domestic well waters. In several instances, glycols were detected in domestic wells using gas chromatography with flame ionization detection (GC-FID; EPA Standard Method 8015). However, glycol analysis using liquid chromatography with tandem mass spectroscopy (GC/MS/MS) failed to replicate these glycol detections, even though the method reporting limit was over an order of magnitude lower, suggesting that Method 8015 is prone to false positive results (possibly due to interactions between the chromatographic column and organic compounds in sample water). This result points to the need for continued and future improvements of analytical methods to detect and quantitate low levels of organic chemicals that may be associated with hydraulic fracturing fluids. Although contamination was detected in some domestic wells proximal to the deep monitoring wells, underscoring potential future risk, the existing data at this time do not establish a definitive link between deep and shallow contamination of the aquifer. An increased number of sampling points (monitoring wells) with vertical profiling in targeted locations are necessary to better define transport and fate characteristics of organic and inorganic contaminants in the ground water system and impact on domestic wells.

Natural Gas Migration

A review of open-hole geophysical logs obtained from the WOGCC internet site indicates the presence of gas-filled porosity at three locations at 198, 208, and 252 m bgs between the years 1965 - 1973 suggesting the presence of natural gas in ground water at depths used for domestic water supply prior to extensive commercial development. However, a review of 10 mud-gas logs recorded in the mid-1970s and early 1980s obtained on line from WOGCC, do not indicate gas shows within 300 m of the surface at any location.

Aqueous analysis of light hydrocarbons, gas and headspace analysis of light hydrocarbons, and isotopic data for dissolved, gas phase, and headspace analysis are summarized in **Tables A3a**, **A3b**, and **A3c** respectively (all investigative phases). Elevated levels of dissolved methane in domestic wells generally increase in those wells in proximity to gas production wells (**Figure 18c**). Methane was not detected in shallow domestic wells (e.g., < 50 m) regardless of proximity to production wells (**Figure 18c**). With the exception of two domestic wells where methane was

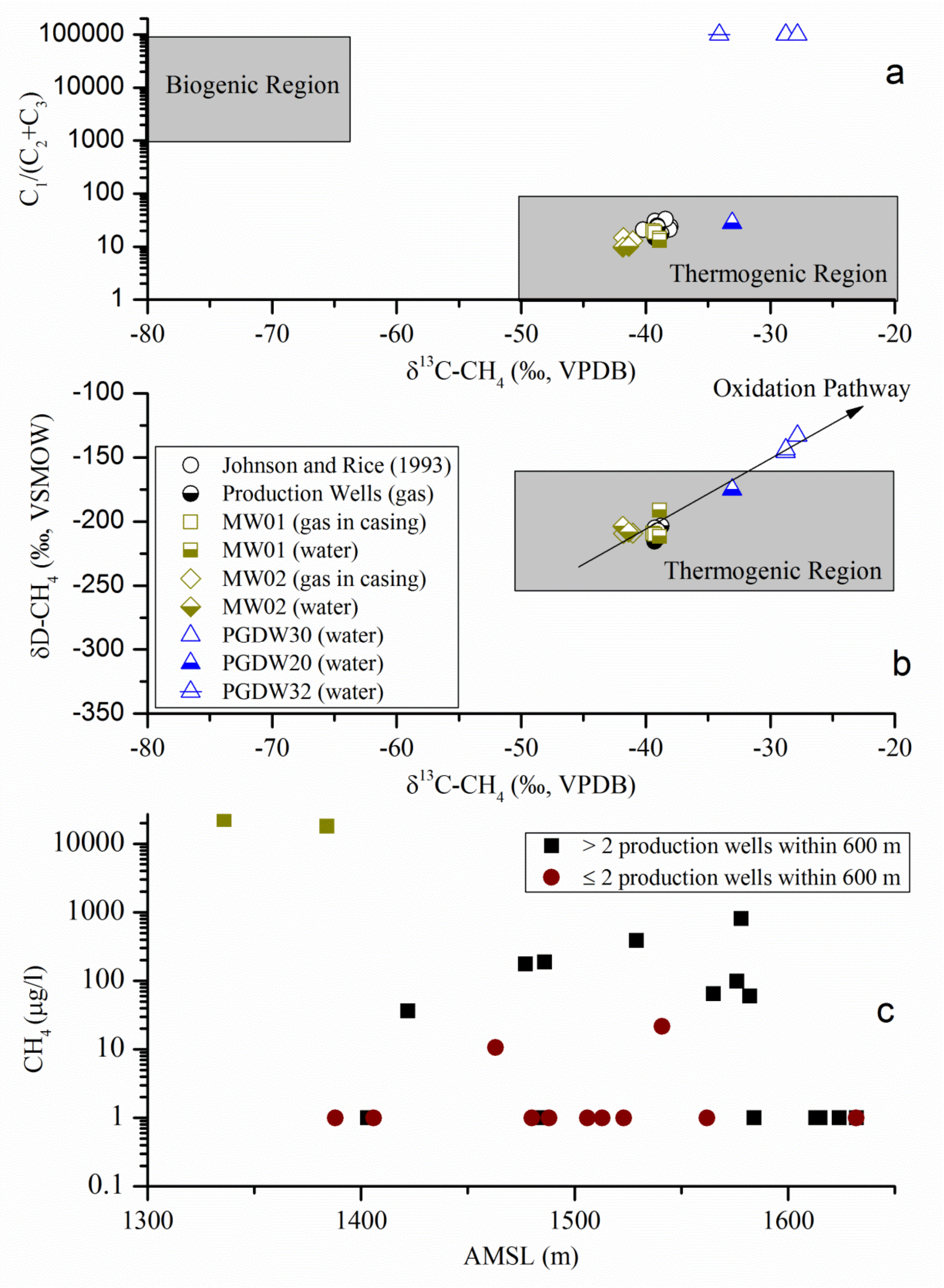

Figure 18. (a) Stable isotope ratios of carbon of methane versus ratio of methane (C_1) to ethane (C_2) and propane (C_3) in gas from production wells, monitoring wells, and domestic wells. Values of 100,000 are used to denote non detection of ethane and propane in samples. **(b)** Stable isotope ratios of carbon versus hydrogen of methane in gas from production wells (both literature and measured values), monitoring wells, and domestic wells. δD was not determined for PGDW32. Oxidation pathway (enrichment of ^{13}C of remaining CH_4 with biodegradation) is illustrated. **(c)** Methane concentration in domestic (red circles and black squares) and monitoring wells (green squares) as a function of proximity to production wells and AMSL. Values of 1.0 were used for non-detection (detection limit 5 µg/L).

detected at less than 22 µg/L, methane was not detected in domestic wells with 2 or less production wells within 600 m (**Figure 18c**). All domestic wells with the exception of PGDW25 with 2 or less production wells within 600 m are located on the periphery of the gas field (**Figure 5**). PGDW25 is located within 1600 m of 15 gas production wells.

Of particular interest is the area encompassing MW01, PGDW30, and PGDW05 (**Figure 19**). Ground water is saturated with methane at MW01 which is screened at a depth (239 m bgs) typical of deeper domestic wells in the area. Methane was detected in PGDW30 at 808 µg/L at a depth of only 80 m, the highest level in any domestic well. A blowout occurred during drilling at a depth of only 159 m bgs in December 2005 adjacent to PGDW05. Natural gas exited the borehole for three days until the gas field operator was ordered to plug the borehole with a dense mud. The owner of PGDW05 was attempting at the time to replace this well due to taste, odor, and yield reduction he stated occurred after hydraulic fracturing at nearby production wells. A mud-gas log conducted on 11/16/1980 at Tribal Pavillion 14-2 (illustrated on **Figure 19** as 14-2) located only 300 m from the location of the uncontrolled release does not indicate a gas show (distinctive peaks on a gas chromatograph) within 300 m of the surface. The owner of PGDW05 complained that well yield decreased after hydraulic fracturing at nearby production wells. Records obtained from the Wyoming State Engineer's office dated January 1973 indicate a yield of 30 to 38 L/min with 1.2 meters of drawdown after 10 hours of pumping. During a sampling event in April 2005, PGDW05 became dry after pumping at a rate of 21.6 L/min for 14 minutes. The cause of reduced well yield requires further investigation.

Similarity of δ^{13}C values for methane, ethane, propane, isobutane, and butane between gas production and monitoring wells and plots of δ^{13}C-CH_4 versus δD -CH_4 (**Figure 18b**) and δ^{13}C-CH_4 versus $C_1/(C_2 + C_3)$ (**Figure 18a**) indicate that light hydrocarbons in casing and dissolved gas in deep monitoring wells are similar to produced gas and have undergone little oxidation or biodegradation. These observations combined with radiocarbon analysis of CH_4 (< 0.2% percent modern carbon) obtained from gas in casing of both MW01 and MW02 indicate that methane in deep monitoring wells is of thermogenic origin. Gas from the Fort Union and lower Wind River Formations is isotopically heavy (δ^{13}C-CH_4 from to -40.24 to -38.04‰) and as previously stated, dry (Johnson and Rice 1993, Johnson and Keighin 1998). Values of δ^{13}C-CH_4 and δD -CH_4 more negative than -64‰ and -175‰, respectively, are indicative of microbial origin (Schoell 1980). The absence of ethane and propane in three of four domestic wells having sufficient methane to allow isotopic analysis and a shift of δ^{13}C-CH_4 and δD-CH_4 values in a positive direction relative to produced gas suggests the presence of gas of thermogenic origin in domestic wells undergoing biodegradation and subsequent enrichment of δ^{13}C and δD. This observation is consistent with a pattern of dispersion and degradation with upward migration observed for organic compounds. Values of δ^{13}C-CH_4 more positive than -64‰ and $C_1/(C_2+C_3)$ ratios above 1000 are often interpreted to indicate gas of mixed biogenic-thermogenic origin or gas of biogenic origin undergoing biodegradation (Whiticar 1999, Whiticar and Faber 1986) since neither ethane nor propane are biogenically generated in significant amounts. However, preferential loss of ethane and propane relative to methane in thermogenic gas produces a similar response (Valentine 2010, Kinnaman et al. 2007).

Evaluation of Cement Bond/Variable Density Logs Along Transect

CBL/VDLs and lithology were examined along a transect (**Figure 19**) which included the deep monitoring wells and three domestic wells where elevated levels of methane were detected. At Pavillion Fee 34-03B, a CBL/VDL conducted on 10/22/2004 indicates no cement below surface casing until 802 m msl (**Figure 20**) and sporadic bonding to 604 m msl (not illustrated). The well completion

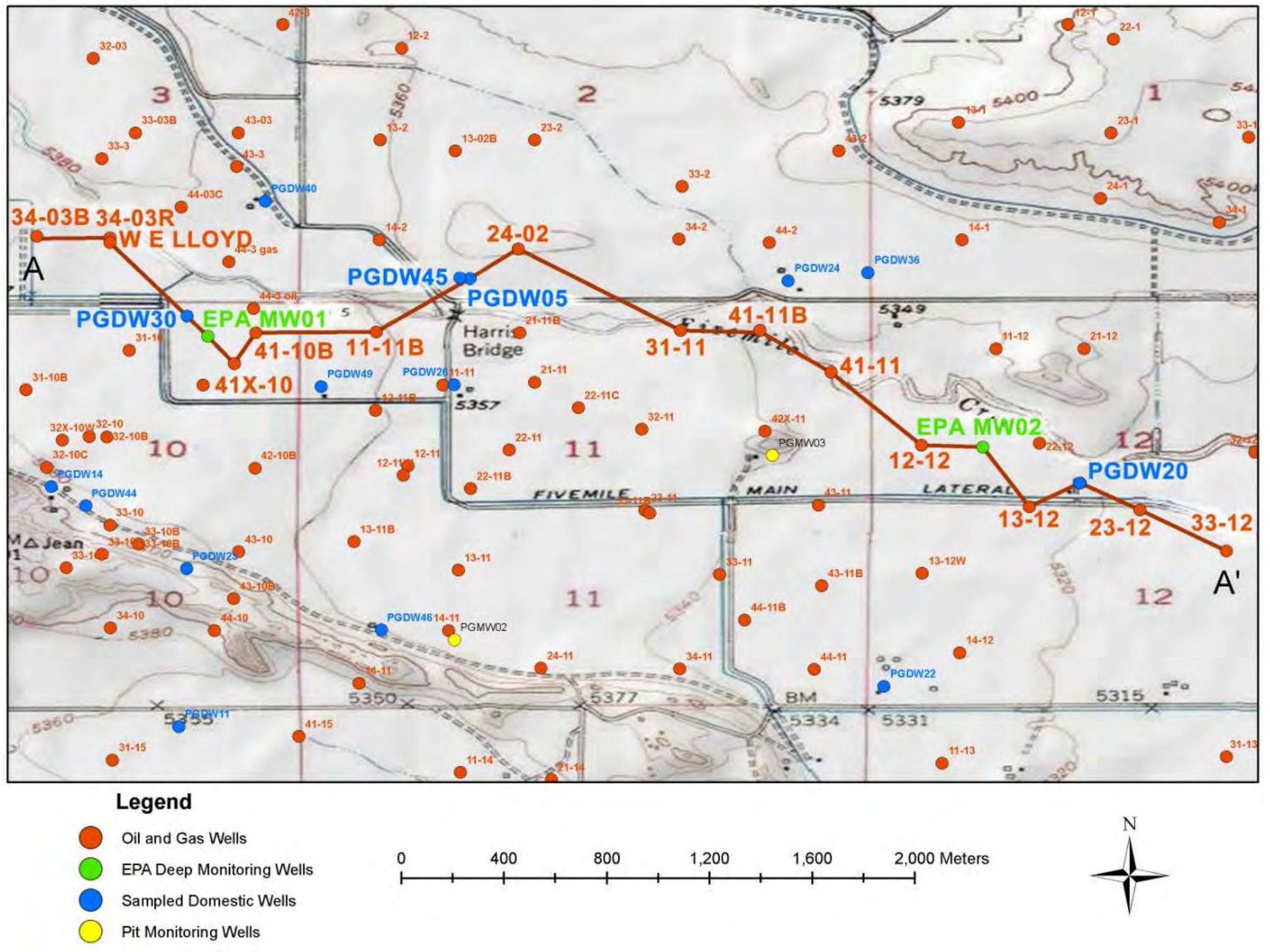

Figure 19. Map illustrating transect used to develop lithologic cross section and evaluation of CBL/VDLs.

report for this production well indicates that hydraulic fracturing was performed at 601 m msl on 11/9/2004. A cement squeeze was subsequently performed at 802 m msl on 4/1/2005 (no CBL/VDL after cement squeeze) with hydraulic fracturing at 689 m msl on 4/19/2005. At Pavillion Fee 34-03R, the CBL/VDL indicates no cement below surface casing until 968 m msl (**Figure 20**). At Tribal Pavillion 41-10 and 41-10B, CBL/VDLs indicate sporadic bonding over extensive intervals. A CBL/VDL conducted on 4/20/2005 at Tribal Pavillion 24-02 after a squeeze perforation at the base of the surface casing indicates poor bonding outside production casing below surface casing to the first perforation interval (**Figure 20**). At Tribal Pavillion 11-11B, a CBL/VDL indicates poor or sporadic bonding to 991 m bgs and no cement or cement bridging from 675 - 857 m msl. Thus, a review of well completion reports and CBL/VDLs indicates instances of sporadic bonding directly above intervals of hydraulic fracturing. This review also indicates instances where cement outside production casing is lacking over an extensive interval providing a potential conduit for fluid migration to within 300 m of the surface. As graphically illustrated in **Figure 20**, production wells having no or sporadic cement outside production casing are located in proximity to deep monitoring wells where aqueous constituents consistent with hydraulic fracturing were detected and methane exsolved from solution during sampling and locations of domestic wells where elevated levels of methane were detected and where an uncontrolled release of natural gas occurred.

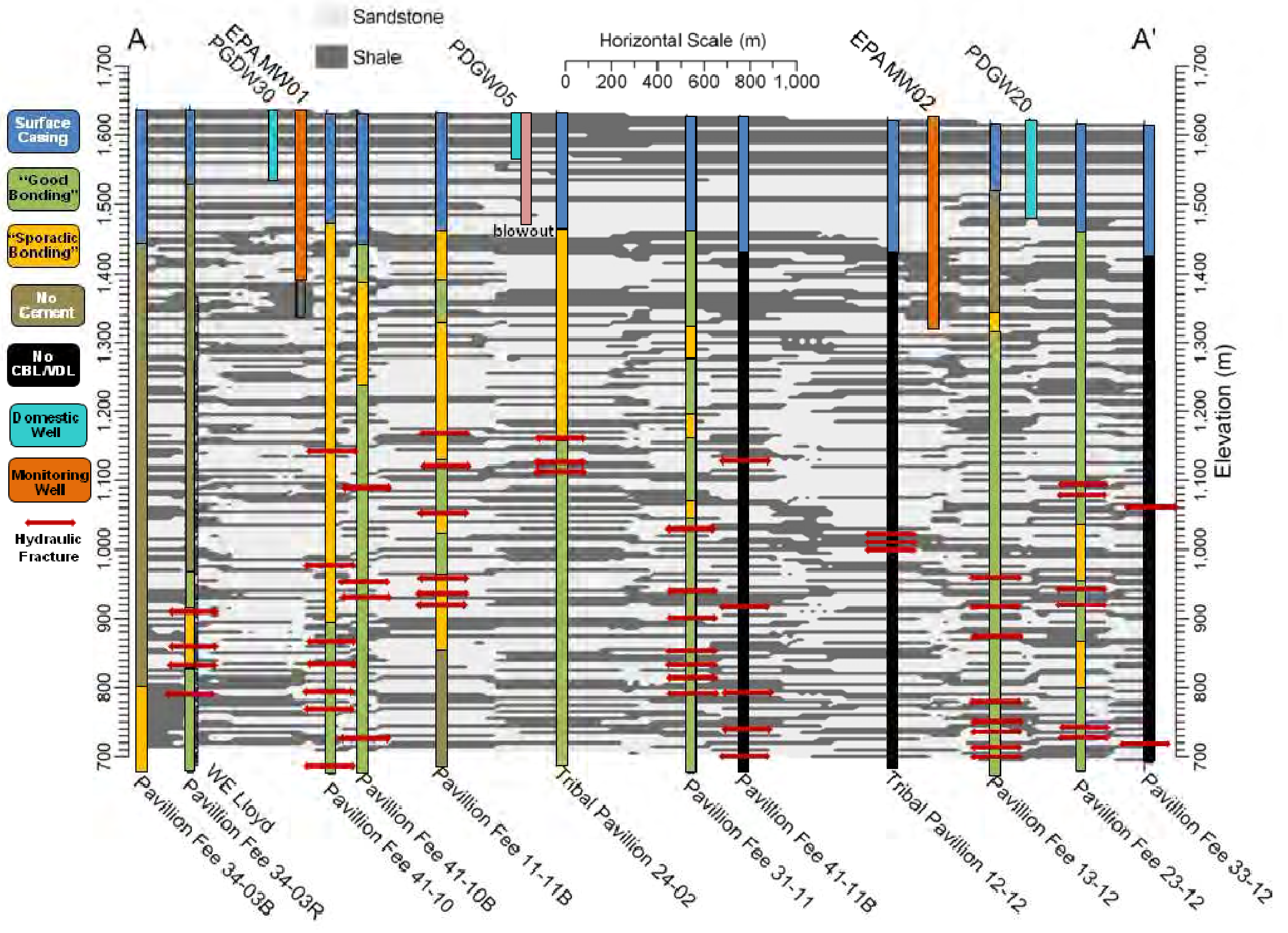

Figure 20. Lithologic cross-section along transect illustrating production wells (with evaluation of CBL/VDLs), domestic wells, and blowout location. Red arrows denote depths of hydraulic fracturing of unknown areal extent. Sandstone units are undifferentiated between fine, medium and coarse-grained units.

Potential Migration Pathways

Further investigation is necessary to determine mechanisms of aqueous and gas phase transport in the area of investigation. However, at least three mechanisms can be postulated at this time. The first mechanism is aqueous and/or gas transport via boreholes due to insufficient or inadequate cement outside production casing. Both aqueous (brine) and gas phase migration vertically up compromised wellbores have been simulated (Nordbotten et al. 2004, 2005a, 2005b) and indicate decreasing mass flux toward the surface with increasing number of permeable formations encountered along the way. Thus, the severity of ground water contamination increases with depth. Migration of gas via wellbores is well documented in the literature (e.g., Harrison 1983, Harrison 1985, Van Stempvoort et al. 2005, Taylor et al. 2000). In Bainbridge, Ohio, an operator initiated hydraulic fracturing despite knowing that only 24 m of cement was present above the perforation interval (Bair et al. 2010, ODNR 2008). Hydraulic fracturing fluid flowed to the surface via surface-production casing annulus which pressurized upon shut-in. Gas subsequently migrated through natural fractures to domestic wells eventually causing an explosion at one home. In northeastern Pennsylvania, two operators were fined for enhanced gas migration into domestic wells attributed to incomplete or inadequate cement outside production casing in wells used for hydraulic fracturing (PADEP 2009a, 2009b, 2010).

The second mechanism is fracture fluid excursion from thin discontinuous tight sandstone units into sandstone units of greater permeability. This would be accompanied by physical displacement of gas-rich solutions in both tight and more permeable sandstone formations. As illustrated in **Figure 20**, there is little lateral and vertical continuity to hydraulically fractured tight sandstones and no lithologic barrier (laterally continuous shale units) to upward vertical migration of aqueous constituents of hydraulic fracturing in the event of excursion from fractures. A third mechanism is that the process of hydraulic fracturing generates new fractures or enlarges existing ones above the target formation, increasing the connectivity of the fracture system.

In all three transport pathways, a general correlation (spatial relationships ultimately determined by fault and fracture systems in addition to lithology) would exist between proximity to gas production wells and concentration of aqueous and gas phase constituents in ground water. For instance, Osborn et al. (2011) observed a correlation between methane concentration and proximity to hydraulically fractured gas production wells at locations above the Marcellus and Utica formations in Pennsylvania and New York. Isotopic data and other measurements for methane in the drinking water were consistent with gas found in deep reservoirs such as the Marcellus and Utica shales at the active sites and matched gas geochemistry from shale-gas wells sampled nearby. Also, in all three transport pathways, advective/dispersive transport would be accompanied by degradation causing a vertical chemical gradient as observed during sampling of MW01 and MW02. Reduced mass flux to the near surface environment and subsequent degradation along vertical and lateral transport pathways would explain lack of detection in domestic wells of compounds observed in MW02.

4.0
Conclusions

The objective of this investigation was to determine the presence of ground water contamination in the Wind River Formation above the Pavillion gas field and to the extent possible, identify the source of contamination. The combined use of shallow and deep monitoring wells allowed differentiation between shallow sources of contamination (pits) and deep sources of contamination (production wells). Additional investigation is necessary to determine the areal and vertical extent of shallow and deep ground water contamination.

Detection of high concentrations of benzene, xylenes, gasoline range organics, diesel range organics, and total purgeable hydrocarbons in ground water samples from shallow monitoring wells near pits indicates that pits are a source of shallow ground water contamination in the area of investigation. Pits were used for disposal of drilling cuttings, flowback, and produced water. There are at least 33 pits in the area of investigation. When considered separately, pits represent potential source terms for localized ground water plumes of unknown extent. When considered as whole they represent potential broader contamination of shallow ground water. A number of stock and domestic wells in the area of investigation are fairly shallow (e.g., < 30 m) representing potential receptor pathways. EPA is a member of a stakeholder group working with the operator to determine the areal and vertical extent of shallow ground water contamination caused by these pits. The operator of the site is currently engaged in investigating and remediating several pit areas.

Detection of contaminants in ground water from deep sources of contamination (production wells, hydraulic fracturing) was considerably more complex than detection of contaminants from pits necessitating a multiple lines of reasoning approach common to complex scientific investigations. In this approach, individual data sets and observations are integrated to formulate an explanation consistent with each data set and observation. While each individual data set or observation represents an important line of reasoning, taken as a whole, consistent data sets and observations provide compelling evidence to support an explanation of data. Using this approach, the explanation best fitting the data for the deep monitoring wells is that constituents associated with hydraulic fracturing have been released into the Wind River drinking water aquifer at depths above the current production zone.

Lines of reasoning to support this explanation consist of the following.

1. <u>High pH values</u>

   pH values in MW01 and MW02 are highly alkaline (11.2-12.0), above the pH range observed in domestic wells (6.9-10), and above the pH range previously reported for the Wind River Formation with up to 94% of the total alkalinity contributed by hydroxide. The presence of hydroxide alkalinity suggests addition of base as the causative factor for elevated pH in the deep monitoring wells. Reaction path modeling indicates that sodium-sulfate composition ground water typical of deeper portions of the Wind River Formation provides little resistance to elevation of pH with small addition of potassium hydroxide.

   With the exception of soda ash, the pH of drilling additives in concentrated aqueous solution was well below that observed in the deep monitoring wells. Dense soda ash was added to the drilling mud which varied between pH 8 - 9.

   The possibility of cement/grout intrusion into the screened intervals was considered as a possibility for elevated pH in both monitoring wells. However, cement intrusion typically leads to pH values between 10 and 11 – below that observed in deep monitoring wells. Prolonged purging did not show decreasing pH trends. Water chemistry results indicate that ground water from the wells was highly undersaturated with respect to cement phases (e.g., portlandite).

Material Safety Data Sheets indicate that potassium hydroxide was used in a crosslinker (<5%) and in a solvent.

2. Elevated potassium and chloride

The inorganic geochemistry of ground water from the deep monitoring wells is distinctive from that in the domestic wells and expected composition in the Wind River formation. Potassium concentration in MW02 (43.6 mg/L) and MW01 (54.9 mg/L) is between 14.5 and 18.3 times the mean value of levels observed in domestic wells (3 mg/L, 99% of values < 10 mg/L). Chloride enrichment in monitoring well MW02 (466 mg/L) is 18 times the mean chloride concentration (25.6 mg/L) observed in ground water from domestic wells. Chloride concentration in this well is significant because regional anion trends show decreasing chloride concentrations with depth. In addition, the monitoring wells show low calcium, sodium, and sulfate concentrations compared to the general trend observed in domestic well waters.

Potassium levels in concentrated solutions of drilling additives were all less than 2 mg/L. One additive (Aqua Clear used during well development) contained 230 mg/L chloride in a concentrated solution. Information from well completion reports and Material Safety Data Sheets indicate that the formulation of fracture fluid provided for foam jobs typically consisted of 6% potassium chloride. Potassium metaborate was used in crosslinkers (5-10%, 30-60%). Potassium hydroxide was used in a crosslinker (<5%) and in a solvent. Ammonium chloride was used in crosslinker (1-27%).

Alternative explanations for inorganic geochemical anomalies observed in deep monitoring wells have been provided and considered. These alternate explanations include contamination from drilling fluids and additives, well completion materials, and surface soil, with contamination from all these sources exacerbated by poor well development. Contamination by drilling fluids and additives is inconsistent with analysis of concentrated solutions of bentonite and additives. Well construction materials (screen and sections of casing) consisted of stainless steel and were power-washed on site with detergent-free water prior to use. Sections of tremie pipe used to inject cement above screened intervals were also power washed with detergent-free water prior to use. Stainless-steel screens and sections of casing and tremie pipe remained above ground level (did not touch soil) prior to use. Both deep monitoring wells were purposefully located away from the immediate vicinity of gas production wells, known locations of pits, and areas of domestic waste disposal (abandoned machinery) to minimize the potential of surface soil contamination. Conductor pipe installed over the first 30.5 m (100 ft) of drilling at both deep monitoring wells eliminated the possibility of surface soil entry into the borehole. Turbidity measurements in MW01 during sampling ranged from 7.5 and 7.9 Nephelometric Turbidity Units (NTUs). Turbidity measurements in MW02 during sampling ranged from 24.0 to 28.0 NTUs, slightly above the stated goal of 10.0 NTUs but nevertheless was clear water typical of domestic wells during sampling. A low recharge rate in MW02 necessitated a prolonged period of well development which was likely due in part to gas flow (reduced relative permeability to water) into the well during development.

3. Detection of synthetic organic compounds

Isopropanol was detected in MW01 and MW02 at 212 and 581 µg/L, respectively. Diethylene glycol was detected in MW01 and MW02 at 226 and 1570 µg/L, respectively. Triethylene glycol was detected in MW01 and MW02 at 46 and 310 µg/L, respectively. Another synthetic compound, *tert*-butyl alcohol, was detected in MW02 at a concentration of 4470 µg/L. *Tert*-butyl alcohol is a known breakdown product of methyl *tert*-butyl ether (a fuel additive) and *tert*-butyl hydroperoxide (a gel breaker used in hydraulic fracturing). EPA methods were utilized for analysis when applicable for compounds or classes of compounds. Detection of synthetic organic compounds in MW01 and MW02 was made in part through the use of non-commercially available modified EPA analytical methods. For instance, high performance liquid chromatography/mass spectrometry/mass spectrometry was utilized for analysis of diethylene, triethylene and tetraethylene glycols. Ethylene glycol, which was widely used for well stimulation, required additional method modification and was not analyzed during this investigation.

Isopropanol was detected in concentrated solutions of drilling additives at a maximum concentration of 87 µg/L, well below that detected in deep monitoring wells. Glycols were not detected in concentrated solutions of drilling additives.

Material Safety Data Sheets indicate that isopropanol was used in a biocide (20-40%), in a surfactant (30-60%), in breakers (<1%, 10-30%), and in foaming agents (<3%, 1-5%, 10-30%). Diethylene glycol was used in a foaming agent (5-10%) and in a solvent (0.1-5%). Triethylene glycol was used in a solvent (95-100%). Material Safety Data Sheets do not indicate that *tert*-butyl hydroperoxide was used in the Pavillion gas field. The source of this compound remains unresolved. However, *tert*-butyl alcohol is not expected to occur naturally in ground water. Material Safety Data Sheets do not contain proprietary information and the chemical ingredients of many additives.

Alternative explanations provided to date and considered by EPA for detection of synthetic organic compounds in deep monitoring wells include arguments previously listed and addressed.

4. Detection of petroleum hydrocarbons

Benzene, toluene, ethylbenzene, and xylenes (BTEX) were detected in MW02 at concentrations of 246, 617, 67, and 750 µg/L respectively. Trimethylbenzenes were detected in MW02 at 105 µg/L. Gasoline range organics were detected in MW01 and MW02 at 592 and 3710 µg/L, respectively. Diesel range organics were detected in MW01 and MW02 at 924 and 4050 µg/L respectively. Naphthalene was detected in MW02 at 6 µg/L. EPA methods were utilized for analysis.

BTEX and trimethylbenzenes were not detected in concentrated solutions of drilling additives.

Material Safety Data Sheets indicate that aromatic solvent (typically BTEX mixture) was used in a breaker (<75%). Diesel oil (mixture of saturated and aromatic hydrocarbons including naphthalenes and alkylbenzenes) was used in a guar polymer slurry/liquid gel concentrate (30-60%) and in a solvent (60-100%). Petroleum raffinates (a mixture of paraffinic, cycloparaffinic, olefinic, and aromatic hydrocarbons) were used in a breaker (<30-60%). Heavy aromatic petroleum naphtha (mixture of paraffinic, cycloparaffinic and aromatic hydrocarbons) was used in surfactants (5-10%, 10-30%, 30-60%) and in a solvent (10-50%). Toluene was used in a flow enhancer (3-7%). Xylenes were used in a flow enhancer (40-70%) and a breaker (confidential percentage). Gasoline range organics correspond to a hydrocarbon range of C6 – C10. It includes a variety of organic compounds ketones, ethers, mineral spirits, stoddard solvents, and naphthas. Detection of gasoline range organics does not infer the use of gasoline for hydraulic fracturing.

Alternative explanations provided to date and considered by EPA for detection of petroleum compounds in deep monitoring wells include arguments previously listed and addressed. An additional alternate explanation for detection of petroleum compounds includes use of lubricants on the drillstem and well casing, use of electrical tape on submersible pumps, and components of submersible pumps. Jet Lube Well Guard hydrocarbon free lubricant specifically designed for monitoring well installation was used for drillstem connections. No lubricants were used to attach sections of casing or sections of tremie pipe during cementation. Clamps, not electrical tape, were used to bind electrical wires for submersible pumps. Water collected for samples during recharge at MW01 and MW02 would have a short contact time with components of submersible pumps. For components of submersible pumps to be a causative factor of high concentrations of petroleum hydrocarbons observed in MW01 and MW02, components of submersible pumps would have to contain high levels of water extractable petroleum compounds and consist of a matrix allowing rapid mass transfer, neither of which is plausible.

Another alternate explanation is that detection of petroleum hydrocarbons in ground water is expected above a natural gas field. Gas from Fort Union and Wind River Formations is dry and unlikely to yield liquid condensates at ground water pressure and temperature conditions. In addition, a condensate origin for petroleum hydrocarbons in ground water is doubtful because dissolved hydrocarbon gas compositions and concentrations are similar between the two deep monitoring wells and therefore would yield similar liquid condensates, yet the compositions and concentrations of organic compounds detected in these wells are quite different.

5. Breakdown products of organic compounds

Detections of organic chemicals were more numerous and exhibited higher concentrations in the deeper of the two monitoring wells. Natural breakdown products of organic contaminants like BTEX and glycols include acetate and benzoic acid. These breakdown products are more enriched in the shallower of the two monitoring wells, suggesting upward/lateral migration with natural degradation and accumulation of daughter products.

Hydraulic gradients are currently undefined in the area of investigation. However, there are flowing stock wells (e.g., PGDW44 - one of the deepest domestic wells in the area of investigation at 229 m below ground surface) suggesting that upward gradients exist in the area of investigation. In the Agency's report on evaluation of impacts to USDWs by hydraulic fracturing of coalbed methane reservoirs (EPA, 2004), hypothetical conceptual models were presented on contaminant migration in a USDW during injection of fracturing fluids into a USDW. In these conceptual models, highly concentrated contaminant plumes exist within the zone of injection with dispersed lower concentration areas vertically and laterally distant from injection points. Data from deep monitoring wells suggests that this conceptual model may be appropriate at this site.

6. Sporadic bonding outside production casing directly above intervals of hydraulic fracturing

It is possible that wellbore design and integrity issues were one causative factor in deep ground water contamination at this site (surface casing of production wells not extending below deepest domestic wells, little vertical separation between fractured zones and domestic wells, no cement or sporadic bonding outside production casing).

A review of well completion reports and cement bond/variable density logs in the area around MW01 and MW02 indicates instances of sporadic bonding outside production casing directly above intervals of hydraulic fracturing. For instance, at Pavillion Fee 34-03B, a cement bond/variable density log conducted on 10/22/2004 indicated no cement until 838 m (2750 ft) and sporadic bonding to 1036 m (3400 ft) below ground surface. The well completion report for this production well indicates that hydraulic fracturing was performed at 1039 m (3409 ft) below ground surface on 11/9/2004 prior to cement squeeze jobs at 823 m (2700 ft) and 256 m (840 ft) below ground surface in April 2005. At Tribal Pavillion 41-10 a cement bond/variable density log indicates sporadic bonding directly above the interval of hydraulic fracturing at 493 m (1618 ft) below ground surface. A cement bond/variable density log conducted on Tribal Pavillion 24-02 after a squeeze job at the base of the surface casing indicates sporadic bonding outside production casing below surface casing to the interval of hydraulic fracturing at 469 m (1538 ft) below ground surface. At Tribal Pavillion 11-11B, a cement bond/variable density log indicates sporadic bonding between 305 to 503 m (1000 to 1650 ft) below ground surface with hydraulic fracturing occurring at 463 m (1516 ft) below ground surface.

7. Hydraulic fracturing into thin discontinuous sandstone units

There is little lateral and vertical continuity to hydraulically fractured tight sandstones and no lithologic barrier (laterally continuous shale units) to stop upward vertical migration of aqueous constituents of hydraulic fracturing in the event of excursion from fractures. Sandstone units are of variable grain size and permeability indicating a potentially tortuous path for upward migration.

In the event of excursion from sandstone units, vertical migration of fluids could also occur via nearby wellbores. For instance, at Pavillion Fee 34-03R, the cement bond/variable density log indicates no cement until 671 m (2200 ft) below ground surface. Hydraulic fracturing occurred above this depth at nearby production wells.

Although some natural migration of gas would be expected above a gas field such as Pavillion, data suggest that enhanced migration of gas has occurred to ground water at depths used for domestic water supply and to domestic wells. Lines of reasoning to support this explanation consist of following.

1. Hydrocarbon and isotopic composition of gas

The similarity of $\delta^{13}C$ values for methane, ethane, propane, isobutane, and butane between gas production and monitoring wells and plots of $\delta^{13}C\text{-}CH_4$ versus $\delta D\text{-}CH_4$ and $\delta^{13}C\text{-}CH_4$ versus methane/(ethane + propane) indicate that light hydrocarbons in casing and dissolved gas in deep monitoring wells are similar to produced gas and have undergone little oxidation or biodegradation indicative of advective transport. The absence of ethane and propane in three of four domestic wells having sufficient methane to allow isotopic analysis and a shift of $\delta^{13}C\text{-}CH_4$ and $\delta D\text{-}CH_4$ values in a positive direction relative to produced gas suggests the presence of gas of thermogenic origin in domestic wells undergoing biodegradation. This observation is consistent with a pattern of dispersion and degradation with upward migration observed for organic compounds.

2. Elevation of dissolved methane concentrations in proximity to production wells

Levels of dissolved methane in domestic wells generally increase in those wells in proximity to gas production wells. With the exception of 2 domestic wells where methane was detected at less than 22 µg/L, methane was not detected in domestic wells with 2 or less production wells within 600 m.

3. Spatial anomaly near PGDW05

Methane concentrations in ground water appear highest in the area encompassing MW01, PGDW30, and PGDW05. Ground water is saturated with methane at MW01 which is screened at a depth (239 m bgs) typical of deeper domestic wells in the area. Methane was detected in PGDW30 at 808 µg/L at a depth of only 80 m, the highest level in any domestic well. A blowout occurred during drilling at a depth of only 159 m bgs in December 2005 adjacent to PGDW05.

An alternative explanation of high methane concentrations in this area is that it is close to the top of the dome comprising the Pavillion gas field which may facilitate natural gas migration toward the surface. However, this geologic feature would also facilitate enhanced gas migration. Also, a mud-gas log conducted on 11/16/1980 (prior to intensive gas production well installation) at Tribal Pavillion 14-2 located only 300 m from the location of the uncontrolled release does not indicate a gas show (distinctive peaks on a gas chromatograph) within 300 m of the surface.

4. Shallow surface casing and lack of cement or sporadic bonding outside production casing

With the exception of two production wells, surface casing of gas production wells do not extend below the maximum depth of domestic wells in the area of investigation. Shallow surface casing combined with lack of cement or sporadic bonding of cement outside production casing would facilitate migration of gas toward domestic wells.

The discussion on migration of fluids associated with hydraulic fracturing is relevant for gas migration and is not repeated here for brevity. Of particular concern are wellbores having no or little cement over large vertical instances. For instance, at Pavillion Fee 34-03R, the cement bond/variable density log indicates no cement until 671 m (2200 ft) below ground surface. At Pavillion Fee 34-03B, a cement bond/variable density log conducted on 10/22/2004 indicated no cement until 838 m (2750 ft) below ground surface. Migration of gas via wellbores having no cement or poor cement bonding outside production casing is well documented in the literature.

An alternative explanation of wellbore gas migration provided to EPA and considered is that domestic wells are poorly sealed and thus constitute a potential gas migration pathway. However, lack of cement and sporadic bonding outside casing in production constitutes a major potential gas migration pathway to the depth of deep monitoring and domestic wells. It is possible that domestic wells could subsequently facilitate gas migration toward the surface.

5. <u>Citizens' complaints</u>

Finally, citizens' complaints of taste and odor problems concurrent or after hydraulic fracturing are internally consistent. Citizens' complaints often serve as the first indication of subsurface contamination and cannot be dismissed without further detailed evaluation, particularly in the absence of routine ground water monitoring prior to and during gas production.

An alternate explanation provided and considered by EPA is that other residents in the Pavillion area have always had gas in their wells. Unfortunately, no baseline data exists to verify past levels of gas flux to the surface or domestic wells.

A lines of reasoning approach utilized at this site best supports an explanation that inorganic and organic constituents associated with hydraulic fracturing have contaminated ground water at and below the depth used for domestic water supply. However, further investigation would be needed to determine if organic compounds associated with hydraulic fracturing have migrated to domestic wells in the area of investigation. A lines of evidence approach also indicates that gas production activities have likely enhanced gas migration at and below depths used for domestic water supply and to domestic wells in the area of investigation.

Hydraulic fracturing in the Pavillion gas field occurred into zones of producible gas located within an Underground Source of Drinking Water (USDW). Hydraulic fracturing for coal-bed methane recovery is often shallow and occurs directly into USDWs (EPA 2004). TDS less than 10,000 mg/L in produced water is common throughout the Rocky Mountain portion of the United States (USGS 2011; Dahm et al. 2011). Ground water contamination with constituents such as those found at Pavillion is typically infeasible or too expensive to remediate or restore (GAO 1989). Collection of baseline data prior to hydraulic fracturing is necessary to reduce investigative costs and to verify or refute impacts to ground water.

Finally, this investigation supports recommendations made by the U.S. Department of Energy Panel (DOE 2011a, b) on the need for collection of baseline data, greater transparency on chemical composition of hydraulic fracturing fluids, and greater emphasis on well construction and integrity requirements and testing. As stated by the panel, implementation of these recommendations would decrease the likelihood of impact to ground water and increase public confidence in the technology.

5.0

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Appendix A

Summary of Analytical Results

Table A1. Summary of subsurface sample locations, depth of sample collection, times (phases) of sampling, target analytes, laboratories utilized, and analytical methods

Sample	Latitude	Longitude	Depth (m bgs)	Type	Media	Major anions and alkalinity phase(lab)	Metals phase(lab)	Alcohols and VOCs phase(lab)	Low molecular weight acids, glycols phase(lab)	SVOCs Pesticides PCBs, TICs phase(lab)	GRO, DRO, THE, TPH phase(lab)	Bacteria phase(lab)	Fixed gases, C_1-C_6+, $\delta^{13}C$ and δD C_1-C_4 DOC DIC, $\delta^{13}C$ DIC $\delta^{18}O$ and δD water phase(lab)
PGPP01 (Tribal Pavillion 14-10)	43.24578857	-108.6356735		PG	gas/ fluid	-----	-----	II(R8^{2})	-----	II(R8^{3})	II(R8^{4})	-----	II(I^{1})
PGPP02	43.2486496	-108.6274796		PG	gas	-----	-----	-----	-----	-----	-----	-----	II(I^{1})
PGPP04 (Tribal Pavillion 24-02)	43.25984955	-108.6116409		PG	gas/ fluid	-----	-----	II(R8^{2})	-----	II(R8^{3})	II(R8^{4})	-----	II(I^{1})
PGPP05 (Tribal Pavillion 33-10)	43.2486496	-108.6274796		PG	gas/ fluid	-----	-----	II(R8^{2})	-----	II(R8^{3})	II(R8^{4})	-----	II(I^{1})
PGPP06 (Tribal Pavillion 14-2)	43.26016998	-108.6165009		PG	gas/ fluid	-----	-----	II(R8^{2})	-----	II(R8^{3})	II(R8^{4})	-----	II(I^{1})
MW01	43.25682	-108.62185	233 - 239	MW	gas/ water	III(O^{1}) IV(O^{1})	III(S^{1}) IV(S^{1})	III(R8^{2},S^{2}) IV(R8^{2},S^{3})	IV(S^{4},R3)	III(R8^{3}) IV(R8^{3})	III(R8^{4}) IV(R8^{4})	-----	III(I^{2},I^{5},O^{2}, S^{5},S^{5}) IV(I^{3},I^{4},O^{2}, S^{5},S^{6})
MW02	43.25293	-108.59468	293 - 299	MW	gas/ water	III(O^{1}) IV(O^{1})	III(S^{1}), IV(S^{1})	III(R8^{2},S^{2}) IV(R8^{2},S^{3})	IV(S^{4},R3)	III(R8^{3}) IV(R8^{3})	III(R8^{4}), IV(R8^{4})	-----	III(I^{2},I^{5},O^{2}, S^{5},S^{5}) IV(I^{3},I^{4},O^{2}, S^{5},S^{6})
PGMW01 (Pit 24-3#1)	43.26122665	-108.6316147	4.6	PGM	water	II(R8^{1})	II(A4)	II(A,R8^{2})	-----	II(A,R8^{3})	II(E^{2},R8^{4})	II(E^{1})	II(R8^{5})
PGMW02 (Pit 14X-11#6)	43.24616241	-108.613205	4.6	PGM	water	II(R8^{1})	II(A4)	II(A,R8^{2})	-----	II(A,R8^{3})	II(E^{2},R8^{4})	II(E^{1})	II(R8^{5})
PGMW03 (Pit 42X-11#4)	43.25263977	-108.6020584	4.6	PGM	water	II(R8^{1})	II(A4)	II(A,R8^{2})	-----	II(A,R8^{3})	II(E^{2},R8^{4})	II(E^{1})	II(R8^{5})
PGSO01 (Pit 24-3)	43.26117325	-108.6316071	< 5	PGS	soil	-----	-----	-----	-----	II(R8^{3})	II(E^{2},R8^{4})	-----	-----
PGSO02 (Pit 14X-11)	43.24636841	-108.6135254	< 5	PGS	soil	-----	-----	-----	-----	II(R8^{3})	II(E^{2},R8^{4})	-----	-----
PGSO03 (Pit 42X-11)	43.2527504	-108.6022339	< 5	PGS	soil	-----	-----	-----	-----	II(R8^{3})	II(E^{2},R8^{4})	-----	-----
PGDW01	unknown	unknown	-----	DW	water	I(R8^{1})	I(K)	I(L)	-----	I(L,R8^{3})	-----	-----	-----
PGDW02	43.21848912	-108.5783117	15.2	DW	water	I(R8^{1})	I(K)	I(L)	-----	I(L,R8^{3})	-----	-----	-----
PGDW03	43.22721318	-108.6584107	152.4	DW	water	I(R8^{1})	I(K), II(A4)	I(L) II(A,R8^{2})	-----	I(L,R8^{3}) II(A,R8^{3})	II(E^{2},R8^{4})	II(E^{1})	II(I^{1},R8^{5})
PGDW04	43.22790981	-108.6542063	152.4	DW	water	I(R8^{1}) II(R8^{1})	I(K), II(A4)	I(L) II(A,R8^{2})	-----	I(L,R8^{3}), II(A,R8^{3})	I(E^{2}) II(E^{2},R8^{4})	I(E^{1}) II(E^{1})	I(R8^{5}) II(I,R8^{5})
PGDW05	43.25884666	-108.6126481	64.0	DW	water	I(R8), II(R8) IV(O^{1})	I(K) II(A4) IV(S^{1})	I(L) II(A,R8^{2}) IV(R8^{2},S^{3})	IV(S^{4},R3)	I(L,R8^{3}) II(A,R8^{3}) IV(R8^{3})	I(E^{2}) II(E^{2},R8^{4})	I(E^{1}) II(E^{1})	I(R8^{5}) II(R8^{5}) IV(I^{2},O^{2},O^{3},S^{6})

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Sample	Latitude	Longitude	Depth (m bgs)	Type	Media	Major anions and alkalinity phase(lab)	Metals phase(lab)	Alcohols and VOCs phase(lab)	Low molecular weight acids, glycols phase(lab)	SVOCs Pesticides PCBs, TICs phase(lab)	GRO, DRO, THE, TPH phase(lab)	Bacteria phase(lab)	Fixed gases, C_1-C_6+, $\delta^{13}C$ and δD C_1-C_4 DOC DIC, $\delta^{13}C$ DIC $\delta^{18}O$ and δD water phase(lab)
PGDW06	43.27110813	-108.5599211	115.8	DW	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^3)	-----	-----	-----
PGDW07	43.24678442	-108.6879085	154.2	PGP	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^3)	-----	-----	I(R8^5)
PGDW08	43.24697265	-108.6840567	157.0	PGP	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^3)	-----	-----	-----
PGDW09	43.27211644	-108.615144	9.1	DW	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^3)	-----	-----	-----
PGDW10	43.23574855	-108.6563896	227.1	DW	water	I(R8^1) II(R8^1)	I(K) II(A4)	I(L) II(A,R8^2)	-----	I(L,R8^3) II(A,R8^3)	I(E^2) II(E^2,R8^4)	II(E^1)	I(R8^5) II(I^1,R8^5)
PGDW11	43.24312049	-108.6228628	227.1	DW	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^3)	-----	-----	-----
PGDW12	43.27628927	-108.5661502	115.8	DW	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^3)	-----	-----	-----
PGDW13	43.2444467	-108.6772771	------	DW	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^3)	-----	-----	-----
PGDW14	43.25154027	-108.6273311	57.9	DW	water	I(R8^1)	I(K)	I(L), IV(R8^2,S^4)	IV(S^4,R3)	I(L,R8^3)	-----	-----	IV(O^4,S^6)
PGDW15	43.24312129	-108.6671791	30.5	DW	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^3)	-----	-----	-----
PGDW16	43.20381363	-108.6405183	161.5	DW	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^3)	-----	-----	-----
PGDW17	43.20416653	-108.6368713	152.4	DW	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^4)	-----	-----	I(R8^5)
PGDW18	43.22491388	-108.569651	67.1	DW	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^3)	-----	-----	-----
PGDW19	43.21382469	-108.651274	19.8	DW	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^4)	-----	-----	-----
PGDW20	43.25166961	-108.5912756	140.2	DW	water	I(R8^1) II(R8^1) III(O^1) IV(O^1)	I(K), II(A4) III (S^1) IV(S^1)	I(L) II(A,R8^2) III(R8^2,S^2) IV(R8^2,S^3)	IV(S^4,R3)	I(L,R8^3), II(A,R8^3) III(R8^3) IV(R8^3)	I(E^2) II(E^2,R8^4) III(R8^4) IV(R8^4)	I(E^1) II(E^1)	I(R8^5) II(R8^5) III(I^2, O^2, S^5,S^6) IV(I^2, O^2, S^2,S^6)
PGDW21	43.25167095	-108.5912762	140.2	DW	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^3)	-----	-----	I(R8^5)
PGDW22	43.24452934	-108.5981513	-------	DW	water	I(R8^1) II(R8^1)	I(K) II(A4)	I(L) II(A,R8^2)	-----	I(L,R8^3), II(A,R8^3)	I(E^2) II(E^2,R8^4)	I(E^1) II(E^1)	I(R8^5) II(R8^5)
PGDW23	43.24866472	-108.6225943	152.4	DW	water	I(R8^1) II(R8^1)	I(K) II(A4)	I(L), II(A,R8^2), IV(R8^2,S^3)	IV(S^4,R3)	I(L,R8^3) II(A,R8^4) IV(R8^3)	I(E^2) II(E^2,R8^4)	I(E^1) II(E^1)	I(R8^5) II(I^1,R8^5) IV(S^6,S^6)
PGDW24	43.25877211	-108.6015059	30.5	DW	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^3)	-----	-----	-----
PGDW25	43.25558722	-108.5694867	243.8	DW	water	I(R8^1) II(R8^1)	I(K), II(A4)	I(L), II(A,R8^2)	-----	I(L,R8^3), II(A,R8^3)	II(E^2,R8^4)	II(E^1)	II(I^1,R8^5)
PGDW26	43.25512275	-108.6132115	19.8	DW	water	I(R8^1), IV(O^1)	I(K)	I(L), IV(R8^2, S^4)	IV(S^4,R3)	I(L,R8^3) IV(R8^4)	IV(R8^4)	-----	I(R8^5) IV(I^2, O^2, O^3,S^6)
PGDW28	43.23993143	-108.6465688	25.9	DW	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^3)	-----	-----	-----
PGDW29	43.21773909	-108.6288449	121.9	DW	water	I(R8^1)	I(K)	I(L)	-----	I(L,R8^3)	I(E^2)	-----	I(R8^5)

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Sample	Latitude	Longitude	Depth (m bgs)	Type	Media	Major anions and alkalinity phase(lab)	Metals phase(lab)	Alcohols and VOCs phase(lab)	Low molecular weight acids, glycols phase(lab)	SVOCs Pesticides PCBs, TICs phase(lab)	GRO, DRO, THE, TPH phase(lab)	Bacteria phase(lab)	Fixed gases, C_1-C_6+, $\delta^{13}C$ and δD C_1-C_4 DOC DIC, $\delta^{13}C$ DIC $\delta^{18}O$ and δD water phase(lab)
PGDW30	43.25753218	-108.6225755	79.2	DW	water	I(R8^{1}) II(R8^{1}) III(O^{1}) IV(O^{1})	I(K), II(A4) III (S^{1}) IV(S^{1})	I(L) II(A,R8^{2}) III(R8^{2},S^{2}) IV(R8^{2},S^{3})	IV(S^{4},R3)	I(L,R8^{3}), II(A,R8^{3}) III(R8^{3}) IV(R8^{3})	II(E^{2}) III(R8^{4}) IV(R8^{4})	II(E^{1})	I(R8^{5}) II(R8^{5}) III(I^{2}, O^{2}, S^{5},S^{6}) IV(I^{2}, O^{2}, S^{5},S^{6})
PGDW31	43.27302485	-108.6615302	------	DW	water	I(R8^{1})	I(K)	I(L)	-----	I(L,R8^{3})	-----	-----	-----
PGDW32	43.24075256	-108.5941561	205.7	DW	water	I(R8^{1}) II(R8^{1}) IV(O^{1})	I(K), II(A4), IV(S^{1})	I(L) II(A) IV(R8^{2},S^{3})	IV(S^{4},R3)	I(L,R8^{3}), II(A,R8^{3}) IV(R8^{3})	II(E^{2},R8^{4}) IV(R8^{4})	II(E^{1})	I(R8^{5}) II(R8^{5}) IV(I^{2}, O^{2}, O^{3},S^{6})
PGDW33	43.23855522	-108.5964146	9.1	DW	water	I(R8^{1})	I(K)	I(L)	-----	I(L,R8^{3})	-----	-----	-----
PGDW34	43.23605297	-108.6058086	30.5	DW	water	I(R8^{1})	I(K)	I(L)	-----	I(L,R8^{3})	-----	-----	-----
PGDW35	43.23021564	-108.6241763	88.4	DW	water	I(R8^{1})	I(K)	I(L)	-----	I(L,R8^{3})		-----	I(R8^{5})
PGDW36	43.25905726	-108.5987059	30.5	DW	water	I(R8^{1})	I(K)	I(L)	-----	I(L,R8^{3})	I(E^{2})	-----	-----
PGDW37	43.24016136	-108.6585376	24.4	DW	water	I(R8^{1})	I(K)	I(L)	-----	I(L,R8^{3})		-----	-----
PGDW38	43.2296203	-108.572037	48.8	DW	water	I(R8^{1})	I(K)	I(L)	-----	I(L,R8^{3})	I(E^{2})	-----	I(R8^{5})
PGDW39	43.23750687	-108.5781708	6.1	DW	water	I(L) II(R8^{1})	I(L), II(A4)	I(L), II(A,R8^{2})	-----	I(L,R8^{3}), II(A,R8^{3})	-----	II(E^{1})	-----
PGDW40	43.26156616	-108.6198273	67.1	DW	water	II(R8)	II(A4)	II(A,R8^{2})	-----	II(A,R8^{3})	II(E^{2},R8^{4})	II(E^{1})	II(I^{1},R8^{5})
PGDW41	43.262146	-108.6378479	114.6	DW	water	II(R8), IV(O^{1})	II(A4) IV(S^{1})	II(A,R8^{2}) IV(R8^{2},S^{3})	IV(S^{4},R3)	II(A,R8^{3}) IV(R8^{3})	II(E^{2},R8^{4}), IV(R8^{4})	II(E^{1})	II(I^{1},R8^{5}) IV(I^{2},S^{5},S^{6})
PGDW42	43.25574493	-108.647316	61.0	DW	water	II(R8^{1})	II(A4)	II(A,R8^{2})	-----	II(A,R8^{3})	II(E^{2},R8^{4})	II(E^{1})	II(I^{1},R8^{5})
PGDW43	43.25749207	-108.64151	------	DW	water	II(R8^{1})	II(A4)	II(A,R8^{2})	-----	II(A,R8^{3})	II(E^{2},R8^{4})	II(E^{1})	II(I^{1},R8^{5})
PGDW44	43.25086975	-108.6261292	228.6	DW	water	II(R8)	II(A4)	II(A,R8^{2}), IV(R8^{2},S^{3})	IV(S^{4},R3)	II(A,R8^{3}), IV(R8^{3})	II(E^{2},R8^{4})	II(E^{1})	II(R8^{5}) IV(I^{2},O^{3},S^{6})
PGDW45	43.25888062	-108.6130142	------	DW	water	II(R8), IV(O^{1})	II(A4) IV(S^{1})	II(A,R8^{2}) IV(R8^{2},S^{3})	IV(S^{4},R3)	II(A,R8^{3}) IV(R8^{3})	II(E^{2},R8^{4}), IV(R8^{4})	II(E^{1})	II(R8^{5}) IV(I^{2},O^{2},O^{3},S^{6})
PGDW46	43.24651337	-108.6157684	14.6	DW	water	II(R8^{1})	II(A4)	II(A,R8^{2})	-----	II(A,R8^{3})	II(E^{2},R8^{4})	II(E^{1})	II(I^{1},R8^{5})
PGDW47	43.24520493	-108.6319885	147.5	DW	water	II(R8^{1})	II(A4)	II(A,R8^{2})	-----	II(A,R8^{3})	II(E^{2},R8^{4})	II(E^{1})	II(I^{1},R8^{5})
PGDW48	43.2299881	-108.6235733	------	DW	water	II(R8^{1})	II(A4)	II(A,R8^{2})	-----	II(A,R8^{3})	II(E^{2},R8^{4})	II(E^{1})	II(R8^{5})
PGDW49	43.25505829	-108.6178741	------	DW	water	II(R8^{1})	II(A4)	II(A,R8^{2}) IV(R8^{2},S^{3})	-----	II(A,R8^{3}) IV(R8^{3})	II(E^{2},R8^{4})	II(E^{1})	II(R8^{5}) IV(I^{2},O^{3},S^{6})
PGPW01	43.24678802	-108.6879349	~ 154	PGP	water	II(R8^{1})	II(A4)	II(A,R8^{2})	-----	II(A,R8^{3})	II(E^{2},R8^{4})	II(E^{1})	II(I^{1},R8^{5})
PGPW02	43.24697113	-108.6840515	~ 154	PGP	water	II(R8^{1})	II(A4)	II(A,R8^{2})	-----	II(A,R8^{3})	II(E^{2},R8^{4})	II(E^{1})	II(I^{1},R8^{5})
LD-02	43.25167095	-108.5912762	185.9	DW	water	III(O^{1})	III(S^{1})	III(S^{2})	-----	III(R8^{3})	-----	-----	III(I^{2},O^{2}, S^{5},S^{6})

Laboratories, Analytes, and Methods

A - ALS Laboratory Group, Salt Lake City, UT. VOCs, SVOCs, pesticides, TCBs, TICs determined using methods specified under the CLP.

A4 - A4 Scientific, The Woodlands, TX. TAL metals determined using methods specified under the CLP.

E^1 - Energy Laboratories Inc., Billings, MT. Heterotrophic plate counts, iron reducing bacteria, sulfur reducing bacteria.

E^2 - Energy Laboratories Inc., Billings, MT. GRO, DRO, THE, and TPH.

I^1 - Isotech Laboratories, Champaign, IL under contract by EnCana. Fixed gases and light hydrocarbons determined using ASTM D1945-03 in gas samples and headspace of aqueous samples. $\delta^{13}C$ and δD for C_1 determined using gas stripping and IRMS in aqueous samples. $\delta^{13}C$ and δD for C_1-C_4 determined using IRMS for gas samples.

I^2 - Isotech Laboratories, Champaign, IL. Fixed gases and light hydrocarbons determined using ASTM D1945-03 in headspace of aqueous samples. $\delta^{13}C$ and δD for C_1 and $\delta^{13}C$ for C_2 and C_3 determined using gas stripping and IRMS in aqueous samples. $\delta^{13}C$ DIC using gas stripping and IRMS.

I^3 - Isotech Laboratories, Champaign, IL. Fixed gases and light hydrocarbons determined using ASTM D1945-03 in headspace of aqueous samples. $\delta^{13}C$ and δD for C_1 , $\delta^{13}C$ for C_2 - C_5, and $\delta^{13}C$ for DIC gas stripping and IRMS in aqueous samples.

I^4 - Isotech Laboratories, Champaign, IL. Fixed gases and light hydrocarbons determined using ASTM D1945-03 in gas samples. $\delta^{13}C$ and δD for C_1 - C_3 using IRMS in gas samples.

I^5 - Isotech Laboratories, Champaign, IL. Fixed gases and light hydrocarbons determined using ASTM D1945-03 in gas samples. $\delta^{13}C$ and δD for C_1 - C_3 using IRMS in gas samples. ^{14}C using AMS in gas samples.

K - KAP Laboratories, Vancouver, WA. TAL metals determined under the CLP.

L - Liberty Analytical, Salt Lake City, UT. VOCs, SVOCs, PCBs, and TICs determined under the CLP.

O^1 - EPA, ORD, Ada, OK. SO_4, Cl, F, and Br determined using RSKSOP 276v3 and EPA Method 6500. NO_3 + NO_2 and NH_4 determined using RSKSOP 214v5 and EPA Method 350.1 and 353.2

O^2 - EPA, ORD, Ada, OK. DIC and DOC determined using RSKSOP-330v0 and EPA Method 9060A.

O^3 - EPA, ORD, Ada, OK. C_1 determined using RSKSOP 175v5 and Cali-5 gas sampling bags.

R3 - U.S. EPA Region 3 Laboratory, Fort Mead, MD. Diethylene glycol, triethylene glycol, tetraethylene glycol, and 2-butoxyethanol analysis by LC/MS/MS. This method is under development with no finalized SOP. EPA Methods 8000C and 8321 were followed for method development and QA/QC limits where applicable.

$R8^1$ - U.S. EPA Region 8 Laboratory, Golden, CO (fluoride, chloride, nitrite-N, nitrate-N, orthophosphate-P, and sulfate determined using EPA Method 300.0 and EPA Region SOP 310. Alkalinity determined using EPA Method 310.0).

$R8^2$ - U.S. EPA Region 8 Laboratory, Golden, CO. VOCs determined using EPA Method 8260B.

$R8^3$ - U.S. EPA Region 8 Laboratory, Golden, CO. SVOCs determined using ORGM-515 r1.1 and EPA Method 8270D.

$R8^4$ - U.S. EPA Region 8 Laboratory, Golden, CO. GRO determined using ORGM-506 r1.0 and EPA Method 8015D. DRO determined using ORGM-508 r1.0 and EPA Method 8015D.

$R8^5$ - U.S. EPA Region 8 Laboratory, Golden, CO. Dissolved C_1 in Phase I and dissolved C_1-C_3 in Phase II using EPA Method 524.2.

S^1 - Shaw Inc, Ada, OK in Phases III and IV. Metals and metals speciation determined using RSKSOP 213v4 and 257v2, or 332V0 and EPA Methods 200.7 and 6020.

S^2 - Shaw Inc, Ada, OK in Phases III and IV. Aromatics and chlorinated hydrocarbons determined using method RSKSOP-259v1 and EPA Method 5021A plus 8260C.

S^3 - Shaw Inc, Ada, OK . Alcohols, aromatics, and chlorinated hydrocarbons determined using method RSKSOP-259v1.

S^4 - Shaw Inc, Ada, OK. Low molecular weight acids determined using RSKSOP-112v6.

S^5 - Shaw Inc, Ada, OK. Dissolved gases C_1-C_4 determined using RSKSOP 194v4 and 175v5.

S^6 - Shaw Inc, Ada, OK. Hydrogen and oxygen isotope ratios of water determined using RSKSOP-296v0.

Abbreviations

I () - Phase I(laboratory/method). Samples collected March, 2009
II() - Phase II(laboratory/method). Samples collected January, 2010
III() - Phase III(laboratory/method). Samples collected September and October 2010
IV() - Phase IV(laboratory/method). Samples collected April 2011.
PG - gas production well
MW - deep monitoring wells
PGM - shallow monitoring wells near pits
PGS - soil samples near pits
DW - domestic wells
PGP - municipal wells in the Town of Pavillion
IRMS - isotope-ratio mass spectrometry
AMS - accelerated mass spectrometry

VOCs - volatile organic compounds
SVOCs - semivolatile organic compounds
PCBs - polychlorinated biphenyls
TICs - tentatively identified compounds
DRO - diesel range organics
GRO - gasoline range organics
TEH - total extractable hydrocarbons
TPH - total purgeable hydrocarbons
DIC - dissolved inorganic carbon
TAL - target analyte list
CLP - U.S. EPA Contract Laboratory Program

C_1 (methane), C_2 (ethane), C_3 (propane), iC_4 (isobutane), nC_4 (normal butane), iC_5 (isopentane), nC_5 (normal pentane), C_6^+ (hexanes + other light hydrocarbons)

Analytical Methods

ORGM-506 r1.0 - Region 8 Standard Operating Procedure.

ORGM-508 r1.0 - Region 8 Standard Operating Procedure.

ORGM-515 r1.1 - Region 8 Standard Operating Procedure.

RSKSOP-112v6 – Standard Operating Procedure for Quantitative Analysis of Low Molecular Weight Acids in Aqueous Samples by HPLC, 22 p.

RSKSOP-175v5 - Sample Preparation and Calculations for Dissolved Gas Analysis in Water Samples Using a GC Headspace Equilibration Technique*,* 16 p.

RSKSOP-194v4 - Gas Analysis by Micro Gas Chromatographs (Agilent MIcro 3000), 13 p.

RSKSOP-213v4 - Standard operating procedure for operation of Perkin Elmer Optima 3300 DV ICP-OES, 21 p.

RSKSOP-214v5 - Quality control procedures for general parameters analysis using Lachat Flow Injection analysis (FIA), 10 p.

RSKSOP-259v1 - Determination of volatile organic compounds (fuel oxygenates, aromatic and chlorinated hydrocarbons) in water using automated headspace gas chromatography/mass spectrometry TEKMAR 7000 HS-Varian 2100T GC/MS system-ION trap detector, 28 p.

RSKSOP-257v2 - Standard operating procedure for elemental analysis by ICP-MS, 16 p.

RSKSOP-299v1 – Determination of Volatile Organic Compounds (Fuel Oxygenates, Aromatic and Chlorinated Hydrocarbons) in Water Using Automated Headspace Gas Chromatography/Mass Spectrometry (Agilent 6890/5973 Quadruple GC/MS System), 25 p.

RSKSOP-276v3 - Determination of major anions in aqueous samples using capillary ion electrophoresis with indirect UV detection and Empower 2 software, 11 p.

RSKSOP-296v0 - Determination of hydrogen and oxygen isotope ratios in water samples using high temperature conversion elemental analyzer (TC/EA), a continuous flow unit, and an isotope ratio mass spectrometer (IRMS), 8 p.

RSKSOP-297v1 – Metals Speciation Determination by LC/ICP-MS, 21 p.

RSKSOP-298v1 - Arsenic Speciation Determination by LC/ICP-MS with Anion Suppression and NaOH Mobile Phase, 21 p.

RSKSOP-313v1 - Determination of R-123 using the H25-IR Infrared Refrigerant Gas Leak Detector, 12 p.

RSKSOP-314v1 - Determination of Fixed Gases using the GEM2000 and GEM2000 Plus Gas Analyzers & Extraction Monitors, 13 p.

RSKSOP-320v1 - Determination of Organic and Inorganic Vapors Using the TVA-1000B Toxic Vapor Analyzer, 18 p.

RSKSOP-330v0 – Determination of Various Fractions of Carbon in Aqueous Samples Using the Shimadzu TOC-VCPH Analyzer, 16 p.

U.S. EPA Method 200.7 - Determination of Metals and Trace Elements in Water and Wastes by Inductively Coupled Plasma-Atomic Spectrometry, Rev. 5, Jan 2001.

U.S. EPA Method 300.0 - Determination of Inorganic Anions by Ion Chromatography, Rev. 2.1, Aug. 1993.
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U.S. EPA method 310.1 - Alkalinity (Titrimetric, pH 4.5), Rev. 1978.

U.S. EPA Method 350.1 - Determination of Ammonia Nitrogen by Semi-Automated Colorimetry, Rev. 2, Aug. 1993.

U.S. EPA Method 5021A - Volatile Organic Compounds in Various Sample Matrices Using Equilibrium Headspace Analysis, Rev. 1, June 2003.

U.S. EPA Method 6020 - Inductively Coupled Plasma-Mass Spectrometry, Rev. 1, Feb. 2007.

U.S. EPA Method 6500 - Dissolved Inorganic Anions in Aqueous Matrices by Capillary Electrophoresis, Rev. 0, Feb. 2007.

U.S. EPA Method 8260C - Volatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS), Rev. 3, Aug. 2006.

U.S. EPA Method 8015B - Determination of Nonhalogenated Organics Using GC/FID, Rev. 2, Dec. 1996.

U.S. EPA Method 8015D - Nonhalogenated Organics Using GC/FID, Rev. 4, May 2003.

U.S. EPA Method 8270D - Determination of Semivolatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS), Rev. 4, Feb. 2007.

U.S. EPA Method 8000C - Determinative Chromatographic Separations, Rev. 3, Mar. 2003.

U.S. EPA Method 8260C - Volatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS), Rev. 3, Aug. 2006.

U.S. EPA Method 8270D - Semivolatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS), Rev. 4, Feb. 2007.

U.S. EPA Method 9060A - Total Organic Carbon, Rev. 1, Nov. 2004.

Table A2a. Geochemical results for Pavillion ground water

Sample ID	T (°C)	pH	SC (µS/cm)	Alkalinity (mg/kg)	Na (ppm)	K (ppm)	Ca (ppm)	Mg (ppm)	Cl (ppm)	SO_4 (ppm)	F (ppm)	NO_3 (N) (ppm)
PGDW01	------	------	------	234	808	6.2	398	93.6	34.3	1860	0.4	6.2
PGDW02	13.4	8.11	551	108	86	1.8	34.8	5.3	2.6	175	0.7	<0.5
PGDW03	11.1	9.37	1333	40	272	0.4	16.3	0.3	25.1	549	0.9	<0.5
PGDW04	11.8	9.17	1370	29	270	0.4	18.0	0.1	21.6	551	0.9	<0.5
PGDW05	12.0	9.02	956	93	192	0.3	3.6	0.1	17	295	0.9	<0.5
PGDW06	13.8	10.20	1262	35	249	0.3	7.1	<0.1	31	485	1.3	<0.5
PGDW07	12.4	8.85	1016	61	213	0.3	8.9	0.1	15.7	390	1.2	<0.5
PGDW08	12.4	8.57	1883	83	390	0.6	36.7	0.2	18.9	857	0.5	<0.5
PGDW09	12.4	8.35	1128	254	233	2.1	16.6	4.1	10.5	279	2.4	3.2
PGDW10	12.2	8.95	948	147	204	0.4	6.1	0.1	8.0	293	0.9	<0.5
PGDW11	13.1	7.17	3400	312	423	5.5	363	80.9	15.3	1780	0.2	1.3
PGDW12	12.4	10.04	1344	37	256	0.6	7.8	0.4	30.8	497	1.5	<0.5
PGDW13	10.9	6.89	1155	303	196	1.9	61.0	19.9	6.2	343	0.7	1.0
PGDW14	10.8	7.85	2990	159	690	4.5	154	18.1	26.1	1820	0.4	0.7
PGDW15	11.4	7.48	1728	277	269	1.2	72.2	10.2	9.9	520	0.6	1.8
PGDW16	13.2	9.30	1011	145	188	0.3	6.4	0.1	13.4	258	0.8	<0.5
PGDW17	12.7	9.61	1490	21	278	0.4	21.2	0.5	49.5	583	2.0	<0.5
PGDW18	10.3	8.87	2002	21	509	0.8	84.5	0.3	27	1380	1.8	0.5
PGDW19	11.8	7.75	707	291	194	1.4	29.0	3.2	6.9	196	0.9	2.6
PGDW20	9.3	8.76	2005	70	520	1.0	79.3	9.3	34.5	1370	0.8	<0.5
PGDW22	8.3	6.93	6180	332	837	9.0	416	126	79.9	2720	<0.2	43.6
PGDW23	11.5	9.43	816	61	208	0.3	6.5	0.1	19.8	365	1.2	<0.5
PGDW24	9.7	7.65	4700	165	938	7.0	327	131	55.7	3200	0.6	<0.5
PGDW25	13.3	8.68	972	205	249	1.1	1.1	1.1	8.4	355	4.1	<0.5
PGDW26	9.2	7.13	2390	337	220	6.8	364	57.7	14.6	1240	0.7	1.5
PGDW28	10.7	8.30	1170	258	239	2.2	40.6	12.9	16.7	298	0.5	3.7
PGDW29	11.5	9.72	1442	52	298	0.4	19.7	0.5	52.3	596	0.9	<0.5
PGDW30	10.4	9.60	902	96	210	0.3	0.9	0.1	16.3	331	0.9	<0.5
PGDW31	9.0	8.60	2006	83	435	0.9	31.2	0.8	13.3	1030	0.4	0.5
PGDW32	9.5	10.47	908	34	199	0.3	7.2	<0.1	34.1	373	2.3	<0.5
PGDW33	3.7	7.77	1662	276	178	5.0	228	40.9	28	670	0.2	2.1
PGDW34	8.3	7.87	4480	373	786	7.4	325	113	23	2690	0.5	3.5
PGDW35	10.6	8.63	2810	84	587	1.1	118	1.1	24.1	1610	0.3	0.5
PGDW36	9.8	7.62	649	232	42	2.6	89.5	28.9	3.2	195	1.0	1.2
PGDW37	10.5	8.14	819	342	187	0.9	12.1	1.3	8.7	89.9	0.9	1.2
PGDW38	9.5	8.68	2030	47	373	2.3	70.0	2.3	46.9	908	1.3	5.9
PGDW39	6.7	7.79	6410	127	1110	5.3	389	147	52.9	3640	0.4	0.6
PGDW40	11.5	9.06	1229	86	244	5.0	6.6	5.0	13.1	426	-----	<0.3
PGDW41	7.2	7.63	4470	108	1030	2.7	270	57.5	31.4	2670	0.5	<0.3
PGDW42	12.1	9.18	888	89	181	5.0	5.1	5.0	13.2	311	1.0	<0.3
PGDW43	0.2	8.19	4410	113	911	5.0	208	13.7	38.4	2470	0.4	<0.3
PGDW44	9.4	8.13	4080	100	994	5.0	259	28.3	39.5	2880	0.3	<0.3
PGDW45	9.3	7.63	1103	379	59	2.6	138	31.2	14.5	213	1.9	0.3
PGDW46	7.9	7.79	855	329	91	1.8	90.3	9.9	8.4	126	0.5	2.3
PGDW47	8.2	9.52	970	44	183	5.0	6.9	5.0	21.6	330	1.5	<0.3
PGDW48	8.7	8.21	3550	90	725	5.0	147	4.4	24.1	1840	0.3	<0.3
PGDW49	7.8	7.66	5470	243	1210	11.4	486	153	64.3	3160	0.4	7.7
PGDW03-0110	8.3	8.71	1390	28	251	5.0	16.3	5.0	20.7	570	0.8	<0.3
PGDW04-0110	8.3	9.07	1388	38	265	5.0	15.5	5.0	23.3	532	0.9	-----
PGDW05-0110	9.4	8.22	900	88	188	5.0	3.3	5.0	16.5	287	0.9	<0.3
PGDW10-0110	10.4	8.62	985	147	195	5.0	5.8	5.0	7.5	293	0.9	<0.3
PGDW20-0110	9.3	8.89	2690	68	550	5.0	71.7	8.1	32.6	1270	0.8	<0.3
PGDW22-0110	8.2	7.06	4230	337	908	5.8	397	130	74.6	2780	-----	40.7
PGDW23-0110	8.2	9.72	780	54	194	5.0	5.8	5.0	19.7	368	1.5	<0.3
PGDW25-0110	7.2	7.94	1511	295	269	5.0	70.1	9.6	9.5	441	-----	1.7
PGDW30-0110	9.2	9.39	967	94	195	5.0	4.1	5.0	15.5	333	0.9	<0.3
PGDW32-0110	8.3	9.87	1018	32	193	5.0	6.9	5.0	21.4	368	2.4	<0.3

Sample ID	T (°C)	pH	SC (µS/cm)	Alkalinity mg/kg	Na (ppm)	K (ppm)	Ca (ppm)	Mg (ppm)	Cl (ppm)	SO_4 (ppm)	F (ppm)	NO_3 (N) (ppm)
MW01	11.8	11.91	3265	430	334	54.9	15.6	0.05	23.3	398	1.6	0.15
MW02	12.3	12.01	3812	456	420	39.5	73.3	0.03	466	12.1	1.0	0.38
RD01	11.5	9.24	1068	78	208	0.2	4.3	0.10	15.2	357	1.0	0.23
LD01	10.9	8.85	2940	54	562	1.1	71.9	8.1	33.0	1320	0.9	0.35
PGDW05-0411	10.5	9.06	820	80	190	0.24	3.35	0.08	16.8	276	1.2	ND
PGDW14-0411	8.5	7.73	3473	156	753	3.52	154	18.6	23.7	1760	<0.05	0.36
PGDW20-0411	8.3	8.59	2430	102	520	0.78	63	6.86	22.9	1150	1.3	<0.03
PGDW23-0411	11.0	9.07	959	72	208	0.31	6.7	0.17	19.9	365	1.6	<0.03
PGDW26-0411	8.3	6.95	2390	196	232	5.15	334	56	13.2	1180	1.0	1.37
PGDW30-0411	10.4	8.92	938	82	210	0.29	4.5	0.09	16.1	327	1.1	<0.03
PGDW32-0411	11.1	9.30	885	46	198	0.09	7.2	0.03	18.8	361	2.0	<0.03
PGDW41-0411	8.2	7.05	4866	112	896	3.18	452	46.9	97.6	2640	<0.05	17.5
PGDW44-0411	10.0	8.17	4730	94	1060	2.09	259	19.2	32.1	2900	<0.05	<0.03
PGDW45-0411	9.1	6.85	1085	364	61.6	2.81	159	34.5	18.4	251	1.7	0.64
PGDW49-0411	10.4	7.34	5333	296	982	9.66	417	127	54.3	3200	<0.05	8.75
MW01-0411	11.2	11.24	2352	388	304	24.7	13.6	0.12	23.1	339	1.9	<0.03
MW02-0411	12.0	11.78	3099	482	448	43.6	60.5	0.03	457	63	1.5	<0.03

------ not measured. SC – specific conductance. Alkalinity – mg/kg $CaCO_3$. Other cations detected include Al (0.05 to 0.74 ppm), Ba (0.01 to 0.21 ppm), Fe (<0.02 to 2.4 ppm), Mn (<0.01 to 0.23 ppm), NH_4^+ (0.4 to 4.6 ppm), and Sr (0.06 to 8.4 ppm). Sulfide was detected in LD01 (0.16 ppm, Phase III, same location as PGDW20), PGDW20 (0.12 ppm, Phase IV), and MW01 (1.1 ppm Phase III, 1.8 ppm Phase IV). Turbidity ranged from 1.7 to 29.7 in domestic wells (Phase III and IV). Turbidity in MW01 was 7.5 (Phase III) and 7.9 (Phase IV). Turbidity in MW02 was 28.8 (Phase III) and 24.0 (Phase IV). All turbidity values are in Nephelometric Turbidity Units (NTUs). Turbidity measurements in MW01 and MW02 could be impacted by gas exsolution.

Table A2b. Charge balance calculations for deep monitoring wells

Well	Phase	Ca, meq	Mg, meq	Na, meq	K, meq	SO_4, meq	CO_3, meq	Cl, meq	F, meq	OH, meq	Σcat, meq	Σan, meq	Balance, %
		cations				*anions*							
MW01	III	0.78	0.00	14.53	1.40	8.29	4.48	0.66	0.08	9.56	16.71	23.08	16.0
MW02	III	3.66	0.00	18.27	1.01	0.25	3.40	13.14	0.05	12.04	22.94	28.89	11.5
MW01	IV	0.68	0.01	13.22	0.63	7.06	2.12	0.65	0.10	1.97	14.54	11.90	10.0
MW02	IV	3.02	0.00	19.49	1.12	1.30	0.23	12.89	0.08	7.01	23.62	21.52	4.7

Balance (%) = $|(\Sigma cat-\Sigma an)/(\Sigma cat+\Sigma an)*100|$. meq OH is calculated as $1000*[a_{OH^-}/\gamma_{OH^-}]$, where $a_{OH^-} = 10^{-(14-pH)}$ and $\gamma_{OH^-} = 0.85$ to 0.88. meq CO_3 is estimated from measurements of Dissolved Inorganic Carbon (DIC) as 2*[DIC/12], where DIC is in mg/L.

Table A3a. Summary of aqueous analysis of light hydrocarbons

Sample (matrix)	Phase	Date	C_1 (ug/l)	C_2 (ug/l)	C_3 (ug/l)	C_4 (ug/l)
MW01(w)	III	10/6/2010	15950	2230	790	158
MW01(w)	IV	4/20/2011	17930	2950	1250	172
MW02(w)	III	10/6/2010	18990	3290	1820	355
MW02(w)	IV	4/19/2011	18820	2550	2260	276
MW02(w)-dup	IV	4/19/2011	22620	3120	2770	356
PGMW01(w)	II	01/21/10	474	nd(10)	nd(15)	------
PGMW02(w)	II	01/21/10	361	299	43.8	------
PGMW03(w)	II	01/21/10	528	nd(10)	nd(15)	------
PGDW03(w)	II	01/20/10	nd(5.0)	nd(10)	nd(15)	------
PGDW04(w)	I	03/03/09	nd(5.0)	------	------	------
PGDW04(w)	II	01/21/10	nd(5.0)	nd(10)	nd(15)	------
PGDW05(w)	I	03/03/09	16.6	------	------	------
PGDW05(w)	II	01/18/10	5.44	nd(10)	nd(15)	------
PGDW05(w)	IV	04/19/11	65*	discarded	nd(1.3)	nd(1.6)
PGDW07(w)	I	03/03/09	nd(5.0)	------	-----	------
PGDW10(w)	I	03/03/09	nd(5.0)	------	-----	------
PGDW10(w)	II	01/18/10	nd(5.0)	nd(10)	nd(15)	------
PGDW14(w)	IV	04/20/11	discarded	nd(1.3)	nd(1.4)	nd(1.7)
PGDW17(w)	I	03/04/09	10.6	------	-----	------
PGDW20(w)	I	03/04/09	137	------	-----	------
PGDW20 (w)	III	10/06/10	189	24.3	nd(0.22)	nd(0.21)
PGDW20(w)-dup	III	10/06/10	168	17.4	nd(0.22)	nd(0.21)
PGDW20(w)	IV	04/18/11	137	discarded	nd(1.43)	2.93
PGDW21(w)	I	03/04/09	54.3	------	-----	------
PGDW22(w)	I	03/04/09	nd(5.0)	------	-----	------
PGDW22(w)	II	01/18/10	nd(5.0)	nd(10)	nd(15)	------
PGDW23(w)	I	03/04/09	146	------	-----	------
PGDW23(w)	II	01/18/10	149	nd(10)	nd(15)	------
PGDW23(w)	IV	04/21/11	176	nd(5.7)	nd(6.6)	nd(6.9)
PGDW25(w)	II	01/19/10	nd(5.0)	nd(10)	nd(15)	------
PGDW26(w)	I	03/05/09	nd(5.0)	------	-----	------
PGDW26(w)	IV	04/18/11	nd(2.2)*	nd(1.4)	nd(1.5)	nd(1.8)
PGDW29(w)	I	03/05/09	nd(5.0)	------	-----	------
PGDW30(w)	I	03/05/09	558	------	-----	------
PGDW30(w)	II	01/19/10	808	nd(10)	nd(15)	-----
PGDW30(w)	III	10/05/10	762	nd(0.19)	nd(0.23)	nd(0.21)
PGDW30(w)	IV	04/18/11	644	discarded	nd(1.5)	4.6
PGDW32(w)	I	03/05/09	21.4	------	-----	------

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Sample (matrix)	Phase	Date	C_1 (ug/l)	C_2 (ug/l)	C_3 (ug/l)	C_4 (ug/l)
PGDW32(w)	II	01/20/10	36.3	nd(10.0)	nd(15.0)	-----
PGDW32(w)	IV	04/18/11	nd(2.2)*	nd(1.2)	nd(1.3)	nd(1.5)
PGDW32(w)-dup	IV	04/18/11	discarded	discarded	nd(1.4)	discarded
PGDW35(w)	I	03/05/09	21.6	------	-----	------
PGDW38(w)	I	03/05/09	nd(5.0)	------	-----	------
PGDW39(w)	II	01/19/10	nd(5.0)	nd(10.0)	nd(15.0)	------
PGDW40(w)	II	01/22/10	98.9	nd(10.0)	nd(15.0)	------
PGDW41(w)	II	01/21/10	nd(5.0)	nd(10.0)	nd(15.0)	-----
PGDW41(w)	IV	04/20/11	385	142	nd(1.35)	discarded
PGDW42(w)	II	01/19/10	60	nd(10.0)	nd(15.0)	------
PGDW43(w)	II	01/21/10	nd(5.0)	nd(10.0)	nd(15.0)	------
PGDW44(w)	II	01/18/10	nd(5.0)	nd(10.0)	nd(15.0)	-----
PGDW44(w)	IV	4/21/2011	nd(2.2)*	nd(1.3)	nd(1.4)	nd(1.7)
PGDW45(w)	II	01/18/10	nd(5.0)	nd(10.0)	nd(15.0)	-----
PGDW45(w)	IV	04/19/11	nd(2.2)*	discarded	nd(1.3)	nd(1.6)
PGDW46(w)	II	01/20/10	nd(5.0)	nd(10.0)	nd(15.0)	-----
PGDW47(w)	II	01/19/10	nd(5.0)	nd(10.0)	nd(15.0)	-----
PGDW48(w)	II	01/20/10	nd(5.0)	nd(10.0)	nd(15.0)	-----
PGDW49(w)	II	01/20/10	nd(5.0)	nd(10.0)	nd(15.0)	------
PGDW49(w)	IV	4/20/2011	nd(2.2)*	discarded	nd(1.3)	nd(1.6)
LD02(w)	III	10/20/2010	229	21	nd(0.24)	nd(0.23)
PGPW01(w)	II	01/20/10	nd(5.0)	nd(10.0)	nd(15.0)	-----
PGPW02(w)	II	01/20/10	nd(5.0)	nd(10.0)	nd(15.0)	-----
Travel Blank(w)	III	10/6/2010	23.3	nd(2.0)	nd(0.24)	nd(0.23)
Equipment Blank(w)	III	10/6/2010	23.0	nd(2.0)	nd(0.29)	nd(0.27)
Field Blank(w)	III	10/6/2010	76.4	nd(2.0)	nd(0.28)	nd(0.26)
Travel Blank(w)	IV	4/14/2011	18.5	56.4	nd(1.63)	nd(1.6)
Field Blank(w)	IV	4/18/2011	45.0	67.9	nd(1.36)	nd(1.66)
equipment blank(w) (on-site GC analysis)	IV	4/18/2011	nd(2.2)	-----	-----	-----
equipment blank(w) (on-site GC analysis)	IV	4/19/2011	nd(2.2)	-----	-----	-----
equipment blank(w) (on-site GC analysis)	IV	4/20/2011	nd(2.2)	-----	-----	-----
equipment blank(w) (on-site GC analysis)	IV	4/20/2011	nd(2.2)	-----	------	------
field blank(w)	IV	4/21/2011	nd(0.32)	nd(1.18)	nd(1.27)	nd(1.54)

* Determined by on-site GC analysis in Phase IV. Fixed laboratory analysis rejected in Phase IV if detection of methane and ethane less than 100 µg/L.

All values of methane in Phase III greater than 100 µg/L accepted.

Ultrapure nitrogen was used for equipment and travel blanks for on-site GC analysis.

nd() - not detected(detection limit) ------ not analyzed

Table A3b. Summary of gas and headspace analysis of light hydrocarbons

Sample (matrix)	Phase	Date	C_1 (%)	C_2 (%)	C_2H_4 (%)	C_3 (%)	iC_4 (%)	nC_4 (%)	iC_5 (%)	nC_5 (%)	C_6+ (%)
Tribal Pavillion 14-6(g) (WR)	----	Johnson and Rice (1993)	95.28	2.83	-----	0.3	0.11	0.18	0.05	0.02	-----
Govt 21-5(g) (WR)	----	Johnson and Rice (1993)	93.24	3.75	-----	0.73	0.33	0.22	0.16	0.09	-----
Tribal Pavillion 41-09(g) (FU)	----	Johnson and Rice (1993)	88.17	3.35	-----	0.36	0.14	0.09	nd	nd	-----
Tribal Pavillion 14-11(g) (FU)	----	Johnson and Rice (1993)	66.00	1.96	-----	0.06	0.054	0.006	0.006	0.002	-----
Blankenship 4-8(g) (FU)	----	Johnson and Rice (1993)	93.38	4.00	-----	0.41	0.05	0.06	0.07	0.01	-----
Tribal Pavillion 14-10(g) (WR)(PGPP01)	II	01/21/10	92.47	4.04	0.001	1.21	0.415	0.372	0.183	0.114	0.486
Tribal Pavillion 43-10(g) (FU)(PGPP02)	II	01/21/10	94.86	3.48	0.0001	0.356	0.143	0.0618	0.0501	0.0194	0.18
Tribal Pavillion 24-2(g) (WR)(PGPP04)	II	01/21/10	90.16	4.64	0.0017	1.46	0.581	0.512	0.335	0.211	1.39
Tribal Pavillion 33-10(g) (FU)(PGPP05)	II	01/21/10	94.68	3.64	nd	0.373	0.131	0.055	0.0427	0.014	0.107
Tribal Pavillion 14-2(g) (FU)(PGPP06)	II	01/21/10	93.23	3.93	0.0012	0.903	0.321	0.25	0.151	0.0905	0.506
MW01(g)	III	9/23/2010	84.22	3.43	0.0007	0.791	0.327	0.191	0.143	0.0632	0.111
MW01(w)	III	10/6/2010	35.11	2.02	0.0008	0.414	0.114	0.0871	0.0499	0.0241	0.0539
MW01(g)	IV	4/18/2011	89.43	3.92	0.0013	0.907	0.298	0.211	0.109	0.0574	0.0972
MW01(g)-dup	IV	4/18/2011	89.49	3.91	0.0013	0.902	0.295	0.206	0.103	0.0533	0.0804
MW01(w)	IV	4/20/2011	38.33	2.46	0.0016	0.504	0.113	0.101	0.0422	0.0229	0.0566
MW02(g)	III	9/24/2010	1.05	0.048	nd	0.022	0.0089	0.0053	0.0020	0.0008	0.0012
MW02(g)-dup	III	9/24/2010	1.04	0.048	nd	0.022	0.0089	0.0053	0.0020	0.0008	0.0009
MW02(w)	III	10/6/2010	28.03	2.16	nd	0.693	0.128	0.101	0.0185	0.0067	0.0174
MW02(g)	IV	4/18/2011	6.74	0.383	nd	0.142	0.0401	0.026	0.0070	0.0025	0.0034
MW02(g)-dup	IV	4/18/2011	7.41	0.422	nd	0.156	0.0439	0.0284	0.0077	0.0027	0.0035
MW02(w)	IV	4/19/2011	26.17	1.80	nd	0.765	0.259	0.147	0.0416	0.0141	0.0237
MW02(w)-dup	IV	4/19/2011	21.32	1.49	nd	0.623	0.204	0.118	0.0324	0.011	0.018
PGMW01(w)	II	01/21/10	2.47	nd	nd	nd	0.0054	0.005	0.0287	0.0092	0.537
PGMW02(w)	II	01/21/10	3.57	1.13	nd	0.103	0.402	0.0134	0.13	0.0003	0.398
PGDW03(w)	II	01/20/10	0.0122	nd	nd	nd	nd	nd	nd	nd	nd
PGDW04(w)	II	01/21/10	0.0036	nd	nd	nd	nd	nd	nd	nd	nd
PGDW05(w)	IV	04/19/11	0.0966	nd	nd	nd	nd	nd	nd	nd	nd
PGDW10(w)	II	01/18/10	0.0266	nd	nd	nd	nd	nd	nd	nd	nd
PGDW14(w)	IV	04/20/11	0.0005	nd	nd	nd	nd	nd	nd	nd	nd

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Sample (matrix)	Phase	Date	C_1 (%)	C_2 (%)	C_2H_4 (%)	C_3 (%)	iC_4 (%)	nC_4 (%)	iC_5 (%)	nC_5 (%)	C_6+ (%)
PGDW20 (w)	III	10/06/10	0.191	0.007	nd	0.0006	nd	nd	nd	nd	nd
PGDW20(w)-dup	III	10/06/10	0.134	0.005	nd	nd	nd	nd	nd	nd	nd
PGDW20(w)	IV	04/18/11	0.221	0.007	nd	0.0007	nd	nd	nd	nd	nd
PGDW22(w)	II	01/18/10	nd	nd	nd	nd	nd	nd	nd	nd	nd
PGDW23(w)	IV	04/21/11	0.248	nd	nd	nd	nd	0.0015	nd	nd	0.0008
PGDW25(w)	II	01/19/10	nd	nd	nd	nd	nd	nd	nd	nd	nd
PGDW26(w)	IV	04/18/11	nd	nd	nd	nd	nd	nd	nd	nd	nd
PGDW30(w)	II	01/19/10	5.99	nd	nd	nd	nd	nd	nd	nd	nd
PGDW30(g)	III	09/23/10	0.0123	nd	nd	nd	nd	nd	nd	nd	nd
PGDW30(w)	III	10/05/10	1.19	nd	nd	nd	nd	nd	nd	nd	nd
PGDW30(w)	IV	04/18/11	1.46	nd	nd	nd	nd	nd	nd	nd	nd
PGDW32(w)	II	01/20/10	0.197	nd	nd	nd	nd	nd	nd	nd	0.0085
PGDW32(w)	IV	04/18/11	0.0752	nd	nd	nd	nd	nd	nd	nd	0.0019
PGDW32(w)-dup	IV	04/18/11	0.0522	nd	nd	nd	nd	nd	nd	nd	0.0013
PGDW39(w)	II	01/19/10	nd	nd	nd	nd	nd	nd	nd	nd	nd
PGDW40(w)	II	01/22/10	0.418	nd	nd	nd	nd	nd	nd	nd	nd
PGDW41(w)	II	01/21/10	0.0091	nd	nd	nd	nd	nd	nd	nd	nd
PGDW41(w)	IV	04/20/11	0.0005	nd	nd	nd	nd	nd	nd	nd	nd
PGDW42(w)	II	01/19/10	0.291	nd	nd	nd	nd	nd	nd	nd	nd
PGDW43(w)	II	01/21/10	0.0016	nd	nd	nd	nd	nd	nd	nd	nd
PGDW44(w)	IV	4/21/11	0.0022	nd	nd	nd	nd	nd	nd	nd	nd
PGDW45(w)	II	01/18/10	nd	nd	nd	nd	nd	nd	nd	nd	nd
PGDW45(w)	IV	04/19/11	nd	nd	nd	nd	nd	nd	nd	nd	nd
PGDW46(w)	II	01/20/10	0.0016	nd	nd	nd	nd	nd	nd	nd	nd
PGDW47(w)	II	01/19/10	0.0428	nd	nd	nd	nd	nd	nd	nd	nd
PGDW47(w)-dup	II	01/19/10	0.0365	nd	nd	nd	nd	nd	nd	nd	nd
PGDW49(w)	IV	4/20/11	nd	nd	nd	nd	nd	nd	nd	nd	nd
LD02(w)	III	10/20/10	0.12	0.007	nd	0.001	0.0008	0.0007	nd	0.0005	nd
PGPW01(w)	II	01/20/10	0.0253	nd	nd	nd	nd	nd	nd	nd	nd
PGPW02(w)	II	01/20/10	0.0389	nd	nd	nd	nd	nd	nd	nd	nd
field blank(w)	II	01/21/10	0.0068	nd	nd	nd	nd	nd	nd	nd	0.0021
field blank(w)	II	01/22/10	nd	nd	nd	nd	nd	nd	nd	nd	nd
travel blank(g)	III	9/23/10	nd	nd	nd	nd	nd	nd	nd	nd	nd
equipment blank(g)	III	9/23/10	0.0029	nd	nd	nd	nd	nd	nd	nd	nd
travel blank(g)	III	9/24/10	nd	nd	nd	nd	nd	nd	nd	nd	nd
equipment blank(g)	III	9/24/10	nd	nd	nd	nd	nd	nd	nd	nd	nd
travel blank(g)	IV	4/18/11	nd	nd	nd	nd	nd	nd	nd	nd	nd
equipment blank(g)	IV	4/18/11	nd	nd	nd	nd	nd	nd	nd	nd	nd
equipment blank(g)	IV	4/18/11	nd	nd	nd	nd	nd	nd	nd	nd	nd

WR - Wind River Formation FU - Fort Union Formation ----- not analyzed nd () not detected

Table A3c. Summary of isotopic data for dissolved, gas phase, and headspace analysis

Sample (matrix)	Phase	Date	δ^{13}C-C$_1$ (‰)	δD-C$_1$ (‰)	δ^{13}C-C$_2$ (‰)	δD-C$_2$ (‰)	δ^{13}C-C$_3$ (‰)	δD-C$_3$ (‰)	δ^{13}C-iC$_4$ (‰)	δD-iC$_4$ (‰)	δ^{13}C-nC$_4$ (‰)	δD-nC$_4$ (‰)	δ^{13}C-iC$_5$ (‰)	δ^{13}C-nC$_5$ (‰)	^{14}C$_1$ (pMC)	δ^{13}C DIC (‰)	δ^{18}O H$_2$O (‰)	δD H$_2$O (‰)
Tribal Pavillion 14-6(g) (WR)	----	Johnson and Rice (1993)	-39.24	------	------	------	------	------	------	------	------	------	------	------	------	------	------	------
Govt 21-5(g) (WR)	----	Johnson and Rice (1993)	-40.2	------	------	------	------	------	------	------	------	------	------	------	------	------	------	------
Tribal Pavillion 41-09(g) (FU)	----	Johnson and Rice (1993)	-38.04	------	------	------	------	------	------	------	------	------	------	------	------	------	------	------
Tribal Pavillion 14-11(g) (FU)	----	Johnson and Rice (1993)	-38.4	------	------	------	------	------	------	------	------	------	------	------	------	------	------	------
Blankenship 4-8(g) (FU)	----	Johnson and Rice (1993)	-38.08	------	------	------	------	------	------	------	------	------	------	------	------	------	------	------
Tribal Pavillion 14-10(g) (WR)(PGPP01)	II	01/21/10	-38.75	-203.4	-26.93	-162.5	-24.93	-147.2	-25.83	-152.4	-25.26	-151.3	------	------	------	------	------	------
Tribal Pavillion 43-10(g) (FU)(PGPP02)	II	01/21/10	-39.07	-212.9	-25.99	-157.5	-19.4	------	------	------	-23.87	------	------	------	------	------	------	------
Tribal Pavillion 24-2(g) (WR)(PGPP04)	II	01/21/10	-39.26	-204.9	-26.79	-166.2	-25.33	-148.0	-25.66	-155.5	-25.05	-154	------	------	------	------	------	------
Tribal Pavillion 33-10(g) (FU)(PGPP05)	II	01/21/10	-39.05	-207.3	-26.21	-161.1	-18.46	-101.7	-23.96	------	-23.64	------	------	------	------	------	------	------
Tribal Pavillion 14-2(g) (FU)(PGPP06)	II	01/21/10	-39.28	-215.3	-26.42	-162.3	-24.01	-145.2	-25.33	-150.1	-24.87	-152	------	------	------	------	------	------
MW01(g)	III	9/23/2010	-39.44	-209.1	-26.63	-165.0	-23.76	-143.7	------	------	------	------	------	------	<0.2	------	------	------
MW01(w)	III	10/6/2010	-38.89	-191.3	-26.55	------	-23.85	------	------	------	------	------	------	------	------	-12.18	-13.77	-113.77
MW01(g)	IV	4/18/2011	-39.25	-211.2	-26.67	-166.8	-23.74	-146.1	------	------	------	------	------	------	------	------	------	------
MW01(g)-dup	IV	4/18/2011	-39.28	-210.1	-26.67	-167.4	-23.91	-146.6	------	------	------	------	------	------	------	------	------	------
MW01(w)	IV	4/20/2011	-38.88	-211.6	-26.70	------	-24.40	------	-25.3	------	-24.4	------	-25.0	-24.7	------	-12.01	-13.26	-109.53
MW02(g)	III	9/24/2010	-41.85	-209.4	------	------	------	------	------	------	------	------	------	------	< 0.2	------	------	------
MW02(g)-dup	III	9/24/2010	-41.72	-209.2	------	------	------	------	------	------	------	------	------	------	< 0.2	------	------	------

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Sample (matrix)	Phase	Date	δ^{13}C-C$_1$ (‰)	δD-C$_1$ (‰)	δ^{13}C-C$_2$ (‰)	δD-C$_2$ (‰)	δ^{13}C-C$_3$ (‰)	δD-C$_3$ (‰)	δ^{13}C-iC$_4$ (‰)	δD-iC$_4$ (‰)	δ^{13}C-nC$_4$ (‰)	δD-nC$_4$ (‰)	δ^{13}C-iC$_5$ (‰)	δ^{13}C-nC$_5$ (‰)	^{14}C$_1$ (pMC)	δ^{13}C DIC (‰)	δ^{18}O H$_2$O (‰)	δD H$_2$O (‰)
MW02(w)	III	10/6/2010	-41.83	-203.8	-26.4	-----	-24.28	-----	-----	-----	-----	-----	-----	-----	-----	Low DIC	-15.55	-117.41
MW02(g)	IV	4/18/2011	-41.05	-208.9	-26.10	-170.5	-24.05	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
MW02(g)-dup	IV	4/18/2011	-41.01	-210.8	-26.09	-171.4	-24.06	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
MW02(w)	IV	4/19/2011	-41.30	-210.7	-26.25	-----	-24.29	-----	-25.3	-----	-24.3	-----	-----	-----	-----	Low DIC	-14.24	-113.42
MW02(w)-dup	IV	4/19/2011	-41.37	-208.2	-26.28	-----	-24.28	-----	-25.3	-----	-24.5	-----	-----	-----	-----	Low DIC	-14.27	-113.46
PGDW05(w)	IV	04/19/11	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-15.12	-13.11	-109.64
PGDW14(w)	IV	04/20/11	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-11.94	-15.79	-126.04
PGDW20 (w)	III	10/06/10	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-16.04	-13.22	-107.70
PGDW20(w)-dup	III	10/06/10	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-15.91	-13.18	-107.38
PGDW20(w)	IV	04/18/11	-33.1	-175	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-16.24	-13.31	-108.35
PGDW23(w)	IV	04/21/11			-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-13.29	-12.40	-97.35
PGDW30(w)	II	01/19/10	-28.77	-143.6	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
PGDW30(w)	III	10/05/10	-28.76	-145.8	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-12.18	-13.02	-109.78
PGDW30(w)	IV	04/18/11	-27.8	-133	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-11.66	-13.23	-108.11
PGDW32(w)	IV	04/18/11	-34.2	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-11.32	-13.33	-108.10
PGDW32(w)-dup	IV	04/18/11	-34.0	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-10.84	-13.28	-108.24
PGDW41(w)	IV	04/20/11	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-12.31	-15.91	-121.93
PGDW44(w)	IV	4/21/2011	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-10.35	-13.29	-100.29
PGDW45(w)	IV	04/19/11	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-14.18	-16.59	-128.18
PGDW49(w)	IV	4/20/2011	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-11.05	-15.57	-122.19
LD02(w)	III	10/20/2010	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-18.58	-13.22	-109.20

WR - Wind River Formation FU - Fort Union Formation ----- not analyzed nd () - not detected

Appendix B

Quality Assurance and Quality Control (QA/QC) for Analysis

Table B1. Sample collection containers, preservation, and holding times for ground-water samples for Phase III and IV

Sample Type	Analysis Method (EPA Method)	Sample Bottles/# of bottles*	Preservation/ Storage	Holding Time(s)
Dissolved gases	RSKSOP-194v4 &-175v5 (No EPA Method)	60 mL serum bottles/2	No Headspace TSP[†], pH>10; refrigerate 4°C[††]	14 days
Metals (filtered)	RSKSOP-213v4 &-257v3 (EPA Methods 200.7 and 6020)	125 mL plastic bottle/1	HNO_3, pH<2; room temperature	6 months (Hg 28 days)
SO_4, Cl, F, Br	RSKSOP-276v3 (EPA Method 6500)	30 mL plastic/1	Refrigerate ≤4°C	28 days
$NO_3 + NO_2$, NH_4	RSKSOP-214v5 (EPA Method 350.1 and 353.2)	30 mL plastic/1	H_2SO_4, pH<2; refrigerate ≤4°C	28 days
DIC	RSKSOP-102v5 or 330v0 (EPA Method 9060A)	40 mL clear glass VOA vial/2	refrigerate ≤4°C	14 days
DOC	RSKSOP-102v5 or 330v0 (EPA Method 9060A)	40 mL clear glass VOA vial/2	H_3PO_4, pH<2; refrigerate ≤4°C	28 days
VOCs	RSKSOP-299v1 or 259v1 (EPA Method 5021A plus 8260C)	40 mL amber glass VOA vial/2	No Headspace TSP[†], pH>10; refrigerate ≤4°C	14 days
Low Molecular Weight Acids	RSKSOP-112V6 (No EPA Method)	40 mL glass VOA vial/2	TSP[†], pH>10; refrigerate ≤ 4°C	30 days
O, H stable isotopes of water	RSKSOP-296v0 (No EPA Method)	20 mL glass VOA vial/1	Refrigerate at ≤ 4°C	Stable
δ^{13}C DIC	Isotech: gas stripping and IRMS (No EPA Method)	60 mL plastic bottle/1	Refrigerate ≤4°C	No information
δ^{13}C and δD of methane	Isotech: gas stripping and IRMS (No EPA Method)	1 L plastic bottle/1	Caplet of benzalkonium chloride; refrigerate ≤4°C	No information
SVOCs	ORGM-515 r1.1, EPA Method 8270D	1L amber glass bottle/2 and for every 10 samples of ground water need 2 more bottles for one selected sample, or if <10 samples collected, collect 2 more bottles for one select sample	Refrigerate ≤4°C	7 days until extraction, 30 days after extraction
DRO	ORGM-508 r1.0, EPA Method 8015D	1L amber glass bottle/2 and for every 10 samples of ground water need 2 more bottles for one selected sample, or if <10 samples collected, collect 2 more bottles for one select sample	HCl, pH<2; refrigerate ≤4°C	7 days until extraction, 40 days after extraction
GRO	ORGM-506 r1.0, EPA Method 8015D	40 mL amber glass VOA vial/2 and for every 10 samples of ground water need 2 more bottles for one selected sample, or if <10 samples collected, collect 2 more bottles for one select sample	No headspace; HCl, pH<2; refrigerate ≤4°C	14 days
Glycols	Region III method** (No EPA Method)	40 mL amber glass VOA vial/2	Refrigerate ≤4ºC	14 days

[†] Trisodium phosphate

[††] Above freezing point of water

*Spare bottles made available for laboratory QC samples and for replacement of compromised samples (broken bottle, QC failures, etc.).

**EPA Methods 8000C and 8321 were followed for method development and QA/AC limits were applicable.

Table B2. Field QC samples for ground-water analysis

QC Sample	Purpose	Method	Frequency
Trip Blanks (VOCs and Dissolved Gases only)	Assess contamination during transportation.	Fill bottles with reagent water and preserve, take to field and returned without opening.	One in an ice chest with VOA and dissolved gas samples.
Equipment Blanks	Assess contamination from field equipment, sampling procedures, decontamination procedures, sample container, preservative, and shipping.	Apply only to samples collected via equipment, such as filtered samples: Reagent water is filtered and collected into bottles and preserved same as filtered samples.	One per day of sampling with submersible pumps
Field Duplicates	Represent precision of field sampling, analysis, and site heterogeneity.	One or more samples collected immediately after original sample.	One in every 10 samples, or if <10 samples collected for a water type (ground or surface), collect a duplicate for one sample.
Temperature Blanks	Measure temperature of samples in the cooler.	Water sample that is transported in cooler to lab.	One per cooler.
Field Blanks**	Assess contamination introduced from sample container with applicable preservative.	In the field, reagent water is collected into sample containers with preservatives.	One per day of sampling.

* Reporting limit or Quantitation Limit

** Blank samples were not collected for isotope measurements, including O, H, C.

Table B3. QA/QC requirements for analysis of metals and major ions

Measurement	Analysis Method	Blanks (Frequency)	Calibration Checks (Frequency)	Second Source (Frequency)	Duplicates (Frequency)	Matrix Spikes (Frequency)
Metals	RSKSOP-213v4 (EPA Methods 200.7 and 6020)	<QL for 80% of metals; (Beginning and end of each sample queue, 10-15 samples)	90-110% of known value (Beginning and end of each sample queue, 10-15 samples)	PE sample acceptance limits or 90-110% of known value (Immediately after first calibration check)	RPD<10 for 80% of metals; for results <5x QL, difference of ≤QL(Every 15 samples)	90-110% Rec. for 80% of metals w/ no individual exceeding 50-150% Rec. (one per sample set, 10-15 samples)
Metals	RSKSOP-257v3 (EPA Methods 200.7 and 6020)	<QL for 80% of metals; none>10xMDL (Beginning and end of each sample queue, 10-15 samples)	90-110% of known value (Beginning and end of each sample queue, 10-15 samples)	PE sample acceptance limits or 90-110% of known value (Immediately after first calibration check)	RPD<10 for 80% of metals; for results <5xQL, difference of <QL (Every 15 samples)	90-110% Rec. for 80% of metals w/ no individual exceeding 70-130% (one per sample set, 10-15 samples)
SO_4, Cl, F, Br	RSKSOP-2 (EPA Method 6500)76v3	<MDL (Beginning and end of each sample queue)	90-110% Rec. (Beginning, end, and every 10 samples)	PE sample acceptance limits (One per sample set)	RPD<10 (every 15 samples)	80-120% Rec. (one per every 20 samples)
$NO_3 + NO_2$, NH_4	RSKSOP-214v5 (EPA Method 350.1 and 353.2)	<½ lowest calib. std. (Beginning and end of each sample queue)	90-110% Rec. (Beginning, end, and every 10 samples)	PE sample acceptance limits (One per sample set)	RPD<10 (every 10 samples)	80-120% Rec. (one per every 20 samples)

Table B4. QA/QC requirements for analysis of dissolved gases, DIC/DOC, VOCs, low molecular weight acids and stable isotopes of water

Measurement	Analysis Method	Blanks (Frequency)	Calibration Checks (Frequency)	Second Source (Frequency)	Duplicates (Frequency)	Matrix Spikes (Frequency)
Dissolved gases	RSKSOP-194v4 &-175v5* (No EPA Method)	≤MDL (He/Ar blank, first and last in sample queue; water blank before samples)	85-115% of known value (After helium/Ar blank at first of analysis queue, before helium/Ar blank at end of sample set, and every 15 samples)	85-115% of known value (After first calibration check)	RPD≤20 (Every 15 samples)	NA
DIC/DOC	RSKSOP-102v5 (Phase III) or 330v0 (Phase IV) (EPA Method 9060A)	- 102v5: <½QL (after initial calib., every 10-15 samples, and at end) -330v0: < MDL (Beginning and end of sample set)	-102v5: 80-120% of known value (after initial calib., every 10-15 samples, and at end-330v0: 90-100% of known value (Beginning and end of sample set and every 10 samples)	-102v5: 80-120% of known value (Immediately after calibration) -330v0: PE sample reported acceptance limits. Others: 90-100% recovery (one per sample set)	-102v5: RPD<10 (every 15 samples) -330v0: RPD<10 (every 10 samples)	-102v5:80-120% Rec. (one per 20 or every set) -330v0:80-120% Rec.
Volatile organic compounds (VOC)**	RSKSOP-299v1 and -259v1 (EPA Method 5021A plus 8260C)	<MDL (Beginning and end of each sample set)	80-120% Rec. (Beginning, end, and every 20 samples)	80-120% of known value Once at beginning (and at end for -259v1)	-299v1 RPD<20 -259v1 RPD<25 (every 20 samples)	70-130% Rec. (every 20 samples)
Low Molecular Weight Acids	RSKSOP-112v6 (No EPA Method)	<MDL (Beginning of a sample queue; every 10 samples; and end of sample queue)	85-115% of the recovery (Prior to sample analysis; every 10 samples; end of sample queue)	85-115% of recovery (Prior to sample analysis)	< 15 RPD (Every 20 samples through a sample queue)	80-120 % recovery (Every 20 samples through a sample queue)
O, H stable isotopes of water***	RSKSOP-296v1 (No EPA Method)	NA	Difference of calibrated/true < 1‰ for δ^2H & < 0.2‰ for $\delta^{18}O$ (Beginning, end and every tenth sample)	Working stds calibrated against IAEAstds.† (Beginning, end, and every tenth sample)	Standard deviation ≤ 1‰ for δ^2H and < 0.2‰ for $\delta^{18}O$ (every sample)	NA

*This table only provides a summary; SOPs should be consulted for greater detail.

**Surrogate compounds spiked at 100 ug/L: p-bromofluorobenzene and 1,2-dichlorobenzene-d4, 85-115% recovery.

***Additional checks: internal reproducibility prior to each sample set, std dev≤ 1‰ for δ^2H and ≤ 1‰ for $\delta^{18}O$

†International Atomic Energy Agency (VSMOW, GISP, and SLAP)

Corrective actions are outlined in the SOPs.

MDL = Method Detection Limit

QL = Quantitation Limit

PE = Performance Evaluation

Table B5. QA/QC requirements for analysis of semi-volatiles, GRO, and DRO

QC Type	Semivolatiles	DRO	GRO	Frequency
Method Blanks	<RL Preparation or Method Blank, one with each set of extraction groups. Calibration Blanks are also analyzed	<RL Preparation or Method Blank	<RL Preparation or Method Blank and IBL	At least one per sample set
Surrogate Spikes	Limits based upon DoD statistical study (rounded to 0 or 5) for the target compound analyses.	60-140% of expected value	70-130% of expected value	Every field and QC sample
Internal Standards Verification	Every sample, EICP area within -50% to +100% of last ICV or first CCV.	NA	NA	Every field and QC sample
Initial multilevel calibration	ICAL: minimum of 6 levels (0.25 -12.5 ug/L) , one is at the MRL (0.50 ug/L), prior to sample analysis (not daily) RSD≤20%, r^2≥0.990	ICAL: 10-500 ug/L RSD<=20% or r^2>=0.990	ICAL: .25-12.5 ug/L for gasoline (different range for other compounds) RSD<=20% or r2>=0.990	As required (not daily if pass ICV)
Initial and Continuing Calibration Checks	80-120% of expected value	80-120% of expected value	80-120% of expected value	At beginning of sample set, every tenth sample, and end of sample set
Second Source Standards	ICV1 70-130% of expected value	ICV1 80-120% of expected value	ICVs 80-120% of expected value	Each time calibration performed
Laboratory Control Samples (LCS)	Statistical Limits from DoD LCS Study (rounded to 0 or 5) or if SRM is used based on those certified limits	Use an SRM: Values of all analytes in the LCS should be within the limits determined by the supplier. Otherwise 70-130% of expected value	Use and SRM: Values of all analytes in the LCS should be within the limits determined by the supplier. Otherwise 70-130% of expected value	One per analytical batch or every 20 samples, whichever is greater
Laboratory Control Samples (LCS)	Statistical Limits from DoD LCS Study (rounded to 0 or 5) or if SRM is used based on those certified limits	Use an SRM: Values of all analytes in the LCS should be within the limits determined by the supplier. Otherwise 70-130% of expected value	Use and SRM: Values of all analytes in the LCS should be within the limits determined by the supplier. Otherwise 70-130% of expected value	One per analytical batch or every 20 samples, whichever is greater
Matrix Spikes (MS)	Same as LCS	Same as LCS	70-130% of expected value	One per sample set or every 20 samples, whichever is more frequent
MS/MSD	% Recovery same as MS RPD ≤ 30	% Recovery same as MS RPD ≤ 25	% Recovery same as MS RPD ≤ 25	One per sample set or every 20 samples, whichever is more frequent
Reporting Limits*	0.1 µg/L (generally)[1]for target compounds HF special compounds are higher	20 µg/L[1]	20 µg/L[2]	NA

[1] Based on 1000 mL sample to 1 mL extract

[2] Based on a 5 mL purge

Table B6. QA/QC requirements for LC/MS/MS analysis of glycols

QC Type	Performance Criteria	Frequency
Method Blanks	<RL	One per every 20 samples
Solvent Blanks	<RL	One per every 10 samples
Initial and Continuing Calibration Checks	80-120% of expected value	At beginning of sample set, after every tenth sample, and end of sample set
Second Source Standards	80-120% of expected value	Each time calibration performed
Laboratory Control Samples (LCS)	80-120% of expected value	One per analytical batch or every 20 samples, whichever is greater
Matrix Spikes (MS)	70-130% of expected value	One per sample set or every 20 samples, whichever is more frequent
MS/MSD	RPD $\leq$ 25	One per sample set or every 20 samples, whichever is more frequent

RL = Reporting Limit
Corrective Actions: If re-analysis was not possible (such as lack of sample volume), the data was qualified with a determination about the impact on the sample data.

DRAFT

Table B7a. ICP-OES blank results for Phase III and Phase IV sampling

Label	Date	Al	Ag	B	Ba	Be	Ca	Co	Fe	K	Mg
		mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L
Trip Blank	10/6/2010	nd	nd	nd	nd	nd	nd	BQL 0.001	nd	nd	nd
EQ Blank	10/7/2010	nd	nd	nd	nd	nd	BQL 0.009	nd	nd	nd	BQL 0.017
Field Blank	10/5/2010	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Trip Blank	4/14/2011	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Field Blank	4/18/2011	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Field Blank	4/21/2011	nd	nd	nd	nd	nd	nd	nd	nd	BQL 0.096	nd
Equip Blank	4/21/2011	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
MDL		0.045	0.015	0.006	0.001	0.001	0.007	0.001	0.019	0.038	0.015
QL		0.149	0.051	0.018	0.004	0.004	0.023	0.004	0.063	0.127	0.049
Detections in samples		17/21	0/21	21/21	21/21	7/21	21/21	2/21	12/21	21/21	21/21
Concentration min		0.054	nd	0.103	0.006	0.001	3.35	0.001	0.019	0.089	0.019
Concentration max		0.736	nd	0.378	0.210	0.003	452	0.002	2.41	54.9	56.0

BQL – below quantitation level. Units are mg/L. nd – not detected. MDL – method detection level. QL – quantitation level. Detections in samples: the number of times the analyte was detected in Phase III and Phase IV sampling. Minimum and maximum sample concentration in Phase III /Phase IV sampling activities in mg/L.

Table B7b. ICP-OES blank results for Phase III and Phase IV sampling

Label	Date	Mn	Mo	Na	Sb	Sr	Ti	Zn	Si	S	P
		mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L
Trip Blank	10/6/2010	nd	nd	nd	nd	nd	nd	nd	BQL 0.077	nd	nd
EQ Blank	10/7/2010	BQL 0.001	nd	nd	nd	nd	nd	BQL 0.017	nd	2.04	nd
Field Blank	10/5/2010	nd	nd	nd	nd	nd	nd	BQL 0.011	nd	1.2	nd
Trip Blank	4/14/2011	nd	nd	nd	nd	nd	nd	nd	nd	nd	BQL 0.007
Field Blank	4/18/2011	nd	nd	nd	nd	nd	nd	nd	nd	nd	BQL 0.009
Field Blank	4/21/2011	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Equip Blank	4/21/2011	nd	nd	nd	nd	nd	nd	nd	nd	nd	BQL 0.011
MDL		0.001	0.002	0.040	0.006	0.001	0.001	0.007	0.037	0.121	0.004
QL		0.004	0.007	0.134	0.019	0.004	0.004	0.024	0.122	0.403	0.013
Detections in samples		16/21	14/21	21/21	11/21	21/21	4/21	15/21	21/21	21/21	5/21
Concentration min		0.001	0.006	61.6	0.007	0.058	0.001	0.009	2.93	6.76	0.008
Concentration max		0.231	0.019	1060	0.033	8.44	0.004	0.201	10.2	1140	0.024

BQL – below quantitation level. Units are mg/L. nd – not detected. MDL – method detection level. QL – quantitation level. Detections in samples: the number of times the analyte was detected in Phase III and Phase IV sampling. Minimum and maximum sample concentration in Phase III /Phase IV sampling activities in mg/L.

Table B7c. ICP-MS blank results for Phase III and Phase IV sampling

Label	Date	As	Cd	Cr	Cu	Hg	Ni	Pb	Se	Tl	U
		µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L
Trip Blank	10/6/2010	BQL 0.096	nd	nd	0.96	0.46	nd	0.981	nd	0.014	-----
EQ Blank	10/7/2010	0.258	nd	0.086	BQL 0.65	nd	0.34	nd	nd	BQL 0.004	-----
Field Blank	10/5/2010	0.263	nd	BQL 0.018	nd	nd	nd	nd	nd	0.014	-----
Trip Blank	4/14/2011	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Field Blank	4/18/2011	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Field Blank	4/21/2011	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Equip Blank	4/21/2011	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
MDL		0.052	0.020	0.008	0.287	0.019	0.048	0.043	0.044	0.004	0.002
QL		0.173	0.067	0.124	0.957	0.064	0.160	0.143	0.147	0.013	0.007
Detections in samples		18/21	3/21	19/21	19/21	5/21	19/21	11/21	21/21	5/21	15/15
Concentration min		0.255	0.028	0.010	0.380	0.117	0.060	0.123	0.337	0.014	0.005
Concentration max		4.96	0.089	0.864	18.9	0.614	9.62	2.37	16.4	0.125	80.1

BQL – below quantitation level. Units are µg/L. ----- not measured. nd – not detected. MDL – method detection level. QL – quantitation level. Detections in samples: the number of times the analyte was detected in Phase III and Phase IV sampling. Minimum and maximum sample concentration in Phase III/Phase IV sampling activities in µg/L.

Table B8. Blank results for Capillary Electrophoresis, Lachat Flow Injection Analysis, Dissolved Inorganic Carbon (DIC) and Dissolved Organic Carbon analyses for Phase III and Phase IV sampling

Label	Date	Cl	SO_4	F	NO_3+NO_2	NH_4	DIC	DOC
		mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L
Trip Blank	10/6/2010	nd	nd	nd	nd	nd	BQL 0.51	BQL 0.06
EQ Blank	10/7/2010	nd	nd	nd	nd	nd	BQL 0.17	BQL 0.03
Field Blank	10/5/2010	nd	nd	nd	nd	nd	BQL 0.08	BQL 0.04
Trip Blank	4/14/2011	nd	nd	nd	nd	nd	BQL 0.09	BQL 0.29
Field Blank	4/18/2011	nd	nd	nd	nd	nd	BQL 0.29	BQL 0.24
Field Blank	4/21/2011	nd	nd	nd	nd	nd	BQL 0.20	BQL 0.17
Equip Blank	4/21/2011	nd	nd	nd	nd	nd	BQL 0.18	BQL 0.28
MDL		0.136	0.103	0.056	0.005	0.014	0.103	0.103
QL		1.00	1.00	0.200	0.100	0.100	0.500	0.500
Detections in samples		21/21	21/21	17/21	11/21	16/21	21/21	21/21
Concentration min		13.2	12.1	0.90	0.08	0.04	1.4	0.51
Concentration max		466	3200	2.02	17.5	4.61	89.1	19.7

BQL – below quantitation level. Units are mg/L. nd – not detected. MDL – method detection level. QL – quantitation level. Detections in samples: the number of times the analyte was detected in Phase III and Phase IV sampling. Minimum and maximum sample concentration in Phase III /Phase IV sampling activities in mg/L.

Table B9. Blank results for Volatile Organic Compounds (µg/L) in Phase III and Phase IV sampling (Region 8 laboratory, Golden, CO)

	Trip Blank	EQ Blank	Field Blank	Trip Blank	Field Blank	Field Blank	RL
	10/6/2010	10/7/2010	10/5/2010	4/14/2011	4/18/2011	4/21/2011	
1,1,1,2-Tetrachloroethane	nd	nd	nd	nd	nd	nd	0.25
1,1,1-Trichloroethane	nd	nd	nd	nd	nd	nd	0.25
1,1,2,2-Tetrachloroethane	nd	nd	nd	nd	nd	nd	0.25
1,1,2-Trichloroethane	nd	nd	nd	nd	nd	nd	0.25
1,1-Dichloroethane	nd	nd	nd	nd	nd	nd	0.25
1,1-Dichloroethene	nd	nd	nd	nd	nd	nd	0.25
1,1-Dichloropropene	nd	nd	nd	nd	nd	nd	0.25
1,2,3-Trichlorobenzene	nd	nd	nd	nd	nd	nd	0.25
1,2,3-Trichloropropane	nd	nd	nd	nd	nd	nd	0.25
1,2,4-Trichlorobenzene	nd	nd	nd	nd	nd	nd	0.25
1,2,4-Trimethylbenzene	nd	nd	nd	nd	nd	nd	0.25
1,2-Dibromo-3-chloropropane	nd	nd	nd	nd	nd	nd	0.25
1,2-Dibromoethane (EDB)	nd	nd	nd	nd	nd	nd	0.25
1,2-Dichlorobenzene	nd	nd	nd	nd	nd	nd	0.25
1,2-Dichloroethane	nd	nd	nd	nd	nd	nd	0.25
1,2-Dichloropropane	nd	nd	nd	nd	nd	nd	0.25
1,3,5-Trimethylbenzene	nd	nd	nd	nd	nd	nd	0.25
1,3-Dichlorobenzene	nd	nd	nd	nd	nd	nd	0.25
1,3-Dichloropropane	nd	nd	nd	nd	nd	nd	0.25
1,3-Dimethyl adamantane	nd	nd	nd	nd	nd	nd	0.25
1,4-Dichlorobenzene	nd	nd	nd	nd	nd	nd	0.25
2,2-Dichloropropane	nd	nd	nd	nd	nd	nd	0.25
2-Butanone	-----	-----	-----	nd	0.64	0.82	0.50
2-Chlorotoluene	nd	nd	nd	nd	nd	nd	0.25
4-Chlorotoluene	nd	nd	nd	nd	nd	nd	0.25
4-Methyl-2-pentanone	-----	-----	-----	nd	nd	nd	0.25
2-Hexanone	-----	-----	-----	nd	0.29	0.41	0.25
Acetone	-----	-----	-----	nd	1.03	1.38	1.00
Acrylonitrile	nd	nd	nd	nd	nd	nd	0.25
Adamantane	nd	nd	nd	nd	nd	nd	0.25
Allyl chloride	nd	nd	nd	nd	nd	nd	0.25
Benzene	nd	nd	nd	nd	nd	nd	0.03
Bromobenzene	nd	nd	nd	nd	nd	nd	0.25
Bromochloromethane	nd	nd	nd	nd	nd	nd	0.25
Bromodichloromethane	nd	nd	nd	nd	nd	nd	0.25
Bromoform	nd	nd	nd	nd	nd	nd	0.25
Bromomethane	nd	nd	nd	nd	nd	nd	0.25
Carbon disulfide	nd	nd	nd	nd	nd	nd	0.25
Carbon tetrachloride	nd	nd	nd	nd	nd	nd	0.25
Chlorobenzene	nd	nd	nd	nd	nd	nd	0.25
Chlorodibromomethane	nd	nd	nd	nd	nd	nd	0.25
Chloroethane	nd	0.25	nd	nd	nd	nd	0.25
Chloroform	nd	nd	nd	nd	nd	nd	0.25
Chloromethane	nd	nd	nd	1.04	nd	nd	0.25
cis-1,2-Dichloroethene	nd	nd	nd	nd	nd	nd	0.25
cis-1,3-Dichloropropene	nd	nd	nd	nd	nd	nd	0.25
Dibromomethane	nd	nd	nd	nd	nd	nd	0.25
Dichlorodifluoromethane	nd	nd	nd	nd	nd	nd	0.25
Ethyl Ether	nd	nd	nd	nd	nd	nd	0.25
Ethylbenzene	nd	nd	nd	nd	nd	nd	0.25
Hexachlorobutadiene	nd	nd	nd	nd	nd	nd	0.25
Hexachloroethane	nd	nd	nd	nd	nd	nd	0.25
Iodomethane	nd	nd	nd	nd	nd	nd	0.25
Isopropylbenzene	nd	nd	nd	nd	nd	nd	0.25
m,p-Xylene	nd	nd	nd	nd	0.69	0.70	0.50
Methacrylonitrile	nd	nd	nd	nd	0.27	nd	0.25

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	Trip Blank	EQ Blank	Field Blank	Trip Blank	Field Blank	Field Blank	RL
	10/6/2010	**10/7/2010**	**10/5/2010**	**4/14/2011**	**4/18/2011**	**4/21/2011**	
Methyl Acrylate	nd	nd	nd	nd	nd	nd	0.25
Methyl tert-Butyl Ether	nd	nd	nd	nd	nd	nd	0.25
Methylene chloride	nd	nd	nd	nd	nd	nd	0.25
Naphthalene	nd	nd	nd	nd	nd	nd	0.25
n-Butyl Benzene	nd	nd	nd	nd	nd	nd	0.25
n-Propyl Benzene	nd	nd	nd	nd	nd	nd	0.25
o-Xylene	nd	nd	nd	nd	nd	nd	0.25
p-Isopropyltoluene	nd	nd	nd	nd	nd	nd	0.25
sec-Butylbenzene	nd	nd	nd	nd	nd	nd	0.25
Styrene	nd	nd	nd	nd	nd	nd	0.25
tert-Butylbenzene	nd	nd	nd	nd	nd	nd	0.25
Tetrachloroethene	nd	nd	nd	nd	nd	nd	0.25
Toluene	0.54	0.16	0.16	nd	nd	nd	0.25
trans-1,2-Dichloroethene	nd	nd	nd	nd	nd	nd	0.25
trans-1,3-Dichloropropene	nd	nd	nd	nd	nd	nd	0.25
Trichloroethene	nd	nd	nd	nd	nd	nd	0.25
Trichlorofluoromethane	nd	nd	nd	nd	nd	nd	0.25
Vinyl chloride	nd	nd	nd	nd	nd	nd	0.25
Xylenes (total)	nd	nd	nd	nd	nd	nd	0.75

RL – Reporting Limit (µg/L). nd – not detected. ----- not measured.

Table B10. Blank results for Volatile Organic Compounds (µg/L) in Phase IV sampling (ORD laboratory, Ada, OK)

	Trip Blank	Field Blank	Field Blank	MDL	QL
	4/14/2011	4/18/2011	4/21/2011		
Vinyl chloride	nd	nd	nd	0.14	1.0
1,1-Dichloroethene	nd	nd	nd	0.07	0.5
Methylene Chloride	nd	nd	nd	0.19	0.5
trans-1,2-Dichloroethene	nd	nd	nd	0.05	0.5
cis-1,2-Dichloroethene	nd	nd	nd	0.15	0.5
Chloroform	nd	nd	nd	0.07	0.5
1,1,1-Trichloroethane	nd	nd	nd	0.03	0.5
Carbon Tetrachloride	nd	nd	nd	0.04	0.5
1,2-Dichloroethane	nd	nd	nd	0.03	0.5
Trichloroethene	nd	nd	nd	0.07	0.5
1,1,2-Trichloroethane	nd	nd	nd	0.03	0.5
Tetrachloroethene	nd	nd	nd	0.09	0.5
Chlorobenzene	nd	nd	nd	0.04	0.5
1,3-Dichlorobenzene	nd	nd	nd	0.06	0.5
1,4-Dichlorobenzene	nd	nd	nd	0.04	0.5
1,2-Dichlorobenzene	nd	nd	nd	0.03	0.5
Ethanol	nd	nd	nd	0.11	1.0
Isopropanol	nd	nd	nd	24.7	100
n-Propanol	nd	nd	nd	11.4	100
Isobutanol	nd	nd	nd	13.5	100
n-Butanol	nd	nd	nd	15.6	100
tert-Butyl Alcohol	nd	nd	nd	15.5	100
Methyl tert-Butyl Ether	nd	nd	nd	1.72	5.0
di-Isopropyl Ether	nd	nd	nd	0.11	0.5
Ethyl tert-Butyl Ether	nd	nd	nd	0.11	0.5
Benzene	nd	nd	nd	0.03	0.5
tert-Amyl Methyl Ether	nd	nd	nd	0.06	0.5
2,5-Dimethylfuran	nd	nd	nd	0.06	0.5
Toluene	BQL 0.228	nd	BQL 0.227	0.03	0.5
1,2-Dibromoethane	nd	nd	nd	0.03	0.5
Ethyl Benzene	nd	nd	nd	0.09	1.0
m+p Xylene	BQL 0.229	nd	BQL 0.133	0.03	0.5
o-Xylene	nd	nd	nd	0.08	0.5
1,3,5-Trimethylbenzene	nd	nd	nd	0.03	0.5
1,2,4-Trimethylbenzene	nd	nd	nd	0.04	1.0
1,2,3-Trimethylbenzene	nd	nd	nd	0.02	1.0
Naphthalene	nd	nd	nd	0.04	1.0

All results in µg/L. MDL – method detection level. QL – quantitation level. nd – not detected.

Table B11. Blank results for Semi-Volatile Organic Compounds (µg/L) in Phase III and Phase IV sampling (Region 8 laboratory, Golden, CO)

	Trip Blank	EQ Blank	Field Blank	Trip Blank	Field Blank	Field Blank	RL
	10/6/2010	10/7/2010	10/5/2010	4/14/2011	4/18/2011	4/21/2011	
1,2,4-Trichlorobenzene	nd	nd	nd	nd	nd	nd	0.100
1,2-Dichlorobenzene	nd	nd	nd	nd	nd	nd	0.100
1,2-Dinitrobenzene	nd	nd	nd	nd	nd	nd	0.100
1,3-Dichlorobenzene	nd	nd	nd	nd	nd	nd	0.100
1,3-Dinitrobenzene	nd	nd	nd	nd	nd	nd	0.100
1,4-Dichlorobenzene	nd	nd	nd	nd	nd	nd	0.100
1,4-Dinitrobenzene	nd	nd	nd	nd	nd	nd	0.100
1-Methylnaphthalene	nd	nd	nd	nd	nd	nd	0.100
2,3,4,6-Tetrachlorophenol	nd	nd	nd	nd	nd	nd	0.250
2,3,5,6-Tetrachlorophenol	nd	nd	nd	nd	nd	nd	0.250
2,4,5-Trichlorophenol	nd	nd	nd	nd	nd	nd	0.100
2,4,6-Trichlorophenol	nd	nd	nd	nd	nd	nd	0.100
2,4-Dichlorophenol	nd	nd	nd	nd	nd	nd	0.100
2,4-Dimethylphenol	nd	nd	nd	nd	nd	nd	0.100
2,4-Dichlorophenol	nd	nd	nd	nd	nd	nd	0.100
2,4-Dimethylphenol	nd	nd	nd	nd	nd	nd	0.100
2,4-Dinitrophenol	nd	nd	nd	nd	nd	nd	1.00
2,4-Dinitrotoluene	nd	nd	nd	nd	nd	nd	1.00
2,6-Dinitrotoluene	nd	nd	nd	nd	nd	nd	0.100
2-Chloronaphthalene	nd	nd	nd	nd	nd	nd	0.100
2-Chlorophenol	nd	nd	nd	nd	nd	nd	0.100
2-Methylnaphthalene	nd	nd	nd	nd	nd	nd	0.100
2-Methylphenol	nd	nd	nd	nd	nd	nd	0.100
2-Nitroaniline	nd	nd	nd	nd	nd	nd	0.100
2-Nitrophenol	nd	nd	nd	nd	nd	nd	0.100
3 & 4-Methylphenol	nd	nd	nd	nd	nd	nd	0.200
3,3´-Dichlorobenzidine	nd	nd	nd	nd	nd	nd	0.500
3-Nitroaniline	nd	nd	nd	nd	nd	nd	0.100
4,6-Dinitro-2-methylphenol	nd	nd	nd	nd	nd	nd	0.500
4-Bromophenyl phenyl ether	nd	nd	nd	nd	nd	nd	0.100
4-Chloro-3-methylphenol	nd	nd	nd	nd	nd	nd	0.100
4-Chloroaniline	nd	nd	nd	nd	nd	nd	0.100
4-Chlorophenyl phenyl ether	nd	nd	nd	nd	nd	nd	0.100
4-Nitroaniline	nd	nd	nd	nd	nd	nd	0.500
4-Nitrophenol	nd	nd	nd	nd	nd	nd	1.00
Acenaphthene	nd	nd	nd	nd	nd	nd	0.100
Acenaphthylene	nd	nd	nd	nd	nd	nd	0.100
Aniline	nd	nd	nd	nd	nd	nd	0.100
Anthracene	nd	nd	nd	nd	nd	nd	0.100
Azobenzene	nd	nd	nd	nd	nd	nd	0.100
Benzo (a) anthracene	nd	nd	nd	nd	nd	nd	0.100
Benzo (a) pyrene	nd	nd	nd	nd	nd	nd	0.100
Benzo (g,h,i) perylene	nd	nd	nd	nd	nd	nd	0.100
Benzo (k) fluoranthene	nd	nd	nd	nd	nd	nd	0.100
Benzo(b)fluoranthene	nd	nd	nd	nd	nd	nd	0.100
Benzoic acid	0.83	0.78	nd	3.00	nd	nd	0.500
Benzyl alcohol	nd	0.40	0.63	nd	nd	nd	0.500
Bis(2-chloroethoxy)methane	nd	nd	nd	nd	nd	nd	0.100
Bis(2-chloroethyl)ether	nd	nd	nd	nd	nd	nd	0.100
Bis(2-chloroisopropyl)ether	nd	nd	nd	nd	nd	nd	0.100
Bis-(2-Ethylhexyl) Adipate	nd	nd	nd	nd	nd	nd	0.100
Bis(2-ethylhexyl)phthalate	nd	nd	nd	5.44	nd	nd	0.500
Butyl benzyl phthalate	nd	nd	nd	nd	nd	nd	0.100
Carbazole	nd	nd	nd	nd	nd	nd	0.100
Chrysene	nd	nd	nd	nd	nd	nd	0.100
Dibenz (a,h) anthracene	nd	nd	nd	nd	nd	nd	0.100

	Trip Blank	EQ Blank	Field Blank	Trip Blank	Field Blank	Field Blank	RL
	10/6/2010	10/7/2010	10/5/2010	4/14/2011	4/18/2011	4/21/2011	
Dibenzofuran	nd	nd	nd	nd	nd	nd	0.100
Diethyl phthalate	nd	nd	nd	nd	nd	nd	0.100
Dimethyl phthalate	nd	nd	nd	nd	nd	nd	0.100
Di-n-butyl phthalate	nd	nd	nd	nd	nd	nd	0.100
Di-n-octyl phthalate	nd	nd	nd	nd	nd	nd	0.100
Diphenylamine	nd	nd	nd	nd	nd	nd	0.100
Fluoranthene	nd	nd	nd	nd	nd	nd	0.100
Fluorene	nd	nd	nd	nd	nd	nd	0.100
Hexachlorobenzene	nd	nd	nd	nd	nd	nd	0.100
Hexachlorobutadiene	nd	nd	nd	nd	nd	nd	0.100
Hexachlorocyclopentadiene	nd	nd	nd	nd	nd	nd	0.100
Hexachloroethane	nd	nd	nd	nd	nd	nd	0.100
Indeno (1,2,3-cd) pyrene	nd	nd	nd	nd	nd	nd	0.100
Isophorone	nd	nd	nd	nd	nd	nd	0.100
Naphthalene	nd	nd	nd	nd	nd	nd	0.100
Nitrobenzene	nd	nd	nd	nd	nd	nd	0.100
N-Nitrosodi-n-propylamine	nd	nd	nd	nd	nd	nd	0.100
Pentachlorophenol	nd	nd	nd	nd	nd	nd	0.500
Phenanthrene	nd	nd	nd	nd	nd	nd	0.100
Phenol	nd	nd	nd	nd	nd	nd	0.100
Pyrene	nd	nd	nd	nd	nd	nd	0.100
Limonene	nd	nd	nd	nd	nd	nd	0.100
1,3-Dimethyl adamantane	nd	nd	nd	nd	nd	nd	0.100
2-Butoxyethanol	nd	nd	nd	nd	nd	nd	0.100
Adamantane	nd	0.32	nd	nd	nd	nd	0.100
Squalene	0.36	0.49	0.23	nd	nd	nd	1.00
Terpiniol	nd	nd	nd	nd	nd	nd	0.100
Tri(2-butoxyethyl) Phosphate	nd	2.53	nd	nd	nd	nd	0.500

RL – Reporting Limit (µg/L). nd – not detected. ----- not measured.

Table B12. Blank results for GRO and DRO analyses for Phase III and Phase IV sampling (Region 8 laboratory, Golden, CO) and blank results for glycol ethers in Phase IV sampling (Region 3 laboratory, Fort Meade, MD)

	Trip Blank	EQ Blank	Field Blank	Trip Blank	Field Blank	Field Blank	RL
	10/6/2010	10/7/2010	10/5/2010	4/14/2011	4/18/2011	4/21/2011	
Gasoline Range Organics	nd	nd	nd	nd	21.3	nd	20
Diesel Range Organics	nd	nd	nd	nd	nd	135	22
2-Butoxyethanol	-----	-----	-----	nd	nd	nd	10
Diethylene Glycol	-----	-----	-----	nd	nd	nd	50
Triethylene Glycol	-----	-----	-----	nd	nd	nd	10
Tetraethylene Glycol	-----	-----	-----	3.6	3.1	3.4	10

RL – Reporting Limit (µg/L). nd – not detected. ----- not measured.

Table B13. Duplicate data for selected major ions, DOC, and DIC in ground water samples collected during Phase III and Phase IV sampling activities

Sample	Date	Na	K	Ca	Mg	Ba	Sr	Si	Cl	SO4	F	NO3	DOC	DIC
		ppm	ppm	ppm	ppm	ppm	ppm	ppm	ppm	ppm	ppm	ppm	ppm	ppm
LD01	10/6/2010	562	1.05	71.9	8.12	0.0096	1.08	5.82	33.0	1320	0.90	0.354	0.568	17.8
LD01 dup	10/6/2010	565	0.97	71.9	8.14	0.0096	1.08	5.81	32.9	1320	0.99	0.337	0.558	17.2
RPD		0.53	7.92	0.00	0.25	0.00	0.00	0.17	0.30	0.00	9.52	4.92	1.78	3.48
PGDW32	4/18/2011	198	0.09	7.19	0.028	0.010	0.090	6.74	18.8	361	1.95	ND	0.41	7.70
PGDW32 dup	4/18/2011	198	0.27	7.28	0.026	0.009	0.090	6.80	19.1	349	2.02	ND	0.37	7.73
RPD		0.00	100	1.24	7.41	10.53	0.00	0.89	1.58	3.38	3.53	NC	10.26	0.39
EPAMW02	4/19/2011	448	43.6	60.5	0.032	0.093	1.78	2.94	457	62.6	1.54	ND	19.7	1.40
EPAMW02 dup	4/19/2011	449	44.0	60.5	0.019	0.093	1.79	2.93	456	62.5	1.49	ND	19.7	1.39
RPD		0.22	0.91	0.00	50.98	0.00	0.56	0.34	0.22	0.16	3.30	NC	0.00	0.72

RPD is the calculated relative percent difference: RPD = |[(sample1-sample2)/((sample1+sample2)/2)]*100|. ND – not detected. ----- not measured. NC – not calculated.

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Table B14. Duplicate data for methane and selected dissolved organic compounds in ground water samples collected during Phase III and Phase IV sampling activities

Sample	Date	Methane	Benzene	Toluene	m,p-Xylenes	Isopropyl alcohol	Tert-butyl alcohol	Phenol	Diethylene Glycol	Triethylene Glycol	Acetone
		ppm	ppb	ppb	ppb	ppb	ppb	ppb	ppb	ppb	ppb
LD01	10/6/2010	0.189	<0.25	<0.25	<0.25	-----	-----	<0.1	-----	-----	-----
LD01 dup	10/6/2010	0.168	<0.25	<0.25	<0.25	-----	-----	<0.1	-----	-----	-----
RPD		11.76	NC	NC	NC	NC	NC	NC	NC	NC	NC
PGDW32	4/18/2011	0.07	<0.25	<0.25	<0.25	<11.4	<1.7	<0.5	<50	<10	<1.00
PGDW32 dup	4/18/2011	0.06	<0.25	<0.25	<0.25	<11.4	<1.7	<0.5	<50	<10	<1.00
RPD		15.38	NC	NC	NC	NC	NC	NC	NC	NC	NC
EPAMW02	4/19/2011	18.82	139	336	280	581	4470	14.5	1570	314	641
EPAMW02 dup	4/19/2011	22.62	164	424	354	553	4580	29.2	1610	293	616
RPD		18.34	16.50	23.16	23.34	4.94	2.43	67.28	2.52	6.92	3.98

RPD is the calculated relative percent difference: RPD = |[(sample1-sample2)/((sample1+sample2)/2)]*100|. ND – not detected. ----- not measured. NC – not calculated.

Table B15. QA/QC requirements for analysis of $\delta^{13}C$ of DIC		
QC Type	**Performance Criteria**	**Frequency**
Mass Spec Calibration Check	Difference of calibrated/true ≤ 0.5‰	One at beginning of day, and one after sample is analyzed.
Mass Spec Zero Enrichment Check	0 +/- 0.1 ‰	Once a day
Lab Duplicates	≤ 1 ‰	1 per every 5 samples*

Working standards were calibrated against IAEA (International Atomic Energy Agency) standard LSVEC and NBS-19; referenced to $\delta^{13}C$ of the PeeDee belemnite (NIST material).
*If < 5 samples were submitted, a duplicate was run regardless of total number.
Corrective Actions: If re-analysis was not possible (such as lack of sample volume), the data was qualified with a determination about the impact on the sample data.

Table B16. QA/QC requirements for analysis for $\delta^{13}C$ and δD of light hydrocarbons for aqueous and gas samples		
QC Type	**Performance Criteria**	**Frequency**
Mass Spec Calibration Check	Difference of calibrated/true ≤ 0.5‰ for $\delta^{13}C$ and ≤ 3‰ for δD +/- 1 pMC for ^{14}C	One at beginning of day and after samples are analyzed for $\delta^{13}C$*; one at beginning of day and every tenth sample for δD**
Mass Spec Zero Enrichment Check	0 +/- 0.1 ‰ for $\delta^{13}C$ and 0 +/- 1 ‰ for δD	Once a day for $\delta^{13}C$ and every tenth sample for δD
Lab Duplicates	≤ 1 ‰ for $\delta^{13}C$ and ≤ 3‰ for δD +/- 1 pMC for ^{14}C	1 per every 10 samples for $\delta^{13}C$ and δD ***
Preparation System Check/Reference Standards	≤ 1 ‰ for $\delta^{13}C$ and ≤ 3‰ for δD +/- 1 pMC	One per every 10 samples for $\delta^{13}C$ and δD

*Working standards calibrated against IAEA (International Atomic Energy Agency) standard LSVEC and NBS-19; referenced to $\delta^{13}C$ of the PeeDee belemnite (NIST material).
**Working standards calibrated against VSMOW, SLAP, and GISP; referenced to VSMOW.
***If < 10 samples were submitted, duplicate run regardless of total number.
Corrective Actions: If re-analysis is not possible (such as lack of sample volume), the data will be qualified with a determination about the impact on the sample data.

Table B17. QA/QC requirements for analysis of fixed gases and light hydrocarbons for aqueous and gas samples						
Measurement	**Analysis Method**	**Blanks (Frequency)**	**Calibration Checks (Frequency)**	**Second Source (Frequency)**	**Duplicates (Frequency)**	**Matrix Spikes (Frequency)**
Ar, He, H_2, O_2, N_2, CO_2, CH_4, C_2H_6, C_2H_4, C_3H_6, C_3H_8, iC_4H_{10}, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, C_6+	Modification of ASTM D1945-03	None Detected (beginning every 10 samples, end of run)	85-115% (beginning every 10 samples, end of run)	85-115% (after each calibration)	RPD <15% (every 10 samples)	NA

Table B18. Summary of quality control samples, purpose, method, and frequency to support gas analysis

QC Sample	Purpose	Method	Frequency	Acceptance Criteria
Equipment Blanks	Ensure that construction materials in gas sample bags and the sample train are not a source of vapors or gases of concern	Fill sample bags with ultrapure N_2 gas via the sample train.	One sample per day	< Detection limit
Travel Blanks	Ensure that cross-contamination does not occur during sampling or transport to the laboratory	Fill sample bags with ultrapure N_2 gas and place in shipping container with other samples.	One sample per shipment	< Detection limit
Duplicates	Check precision of sampling method and analysis	Use a tee to collect two samples simultaneously.	One sample every 10 samples	RPD < 20%

Table B19. Summary of analytes, instruments, calibration, and check standards for portable gas analyzers

Analyte	Instrument (Detector)	Method	Range	Calibration	Check Standard	Accuracy
O_2	GEM-2000 Plus CES-LANDTEC (EC Cell)	RSKSOP-314v1	0 - 21%	4%, 10%, or 20.9%	4% 10%, 20.9%	±1.0% (0-5%) ±1.0% (5-21%)
CH_4	GEM-2000 Plus CES-LANDTEC (IRGA)	RSKSOP-314v1	0 - 100%	2.5% or 50%	2.5%, 50%	±0.3% (0-5%) ±1% (5-15%) ±3% (15-100%)
CO_2	GEM-2000 Plus CES-LANDTEC (IRGA)	RSKSOP-314v1	0 - 100%	5%, 20%, or 35%	5%, 20%, 35%	±0.3% (0-5%) ±1.0% (5-15%) ±3.0% (15-50%)
VOCs	Thermo Scientific TVA-1000B (FID)	RSKSOP-320v1	1.0 – 10,000 ppmv	0.0, 10, 100, 1000, 9000 ppmv CH_4	10, 100, 1000, 9000 ppmv CH_4	±25% or ±2.5 ppmv, whichever is greater, from 1.0 to 10,000 ppmv.
VOCs	Thermo Scientific TVA-1000B (PID)	RSKSOP-320v1	0.5 – 500 ppmv	0.0, 250, 475 ppmv	250, 475 ppmv Isobutylene	±25% or ±2.5 ppmv, whichever is greater, from 0.5 to 500 ppmv.

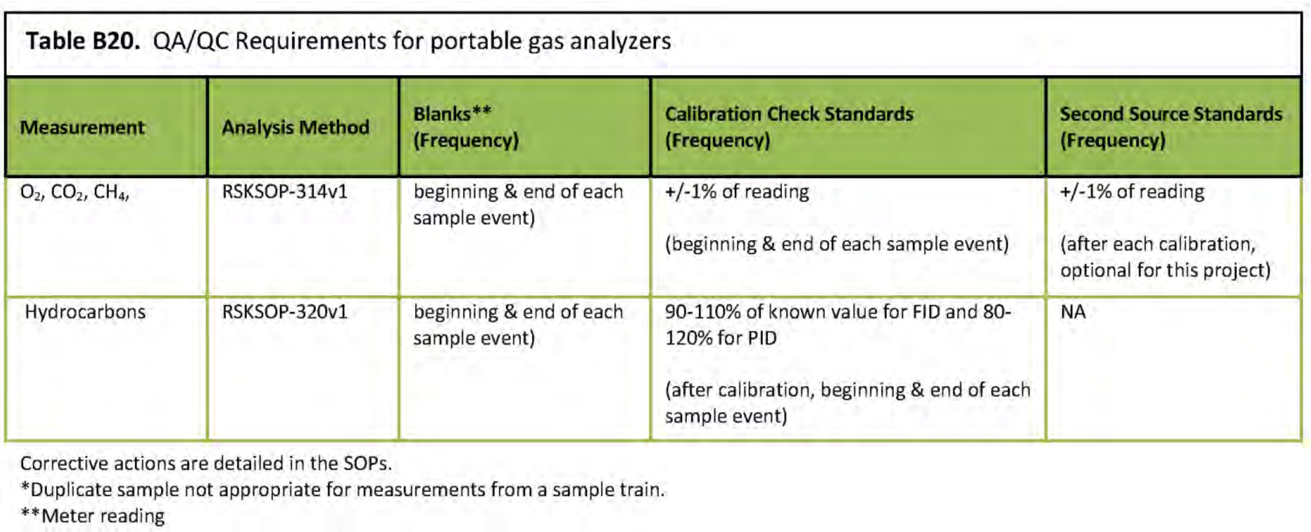

Table B20. QA/QC Requirements for portable gas analyzers

Measurement	Analysis Method	Blanks** (Frequency)	Calibration Check Standards (Frequency)	Second Source Standards (Frequency)
O_2, CO_2, CH_4,	RSKSOP-314v1	beginning & end of each sample event)	+/-1% of reading (beginning & end of each sample event)	+/-1% of reading (after each calibration, optional for this project)
Hydrocarbons	RSKSOP-320v1	beginning & end of each sample event)	90-110% of known value for FID and 80-120% for PID (after calibration, beginning & end of each sample event)	NA

Corrective actions are detailed in the SOPs.
*Duplicate sample not appropriate for measurements from a sample train.
**Meter reading

Appendix C

Photographic Log of Deep Monitoring Well Construction

Figure C1. Photograph of drilling rig on platform with shakers for mud recirculation at MW02.

Figure C2. Photograph of blowout prevention (BOP) for annular space at base of drilling rig platform at MW02.

Figure C3. Photograph of blowout preventer for drillstem.

Figure C4. Photograph of bit and drillstem with bit for mud rotary drilling at MW02.

Figure C5. Photograph of water truck used to transport water to mix mud.

Figure C6. Photograph of Quik-Gel bentonite (Halliburton) used to create mud for drilling.

Figure C7. Photograph of mud additives EZ Mud Gold (Halliburton) and Dense Soda Ash.

Figure C8. Photograph of mud additive Penetrol (Halliburton).

Figure C9. Photograph of flow of mud and cuttings from borehole at MW02.

Figure C10. Photograph of monitoring of mud and cuttings using a Thermo Scientific TVA-1000B FID/PID at MW02.

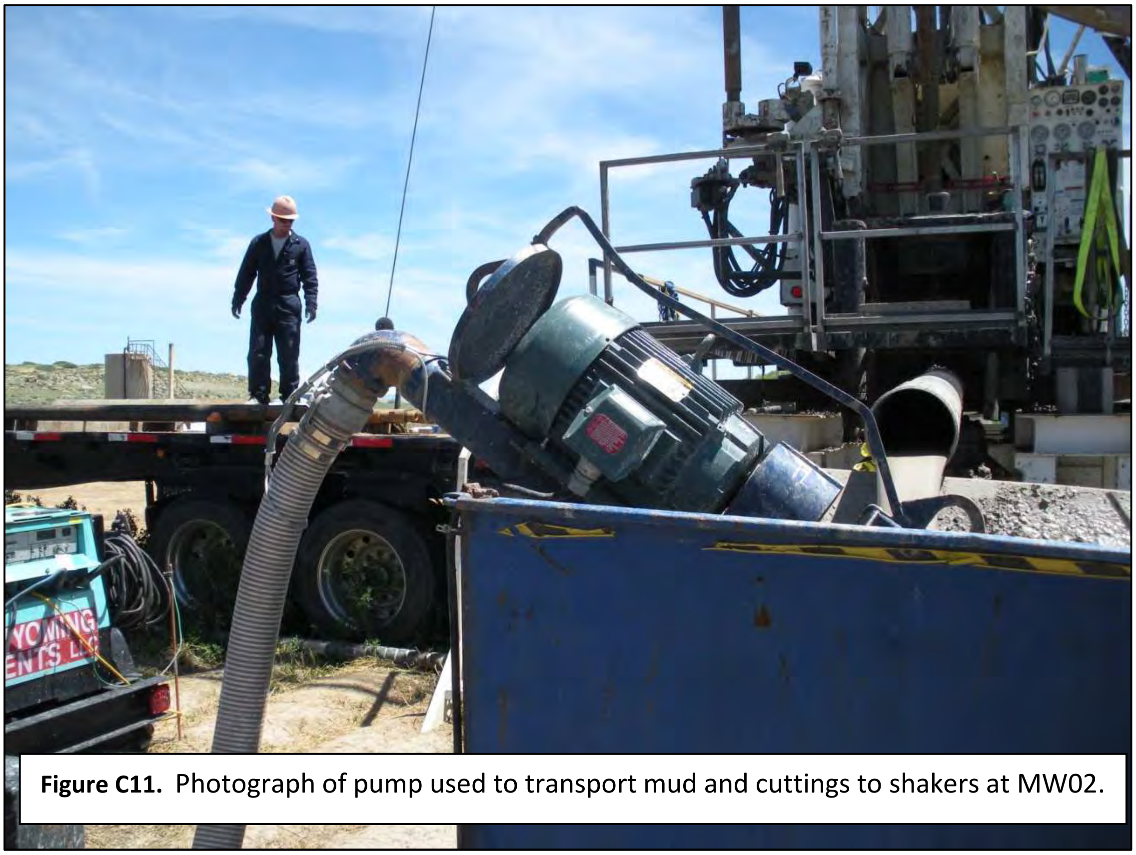

Figure C11. Photograph of pump used to transport mud and cuttings to shakers at MW02.

Figure C12. Photograph of flow of mud and cuttings to shakers at MW02.

Figure C13. Photograph of shakers separating mud from cuttings at MW02.

Figure C14. Photograph of cuttings transported to disposal bins at MW02.

Figure C15. Photograph of pumping of mud back to borehole at MW02.

Figure C16. Photograph of injection of mud to borehole at MW02.

Figure C17. Photograph of collection of cuttings for lithologic characterization at MW02.

Figure C18. Photograph of removal of mud from cuttings at MW02.

Figure C19. Photograph of white coarse-grained sand targeted by local well drillers and media in which screens are set in for both deep monitoring wells.

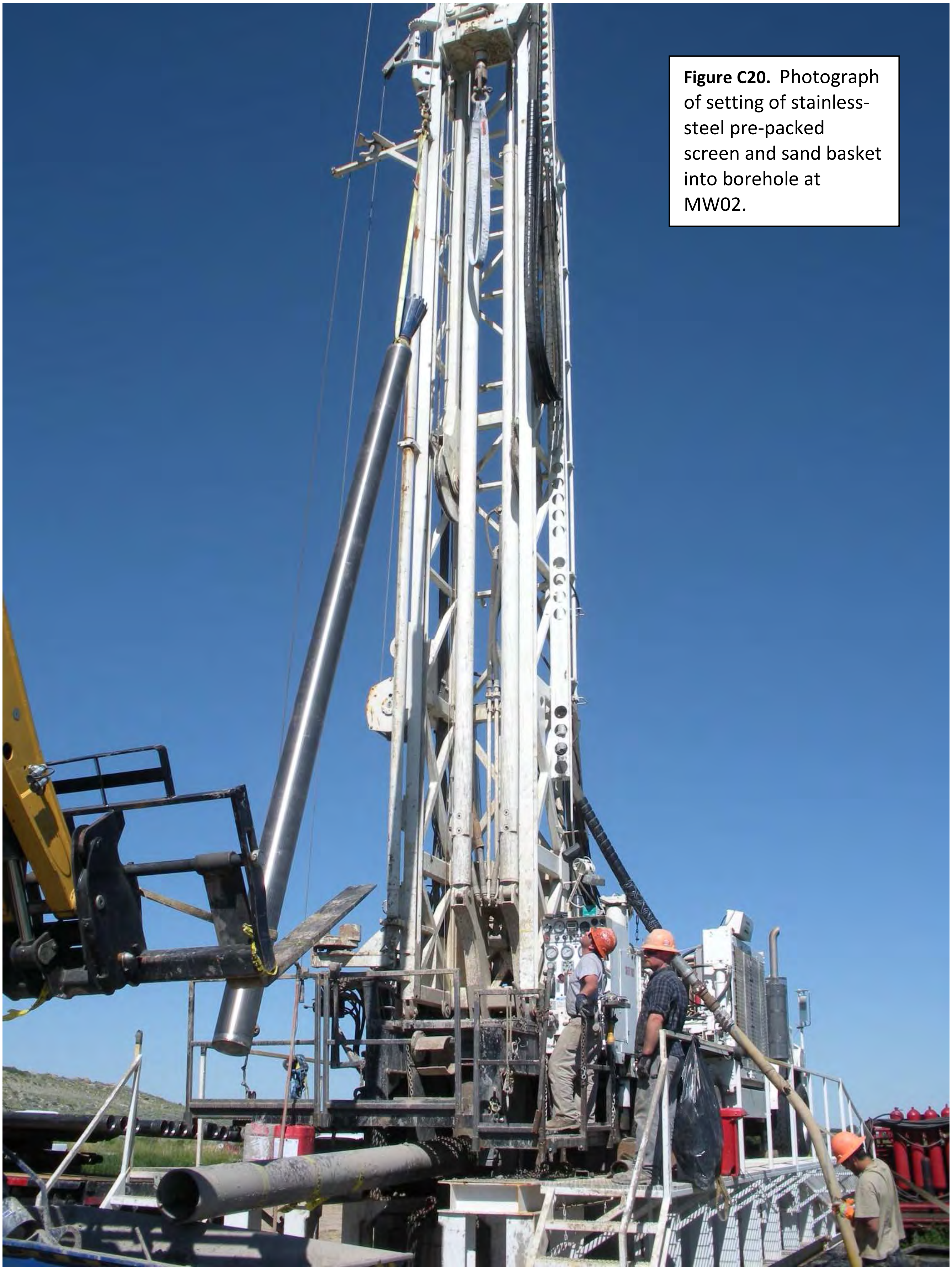

Figure C20. Photograph of setting of stainless-steel pre-packed screen and sand basket into borehole at MW02.

Figure C21. Photograph of securing sand basket and casing above screen.

Figure C22. Photograph of placement of sand in sandbasket.

Figure C23. Photograph of well development at MW02.

Appendix D

Photographic Log of Ground Water Sampling

Figure D1. Photograph of flow from submersible pump through flowmeter at MW02.

Figure D2. Photograph of flow of water to purge water disposal tank at MW02.

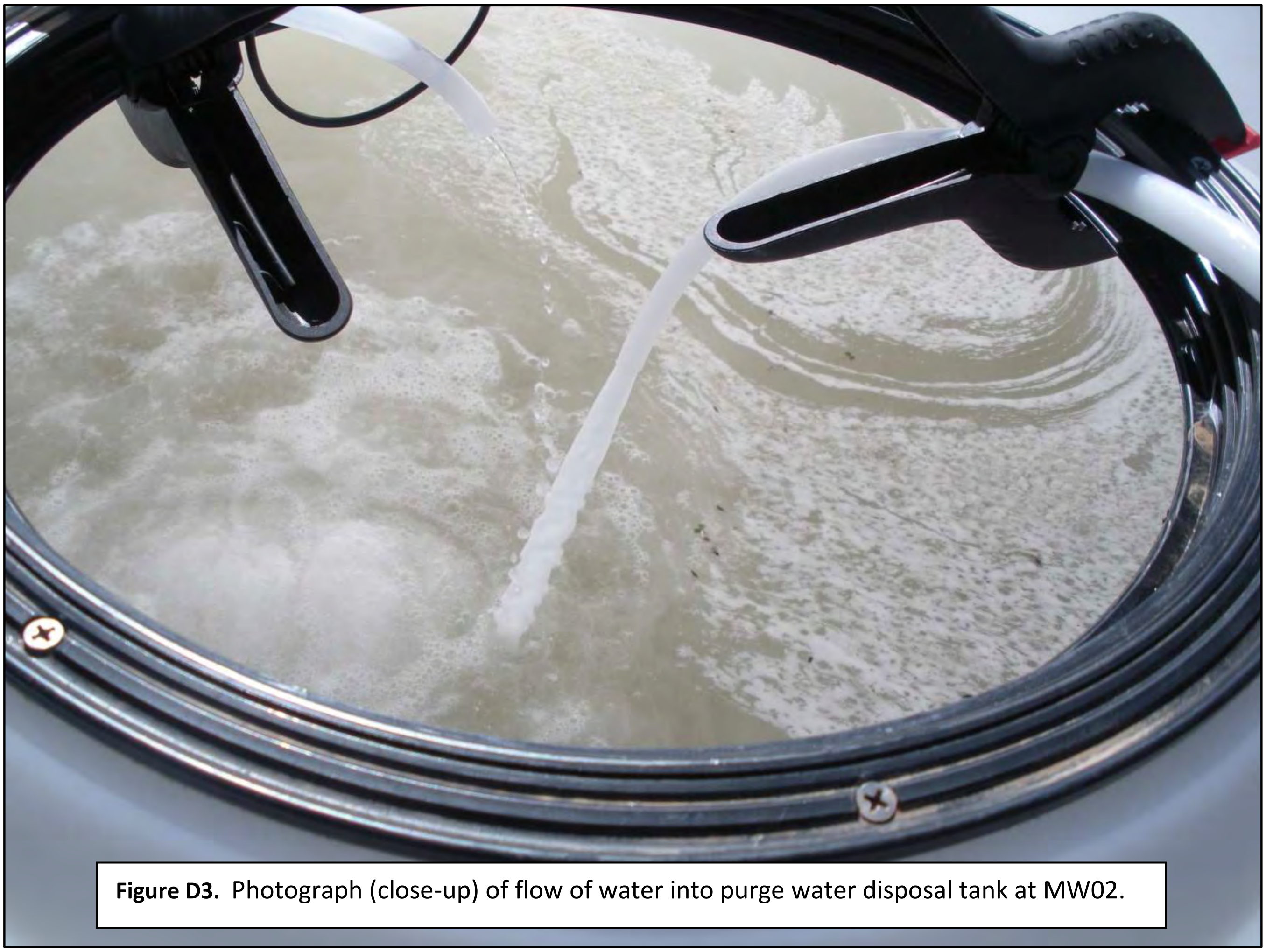

Figure D3. Photograph (close-up) of flow of water into purge water disposal tank at MW02.

Figure D4. Photograph of water (foaming) flowing into YSI flow cell at MW02.

Figure D5. Photograph of sampling at MW02. The sample train was split prior to entry into purge water disposal container.

Figure D6. Photograph of field filtering samples for metals analysis at MW02.

Figure D7. Photograph of sample collection at PGDW14.

Figure D8. Photograph of cooler packed with samples for shipment.

Appendix E

Examples of Cement Bond/Variable Density Log Interpretation

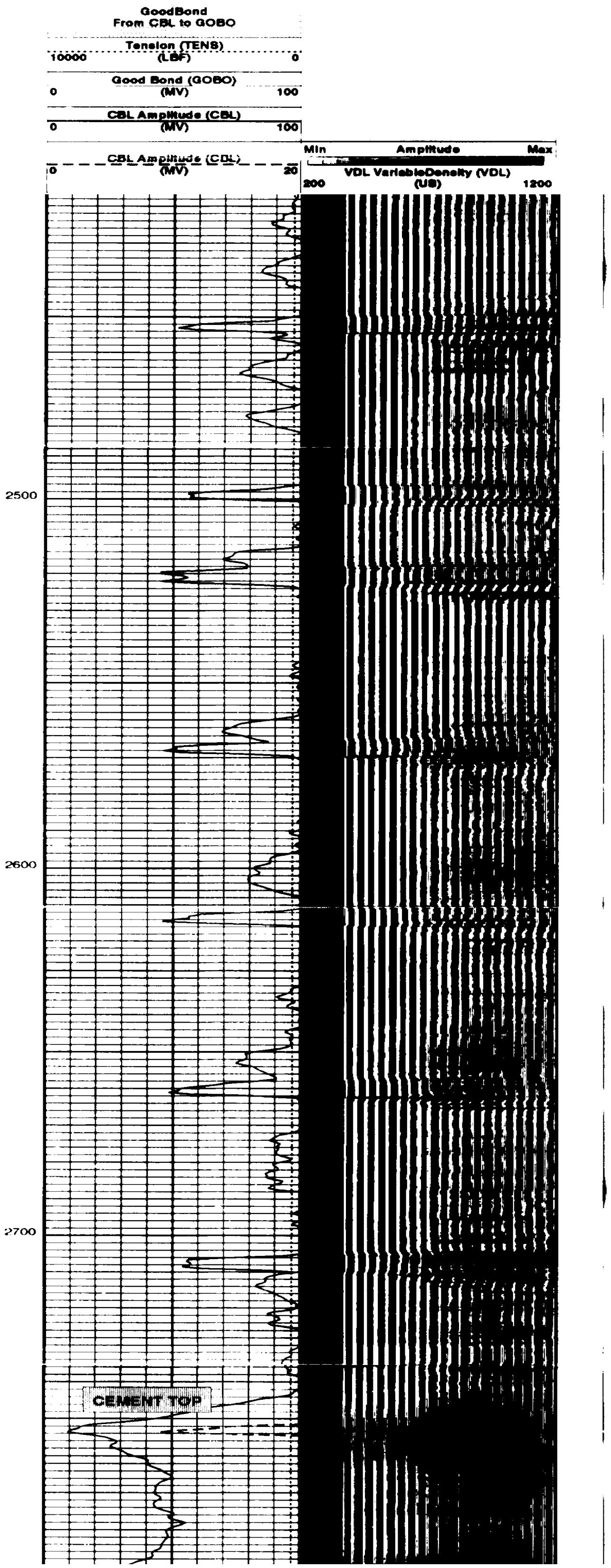

Figure E1. Example of CBL/VDL indicating "no cement" at Pavillion Fee 34-03B. The CBL/VDL indicates no cement 2750 feet below ground surface at the time of logging.

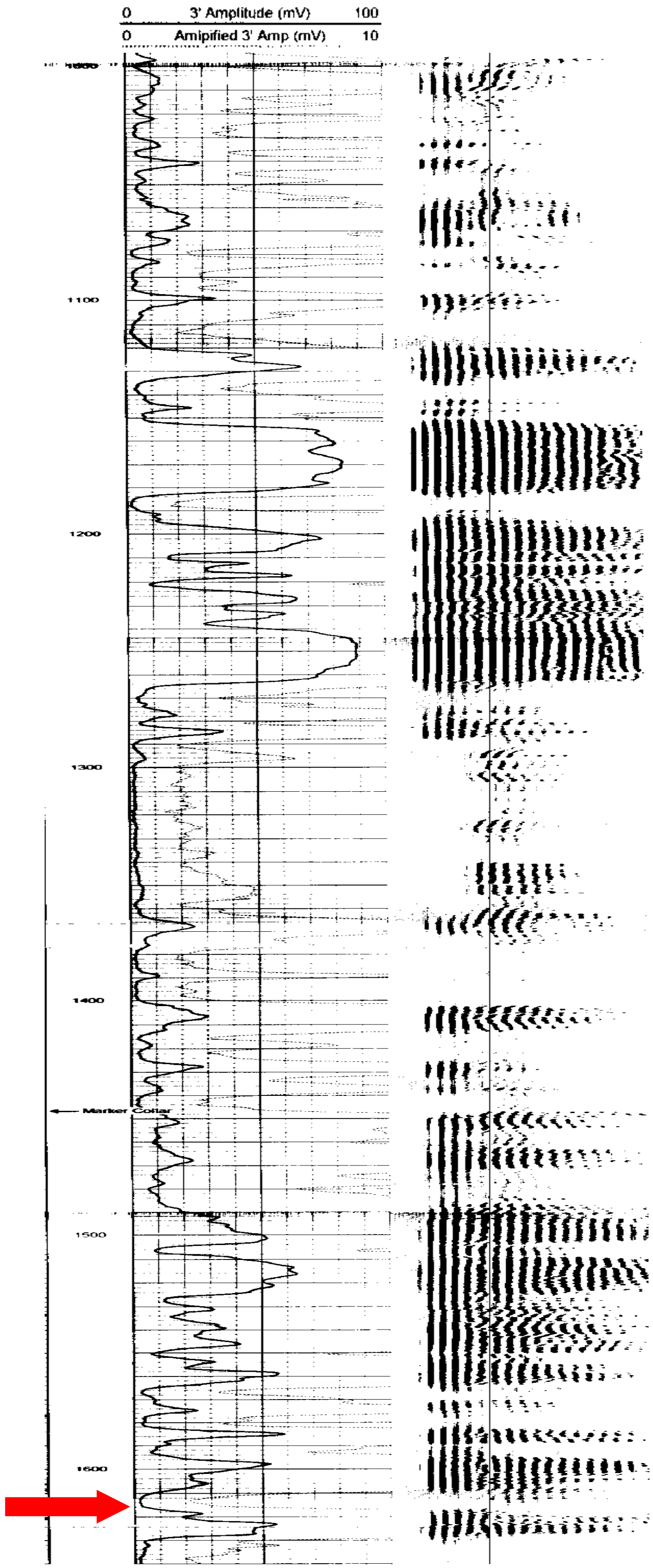

Figure E2. Example of "sporadic bonding" at Pavillion Fee 41-10 from 1000 to 1640 ft bgs. Hydraulic fracturing occurred at 1618 feet below ground surface. Arrow denotes interval of hydraulic fracturing.

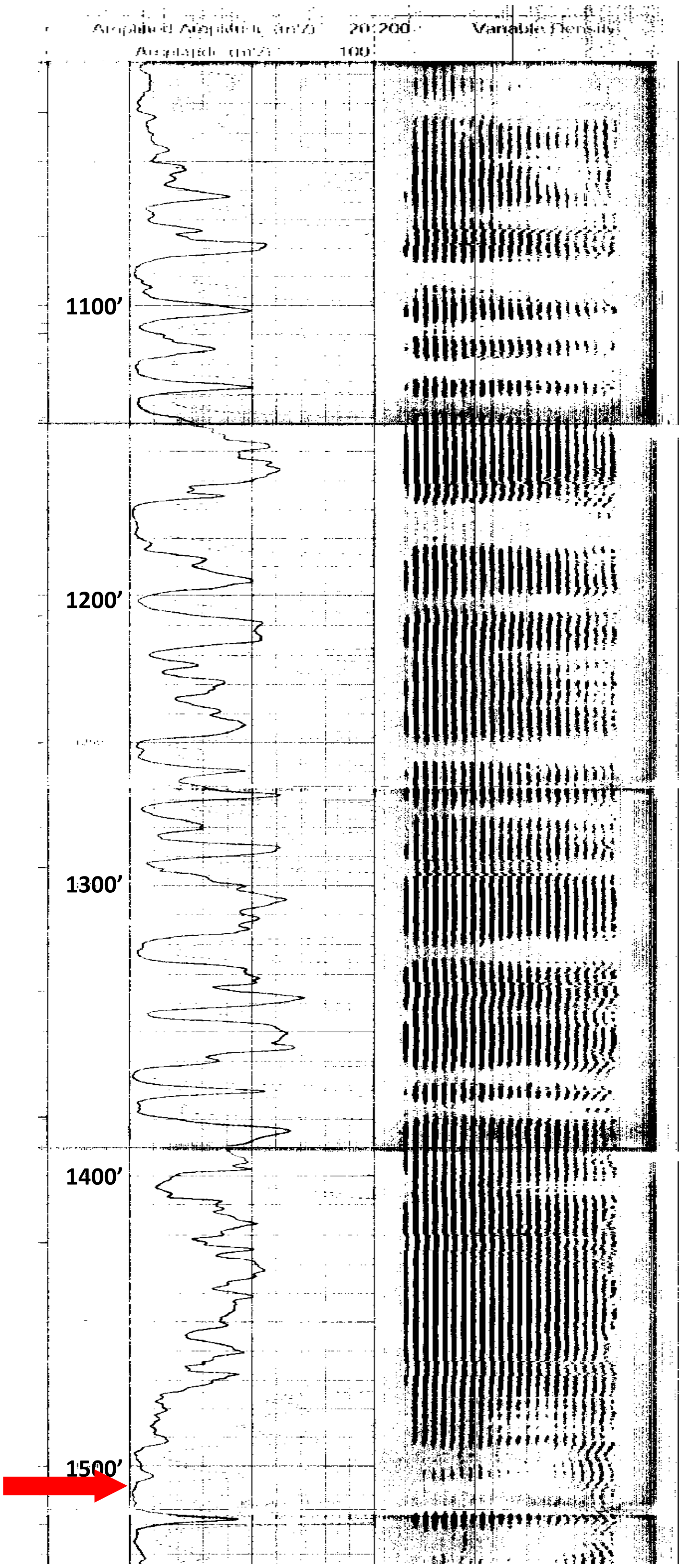

Figure E3a. Example of "sporadic bonding" at Pavillion Fee 11-11B. Hydraulic fracturing occurred at 1516 feet below ground surface. Arrow denotes interval of hydraulic fracturing. Depths on CBL/VDL difficult to read and inserted on left margin.

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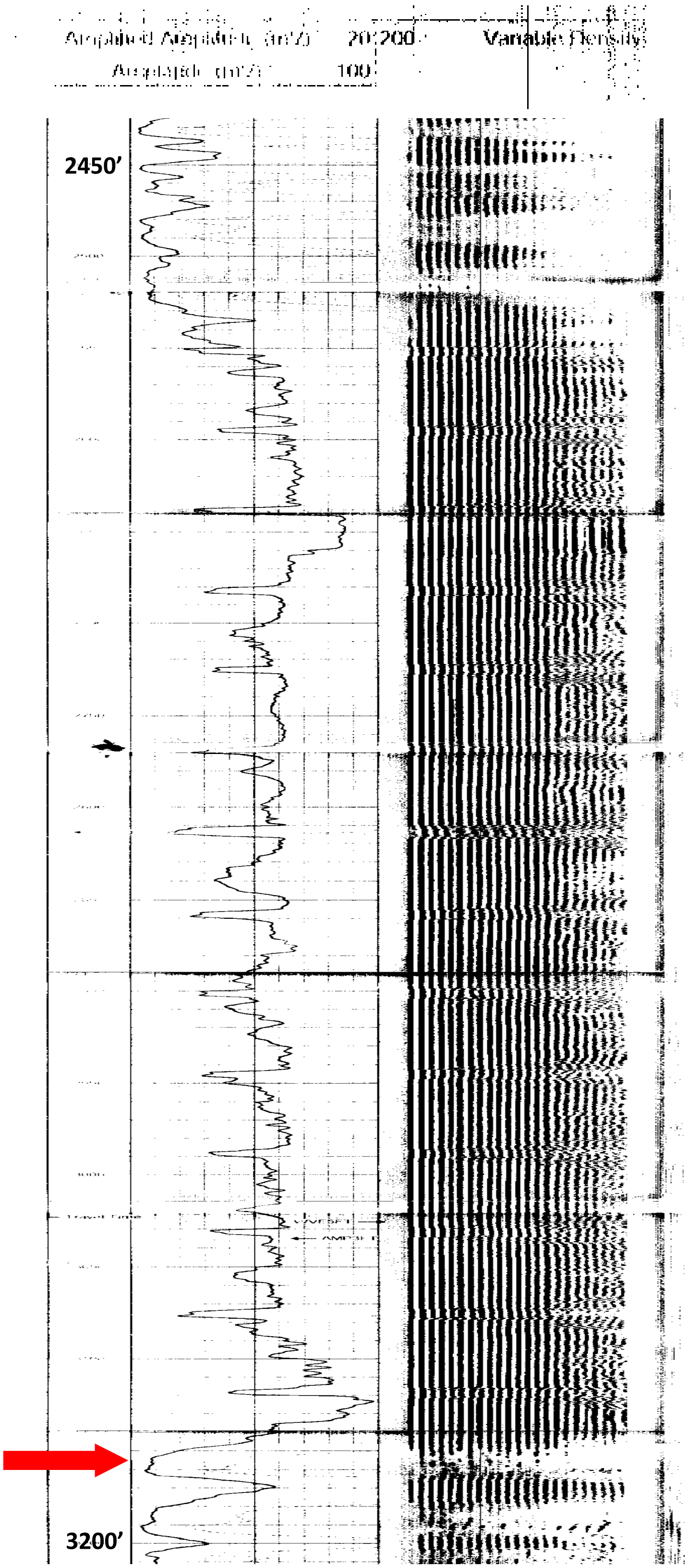

Figure E3b. Example of "sporadic bonding" Pavillion Fee 11-11B between 2350-3200 feet below ground suface. Hydraulic fracturing occurred at 3165 feet below ground surface. Arrow denotes interval of hydraulic fracturing. Depths on CBL/VDL difficult to read and inserted on left margin.

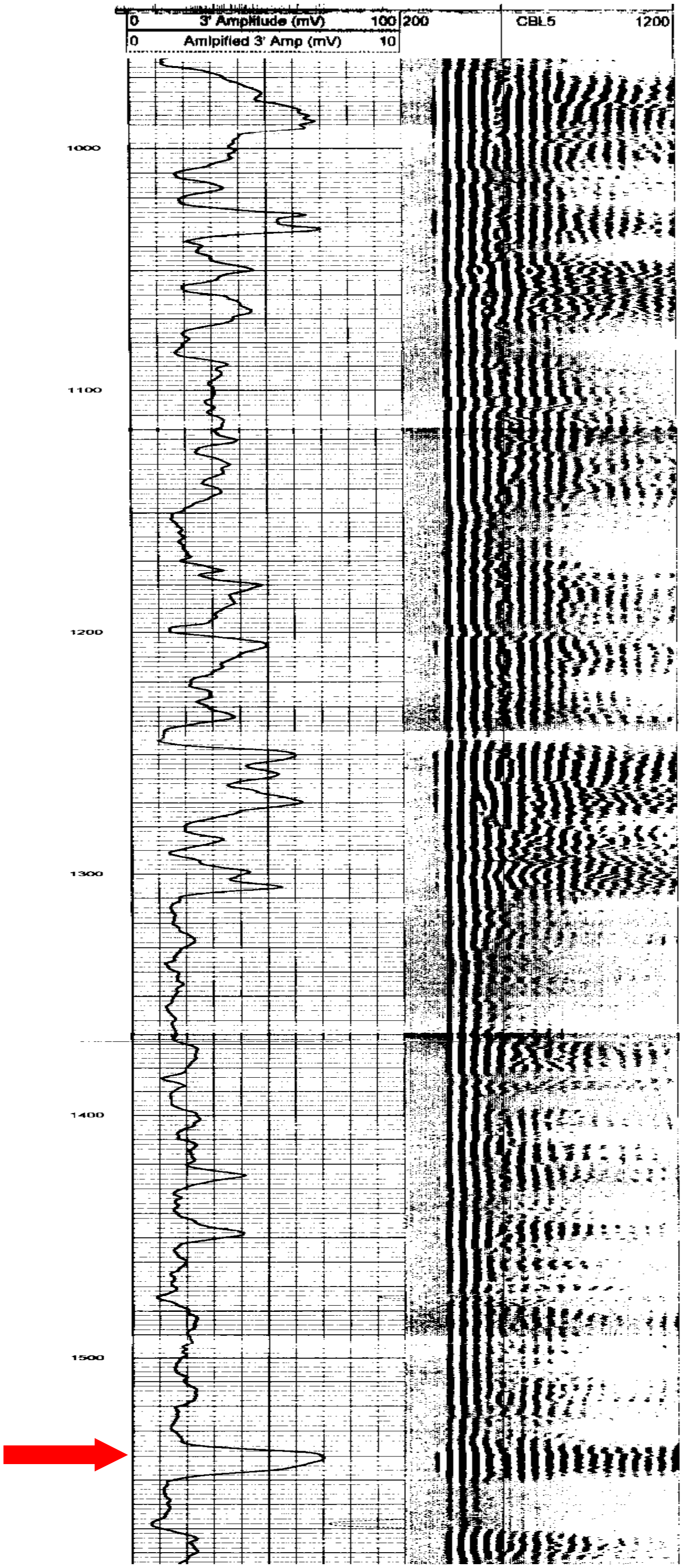

Figure E4. Example of "Sporadic Bonding" at Tribal Pavillion 24-02. Hydraulic fracturing occurred at 1538 feet bgs. Arrow denotes interval of hydraulic fracturing.

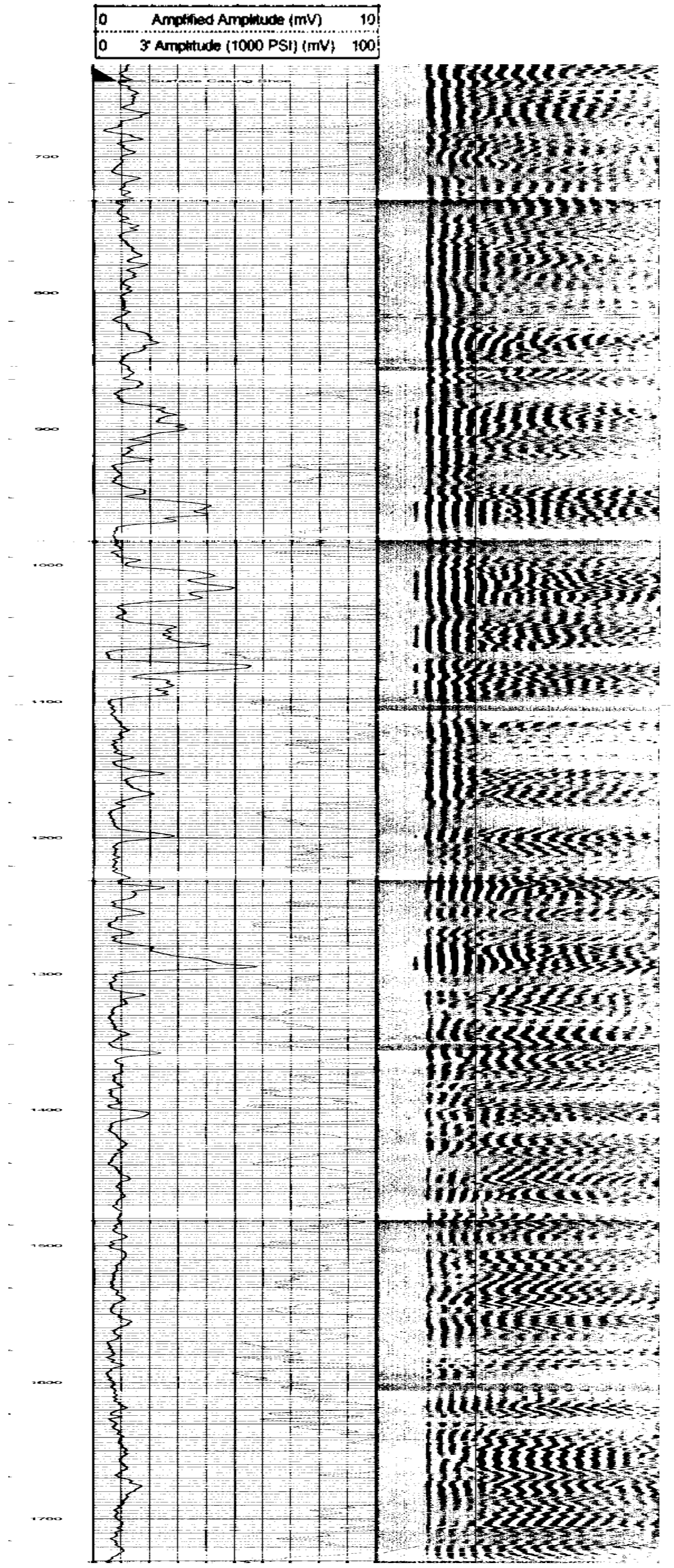

Figure E5. Example of "Good Bonding" (from surface casing at 645 ft bgs to 820 ft bgs) followed by "Sporadic Bonding" (from 820 ft bgs 1310 ft bgs) to "Good Bonding" at 1310 to target depth at Pavillion Fee 41-10B.

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Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United States

By U.S. Geological Survey Oil and Gas Assessment Team

Open-File Report 2012–1118

U.S. Department of the Interior
U.S. Geological Survey

U.S. Department of the Interior
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U.S. Geological Survey, Reston, Virginia: 2012

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Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United States

By U.S. Geological Survey Oil and Gas Assessment Team

Abstract

Since 2000, the U.S. Geological Survey has completed assessments of continuous (unconventional) resources in the United States based on geologic studies and analysis of well-production data. This publication uses those 132 continuous oil and gas assessments to show the variability of well productivity within and among the 132 areas. The production from the most productive wells in an area commonly is more than 100 times larger than that from the poorest productive wells. The 132 assessment units were classified into four categories: shale gas, coalbed gas, tight gas, and continuous oil. For each category, the mean well productivity in the most productive assessment units is considerably greater than that of the least productive assessment units.

Introduction

The U.S. Geological Survey (USGS) conducts quantitative assessments of potential oil and gas resources of the onshore United States and State waters. Since 2000, 132 assessments have been performed for continuous (unconventional) oil and gas resources, based on geologic studies and analysis of well-production data. Assessment methods are documented in Crovelli (2000, 2003), Klett and Charpentier (2003), Klett and Schmoker (2003), and Schmoker (2003). Each assessment unit (AU) was divided into cells, with each cell representing a well-drainage area. The estimates of resource potential were derived from estimates of the potential number of undrilled productive cells and of the productive capacities of those cells.

Estimated ultimate recovery (EUR) distributions were estimated for each AU, based on decline-curve analysis from monthly production data (IHS Energy, 2011) of hundreds to thousands of wells per AU. The EUR distribution used for each assessment calculation was specifically that for undrilled cells. Commonly, this EUR distribution for undrilled cells is closely similar to the distribution for drilled cells. In general, wells drilled early in the development of an AU, before drilling and completion techniques are optimized, have relatively low EURs. This can cause the estimated EURs for undrilled cells to be higher than those for drilled wells. Conversely, if the geologically most favorable parts of the AU have already been drilled, the EURs for undrilled cells may be lower than those of drilled wells.

The 132 AUs were classified into four categories: shale gas, coalbed gas, tight gas, and continuous oil. This categorization facilitated use of these data as analogs for hypothetical AUs. Sources for reports of these assessments are listed in appendix 1.

Estimated Ultimate Recovery Distributions

Shifted truncated lognormal distributions were fit using the minimum, median, and maximum input values of estimated ultimate recovery (EUR). The upper end of the distribution was truncated at the 0.1 percent (1 in 1000) fractile.

$$\mu = \ln(EUR_{med} - EUR_{min})$$

$$\sigma = \frac{\ln((EUR_{max} - EUR_{min})/(EUR_{med} - EUR_{min}))}{3.09}$$

$$E(x) = exp\left(\mu + (\sigma^2/2)\right) * \frac{normsdist((\ln(EUR_{max}) - \mu - \sigma^2)/\sigma)}{normsdist((\ln(EUR_{max}) - \mu)/\sigma)}$$

$$E(x^2) = exp(2\mu + 2\sigma^2) * \frac{normsdist((\ln(EUR_{max}) - \mu - 2\sigma^2)/\sigma)}{normsdist((\ln(EUR_{max}) - \mu)/\sigma)}$$

$$EUR_{mean} = EUR_{min} + E(x)$$

$$EUR_{sd} = \sqrt{E(x^2) - E(x)^2}$$

where:

EUR_{min} = minimum EUR

EUR_{med} = median EUR

EUR_{max} = maximum EUR

EUR_{mean} = mean EUR

EUR_{sd} = standard deviation of EUR

normsdist = normal distribution function

The input values, as well as the calculated mean for each distribution, are given in tables 1 to 4.

Table 1. Input data for estimated ultimate recovery distributions for United States shale-gas assessment units, values in billions of cubic feet of natural gas. [AU, assessment unit; and EUR, estimated ultimate recovery]

AU number	AU name	Province	Year assessed	Minimum EUR	Median EUR	Maximum EUR	Mean EUR
50490161	Haynesville Sabine Platform Shale Gas	Gulf Coast Mesozoic	2010	0.02	2	20	2.617
50490163	Mid-Bossier Sabine Platform Shale Gas	Gulf Coast Mesozoic	2010	0.02	1	10	1.308
50580161	Woodford Shale Gas	Anadarko Basin	2010	0.02	0.8	15	1.233
50670468	Interior Marcellus	Appalachian Basin	2011	0.02	0.8	12	1.158
50490167	Eagle Ford Shale Gas	Gulf Coast Mesozoic	2010	0.02	0.8	10	1.104
50620362	Fayetteville Shale Gas - High Gamma-Ray Depocenter	Arkoma Basin	2010	0.02	0.8	10	1.104
50450161	Greater Newark East Frac-Barrier Continuous Barnett Shale Gas	Bend Arch-Fort Worth Basin	2003	0.02	0.7	10	1.000
50440161	Delaware/Pecos Basins Woodford Continuous Shale Gas	Permian Basin	2007	0.02	0.6	8	0.842
50440162	Delaware/Pecos Basins Barnett Continuous Shale Gas	Permian Basin	2007	0.02	0.6	8	0.842
50580261	Thirteen Finger Limestone-Atoka Shale Gas	Anadarko Basin	2010	0.02	0.5	10	0.785
50620261	Woodford Shale Gas	Arkoma Basin	2010	0.02	0.5	10	0.785
50210364	Gothic, Chimney Rock, Hovenweep Shale Gas	Paradox Basin	2011	0.02	0.4	10	0.672
50630561	Devonian Antrim Continuous Gas	Michigan Basin	2004	0.02	0.4	4	0.523
50620363	Fayetteville Shale Gas - Western Arkansas Basin Margin	Arkoma Basin	2010	0.02	0.3	6	0.470
50210362	Cane Creek Shale Gas	Paradox Basin	2011	0.02	0.3	5	0.446
50440163	Midland Basin Woodford/Barnett Continuous Gas	Permian Basin	2007	0.02	0.3	5	0.446
50490165	Maverick Basin Pearsall Shale Gas	Gulf Coast Mesozoic	2010	0.02	0.25	5	0.391
50450162	Extended Continuous Barnett Shale Gas	Bend Arch-Fort Worth Basin	2003	0.02	0.2	5	0.334
50390761	Niobrara Chalk	Denver Basin	2001	0.025	0.2	2	0.261
50620262	Chattanooga Shale Gas	Arkoma Basin	2010	0.02	0.1	6	0.223
50670467	Foldbelt Marcellus	Appalachian Basin	2011	0.02	0.1	5	0.208
50620364	Caney Shale Gas	Arkoma Basin	2010	0.02	0.08	5	0.179
50670469	Western Margin Marcellus	Appalachian Basin	2011	0.02	0.05	5	0.129
50640361	Devonian to Mississippian New Albany Continuous Gas	Illinois Basin	2007	0.01	0.08	1	0.110
50670462	Northwestern Ohio Shale	Appalachian Basin	2002	0.01	0.04	0.5	0.055
50670463	Devonian Siltstone and Shale	Appalachian Basin	2002	0.01	0.03	0.5	0.044

Table 2. Input data for estimated ultimate recovery distributions for United States coalbed-gas assessment units, values in billions of cubic feet of natural gas. [AU, assessment unit; and EUR, estimated ultimate recovery]

AU number	AU name	Province	Year assessed	Minimum EUR	Median EUR	Maximum EUR	Mean EUR
50220181	Fruitland Fairway Coalbed Gas	San Juan Basin	2002	0.02	8	40	9.125
50200181	Northern Coal Fairway/Drunkards Wash	Uinta-Piceance	2000	0.05	0.8	12	1.156
50220182	Basin Fruitland Coalbed Gas	San Juan Basin	2002	0.02	0.6	20	1.110
50200182	Central Coal Fairway/Buzzards Bench	Uinta-Piceance	2000	0.05	0.4	10	0.666
50010181	Nanushuk Formation Coalbed Gas	Northern Alaska	2006	0.02	0.25	12	0.524
50410182	Vermejo Coalbed Gas	Raton Basin-Sierra Grande Uplift	2004	0.02	0.25	9.5	0.481
50200281	Uinta Basin Blackhawk Coalbed Gas	Uinta-Piceance	2000	0.05	0.25	10	0.480
50360281	Frontier-Adaville-Evanston Coalbed Gas	Wyoming Thrust Belt	2003	0.02	0.4	2	0.456
50410181	Raton Coalbed Gas	Raton Basin-Sierra Grande Uplift	2004	0.02	0.25	8	0.453
50650281	Warrior Basin	Warrior Basin	2002	0.01	0.25	5	0.392
50620481	Arkoma Coalbed Gas	Arkoma Basin	2010	0.02	0.3	3	0.392
50330182	Upper Fort Union Formation	Powder River Basin	2000	0.02	0.23	4	0.345
50200183	Southern Coal Fairway	Uinta-Piceance	2000	0.05	0.2	5	0.328
50210581	Kaiparowits Plateau	Paradox Basin	2011	0.02	0.2	4	0.312
50010183	Sagavanirktok Formation Coalbed Gas	Northern Alaska	2006	0.02	0.18	5	0.310
50330181	Wasatch Formation	Powder River Basin	2000	0.02	0.18	3	0.267
50370882	Fort Union Coalbed Gas	Southwestern Wyoming	2002	0.02	0.2	1.5	0.246
50670581	Pocahontas Basin	Appalachian Basin	2002	0.01	0.15	2	0.210
50350281	Mesaverde Coalbed Gas	Wind River Basin	2005	0.02	0.1	5	0.208
50030281	Cook Inlet Coalbed Gas	Southern Alaska	2011	0.02	0.16	1.5	0.206
50370881	Lance Coalbed Gas	Southwestern Wyoming	2002	0.02	0.15	1	0.180
50200282	Mesaverde Group Coalbed Gas	Uinta-Piceance	2000	0.02	0.08	5	0.179
50220381	Menefee Coalbed Gas	San Juan Basin	2002	0.02	0.08	5	0.179
50200185	Southern Coal Outcrop	Uinta-Piceance	2001	0.05	0.1	3	0.165
50670582	Eastern Dunkard Basin	Appalachian Basin	2002	0.01	0.1	2	0.156
50040381	Eocene Coalbed Gas	Western Oregon-Washington	2009	0.02	0.1	2	0.155
50010182	Prince Creek–Tuluvak Formations Coalbed Gas	Northern Alaska	2006	0.02	0.1	1.5	0.143
50340281	Mesaverde-Meeteetse Formation Coalbed Gas	Big Horn Basin	2008	0.02	0.1	1.2	0.136
50350282	Meeteetse Coalbed Gas	Wind River Basin	2005	0.02	0.08	2	0.131
50350283	Fort Union Coalbed Gas	Wind River Basin	2005	0.02	0.08	2	0.131
50370682	Fort Union Coalbed Gas	Southwestern Wyoming	2002	0.02	0.1	1	0.130
50370981	Wasatch-Green River Coalbed Gas	Southwestern Wyoming	2002	0.02	0.1	0.8	0.124
50311081	Fort Union Coalbed Gas	Williston Basin	2008	0.02	0.085	1	0.114
50330183	Lower Fort Union-Lance Formations	Powder River Basin	2000	0.02	0.085	1	0.114
50340282	Fort Union Formation Coalbed Gas	Big Horn Basin	2008	0.02	0.08	1	0.109
50370581	Mesaverde Coalbed Gas	Southwestern Wyoming	2002	0.02	0.06	2	0.106
50370681	Mesaverde Coalbed Gas	Southwestern Wyoming	2002	0.02	0.06	2	0.106
50470381	Wilcox Coalbed Gas	Western Gulf	2007	0.01	0.05	0.5	0.065
50640481	Desmoinesian-Virgilian Coalbed Gas	Illinois Basin	2007	0.01	0.03	0.25	0.037
50470281	Cretaceous Olmos Coalbed Gas	Western Gulf	2007	0.01	0.03	0.1	0.032

Table 3. Input data for estimated ultimate recovery distributions for United States tight-gas assessment units, values in billions of cubic feet of natural gas. [AU, assessment unit; and EUR, estimated ultimate recovery]

AU number	AU name	Province	Year assessed	Minimum EUR	Median EUR	Maximum EUR	Mean EUR
50370661	Mesaverde-Lance-Fort Union Continuous Gas	Southwestern Wyoming	2002	0.02	1.2	15	1.657
50370561	Almond Continuous Gas	Southwestern Wyoming	2002	0.02	0.9	20	1.460
50200261	Uinta Basin Continuous Gas	Uinta-Piceance	2000	0.02	0.5	40	1.293
50030161	Tuxedni-Naknek Continuous Gas	Southern Alaska	2011	0.02	0.6	30	1.286
50620161	Arkoma-Ouachita Foredeep Continuous	Arkoma Basin	2010	0.02	0.6	30	1.286
50350261	Frontier-Muddy Continuous Gas	Wind River Basin	2005	0.02	0.7	15	1.123
50370261	Mowry Continuous Gas	Southwestern Wyoming	2002	0.02	0.7	15	1.123
50350265	Lance-Fort Union Sandstone Gas	Wind River Basin	2005	0.02	0.6	20	1.110
50370861	Lance-Fort Union Continuous Gas	Southwestern Wyoming	2002	0.02	0.8	10	1.104
50370761	Lewis Continuous Gas	Southwestern Wyoming	2002	0.02	0.6	15	1.009
50200362	Uinta Basin Continuous Gas	Uinta-Piceance	2000	0.02	0.5	16	0.911
50200263	Piceance Basin Continuous Gas	Uinta-Piceance	2000	0.02	0.5	15	0.892
50350264	Mesaverde-Meeteetse Sandstone Gas	Wind River Basin	2005	0.02	0.5	15	0.892
50350262	Cody Sandstones Continuous Gas	Wind River Basin	2005	0.02	0.4	20	0.855
50670364	Tuscarora Basin Center	Appalachian Basin	2002	0.01	0.7	4	0.817
50220261	Lewis Continuous Gas	San Juan Basin	2002	0.02	0.5	6	0.683
50220361	Mesaverde Central-Basin Continuous Gas	San Juan Basin	2002	0.02	0.5	6	0.683
50220363	Dakota-Greenhorn Continuous Gas	San Juan Basin	2002	0.02	0.4	8	0.627
50370461	Hilliard-Baxter-Mancos Continuous Gas	Southwestern Wyoming	2002	0.02	0.4	8	0.627
50200161	Deep (6,000 feet plus) Coal and Sandstone Gas	Uinta-Piceance	2000	0.2	0.5	4	0.617
50200262	Uinta Basin Transitional Gas	Uinta-Piceance	2000	0.02	0.25	15	0.570
50340261	Muddy-Frontier Sandstone and Mowry Fractured Shale Continuous Gas	Big Horn Basin	2008	0.02	0.35	7.5	0.560
50220362	Mancos Sandstones Continuous Gas	San Juan Basin	2002	0.02	0.35	5	0.499
50370562	Rock Springs-Ericson Continuous Gas	Southwestern Wyoming	2002	0.02	0.4	3	0.491
50200361	Piceance Basin Continuous Gas	Uinta-Piceance	2000	0.02	0.25	10	0.490
50280163	Eagle Sandstone and Claggett Shale West	North-Central Montana	2000	0.01	0.25	9	0.475
50220161	Pictured Cliffs Continuous Gas	San Juan Basin	2002	0.02	0.25	7	0.434
50280162	Eagle Sandstone and Claggett Shale East	North-Central Montana	2000	0.01	0.2	7	0.375

Table 3. Input data for estimated ultimate recovery distributions for United States tight-gas assessment units, values in billions of cubic feet of natural gas. [AU, assessment unit; and EUR, estimated ultimate recovery]—Continued

AU number	AU name	Province	Year assessed	Minimum EUR	Median EUR	Maximum EUR	Mean EUR
50200363	Uinta-Piceance Transitional and Migrated Gas	Uinta-Piceance	2000	0.02	0.2	7	0.373
50200264	Piceance Basin Transitional Gas	Uinta-Piceance	2000	0.02	0.25	4	0.367
50280166	Greenhorn-Upper Belle Fourche	North-Central Montana	2000	0.01	0.2	6	0.356
50280167	Bowdoin Dome	North-Central Montana	2000	0.01	0.2	5	0.336
50340263	Cody Sandstone Continuous Gas	Big Horn Basin	2008	0.02	0.2	5	0.334
50340264	Mesaverde Sandstone Continuous Gas	Big Horn Basin	2008	0.02	0.2	5	0.334
50280165	Greenhorn-Lower Belle Fourche	North-Central Montana	2000	0.01	0.25	2.5	0.327
50050161	Columbia Basin Continuous Gas	Eastern Oregon and Washington	2006	0.02	0.2	3	0.288
50390662	Dakota Group Basin-Center Gas	Denver Basin	2001	0.02	0.2	2.5	0.275
50670461	Greater Big Sandy	Appalachian Basin	2002	0.01	0.15	2	0.210
50330461	Shallow Continuous Biogenic Gas	Powder River Basin	2002	0.01	0.08	1.5	0.122
50670361	Clinton-Medina Basin Center	Appalachian Basin	2002	0.01	0.08	1.2	0.115
50670465	Catskill Sandstones and Siltstones	Appalachian Basin	2002	0.01	0.07	1.5	0.111
50280161	Judith River Formation	North-Central Montana	2000	0.01	0.06	2	0.109
50280164	Niobrara-Carlile	North-Central Montana	2000	0.01	0.07	1	0.099
50670363	Clinton-Medina Transitional	Appalachian Basin	2002	0.01	0.06	1	0.089
50670362	Clinton-Medina Transitional Northeast	Appalachian Basin	2002	0.01	0.06	0.9	0.086
50670466	Berea Sandstone	Appalachian Basin	2002	0.01	0.03	0.5	0.044

Table 4. Input data for estimated ultimate recovery distributions for United States continuous-oil assessment units, values in millions of barrels of oil. [AU, assessment unit; and EUR, estimated ultimate recovery]

AU number	AU name	Province	Year assessed	Minimum EUR	Median EUR	Maximum EUR	Mean EUR
50310164	Eastern Expulsion Threshold	Williston Basin	2008	0.002	0.12	5	0.241
50310163	Nesson-Little Knife Structural	Williston Basin	2008	0.002	0.09	4	0.185
50210361	Cane Creek Shale Oil	Paradox Basin	2011	0.002	0.08	3	0.154
50310165	Northwest Expulsion Threshold	Williston Basin	2008	0.002	0.065	4	0.151
50310161	Elm Coulee-Billings Nose	Williston Basin	2008	0.002	0.08	2	0.135
50270561	Marias River Shale Continuous Oil	Montana Thrust Belt	2002	0.001	0.08	1.6	0.126
50370361	Niobrara Continuous Oil	Southwestern Wyoming	2002	0.001	0.08	1.6	0.126
50300361	Niobrara Continuous Oil	Hanna, Laramie, Shirley Basins	2005	0.001	0.04	1.6	0.079
50310162	Central Basin-Poplar Dome	Williston Basin	2008	0.002	0.025	2	0.064
50210363	Gothic, Chimney Rock, Hovenweep Shale Oil	Paradox Basin	2011	0.002	0.03	1.5	0.064
50580162	Woodford Shale Oil	Anadarko Basin	2010	0.003	0.03	1.5	0.064
50200561	Deep Uinta Overpressured Continuous Oil	Uinta-Piceance	2000	0.003	0.045	0.45	0.059
50440165	Spraberry Continuous Oil	Permian Basin	2007	0.001	0.045	0.4	0.057
50490170	Eagle Ford Shale Oil	Gulf Coast Mesozoic	2010	0.002	0.03	1	0.055
50490168	Austin Pearsall-Giddings Area Oil	Gulf Coast Mesozoic	2010	0.002	0.04	0.5	0.055
50330361	Niobrara Continuous Oil	Powder River Basin	2002	0.002	0.028	0.5	0.042
50330261	Mowry Continuous Oil	Powder River Basin	2002	0.002	0.025	0.35	0.035
50340262	Mowry Fractured Shale Continuous Oil	Big Horn Basin	2008	0.002	0.025	0.35	0.035
50390261	Fractured Niobrara Limestone (Silo Field Area)	Denver Basin	2001	0.002	0.022	0.4	0.033
50390661	Niobrara-Codell (Wattenberg Area)	Denver Basin	2001	0.003	0.008	0.1	0.011

Results

The results are presented in figures 1 through 4. Each line shows the range of EURs for a single AU. Only those EURs greater than the minimum assessed value (for that particular AU assessment) are included. Individual AU distributions show approximately two orders of magnitude difference between the smallest and largest EURs within a single AU. This range would be even larger if the distributions were not truncated.

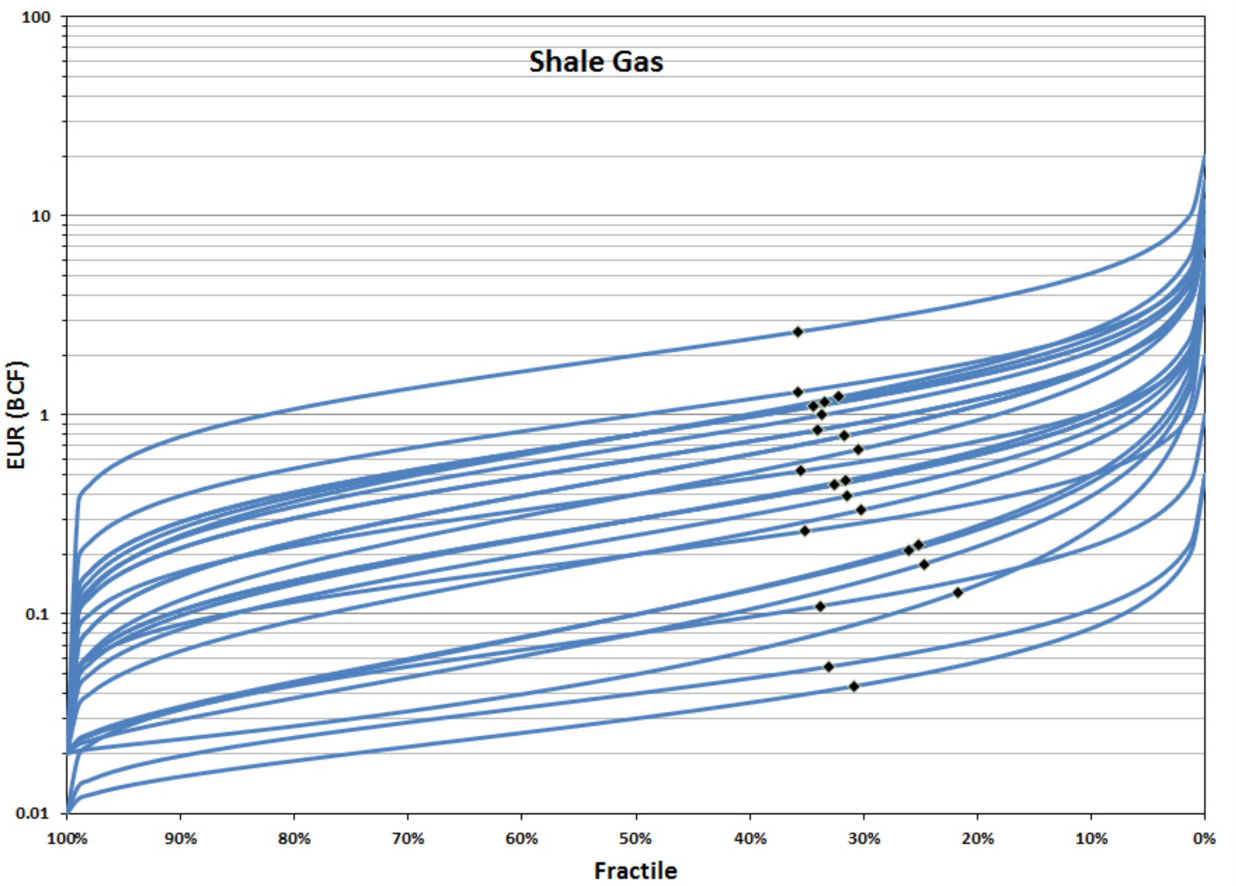

Figure 1. Cloud plot for United States shale-gas assessment units. Each curve represents one assessment unit and is based on the input data in table 1. Black diamonds indicate the mean value for each curve. [AU, assessment unit; EUR, estimated ultimate recovery; and BCF, billions of cubic feet]

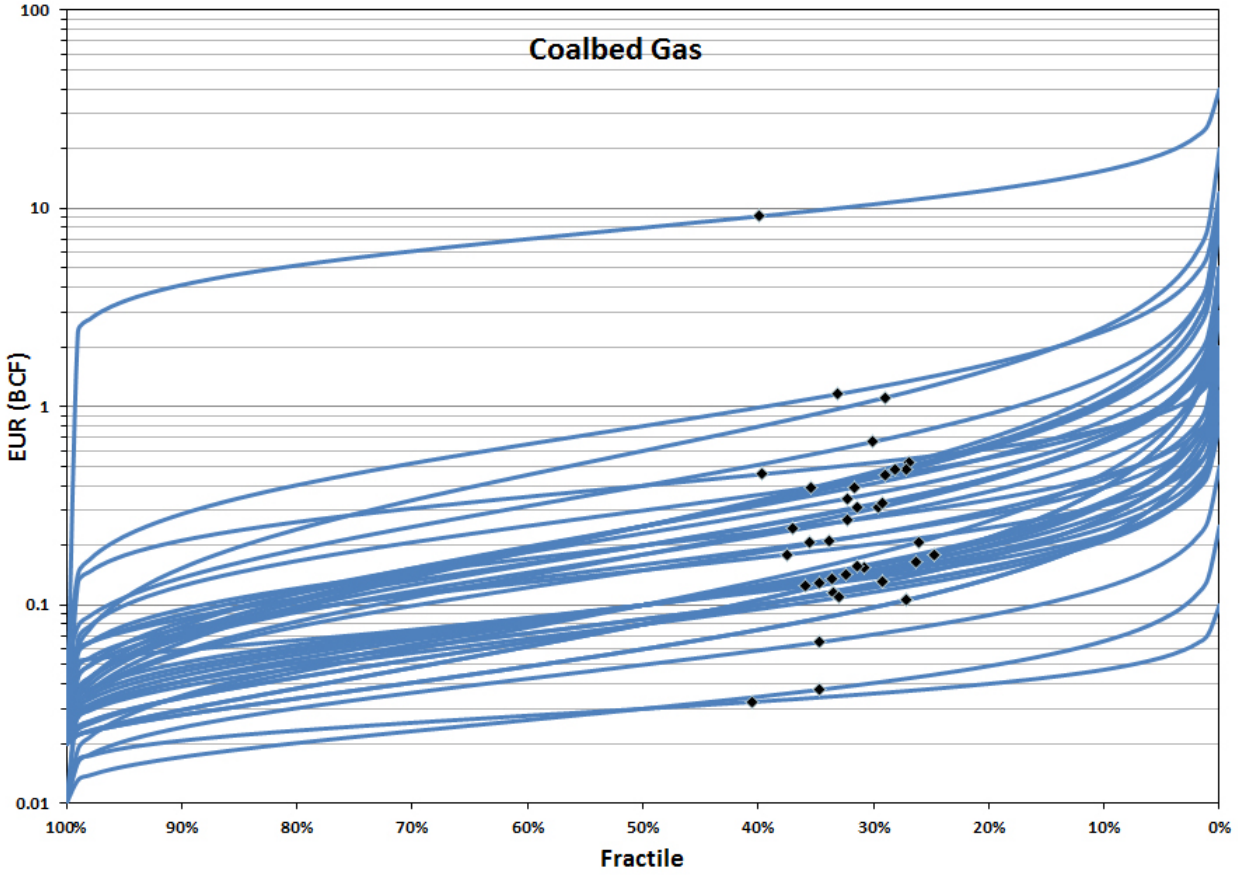

Figure 2. Cloud plot for United States coalbed-gas assessment units. Each curve represents one assessment unit and is based on the input data in table 2. Black diamonds indicate the mean value for each curve. [AU, assessment unit; EUR, estimated ultimate recovery; and BCF, billions of cubic feet]

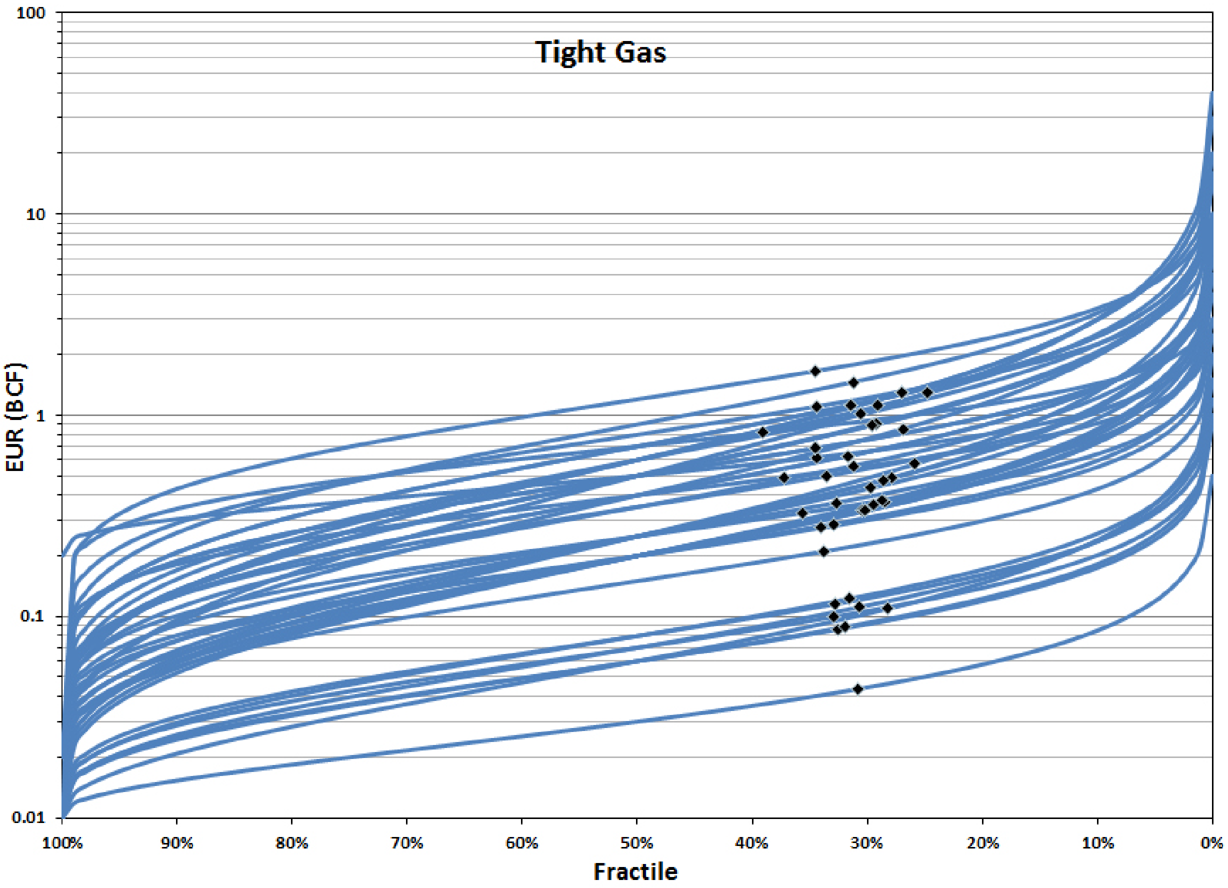

Figure 3. Cloud plot for United States tight-gas assessment units. Each curve represents one assessment unit and is based on the input data in table 3. Black diamonds show the mean value for each curve. [AU, assessment unit; EUR, estimated ultimate recovery; and BCF, billions of cubic feet]

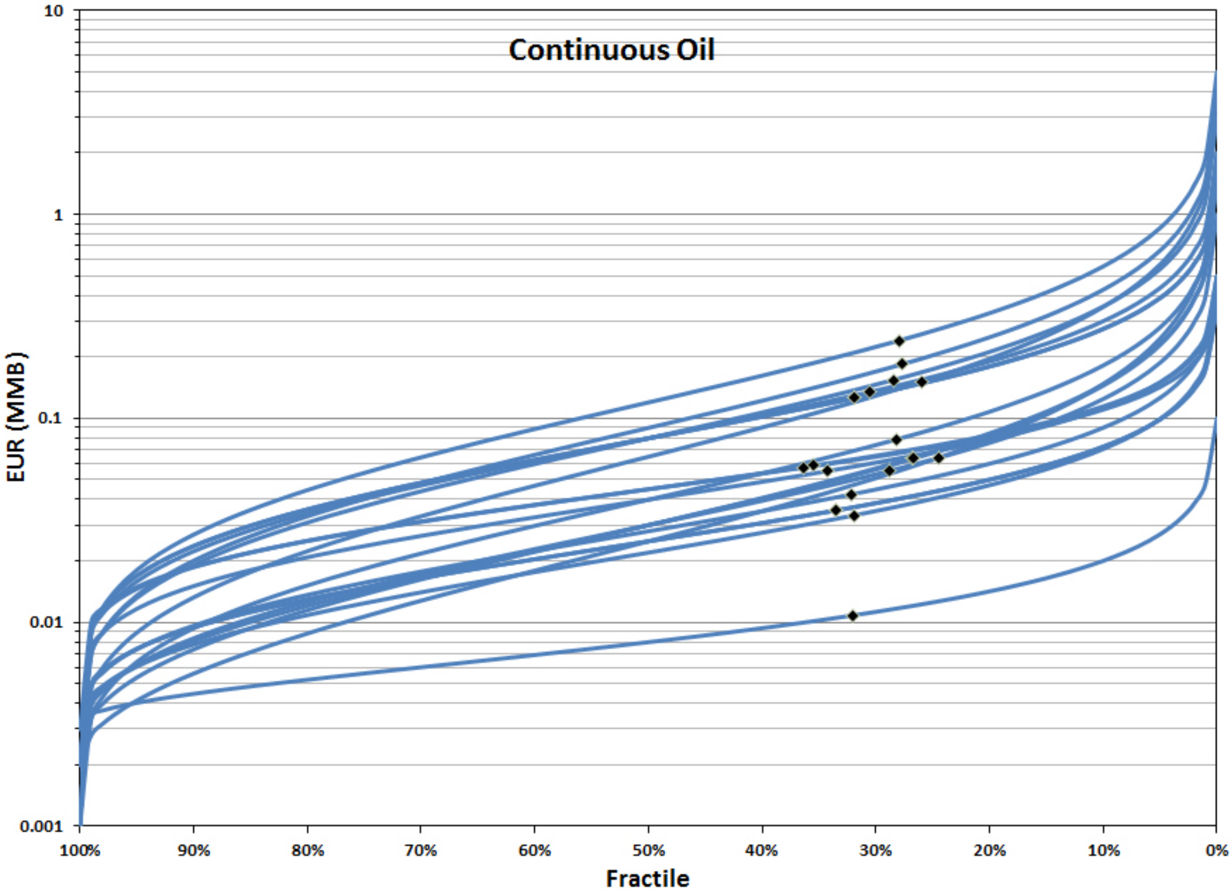

Figure 4. Cloud plot for United States continuous-oil assessment units. Each curve represents one assessment unit and is based on the input data in table 4. Black diamonds indicate the mean value for each curve. [AU, assessment unit; EUR, estimated ultimate recovery; and MMB, millions of barrels]

Each figure shows the EUR curves for a single category (shale gas, coalbed gas, tight gas, and continuous oil), allowing comparison of EUR distributions among AUs. The four figures are termed "cloud plots," which show the "cloud" of data representing the distribution of EUR distributions. Cloud plots of the distributions of drilled wells show similar ranges of variability.

Individual cloud plots show the wide variability among AUs of a particular category. The most productive AUs have average EURs from 22 to almost 300 times those of the least productive AUs. Also note the strong similarity of the shale gas and tight gas clouds (figs. 1, 3).

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ATSDR Record of Activity/ Technical Assist

UID #: IBD7 Date: 12/28/2011 Time: 12:00 am pm X

Site Name: Dimock Area City: Dimock State: Pennsylvania

CERCLIS #:______ Cost Recovery #: 3ATA00 Region: 3

Site Status (1) NPL Non-NPL RCRA Non-Site specific Federal
(2) Emergency Response Remedial _Removal Other

Activities

Incoming Call
Outgoing Call
X Conference Call
Incoming Mail
Public Meeting*
Other Meeting
X Data Review
Other
X Health Consult*
_ Health Referral
Written Response
Site Visit*
Info Provided
Training

Requestor: Jon Capacasa, EPA Region 3 Water Protection Division

NARRATIVE SUMMARY

On December 7, 2011, EPA Region 3 requested ATSDR conduct an evaluation of available Dimock private well data, stating that "residents are potentially in contact through dermal, inhalation and ingestion pathways, if you should identify any potential health threats please notify us as soon as possible." In order to conduct an immediate preliminary evaluation of the large data set as requested by EPA, on December 9, 2011, ATSDR Region 3 requested support from ATSDR Emergency Response in Atlanta. Home owners and numerous other concerned citizens contacted EPA and ATSDR in November 2011 asking for help in evaluating the well sampling data and requesting that alternative supplies of drinking water continue to be supplied to the residents. Following the residents' request, EPA acquired a large amount of summarized data tables regarding the Dimock site concern. After communicating with PADEP, EPA and ATSDR visited the Dimock homes along Carter Road and State Route 3023 on November 10, 2011 and were provided a large amount of well data. Based on the home visits and preliminary review of data, EPA and ATSDR raised the following concerns: the reliability of methane removal systems; the presence of other contaminants besides methane (metals, volatile organics and non-naturally occurring organics) for which the well treatment systems are not designed or in place to address; and homes/wells in Dimock that may have never been tested and may be contaminated. The multiple sampling efforts at this site to date were conducted by PADEP and private contractors not affiliated with EPA.

The site area is located in Dimock, a rural area of northeastern Pennsylvania in Susquehanna County. A map of the area is included as Attachment 1. Cabot began natural gas drilling in the Dimock area in 2008. Methane contamination was detected in private wells soon thereafter. The Pennsylvania Department of Environmental Protection (PADEP) has had the lead in investigating the environmental complaints in Dimock. After first calling for the provision of public water, which the State Public Utility Commission vetoed based on cost and feasibility, in November 2009 (last amended December 2010), PADEP issued a consent agreement with Cabot for methane and metals removal systems for eighteen private wells in the site area. The agreement calls for each well owner to enter into the agreement with Cabot. Until the treatment systems are installed, Cabot was to provide delivered water. There are eighteen wells that are part of the PADEP/Cabot agreement. Six well owners have signed agreements and have systems installed. However, most of them are buying bottled water because they do not have confidence that the treatment systems are working. Twelve well owners have not signed the agreement and are part of a civil suit. These 12 owners were being provided delivered water by Cabot. However on November 30, 2011, Cabot ceased delivering water to these homes.

PADEP approved the stoppage of water delivery scheduled for November 30, 2011 on the grounds that Cabot has allowed sufficient time for residents to sign the agreement and that a remedy for home owners has been provided. However, other private wells appear to exist in the site area. The exact number of these other private wells has not been confirmed by EPA or ATSDR at this time. These additional wells are not part of the existing PADEP/Cabot agreement, and very little if any sampling data are currently available for these wells.

DISCUSSION

ATSDR Division of Regional Operations received the water sampling data for the 18 properties that are part of the consent order between Cabot and PADEP. This information was provided to EPA and ATSDR Division of Regional Operations from PADEP and the legal representative for some of the residents. ATSDR Division of Regional Operations prepared a summary of this information for ATSDR Emergency Response. The data package provided to ATSDR Emergency Response for this review consisted of maximum concentrations reported over numerous sampling events over several years. It is not possible from this summary to evaluate the changes in conditions over time or determine if there is any potential synergism from the chemicals involved. Note, it is fairly unusual for metal contamination to be detected in field blanks, as was documented in the summary sampling data provided. Therefore, the quality control of the field sampling methods needs to be further evaluated. At this time, the full quality assurance/quality control information for these sampling data has not been provided to EPA or ATSDR.

Based on the maximum results for the approximately 18 wells sampled, levels of coliform bacteria, methane, ethylene glycol, bis(2-ethylhexyl) phthalate (DEHP), 2-methoxyethanol, aluminum, arsenic, lithium, manganese, sodium, and iron were elevated above comparison values (CVs).

Bacteriological/Coliform Results

CDC/NCEH (National Center for Environmental Health) reviewed the summary sampling results for bacteriological contamination. The review of the coliform data concluded that bacteria were detected in 9 of the 18 private wells. Any detection of coliform in drinking water supplies is of potential health concern. Total coliform bacteria are "indicators" used to determine if a pathway exists that might allow disease-causing bacteria to contaminate the water supply. E. coli bacteria are a subset of coliform bacteria that only occur in animal or human wastes and indicate more serious contamination. The coliform results were particularly elevated in five of the wells (in two cases noted by the laboratory as too high to count). Prior studies of private well water in Pennsylvania have found that approximately one third of private wells have total coliform detections Higher incidences of total coliform bacteria have been found in the southeast and southwest regions of Pennsylvania, while the lowest incidence was observed in the northwest and northeast regions (Swistock et al 2009).

Combustible Gas Results

In the summary data set provided, methane levels ranged from 79 μg/L dissolved in water to 64,300 μg/L dissolved in water. A level of 28,000 μg/L methane dissolved in water was used as a comparison level for the methane detections in these private wells. This level is based on the recommended action levels (RALs) from the Department of the Interior Office of Surface Mining Reclamation and Enforcement (DOI 2001). Elevated concentrations of methane can produce explosive environments. Additional combustible gases, including butanes, propane, ethane and ethene were also identified in many of the well sample results. Of the approximately 18 private wells in this data set, ten had maximum dissolved methane levels higher than 28,000 ug/L. Methane venting systems were offered to the 18 properties that are part of the Cabot/PADEP order. ATSDR and EPA do not have precise information at this time about which of the approximately 18 private wells for which sampling data are available have functioning methane venting systems at this time.

Methane is a simple asphyxiant (at around 87% by volume). Asphyxiants displace oxygen from air primarily in enclosed spaces. This can result in insufficient oxygen in the blood and eventual asphyxiation. Exposure to low oxygen environments (such as resulting from methane displacement) produces symptoms of central nervous depression, including nausea, headache, dizziness, confusion, fatigue, and weakness.

Organic Chemical Detections

Not all the private wells in this data set were analyzed for organic constituents. For the subset of these private wells that did have organic analyses conducted, a number of organic compounds were detected. These organic detections included glycols and phthalates, both used extensively in the natural gas field. Glycol detections included ethylene glycol, triethylene glycol, and 2,2'oxybisethanol (diethylene glycol). For ethylene glycol, ATSDR has identified an intermediate exposure duration (14 days to 364 days) drinking water ingestion CV of 8,000 μg/L for children and 30,000 μg/L for adults. EPA has identified an ethylene glycol lifetime health advisory (LTHA) value of 14,000 μg/L. Some wells had all three reported glycols present in their wells, including ethylene glycol, triethylene glycol and 2,2'oxybisethanol.

All of the glycol sampling detections (with the exception of the maximum ethylene glycol result of 8,410 ug/L) were data qualified with a "J" indicating the presence of the compound was confirmed but the concentration was estimated. These data qualifiers are likely a result of the difficulties in laboratory analysis for this class of compounds.

It is important to note that the maximum ethylene glycol result (8,410 ug/L) in this data set was from a sample collected after the treatment system on this private well. This maximum post-treatment ethylene glycol result exceeds the ATSDR child intermediate CV of 8,000 µg/L, but is below the EPA LTHA of 14,000 µg/L. It should also be noted that four additional samples may have exceeded the ATSDR EMEG of 8,000 µg/L with sample results indicated in the data package as less than 10,000 µg/L. Ethylene glycol is used to make antifreeze and de-icing solutions for cars, airplanes, and boats. It is also used in hydraulic brake fluids and inks used in stamp pads, ballpoint pens, and print shops.

Bis(2-ethylhexyl) phthlate (DEHP) is a manufactured chemical that is commonly added to plastics to make them flexible. DEHP is not toxic at the low levels usually present in the environment. In animals, high levels of DEHP can damage the liver and kidney and affect the ability to reproduce. Bis(2-ethylhexyl) phthalate (DEHP) was detected in five samples and ranged from 0.14 µg/L to 22 µg/L . These levels did not exceed the chronic health comparison values for non-cancer health effects; however four of the 5 samples exceeded the drinking water comparison value of 2 µg/L (ATSDR Cancer Risk Evaluation Guide (CREG) and one sample exceeded the EPA Maximum Contaminant Level (MCL) for public drinking water supplies for this chemical of 6 ug/L. A drinking water concentration of 22 µg/L would result in an exposure dose for an adult of 0.00063 mg/kg/day and 0.0022 mg/kg/day for a child.

Estimated 2-methoxyethanol concentrations (ranging from 880 µg/L to 1,300 µg/L) were detected in each of six wells assessed for this chemical, although all results were "J" qualified as estimated results. Each of these estimated results exceed the EPA Risk Screening Level (RSL) for 2-methoxyethanol of 110 µg/L. 2-Methoxyethanol is mainly used as a solvent and is found in the glycol ethers class. It is also used as an additive in deicing solutions.

Inorganic Chemical Detections

Aluminum was detected in each of the approximately 18 wells sampled, ranging from under 10 µg/L up to 44,100 µg/L. The two wells with the highest aluminum concentrations (13,700 µg/L and 44,100 µg/L) exceeded the ATSDR CV for chronic exposures (greater than 364 days) to children, set at 10,000 µg/L. The well with the maximum aluminum concentration (44,100 ug/L) also slightly exceeds the adult health-based CV for chronic exposures (40,000 µg/L).

Arsenic was detected in all of the wells, ranging from 0.67 µg/L to 37 µg/L. The two highest levels of arsenic detected were 37 µg/L and 25 µg/L; these were the only two arsenic concentrations that exceeded EPA's Maximum Contaminant Level (MCL) for this chemical in public drinking water supplies. The arsenic concentrations in approximately

12 of the samples from this data set were above the ATSDR Child EMEG (Environmental Media Evaluation Guide) of 3.0 µg/L for non-cancer effects. Arsenic has been classified as a known human carcinogen. This classification is based on animal and human studies which indicate an increased risk for developing cancers of the skin, lung, bladder, kidney, liver, and prostate from consuming water containing arsenic. All of the arsenic detections in the wells exceeded the estimated lifetime 10E-6 cancer risk level from exposure of 0.02 µg/L. A "B" data qualifier indicating this contaminant was also detected in blank quality control samples was assigned to four of the lower arsenic sampling results (ranging from 0.67-7.2 ug/L) in this summary.

Seven samples indicated lithium at concentrations ranging from 8.3 µg/L to 380 µg/L. Five of the 7 samples were above the child provisional Reference Dose Media Evaluation Guide (RMEG) of 20 µg/L. Therapeutically, lithium (lithium carbonate) is used to control manic episodes in manic depressive illness in doses of 900 to 1,800 mg/day. The estimated lithium intakes at the maximum concentrations at this site are well below reported therapeutic levels.

Manganese concentrations in the well water samples ranged from 2.4 µg/L to 1,920 µg/L. Although the concentrations of manganese in all but two of the samples in this data summary are greater than EPA's secondary drinking water standard for this contaminant (50 µg/L), this standard was set for aesthetic reasons and is not health based. Ten of the wells had maximum results exceeding EPA's health advisory level for manganese of 300 ug/L. Manganese is an essential mineral that occurs naturally; however excess exposure can cause health effects that include behavioral changes and other nervous system effects.

Sodium levels exceeded EPA's Drinking Water Advisory levels of 20,000 µg/L in ten of the samples. The highest concentration was detected at 131 mg/L. Drinking water from these wells would increase the amount of sodium consumption in a person's diet. This could be particularly problematic for sodium sensitive individuals.

Iron concentrations were found greater than EPA's secondary drinking water standard for this contaminant (300 µg/L) in 16 of the samples. This standard was set for aesthetic reasons and is not health based. The maximum level of iron in this data set was 24,100 ug/L, and this result is from a private well that is not known to have any treatment systems. At the levels detected, the taste of the water will be affected. Iron is an essential mineral with recommended average intakes of 8 mg/day for men and post-menopausal women, 18 mg/day for pre-menopausal women, 10 mg/day for adolescents, and 27 mg/day for pregnant women. The Institute of Medicine Upper Tolerable Intake Level (UL) for iron is 45 mg/day. Drinking water from the well with the highest level of iron would add approximately 48.2 mg of iron to an adult's daily diet and add approximately 24.1 mg of iron to a 10-16 kg child's daily diet.

CONCLUSIONS

These sample results indicate that there is a possible chronic public health threat based on prolonged use of the water from at least some of these wells - assuming future exposure to these contaminants at these concentrations is not reduced. Based on the potential quality control issues, a potential health threat for the remaining wells cannot be disregarded. Additional characterization of the groundwater quality and a thorough review of any changes in concentration over time are indicated.

There are important data gaps for evaluating water quality in private wells that have been assessed and un-assessed in the site area. Further evaluation of all potentially impacted private wells in the site area and of treatment systems in use is needed.

RECOMMENDATIONS

ATSDR supports a "Do Not Use Until Further Notice" action regarding the private wells sampled to date at this site until the site can be characterized further. Distribution of alternative residential water supplies should be considered until potential exposures are further understood and mitigated as needed.

ATSDR and NCEH recommend that further sampling be conducted by EPA to ensure the highest quality sampling methodology possible, including appropriate quality assurance samples. Next steps, if implemented, should be focused on areas of primary concern delineated by EPA or the appropriate agency. Further sampling plans should consider a full set of appropriate inorganic, organic, and bacteriological (total and fecal) constituents.

A full public health evaluation should be conducted on the data from the site area. Because many of these compounds (e.g., metals) affect the same organ systems, ATSDR recommends evaluating the mixture for public health impacts using computational techniques or other suitable methods to evaluate the potential for synergistic actions. The cumulative concentration of all dissolved combustible gases should be considered to protect against the buildup of explosive atmospheres in all wells in the area.

PUBLIC HEALTH ACTION PLAN

ATSDR Division of Regional Operations in consultation with ATSDR/NCEH Headquarters has begun drafting a full health consultation on the available data set for the Dimock site, including Cabot, PADEP, and residents' consultant-collected samples over the past 2 years. ATSDR will review any follow up environmental monitoring being considered by EPA to assess current community exposures at the site and will continue to coordinate data reviews with Federal and Commonwealth public health and environmental authorities.

Signature:

Signature: ______________________ Date: 12/29/11
Charles Edge, Health Scientist, ATSDR ERS

Signature: ______________________ Date: 12-29-11
Robert Helverson, Regional Representative, ATSDR R3

Concurrence:______________________________ Date: 12/30/11

Lora Werner, Senior Regional Representative, ATSDR R3

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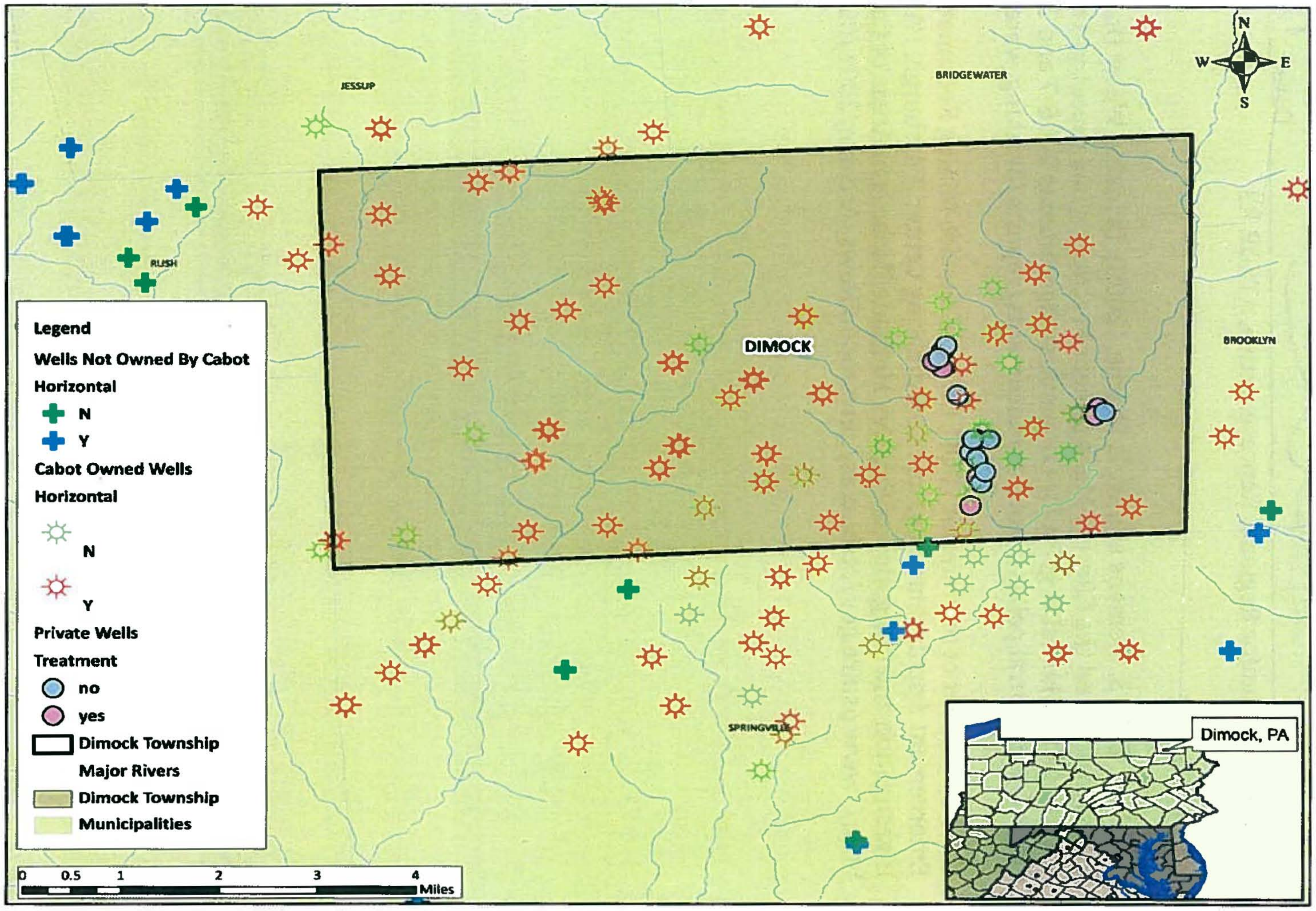
Attachment 1.



NATURE | NEWS: EXPLAINER

Is fracking behind contamination in Wyoming groundwater?

Questions about whether hydraulic ‘fracking’ is to blame remain as the US EPA prepares for peer review.

Jeff Tollefson

04 October 2012 Clarified: 10 October 2012

Natural gas extraction via hydraulic fracturing has been linked to contamination in groundwater.

GETTY IMAGES

The US Environmental Protection Agency (EPA) sparked a firestorm in December last year when it released a draft report[1] suggesting that the use of hydraulic fracturing — or 'fracking' — to extract natural gas had contaminated groundwater near Pavillion, Wyoming. Industry officials have long denied that fracking affects groundwater, and Pavillion has become the first high-profile test of this claim. On 26 September, the US Geological Survey (USGS) released data showing the presence of groundwater contamination in the region[2]. Although the data would seem to support the EPA’s assessment — as does an independent analysis released by environmental groups this week[3] — the survey did not seek to determine the source of the contamination. *Nature* examines the on-going debate and how it relates to broader questions about groundwater contamination from fracking across the United States.

How did this investigation begin?

After local landowners complained about the smell and taste of their water, the EPA began in 2009 to analyse the groundwater outside Pavillion. The agency tested the water in the shallow wells that tap the groundwater above the 169 gas-producing wells in the field; in two municipal wells in the town; and in several surface and deep wells that it drilled for monitoring purposes. It found evidence of contamination in both the shallow and deep wells, and attributed the shallow contamination to the 33 or so nearby surface pits used to store drilling wastes[1]. The pits could not, however, explain the contamination in the deeper groundwater.

What is the evidence that fracking contaminated the deep groundwater?

A range of hydrocarbons showed up in the deep wells, as did some synthetic organic chemicals associated with fracking fluids and drilling activities. The EPA also found high pH levels that could be explained by potassium hydroxide, which was used in a solvent at the site. The agency also analyzed the evolution of the pollution plume to determine that groundwater seems to be migrating upward, suggesting that the source of contamination came from the gas production zone rather than the surface pits.

Officials with both industry and the state of Wyoming questioned the EPA’s data as well as its interpretation, arguing that some hydrocarbons are to be expected through natural migration from the gas field. The state then asked the USGS to conduct a new analysis and provide the data to the state. The USGS provided those data last week[2]; it also sent samples to the EPA, which is conducting its own analysis.

Related stories

- Fracking boom spurs environmental audit
- Air sampling reveals high emissions from gas field

What do the latest results suggest?

The USGS provided only the raw data and no interpretation. An analysis released this week by two environmental groups found that the data support the EPA’s original conclusion. A scientist who has investigated possible contamination at other sites, Rob Jackson of Duke University in Durham, North Carolina, says that multiple lines of evidence are certainly “suggestive” of fracking as a source of contamination.

Does this settle the debate?

No. Encana Corporation, an energy producer based in Calgary, Canada, that has wells in the field near Pavillion, maintains that neither the EPA draft report nor the USGS results provide any proof that drilling operations are to blame.

Is this case unique?

There have been allegations of groundwater contamination at other locations where fracking has taken place, but it is not yet clear how common the problem might be. It is less likely, for instance, in regions where the gas is very deep in the ground, such as in Pennsylvania, where production takes place at depths of 1,500 meters or more. In Pavillion, the gas wells are as shallow as 372 metres, while wells tapping groundwater are up to 244 metres deep; this makes communication between the two zones much easier.

A report in February by the University of Texas at Austin's Energy Institute found no evidence of contamination from fracking near wells in Texas, Pennsylvania or New York, but the university is currently reviewing that report after the lead scientist, Charles Groat, was accused of having a conflict of interest (see 'Unfortunate oversight').

A 2011 study in the *Proceedings of the National Academy of Sciences* by Jackson and his colleagues[4] documented high concentrations of methane and other hydrocarbons in groundwater close to fracking operations in Pennsylvania and New York. But Jackson says that the contamination may have come not from the fracking but from the wells themselves, which can serve as a conduit between geological formations if not properly sealed.

What comes next?

The EPA plans to complete its analysis of the water samples and then turn over all of the data for an independent peer review later this year. In a press conference on Tuesday, Wyoming Governor Matt Mead said that the state would analyse the USGS data and then determine whether it needs to change its rules on fracking operations.

In parallel, the EPA is conducting a national assessment of environmental and public-health issues associated with fracking and expects to produce an initial report later this year.

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Clarifications

Clarified: An earlier version of this story did not make clear that an analysis of USGS data by environmental groups found that the data are consistent with but do not confirm - with EPA conclusions about water contamination due to fracking. This has been clarified.

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   Show context
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Comments

2012-10-04 06:49 AM

Sherif Hindi said: Induced hydraulic fracturing is a technique used to increase the released petroleum and/or natural gas. This type of fracturing creates fractures from a wellbore drilled into reservoir rock formations. Potential environmental impacts, including contamination of ground water, risks to air quality, the migration of gases and hydraulic fracturing chemicals to the surface, surface contamination from spills and flowback and the health effects of these factors. For these reasons, hydraulic fracturing has come under scrutiny internationally, with some countries suspending or even banning it. Hydraulic fracturing has raised environmental concerns and is challenging the adequacy of existing regulatory regimes. These concerns have included ground water contamination, risks to air quality, migration of gases and hydraulic fracturing chemicals to the surface, mishandling of waste, and the health effects of all these. Accordingly, a fair decision must be regarded for selecting either profit or human health, especially when the petroleum projects approaches to residential communities. However, accurate fracturing monitoring must be regarded by measuring of the pressure and rate during the growth of a hydraulic fracture, the fluid properties along with geology information that provide the simplest monitoring method. In addition, injection of radioactive tracers is sometimes used for this monitoring task. Furthermore, microseismic monitoring is sometimes used to estimate the size and orientation of hydraulically induced fractures by placing an array of geophones in a nearby wellbore. Tiltmeter arrays, deployed on the surface or down a well, provide another technology for monitoring the strains produced by hydraulic fracturing. Dr. Sherif Shawki Zaki Hindi King Abdull-Aziz Univ. Saudi Arabia

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TECHNICAL MEMORANDUM

April 30, 2012

Review of DRAFT: Investigation of Ground Water Contamination near Pavillion Wyoming Prepared by the Environmental Protection Agency, Ada OK

Prepared by: Tom Myers, Ph.D.
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Reno NV

SUMMARY AND RECOMMENDATIONS

After consideration of the evidence presented in the EPA report and in URS (2009 and 2010), it is clear that hydraulic fracturing (fracking (Kramer 2011)) has caused pollution of the Wind River formation and aquifer. The EPA documents that pollution with up to four sample events in the domestic water wells and two sample events in two monitoring well constructed by the EPA between the level of the domestic water wells and the gas production zone. The EPA's conclusion is sound.

Three factors combine to make Pavillion-area aquifers especially vulnerable to vertical contaminant transport from the gas production zone or the gas wells – the geology, the well design, and the well construction. Natural flow barriers are not prevalent in this area, so there are likely many pathways for gas and contaminants to move to the surface, regardless of the source. There is also a vertical gradient, evidenced by flowing water wells, although its magnitude and extend are undefined, to drive advective vertical transport. The entire formation is considered an underground source of drinking water, but 169 gas wells have been constructed into it; this is fracking fluid injection directly into an underground source of drinking water.

The well design is poor because the surface casing does not extend below the level of the water wells, as is required in many other states, and because the wells contain substantial borehole lengths without surface casing or cement between the production casing and the edge of the borehole. This allows vertical transport of gas and fluids and decreases the protection against leakage during fracking or gas production. Third, the EPA documented many instances of sporadic bonding, which simply means the cement does not completely seal the annulus between the production casing and the edge of the borehole. This provides pathways which could allow gas and contaminant transport along the well bore.

The EPA also appropriately accounted for the potential that their monitoring well construction could have explained the contamination. "Since inorganic and organic concentration patterns measured in the drilling additives do not match patterns observed in the deep monitoring wells and because large volumes of ground water were extracted from the wells during development and prior to sampling, it is unlikely that ground-water chemistry was at all impacted by drilling additives."(EPA, 2011, p 7).

The EPA also demonstrated that the inorganic geochemistry in the monitoring wells is substantially different than that which would occur naturally in the area, and that the enrichment of numerous constituents is most likely due to the interaction of fracking fluid with the groundwater near the sampled well. This is particularly true for the elevated levels of potassium, chloride, and pH.

Any of the three contaminant transport pathways suggested by the EPA could be responsible for the contamination moving from the fracking zone to the drinking water wells. The EPA has also presented evidence that contamination in surface ponds has not caused the contamination in the water wells or their monitoring wells.

The situation at Pavillion is not an analogue for other gas plays because the geology and regulatory framework may be different. The vertical distance between water wells and fracking wells is much less at Pavillion than in other areas, so the transport time through the pathways may also be low compared to other gas plays. It is important, however, to consider that the pathways identified at Pavillion could be applicable elsewhere (Myers, 2012; Osborn et al, 2011). In addition to improving and enforcing the relevant regulations, monitoring the pathways between the target formation and aquifers should be standard at all gas plays with fracking.

The following recommendations would improve the analysis and continue the study into the future made throughout this review.

1. The EPA should continue data collection to better verify the sources and map the potential contaminant plumes.
2. EPA should map the gas production wells according to their construction date. The EPA should also compare the locations of observed contamination with the nearby well construction dates to estimate the travel times from the sources to the well receptors.
3. The EPA should map the depth to water prior to sampling in the water wells. Using this, they should map vertical gradients and correlate these gradients to areas with contaminants most likely sourced to deep aquifers.
4. The EPA should install deeper monitoring wells near the shallow pits to better map the depth of the plume emanating from those pits.
5. Data collection should continue so the results can be replicated. An additional, deeper monitoring well should be constructed in the gas production zone between the existing monitoring wells to determine the vertical gradient and estimate the rate of vertical flow.
6. The EPA presents no evidence regarding the extent that fracturing extends above targeted formations. It may not be possible to prove whether this occurred at this site, but the EPA should at least discuss the possibility. It would be useful to perform some simple testing to map the extent of fractures, as described by Fisher and Warpinski (2010).

INTRODUCTION

The Environmental Protection Agency (EPA) has released a study of groundwater contamination in the Pavillion gas play in west-central Wyoming. Their preliminary conclusion is that gas well development and hydraulic fracturing (fracking (Kramer, 2011)) has caused the contamination. The EPA report is in draft form and is open for comment until March 12, 2012. This technical memorandum reviews the EPA report. This review was prepared with support from the Natural Resources Defense Council, Wyoming Outdoor Council, Earthworks, Oil and Gas Accountability Project and Sierra Club.

This review discusses in detail the appropriateness of the study design, methodology, execution, results, and interpretation and the reasonableness of the conclusions. It specifically follows and considers the EPA's "lines of reasoning" approach used to reach its conclusion.

STUDY AREA

The study area is in the Pavillion gas field in west-central Wyoming. It lies northeast of the Wind River Range. The general geology for uppermost 1000 meters (m) is the Eocene-aged ((56 to 34 million years before present) Wind River Formation, which is interbedded sandstone and shale with coarse-grained meandering stream channel deposits. The presence of stream channel deposits indicates that the formation has been carved by river beds which left fluvial deposits interspersed among formation layers These fluvial deposits often provide connectivity among formation layers and can fragment otherwise continuous sedimentary layers.

The area has experienced gas development since the 1960s, with 169 gas wells constructed in the study area. EPA Figure 2 shows the gas well construction chronology. There were three main periods of construction – 1963-65, 1975-83, and 1998 – 2006, with each subsequent period having more new wells constructed than the previous period. EPA does not specify when fracking first occurred, however.

Recommendation: Add a map of gas production wells coded for the year or time period during which the well was completed (or fracking occurred if substantially different). This would allow an assessment of travel time for contaminants to flow from production zones to the monitoring wells and domestic wells.

The US Geological Survey studied the water resources on the Wind River Reservation (Daddow 1996), which surround this study area (but does not include it). The Wind River Formation is the primary source of drinking water on the reservation. Daddow's (1996) description of the formation indicates that the formation consists of interbedded shale and sandstone with extremely variable permeability that could lead to highly variable contaminant loads throughout the formation (Osiensky et al 1984).

Recommendation: A more detailed description of the geology and hydrogeology of the area, perhaps based on the relevant Geological Survey reports would provide more insight regarding geochemical trends as found by the USGS.

STUDY LAYOUT AND DESIGN

EPA started this study in response to citizen complaints regarding contamination in their water wells. EPA established dedicated monitoring wells after two rounds of sampling various water wells rather than prior to construction of the gas wells. For much of their study data, the EPA had to use sample data collected from existing water wells. Water wells are not the best tool for monitoring groundwater quality because, even if the well construction is of similar quality to a dedicated monitoring well, water wells have much longer screens, or open intervals, than do monitoring wells. They screen the most productive formation layers, usually based on observations made during drilling, to maximize the pumping rate while minimizing the drawdown. Wells drilled specifically for monitoring wells also screen productive zones, but target the screen to a specific zone, usually 20 feet or less thick, so that the sample represents a given aquifer level.

Samples from water wells are therefore a mixture of water from all productive zones of the entire open interval, weighted according to the transmissivity of each zone. A domestic water well sample is useful for determining whether a contaminant exists at some point in the aquifer, but a dedicated monitoring well is necessary to determine which layer is contaminated.

EPA established two dedicated monitoring wells to supplement the data obtained from the water wells. The new monitoring wells were primarily screened below the level of the water wells (Figure 1) and above the gas production wells to "differentiate potential deep (e.g., gas production related) versus shallow (e.g., pits) sources of groundwater contamination" (EPA p 5). The EPA established just two monitoring wells due to a limited budget (Id.). EPA placed the monitoring wells' screened interval along the conceptualized vertical pathway between the potential contaminant source (i.e. the production wells and/or zone) and the water wells. The monitoring wells were designed appropriately to detect and monitor contaminant movement upward from the production zone to the water wells; if the monitoring wells had been constructed at the same depth as the water wells, they would not have added substantial useful information.

Figure 1 (EPA Figure 3) shows that domestic water wells in the regions are screened at all levels down to about 250 m, or more than 800 feet, with half of the wells being deeper than 300 feet, similar to the depths found by Daddow (1996) in other areas of the aquifer. However, the EPA states the information source was from the State Engineer *and* homeowner interviews (EPA p 2). It is unclear whether both were used for each well. It is my experience that homeowners have a poor concept of the depth of their well unless they have paperwork that documents it.

Recommendation: The EPA should provide more information about the source of its water well construction data, showing it in EPA Table A1.

The following table summarizes in general terms the wells that were sampled during each sampling phase (other media were also sampled but not included in this table). It is apparent that the wells sampled in phases subsequent to the first phase depended in part on the results of the prior phases.

Phase	Date	Domestic and Stock Wells	Municipal Wells	Stock Wells	Monitoring Wells	Comments
I	3/09	35	2	0	0	
II	1/10	17 (10 previously sampled)	2	4	0	This phase came about because EPA had detected methane and dissolved hydrocarbons during Phase I.
III	10/10	3 (2 previously sampled)	0	0	2	Gas samples also collected from the well casing of EPA's two deep monitoring wells.
IV	4/11	8 previously sampled	0	3 previously sampled	2	Added glycols, alcohols, low molecular weight acids

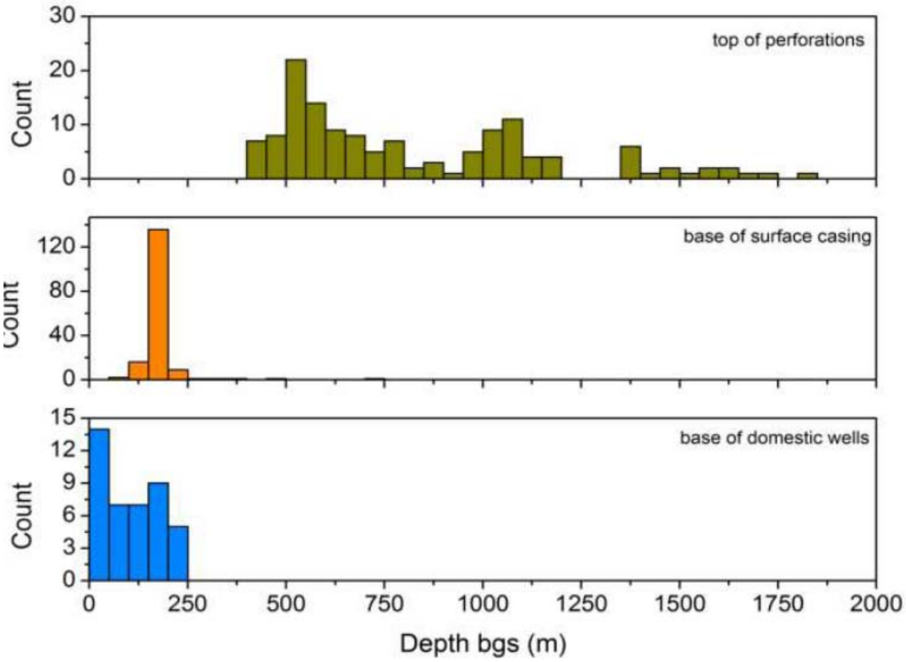

Figure 1: Snapshot from EPA (2011) Figure 3 showing frequency of depth for gas wells (top), surface casing for gas wells, and base of domestic wells.

EPA Table A1 lists the wells and the phase during which they were sampled, broken into eight data types.

1. anions and alkalinity
2. metals
3. alcohols and VOCs
4. low molecular weight acids and glycols
5. semi-volatile organic compounds (SVOCs), pesticides, PCBs, and tentatively identified compounds (TICs);

6. gas/diesel related compounds, and hydrocarbons
7. bacteria
8. fixed gases, heavy hydrocarbons, dissolved carbon, and gas and water isotopic ratios

EPA Table A2a presents the geochemical results – anions, cations, and alkalinity. Unfortunately, this table does not consistently state in which phase the initial sample was taken. Additional samples are identified with a suffix on the sample number. The other data tables in Appendix A provide results by phase, but some results are found only in other reports, including URS (2009 and 2010).

URS (2009) reports the Phase 1 sampling (water wells only) in their Table 9, which shows concentration of SVOC contaminants, including caprolactam at 1.4 ug/l at PGDW20, dimethylphthalate detected at nine wells, and Bis (2-ethylhexyl)phthata at 9.8, 6.4 and 12 ug/l in PGDW25, -20 and -14[1], respectively, and detect levels at ten other wells. Total purgeable hydrocarbons were 26 and 25 ug/l in wells PGDW05 and PGDW30, respectively. Measurable methane concentrations were found in 8 wells. Total purgeable organics are generally gasoline and diesel range organics. PGDW25 is one of the deeper wells at 243.8 m below ground surface (bgs) and PGDW05 and -30 are at 64.0 and 79.2 m bgs, respectively. URS (2010) reports the Phase 2 sampling in more detail. It shows more than 20 wells with detectable levels of a variety of semi-volatile organics (URS 2010, Table 9). The report does not assess these detects with the depth of the well, but a quick glance suggests that most of them are on the deeper half of the domestic wells. An exception is PGDW39, reported to be just 6.1 m deep, although the EPA should consider whether "6.1" is correct because if so it would be tens of meters shallower than any other water well in the aquifer.

Recommendation: The EPA should present and discuss the correlation of contaminant detects in the domestic wells with depth.

EPA based this study on four sample events including various subsets of domestic, municipal, and stock wells and two sample events in the monitoring wells. A reasonable question is whether the number of samples is sufficient for developing an opinion? A time series would help to identify a trend, but is not necessary to establish presence/absence. Objections to this data on the basis of there being just two samples are without merit – simple presence of a substance that would not naturally occur in the aquifer, if other causes can be eliminated, is sufficient to reach a preliminary conclusion that fracking fluid has affected the aquifer. However, the EPA should continue the sampling to determine whether the concentrations are trending higher, or not, and determine how or whether the plume expands.

TRANSPORT PATHWAYS

The EPA identifies three potential pathways for contaminants to reach the water wells from the fracking (EPA, p 32).

- Fluid and gas movement up compromised gas wells.

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[1] The table did not highlight the values at PGDW14 and -20 as being exceedences.

- Fluid excursion from thin discontinuous tight sandstone units into sandstone units of greater permeability.
- Out-of-formation fracking, whereby new fractures are created or existing fractures are enlarged above the target formation, increasing the connectivity of the fracture system.

The EPA does not conclude which or whether any of these pathways actually facilitated the contamination at Pavillion, although arguments throughout the document (and reviewed in this report) support the potential for any of them. EPA correctly notes that for all three pathways there would be a correlation between the concentration of gas in the water wells and the proximity to gas well, as found by Osborn et al (2011) in the Marcellus shale in Pennsylvania. They also note that for all three pathways, "advective/dispersive transport would be accompanied by degradation causing a vertical chemical gradient" (EPA, p 32) as discussed in other portions of the report. In other words, with increasing distance from the source, both vertical and horizontal, the contaminant concentration would decrease. This would be due in part to chemical degradation, dispersion of a finite mass over a larger volume, attenuation due to chemicals adsorbing to soil particles, and dilution by mixing with groundwater..

The following sections consider evidence from various aspects of the EPA report in context of the pathways.

Lithologic Barriers

Very low permeability layers can prevent or impede the upward movement of fluid or gas from depth to the water well zone, which in the Wind River Formation is the upper 250 meters (based on the reported water well depth). Extensive layers of shale are often sources of gas and/or capstones, which prevent gas in underlying sandstone from escaping to the surface. However, the shale must be horizontally extensive and not fractured to be an effective seal, which is not the situation in the Pavillion field as quoted above. The formation is most productive (for gas) at its base with gas trapping occurring in "localized stratigraphic sandstone pinchouts on the crest and along flanks of a broad dome" (EPA p 2).

Hypothesis: The lithology in the Pavillion area does not prevent the vertical movement of gas or contaminants to the surface because it is either not sufficiently extensive or impervious. EPA claims there is no "lithologic barrier … to stop upward vertical migration" (EPA p viii) and also that "there is little lateral and vertical continuity of hydraulically fractured tight sandstones" (Id.).

Evidence: EPA presented a lithologic cross-section (Figure 20) showing mapped shale layers, production, water, and monitoring wells and the points where the production wells had been fracked. EPA found that the lithology is "highly variable and difficult to correlate from borehole to borehole" (EPA p 15). "Sandstone and shale layers appeared thin and of limited lateral extent" (Id.). Pathways could go around the intermittent shale so that contaminants in a given monitoring well may not result from the nearest production well. Pathways for movement through sandstone could be tortuous (EPA p 37); vertical pathways through sandstone could be more tortuous than horizontal pathways because the particles in sandstone tend to be elongated with the longer side being horizontal.

Fracking has occurred for up to 45 years, so there is potential for many pathways from various sources to a receptor well. The travel time to a given point could be any time period up to 45 years. Additionally, out-of-formation fracking occurring at any time could have shortened the pathway.

Conclusion: The lithology in most areas would not prevent the vertical movement of contaminants to the water wells because of the lateral variation.

Vertical flow and gradient

In order for contaminants to move from the fracked zones or from deep well bores to surface aquifers, there should be a vertical hydraulic gradient. Lacking such a gradient, movement could still be possible due to lateral dispersion and upward concentration gradients, but it would be much slower.

Hypothesis: There is upward flow in the Pavillion gas field that would support advection of contaminants associated with fracking fluids to the monitoring and water wells.

Evidence: In the Pavillion area, there are flowing wells, which would indicate an upward gradient, at least at depth, which could drive vertical advection, or contaminant transport with the groundwater flow . Daddow (1996) also documented flowing wells in other areas of the Wind River Range, with the depth range from 225 to 450 feet bgs. EPA uses PGDW44 as an example (p 36). This water well lies near the middle of the field near MW01. MW01 showed a depth to water equal to 61.2 m at the beginning of a purge for sampling (p 11 and Figure 8). MW02 had depth to water of 80.5 m (p 12). The depth to water in the monitoring wells does not support the idea of an upward gradient, but being the only wells at that depth, the data is not conclusive. Table A1 reports the PGDW44 well depth is 228.6 m; PGDW25 is deeper, at 243.8 m bgs. MW01 is just 10 m deeper. There is apparently an upward gradient at that point because the well is flowing, but the analysis could be improved, as follows.

EPA documents that the shallower monitoring well has more natural breakdown products of the organic contaminant like BTEX or glycol that are found in the deeper monitoring well and in fracking fluids (p 36). It suggests that the contaminants in the shallow well are derived from the natural breakdown of the contaminants found in the deeper well. This could only occur if the wells represent a vertical flow path, which they do and therefore these findings support the hypothesis of upward movement.

The gas found in the deep Wind River Formation is chemically similar to gas in the underlying Fort Union Formation suggesting that gas in the Wind River Formation has naturally moved upward until captured in localized capstones, or “localized stratigraphic sandstone pinchouts” (EPA, p 2). EPA concludes that differences in gas composition and isotopes support the hypothesis of upward migration through the various layers in the Wind River formation (p 29). The fraction of ethane and propane in the gas from domestic wells is mostly less than in the produced gas, but the isotopic composition is clearly thermogenic, which suggest there is an ongoing “preferential loss of ethane and propane relative to methane” (p 29, 38). This evidence supports the hypothesis of upward fluid and gas movement.

Vertical movement could occur in the absence of a vertical gradient, if the pressurization caused by the fracking is sufficient and there is a poorly developed well bore nearby. Contaminants can migrate quickly upward through a leaky borehole due to the transient pressure gradient across an aquitard created by the fracking pressure (Lacombe et al, 1995).

Conclusion: There is evidence to support the concept of upward movement in the area, but it is not conclusive. The EPA should complete more studies documenting the vertical hydraulic gradient throughout the area.

Recommendation: The EPA report should document the depth to water in the domestic wells prior to sampling so that they could map water levels for different well depths and determine the zones of upward gradient.

Contamination from shallow pits

The presence of shallow disposal pits is an alternative source of contamination. EPA notes that there are 33 shallow pits that had been used for the "storage/disposal of drilling wastes, produced water, and flowback fluids in the area of investigation" (EPA p 17). As part of this study, the EPA communicated with stakeholders to further determine the location of pits. Shallow monitoring wells have found very high concentrations of several contaminants that were also found in deeper water wells and the EPA monitoring wells. These pits could have received the detritus of fracking operations in the past.

Hypothesis: Contaminated water seeping from these pits could be responsible for the observed contamination.

Evidence: Shallow monitoring wells that had been installed previously for reasons not associated with this project (EPA, p 11) are reported to have very high contaminant concentrations, although this data is not well summarized in the report. The shallow monitoring wells are only 4.6 m bgs (EPA p 17), so there is little information about how deep the contamination extends beneath the pits. Assuming the pits are some distance away from homes and people avoided them when constructing their water wells, it is possible the shallow disposal pits are sources of contamination beyond the level the EPA considers shallow, or 31 m bgs (Id.).

Irrigation could help to contain the contamination near the shallow pits because they would be located in low recharge areas, either by design or in comparison with irrigated fields. It would be unlikely that the pits would have been constructed within irrigated fields, so the seepage from the pits may be much less than the seepage beneath irrigated fields because of the continuous application of water to the field, and for a much shorter time period. Irrigation water would have seeped deeper and faster due to the likely higher rate of application and effectively diluted or prevented the deeper circulation of seepage from the pit.

Conclusion: The EPA concludes that these shallow pits are not the source of contaminants found in deeper water wells. Because there is little contamination in intermediate-depth wells, their conclusion is sound, but the document would benefit from more analysis and discussion.

Recommendation: The EPA should document more fully the contaminant plumes near the pits. Specifically, deeper monitoring wells near the pits should be constructed to construct a contamination *profile beneath the pits. Better investigation of the pits as a source would also facilitate the remediation of the groundwater near those pits.*

LINES OF REASONING

The EPA used a line of reasoning analysis regarding the presence of fracking fluid constituents and gas in monitoring wells in support of their preliminary conclusion that fracking has contaminated aquifers in Pavillion Wyoming. This is critical because the conclusion is not just that leakage from the wells or spills caused contamination, but that the fracking process itself caused the contamination. EPA deemed the multiple lines of reasoning approach necessary due to the complexity in detecting contaminants in groundwater from deep sources. This section critically reviews each of the EPA's lines of reasoning.

High pH Values

The EPA monitoring wells both have very high pH, ranging from 11.2 to 12.0, which is much higher than the level seen in the domestic water wells in the Wind River formation. EPA concluded the high pH was due to hydroxide (OH) which indicated the addition of a strong base to the background water (EPA p xii). EPA's reaction path modeling suggested that the addition of just a small amount of potassium hydroxide to the sodium-sulfate waters typical of deep portions of the Wind River formation would cause such a pH change; EPA concludes from the modeling that the typical groundwater in the Pavillion aquifer "is especially vulnerable to the addition of a strong base" (EPA p 20).

Potassium hydroxide was used as a crosslinker and solvent for fracking the production wells in the area (EPA p 33), which could be a source of the OH to increase the pH of the water in the area of the production wells.

The use of soda ash as a drilling additive when drilling the monitoring wells, often to control the pH, is a possible alternate explanation for the elevated pH[2]. Soda ash is 100% Na_2CO_3. At a 1:100 mixing ratio with water, the pH of dense soda ash was 11.2 (EPA Table 2). The recommended ratio for use in fracking fluid is 1:100 to 1:50 (EPA Table 1). The pH of drilling mud varied between 8 and 9. The concentrations of neither sodium nor carbonate are abnormal in the monitoring wells. If the soda ash did separate from the drilling mud, mixing with background groundwater would further dilute it so that the pH would be less than observed at the 1:100 mixing ratio.

EPA Figure 12 verifies these pH values are higher than in the domestic wells, but also shows they fall on the general trend of pH with elevation of the well open interval. Based on this information, it is not possible to conclude that the high pH is not natural, but the EPA's conclusion appears to be justified based cumulatively on all of the facts concerning pH. EPA should consider geophysical logging completed by the industry if it includes pH logs to improve their analysis; such logs could provide pH values for deeper areas that could be compared with the pH values for their monitoring wells.

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[2] http://www.halliburton.com/ps/default.aspx?navid=125&pageid=60&prodgrpid=MSE%3a%3a1053024648177449, visited 1/13/12

Chemistry in the shallow wells has been affected by irrigation with Wind River water. This irrigation water has very low total dissolved solids (TDS) and neutral pH (<8) (EPA Figure 11) but the other shallow groundwater wells show that the irrigation water picks up contaminants as it seeps.

The methods used to collect samples probably minimized contamination causing high pH in the monitoring wells. EPA purged the monitor wells until pH stabilized, a process which would minimize the potential that any residual contamination from well development would have been sampled.

EPA's analysis associated with Figures 11 and 12, explaining the shallow water geochemistry, is accurate and useful. It utilizes data from all of the wells in the area and surface waters to show water chemistry trends through the study area. It also shows how EPA's monitoring wells differ substantially from the general trends, supporting the conclusion that elevated pH in water samples from EPA's deep monitoring wells was likely caused by contamination with hydraulic fracturing chemicals.

Elevated potassium and chloride

The monitoring wells both have concentrations of K and Cl much higher, 14 to 18 times, than the domestic water wells (EPA p 34). Potassium concentration ranged from 43.6 to 53.9 mg/l and Cl concentration averaged 466 mg/l (Id.). The drilling additives reported by EPA to have been used at Pavillion had a much lower concentration for both anions. The fracking fluid contained several compounds with high concentrations of both ions (Id.). Therefore, the high concentrations of K and Cl suggest contamination with fracking fluid.

The chloride concentration data plotted in EPA Figure 12 shows clearly that Cl concentration in two of the three samples from EPA's deep monitoring wells are much higher than those in domestic wells, and EPA correctly assesses there must be a cause other than natural variation for the high concentrations. However, in this case I disagree with EPA's assessment that "regional anion trends tend to show decreasing Cl concentrations with depth" (EPA p 19) because EPA Figure 12 shows little variation with depth although there are a couple of high concentration outliers near the surface. Regardless of the interpretation of trend, concentrations from the EPA monitoring wells plot far higher than the Cl data from domestic wells.

The chloride concentrations reported from the EPA monitoring wells are also much higher than reported by the USGS in their Wind River study (Daddow 1996). He describes the formation water as having TDS concentration as high as 5000 mg/l, but Cl is a small proportion of that. He also reported that the highest Cl concentration on surface water sites was less than about 30 mg/l, so assuming the river recharges the alluvial aquifer, the source of the groundwater is relatively clean with respect to chloride. Cl concentrations at EPA's monitoring wells are much higher than the regional values reported by USGS in either ground or surface water on the Wind River Reservation, and are unlikely to be properly considered "naturally occurring".

For potassium, it is much clearer that the monitoring well concentrations exceed the domestic water well concentrations by many times (EPA Figure 12, p 20).

There is too little of either K or Cl in drilling mud or additives for it to have been the source or cause of the enrichment in the monitoring wells. Also, purging prior to sampling occurred until the specific conductivity (SC) of the purged water reached a relative steady state (EPA Figure 9). K and Cl both contribute to the SC of the water being sampled. Any potential contamination due to well construction or development has most likely been purged from the system.

The high K and Cl concentrations are clearly present in the formation water near the monitoring wells. Without a natural source as explanation, the mostly likely source is the fracking fluid which used compounds that have high concentrations of both anions. EPA has reasonably concluded the most likely source of elevated K and Cl is fracking fluid.

Detection of synthetic organic compounds

The EPA found in the monitoring wells significant concentrations of isopropanol, diethylene glycol, triethylene glycol, and tert-butyl alcohol (TBA) (in MW02). TBA was not directly used as a fracking fluid, but "is a known breakdown product of methyl tert-butyl ether and tert-butyl hydroperoxide". The first three products are found in fracking fluid based on the material safety data sheets (MSDSs) analyzed by EPA, but the parent compounds of TBA have not been reported as such; importantly, MSDSs, which are the source of the fracking fluid additives lists in the report, do not list all chemicals because the formulas are proprietary. That a chemical is missing from the list of additives is not evidence they were never in fracking fluid.

Isopropanol was found in "concentrated solutions of drilling additives" at concentrations much lower than detected in the monitoring wells (EPA p 35) and the others, glycols and alcohols, were not used for drilling.

None of these compounds naturally occur in groundwater. The EPA is correct in its conclusion that there is no acceptable alternative explanation and the most likely source of these contaminants is fracking fluid.

Detection of petroleum hydrocarbons

EPA detected benzene, toluene, ethylbenzene, and xylenes (BTEX), trimethylbenzenes, and naphthalene at MW02 (EPA, p 35). They detected gasoline and diesel range organics at both monitoring wells (Id.). These are not found in drilling additives, but the MSDSs showed a long list of additives in the fracking fluid that could be the source of the contamination just cited (EPA p 35, 36). For example, a BTEX mixture had been used in the fracking fluid as a breaker and a diesel oil mixture was used in guar polymer slurry (Id.).

EPA rejects alternative explanations that claim that substances, used on the well or pump, caused these contaminant detections. Specifically, the agency points out that the contact time for water with the well or pump during purging and sampling would be so low that contamination would be unlikely, especially after purging. This would be especially true for the Phase 4 sampling which would have occurred after the well had been purged for sampling twice and had several months of natural groundwater flow through it.

An alternate explanation considered by EPA is that the constituents are due to the groundwater being above a natural gas field. In fact, the EPA has noted that historically some wells encountered gas at levels shallower than the monitoring wells. EPA encountered methane while logging MW01 (EPA p 11). EPA notes that the gas from the Wind River formation is "dry and unlikely to yield liquid condensates" (EPA p 36). They also argue that the monitoring wells have substantially different compositions of liquid condensates, which would not result if they came from a common source of gas. The explanation is reasonable, unless there is a variation with depth. Because these contaminants occur only at low concentrations in the deepest domestic wells, the data does not rule out a natural gradient from the gas sources at depth to the shallower zones of the formation. However, the EPA explanation is supported by the fact that the monitoring wells are far enough apart, more than a mile, that they must have different gas well sources and represent different pathways..

Recommendation: To further decrease the uncertainty, the EPA should complete an additional sampling event with more domestic wells sampled. It would also be desirable to have another monitor well screened at the level of the gas wells. The EPA could then develop a concentration profile as a function of depth and formation layer.

Breakdown products of organic compounds

EPA verified a vertical pathway by showing that organic compounds in the shallower monitoring wells are daughter products of the organic compounds found in the deeper monitoring wells. This supports the concept of upward migration with ongoing biologic transformation or natural degradation. It supports the concept of an upward flow gradient. It cannot be asserted that the EPA monitoring wells are on the same flow pathway, as they are more than a mile apart, therefore, the presence of contaminants in the monitoring wells is evidence that there are multiple sources of contaminants at the level of the gas production wells.

As part of this line of reasoning, the EPA presents the "hypothetical conceptual model" that "highly concentrated contaminant plumes exist within the zone of injection with dispersed lower concentration areas vertically and laterally distant from the injection points". This refers to how the fracking fluids, once injected, simply disperse in all directions because there are no confinements, similar to how they disperse from coal seam fracking. It is consistent with the lower concentrations found further from the source.

EPA's hypothesis is reasonable and explains the vertical movement of contaminants from a broad zone of production wells. Its simplicity indicates that fracking in such a formation will eventually lead to contamination moving vertically from the gas wells – it is only a matter of time (Myers, 2012).

Sporadic bonding outside of production casing and hydraulic fracturing in thin discontinuous sandstone

The last two lines of reasoning are considered together because they describe two pathways for fracking fluid to get into the aquifer. The fracking that occurs in the Pavillion gas field directly injects fracking fluid into an underground source of drinking water. Fracking occurs as little as 150 m below the bottom of the deeper water wells. The sandstone and intervening shale zones are discontinuous, which suggests there are no significant continuous barriers to a vertical component of flow and contaminant movement. Fracking has also occurred for up to 40 years, so the pathways could have required up to 40 years for transport. Sporadic bonding above the zone being fracked basically means the annulus between the production zone and surface casing may not be fully sealed with cement which may allow gas or fluids to move vertically among formation layers. During fracking, the high pressure could force some of the fracking fluid through improperly sealed well bores to contaminate formations nearer the water wells.

Both of these lines of reasoning correctly describe potential pathways and sources of fluids in the aquifer. The EPA's conclusions in this regard are reasonable and appropriate and conform to the available facts and data.

Gas in Monitoring and Shallow Wells

Many shallow water wells have gas concentrations that exceed expected background levels. EPA also uses several lines of reasoning to conclude that gas has migrated to domestic wells from the fracked zones, in addition to or instead of it occurring naturally in those wells.

Isotopic composition of gas samples from shallow wells, deeper monitoring wells and produced gas are all similar in that all have a thermogenic origin. However, the shallower domestic water wells have very little higher chain carbon-based gas, which suggests some dispersion and decomposition with vertical movement (ethane and propane degrade faster). The isotopic composition of most wells is thermogenic and indicative of a deep source; URS (2010) noted that methane in one domestic well of eight sampled with measurable methane had biogenic origins.

EPA also found that the concentration of methane in domestic water wells was generally higher in areas of higher gas production, as counted by the number of gas wells. Although it could be coincidental because more gas wells are constructed where more gas naturally occurs, this seems unlikely because the presence of gas in domestic water wells shows that gas is occurring outside of the production zones deep in the Wind River Formation or high in the underlying Fort Union Formation. Gas would only move naturally from depth to areas near the surface if there is a lack of containment which would have depleted the gas source at some point in the last 40,000,000 years. Thus, the gas wells have apparently provided a migration pathway for gas released by fracking into overlying formations; this migration occurred at a rate sufficient to allow gas to accumulate to a concentration capable of causing a blowout at 159 m bgs near well PDGW05.

The area also generally has gas well designs that are below current industry standards in some states, with surface casing not extending below the maximum depth of water wells and with a "lack of cement or sporadic bonding of cement outside of production casing" (EPA p 38). This would provide a pathway from depth to at least the bottom of the surface casing, and allow gas leakage to higher levels in the aquifer. Many states and areas require surface casing to extend below the maximum depth of USDWs (a USDW must generally have TDS less than10,000 mg/l). The gas well design in Pavillion appears to be below industry standards because the surface casing does not extend even below the bottom of the zone of domestic wells. The pathways discussed above for fluid movement would also facilitate gas movement (Id.).

The EPA acknowledges that poorly sealed domestic wells could also be a pathway (EPA p 38-39). This is true but not a relevant argument because the gas wells are much deeper and actually tap formation layers with gas. Once gas reaches a domestic well, it is possible that the well provides an additional pathway, but it is not the source of the contamination or the primary pathway from the gas source zone to the aquifers.

The EPA also references the fact of citizen's complaints (EPA p 39) as an indicator that gas contamination started after fracking. Citizens do not complain until a problem occurs. Assuming their water well was initially acceptable, they would complain when they noticed a change.

DISCUSSION OF CONTAMINANT TRANSPORT PATHWAYS

The general dispersion of contaminants upward from the fracking zone would result from either well bore transport or transport through overlying higher permeability sandstone. Transport through wellbores that cross multiple aquifer layers, as the gas wells do near Pavillion, would allow contaminants to reach the different levels. However, the concentration reaching shallower formations would be much less because the contaminants bleed off to the deeper aquifer zones (Nordbotten et al 2004). Fracking could also create the vertical gradient to temporarily cause contaminants to move vertically upward through wellbores to contaminate shallower aquifer layers (Lacombe et al 1995).

Because there are not any significant horizontal confining units within the Pavillion Field, the upward vertical contaminant transport is partially due to dispersion through relatively porous media. In areas with extensive horizontal confining layers, such as the Marcellus shale areas, transport through vertical fractures, similar to that through wellbores, could transport substantial contaminant mass through the impervious zones (Myers, 2012). If the bulk media bounding the fractures have conductivity less than one hundredth that in the fracture, the contaminants will transport with little dispersion, or loss, into the bulk media (Zheng and Gorelick, 2003).

This appears to be the case in the Pavillion Field, given the existing geology. Thus, unless fracking is very carefully done, and well bores are solidly (not intermittently) bonded, this result is to be expected. In the case of the Pavillion Field, sporadic bonding is revealed and reported for 9 of the wells that EPA examined well bore data made available to them. To the extent that this is indicative of the entire field, it would greatly increase the likelihood that transport of contaminants from the gas wells to the water wells of the rural Pavillion residents would occur.

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

Subject: Action Memorandum - Request for Funding for a Removal Action at the Dimock Residential Groundwater Site, Intersection of PA Routes 29 & 2024
Dimock Township, Susquehanna County, Pennsylvania

Gerald T. Hart
From: f Richard M. Fetzer, On-Scene Coordinator
Eastern Response Branch (3HS31)

JAN 19 2012

To: Dennis P. Carney, Associate Division Director
Hazardous Site Cleanup Division (3HS30)

I. PURPOSE

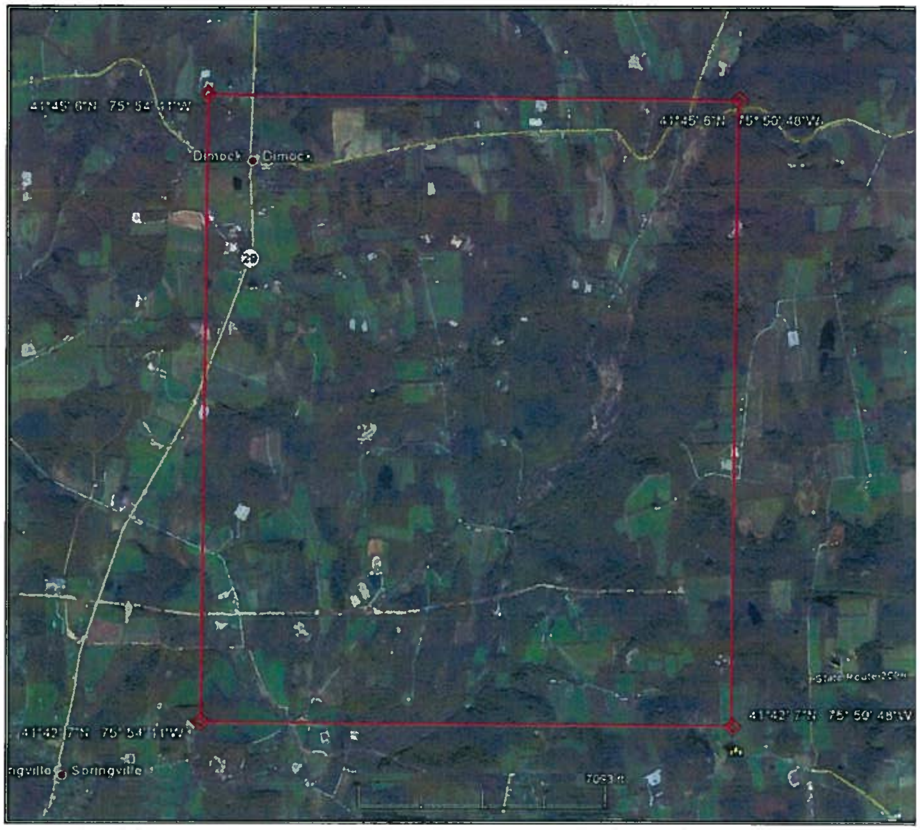
The purpose of this Action Memorandum is to request and document approval of an emergency removal action to prevent, limit, or mitigate the threats posed by the presence of hazardous substances at the Dimock Residential Groundwater Site (the "Site"), pursuant to Section 104(a) of the Comprehensive Environmental Response, Compensation and Liability Act, 42 U.S.C. § 9604(a) (CERCLA). The Site is located in Dimock Township, Susquehanna County, Pennsylvania. The OSC has initiated a removal site evaluation in accordance with the National Oil and Hazardous Substances Pollution Contingency Plan (NCP), 40 C.F.R. Part 300. The OSC has determined, based on Pennsylvania Department of Environmental Protection (PADEP) and Cabot Oil and Gas Corporation (Cabot) sampling information, consultation with an EPA toxicologist, the Agency for Toxic Substances and Disease Registry (ATSDR) Record Of Activity (AROA), issued 12/28/11, and the recent EPA well survey effort, that a number of home wells in the Dimock area contain hazardous substances, some of which are not naturally found in the environment. Inorganic hazardous substances are present in four home wells at levels that present a public health concern. These four specific homes have been dependent upon donated water for drinking and/or household use and the reliability of the sources for donated water is at this point uncertain.

Historic drilling activities in the Dimock area may have used materials containing hazardous substances. Spills and other releases have been documented by PADEP from these drilling activities. There is reason to believe that a release of hazardous substances has occurred. The presence of hazardous substances in the four home wells constitutes a release or substantial threat of a release and the situation meets the criteria for conducting a removal action under Section 300.415 of the NCP. The OSC has determined that funds in the amount of $100,000 are needed to mitigate the human health concern initially at four homes and therefore proposes the actions included in this Action Memorandum. This action includes provision of alternate water to four homes and home well sampling at approximately 61 homes within the Site area.

II. SITE CONDITIONS AND BACKGROUND

A. Background

1. Site Description - The Site area is located in Dimock, a rural area of northeastern Pennsylvania in Susquehanna County. A map of the area is included below.



2. History - Cabot began drilling for natural gas in the Dimock area in 2008. Methane contamination was detected in private wells thereafter in concentrations exceeding those previously found. PADEP had the lead in investigating the environmental complaints in Dimock. PADEP entered into a Consent Order and Agreement (CO&A) with Cabot which required permanent restoration or replacement of the affected water supply. A public water line was initially considered. PADEP later modified the CO&A to require installation of "gas mitigation" systems for 19 homes served by 18 private wells in the Site area.[1] Until the gas mitigation systems were installed, Cabot was to provide a temporary water source. Some well owners, within the scope of the PADEP CO&A, have gas mitigation systems installed, but others do not. While the gas mitigation systems were designed to remove methane, a potential exists that they may remove some hazardous substances as a by-product of their operation. Regardless, EPA does not know what, if any, hazardous substances these "gas mitigation" systems, originally designed to address methane, are removing. Therefore, EPA is including both pre- and post-treatment sampling in the scope of this action. Furthermore, there are

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[1] It had originally been reported that 19 homes were served by the 18 wells included within the scope of the CO&A but the door-to-door home well survey conducted to date by EPA has identified that there are currently 21 homes served by 20 wells on those same properties.

other homes served by private wells that were not covered by the scope of the PADEP CO&A, but are within this Site area.

III. Quantities/Types of Substances Present

1. Arsenic* – Arsenic is a naturally occurring element widely distributed in the earth's crust. Arsenic may also be present at elevated concentrations in the groundwater due to the use and effects of drilling fluids. Arsenic is classified as a known human carcinogen. This classification is based on animal and human studies, which indicate an increased risk for developing cancers of the skin, lung, bladder, kidney, liver, and prostate from consuming arsenic containing water. Non-cancer health effects associated with ingestion of arsenic include circulatory problems and skin damage.
2. Barium – Barium is a silvery-white metal that exists in nature only in ores containing mixtures of elements. It combines with other chemicals such as sulfur or carbon and oxygen to form barium compounds. Barium sulfate is sometimes used by doctors to perform medical tests and to take x-rays of the gastrointestinal tract. Ingesting drinking water containing levels of barium above the EPA drinking water guidelines for relatively short periods of time can cause gastrointestinal disturbances and muscle weakness. Ingesting high levels for a long time can damage the kidneys. Barium is known to be a common constituent of drilling fluids.
3. Bis(2-ethylhexyl)phthalate (DEHP)* - DEHP is a manufactured chemical that is commonly added to plastics to make them flexible. The phthalates are generally considered to be of slight to moderate toxicity. DEHP may be irritating to the eyes, skin, and mucous membranes. Mild gastric disturbances and diarrhea may occur following ingestion of larger doses. Central nervous system (CNS) depression may occur if large amounts of phthalate acid esters are absorbed. EPA has determined that DEHP is a probable human carcinogen. These determinations were based entirely on liver cancer in rats and mice. DEHP is known to be associated with drilling activities.
4. Glycol Compounds (including Ethylene Glycol* and 2-Methoxyethanol) – Glycol compounds are a class of organic compounds belonging to the alcohol family. Exposure to large amounts of ethylene glycol can damage the kidneys, nervous system, lungs, and heart. Exposure to high concentrations of 2-methoxyethanol is associated with testicular damage, impaired nervous system, and anemia. Glycols are known to be common in drilling fluids.
5. Manganese* – Manganese is a naturally occurring substance found in many types of rock and soil. Manganese is also known to be a constituent of some specialized drilling fluids. Eating a small amount of manganese from food or water is needed to stay healthy. At high levels, it can cause damage to the nervous system.

6. Phenol* - Phenol is both a manufactured chemical and a natural substance. Phenol is used as a disinfectant and is found in a number of consumer products. Skin exposure to high amounts can produce skin burns, liver damage, dark urine, and irregular heart beat. Various phenols are commonly associated with drilling fluids.
7. Sodium* – Sodium is an essential nutrient and occurs naturally in most foods. Excessive sodium intake is associated with high blood pressure. Various sodium containing compounds are associated with drilling fluids.

*A hazardous substance, as defined under CERCLA Section 101(14) and designated in Section 302.4 of the National Contingency Plan (NCP), 40 C.F.R. Section 302.4.

B. National Priorities List

The Dimock Residential Groundwater Site is not on the CERCLA National Priorities List (NPL).

C. State and Local Authorities' Roles

Cabot had been sampling the home wells and providing bottled drinking water and alternate water for non-potable use, through a Consent Order and Agreement (CO&A) with PADEP. The CO&A applies only to a specific list of homes, and does not include other homes, also located within the same geographic area. Some of these additional homes have had limited sampling conducted by Cabot and/or PADEP. PADEP determined that Cabot has complied with the terms of the CO&A, as it applies to the provision of temporary water, and subsequently approved Cabot's request to stop the delivery of alternate water.

IV. THREATS TO PUBLIC HEALTH OR WELFARE OR THE ENVIRONMENT

Section 300.415 of the NCP lists the factors to be considered in determining the appropriateness of a Removal Action. Paragraphs (b)(2)(i), (ii), and (vii) of Section 300.415 directly apply to the conditions found at the Dimock Residential Groundwater Site.

In evaluating the situation, the OSC first considered whether hazardous substances were present in a home well. The levels of those hazardous substances were then considered against primary Maximum Contaminant Levels (MCLs). They were also considered for non-cancer risk to determine if the levels generate a hazard quotient greater than 2. The presence of inorganic and organic chemicals in a number of wells supports the need for this action.

300.415 (b)(2)(i) "Actual or potential exposure to nearby human populations, animals or the food chain from hazardous substances or pollutants or contaminants"

The hazardous substances listed above, present in water from home wells at this Site based on sampling data described below, could cause adverse health impacts when chronic exposure through drinking water or other uses of water in the home occurs. There are other contaminants discussed in the Agency for Toxic Substances and Disease Registry's (ATSDR) Record of Activity (AROA) issued on December 28, 2011, which could also cause adverse health impacts. ATSDR has concluded for the area originally included with the PADEP/Cabot CO&A, which includes the four homes being considered here for alternate water, that a chronic health risk exists for most wells and that the situation supports a "Do Not Use the Water" action including the consideration of alternative home water supplies until further characterization is completed. An EPA Region III toxicologist's opinion is that, of the homes evaluated to date in an on-going effort, that four home wells contain contaminants at levels that present a public health concern. In one home, manganese was detected at 628 ug/L. Exposure to this concentration would yield a Hazard Quotient of approximately 2. In another home, manganese (1360 ug/L) was detected at a level that generates a Hazard Quotient of approximately 4. Note that children reside at this location. In the third home, arsenic was observed at a concentration (37 ug/L) that exceeds its MCL of (10 ug/L) and would pose a long-term cancer risk of 8E-04. Note that children reside at this location. In the fourth home, manganese was detected at 669 ug/L. Exposure to this concentration would yield a Hazard Quotient of approximately 2.3. Available data also indicate that hazardous substances may be present in a number of other homes. Because the available data is not complete and is of uncertain quality, additional sampling is needed to facilitate a further evaluation of any potential health concerns from the drinking water at home wells in the Site area.

EPA is providing water based upon a risk of exposure to hazardous substances above health-based levels. Furthermore, the OSC notes that for those homes where the EPA toxicologist has not identified contaminants that present a public health concern, that the limited data available does identify the existence of hazardous substances. In addition, PADEP's CO&A determined that 18 home wells were impacted by drilling activities; such impact may be evidence of the migration of hazardous substances.

Again, it is noted that this determination is based upon data which was collected by parties other than EPA (Cabot and PADEP). The quality assurance/quality control (QA/QC) information has not been verified. However, what is clear is that this data strongly suggests that hazardous substances have been released and are present in some home wells at levels that may present a public health concern. Current data does show arsenic and manganese at higher levels than may be typically found, in post drilling samples. Since arsenic and manganese are naturally occurring substances, EPA's assessment will include comparisons of background concentrations and post drilling concentrations present. EPA routinely acts under CERCLA to protect public health first while it acts to further define contamination. Thus, within this action, EPA will complete an assessment of the water quality of the home wells in the Site area to close information gaps as soon as possible. This sampling will be focused initially on evaluating those homes in the Site area that have been sampled in the past. Beyond that, sampling at homes will be based upon a sampling rationale using information regarding alleged health impacts and data gaps. In addition, EPA will continue to evaluate the updated data, and may revise its actions to provide water to any of the additional homes, or to cease provision of water, as warranted by the data.

300.415 (b)(2)(ii) "Actual or potential contamination of drinking water supplies or sensitive ecosystems"

The discussion of 300.415 (b) (2) (i) above applies to this factor. Both organic and inorganic contaminants have been detected in home wells. Although this action is predominantly based upon inorganic data at the four homes, it should be noted that organic compounds have been detected at other homes as detailed in the ATSDR AROA. Glycol detections included ethylene glycol, triethylene glycol, and 2,2'oxybisethanol (diethylene glycol). Some wells had all three reported glycols present in their wells but no exceedances of risk based screening criteria (note: the analytical detection level used appeared to be higher than screening levels). Bis(2-ethylhexyl) phthalate (DEHP) was detected in five samples and ranged from 0.14 µg/L to 22 ug/L. 2-methoxyethanol concentrations (ranging from 880 ug/L to 1,300 ug/L) were detected in each of six wells.

300.415 (b) (2) (vii) "The availability of other appropriate federal or state response mechanisms to respond to the release"

The four homes being considered for alternate water under this action were all dependent upon donated water, either bottled, water buffaloes (temporary storage tanks) or both. It is the OSC's understanding that the last delivery of bulk water from those organizations ceased on January 3, 2012. In any case the reliability of sources for donated water is at best uncertain.

V. PROPOSED ACTIONS AND ESTIMATED COSTS

A. Proposed Action

1. Proposed Action Description

Throughout the duration of Site activities, all personnel involved with execution of this proposed action will comply with the requirements of CERCLA and with all other applicable Federal and State regulations to the extent practicable considering the exigencies of the situation in accordance with 40 CFR § 300.415(j). Available data indicate that a number of homes in the area have hazardous substances present in the home wells, but only four indicate concentrations identified by the EPA toxicologist at a level of concern. Thus, those four homes will be immediately supplied with water. At the same time, approximately 61 home wells will be sampled by EPA to obtain data of known quality assurance to support future evaluations and response decisions. EPA will continue to evaluate the updated data, and may revise its actions to provide water to any of the additional homes, or to cease provision of water, as warranted by the data. The Removal activities at the Site will include the following:

1. Mobilize and demobilize personnel and equipment to conduct the action;
2. Delivery of a temporary source of clean water for household use to the four (4) homes with wells that contain contaminants at levels of public health concern. This provision of temporary water will continue until potential exposures are further understood and mitigated as needed.
3. The sampling program will include analysis for a broad range of parameters with a special priority being placed on quick turnaround for those parameters which are most frequently observed in the data available to EPA at this time. The Agency will also do some limited sampling for methane and bacteriological constituents. Home well water sampling will be performed by EPA in the Site area using the following assigned priority:

   i. The four (4) homes considered for provision of alternate water, to assess the potential exposure to hazardous substances and to determine whether continued temporary provision of clean water for household use is required.
   ii. The seventeen (17) remaining homes located on properties included in the PADEP/Cabot CO&A[2], which were identified as being impacted by drilling activities.
   iii. Approximately thirty (30) additional homes in the immediate area that have been sampled in the past.
   iv. Additional homes in the Site area where one or more of the factors below supports sampling.
      1. Direct observation or other evidence (home well surveys) of adverse health effects potentially attributable to contaminated groundwater use.
      2. Where data gaps in groundwater measurement or sampling need to be filled to gain an adequate understanding of Site conditions.

   Approximately ten (10) homes are currently identified from well surveys, but more could be added based upon data review.
4. Maintain necessary documentation of Site activities.
5. Develop and implement appropriate health and safety protocols for the removal activity.

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[2] It had originally been reported that 19 homes were served by the 18 wells included within the scope of the CO&A but the door-to-door home well survey conducted to date by EPA has identified that there are currently 21 homes served by 20 wells on those same properties.

2. Contribution to Remedial Performance

A remedial action is not anticipated and therefore this removal action is not inconsistent with any proposed remedial action.

3. Applicable or Relevant and Appropriate Requirements ("ARARs")

Actions will be conducted in compliance with Applicable or Relevant and Appropriate Regulations (ARARs) to the extent practicable considering the exigencies of the situation, in accordance with 40 CFR 300.415(j).

B. Estimated Costs

Extramural Costs	Total
Regional Allowance Costs: (ERRs Contractors and Subcontractors)	$ 50,000
Other Extramural Costs Not Funded From the Regional Allowance: START Contractor	$ 25,000
Subtotal, Extramural	$ 75,000
Extramural Costs Contingency	$ 25,000
Total Removal Action Project Ceiling	**$100,000**

VI. EXPECTED CHANGE IN SITUATION SHOULD ACTION BE DELAYED OR NOT TAKEN

If no action is taken, the residents may utilize well water which poses a potential public health concern.

VII. OUTSTANDING POLICY ISSUES

Because this response action could be considered nationally significant or precedent setting, it requires the prior concurrence of the Assistant Administrator, Office of Solid Waste and Emergency Response (AA-OSWER). Furthermore, because the action appears to be nationally significant and/or precedent-setting, the Region will continue to coordinate closely with Headquarters. EPA also will maintain coordination and communications with PADEP. In taking this action, EPA is aware of and has considered the potential applicability of the natural gas exclusion under CERCLA, the Bentsen Amendment under the Resource Conservation and Recovery Act (RCRA), and the exclusions to the definition of 'underground injection' under the Safe Drinking Water Act (SDWA). EPA has concluded that this action is appropriate under CERCLA at this time.

VIII. ENFORCEMENT

The total EPA costs for this removal action based upon full-cost accounting practices that will be eligible for cost recovery are estimated below as follows:[3]

Direct Extramural Costs	$100,000
Direct Intramural Costs	$ 25,000
Total Direct Costs	$125,000
Indirect Cost (67.13% x Direct Costs)	$ 83,912
Total Costs (Direct and Indirect)	$208,912

IX. RECOMMENDATION

This Action Memorandum represents the selected Removal Action for the Dimock Residential Groundwater Site in Dimock Township, Susquehanna County, Pennsylvania, developed in accordance with CERCLA, as amended, and is consistent with the NCP. This decision is based on the administrative record for the Site. The administrative record consists of the following documents

1. 1/13/12 "Dimock Home Well Data" memo from EPA Toxicologist Dawn Ioven.
2. ATSDR AROA Issued 12/28/11.
3. Summary of Portions of data received by EPA and reviewed by the OSC.
4. PADEP Consent Order and Agreement, dated December 15, 2010.
5. EPA Data Review Memo, January 13, 2012.
6. EPA 104e request to Cabot, January 6, 2012

Conditions at the Site meet the Removal Action requirements of Section 300.415(b) of the NCP and I recommend your approval of the proposed removal action and exemption from the statutory limits. The total project ceiling, if approved, will be $100,000. Of this, as much as, $50,000 comes from the Regional removal allowance. Please indicate your approval or disapproval below.

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[3] Direct Costs include direct extramural costs and direct intramural costs. Indirect costs are calculated based on an estimated indirect cost rate expressed as a percentage of site-specific direct costs, consistent with the full cost accounting methodology effective October 2, 2000. These estimates do not include pre-judgment interest, do not take into account other enforcement costs, including Department of Justice costs, and may be adjusted during the course of a removal action. The estimates are for illustrative purposes only and their use in not intended to create any rights for responsible parties. Neither the lack of a total cost estimate nor deviation of actual total costs from this estimate will affect the United States' right to cost recovery.

Action by the Approving Official:

I have reviewed the above-stated facts and, based upon those facts and the information compiled in the documents described above, I hereby approve/disapprove the selected removal action.

APPROVED: Dennis P Carney **DATE** 1/19/2012
Dennis P. Carney, Associate Division Director
Hazardous Site Cleanup Division
EPA Region 3

DISAPPROVED: ______________________________ **DATE**________________
Dennis P. Carney, Associate Division Director
Hazardous Site Cleanup Division
EPA Region 3

EPA United States Environmental Protection Agency

Newsroom
News Releases By Date

EPA Completes Drinking Water Sampling in Dimock, Pa.

Release Date: 07/25/2012
Contact Information: Terri White white.terri-a@epa.gov (215) 814-5567

PHILADELPHIA (July 25, 2012) – The U.S. Environmental Protection Agency announced today that it has completed its sampling of private drinking water wells in Dimock, Pa. Data previously supplied to the agency by residents, the Pennsylvania Department of Environmental Protection and Cabot Oil and Gas Exploration had indicated the potential for elevated levels of water contaminants in wells, and following requests by residents EPA took steps to sample water in the area to ensure there were not elevated levels of contaminants. Based on the outcome of that sampling, EPA has determined that there are not levels of contaminants present that would require additional action by the Agency.

“Our goal was to provide the Dimock community with complete and reliable information about the presence of contaminants in their drinking water and to determine whether further action was warranted to protect public health,” said EPA Regional Administrator Shawn M. Garvin. “The sampling and an evaluation of the particular circumstances at each home did not indicate levels of contaminants that would give EPA reason to take further action. Throughout EPA's work in Dimock, the Agency has used the best available scientific data to provide clarity to Dimock residents and address their concerns about the safety of their drinking water.”

EPA visited Dimock, Pa. in late 2011, surveyed residents regarding their private wells and reviewed hundreds of pages of drinking water data supplied to the agency by Dimock residents, the Pennsylvania Department of Environmental Protection and Cabot. Because data for some homes showed elevated contaminant levels and several residents expressed concern about their drinking water, EPA determined that well sampling was necessary to gather additional data and evaluate whether residents had access to safe drinking water.

Between January and June 2012, EPA sampled private drinking water wells serving 64 homes, including two rounds of sampling at four wells where EPA was delivering temporary water supplies as a precautionary step in response to prior data indicating the well water contained levels of contaminants that pose a health concern. At one of those wells EPA did find an elevated level of manganese in untreated well water. The two residences serviced by the well each have water treatment systems that can reduce manganese to levels that do not present a health concern.

As a result of the two rounds of sampling at these four wells, EPA has determined that it is no longer necessary to provide residents with alternative water. EPA is working with residents on the schedule to disconnect the alternate water sources provided by EPA.

Overall during the sampling in Dimock, EPA found hazardous substances, specifically arsenic, barium or manganese, all of which are also naturally occurring substances, in well water at five homes at levels that could present a health concern. In all cases the residents have now or will have their own treatment systems that can reduce concentrations of those hazardous substances to acceptable levels at the tap. EPA has provided the residents with all of their sampling results and has no further plans to conduct additional drinking water sampling in Dimock.

For more information on the results of sampling, visit: http://www.epa.gov/aboutepa/states/pa.html .

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11/03/2012	EPA Approves Additional Fuel Waivers for New Jersey, Pennsylvania, and New York
11/02/2012	Hyundai/Kia to Correct Overstated MPG Claims as Result of EPA Investigation

NRDC
THE EARTH'S BEST DEFENSE

NATURAL RESOURCES DEFENSE COUNCIL

September 8, 2010

By FedEx and e-mail

The Honorable Lisa Jackson
Administrator
United States Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Petition for Rulemaking Pursuant to Section 6974(a) of the Resource Conservation and Recovery Act Concerning the Regulation of Wastes Associated with the Exploration, Development, or Production of Crude Oil or Natural Gas or Geothermal Energy.

Dear Administrator Jackson:

To best protect human health, food sources, and our environment from the toxicity of contaminants found in wastes associated with the exploration, development and production of oil, gas, and geothermal energy, we believe it is appropriate for the Environmental Protection Agency (EPA) to reconsider its 1988 Regulatory Determination and regulate these wastes under Subtitle C of the Resource Conservation and Recovery Act (RCRA). The Natural Resources Defense Council (Petitioner) is submitting the attached rulemaking petition pursuant to Section 6974(a) of RCRA, 42 U.S.C. § 6974(a). In support of this petition, we identify numerous reports and data produced since the EPA's Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development, and Production Wastes (July 6, 1988) which quantify the waste's toxicity, threats to human health and the environment, inadequate state regulatory programs, and readily available solutions.

The Natural Resources Defense Council (NRDC) is a nonprofit environmental action group established in 1970 by a group of law students and attorneys at the forefront of the environmental movement. The Natural Resources Defense Council's purpose is to safeguard the Earth: its people, its plants and animals and the natural systems on which all life depends. NRDC uses law, science and the support of 1.2 million members and online activists to protect the planet's wildlife and wild places and

www.nrdc.org

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to ensure a safe and healthy environment for all living things. NRDC has worked for many years to ensure the proper regulation of oil and gas exploration and production operations.

Section 6974(a) of RCRA allows any person to petition the Administrator of the EPA to promulgate an environmental regulation. Within a reasonable time following receipt of such petition, the Administrator shall take action with respect to such petition and shall publish notice of such action in the Federal Register, together with the reasons therefor. This petition asks the EPA to take specific actions and directs the EPA's attention to the ample documentation in the record, which provides full support for the designation of wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy as hazardous waste under RCRA and provides a firm and compelling basis for the reconsideration of the EPA's July 1998 Regulatory Determination.

Thank you in advance for your consideration of this petition.

Respectfully submitted by:

Amy Mall

Amy Mall
Senior Policy Analyst

Diane Donnelly
Legal Intern

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IV. APPENDIX B: CD WITH ALL REFERENCE DOCUMENTS

I. THE EPA SHOULD REGULATE WASTE FROM THE EXPLORATION, DEVELOPMENT AND PRODUCTION OF CRUDE OIL AND NATURAL GAS UNDER SUBTITLE C OF RCRA.

We request that the U.S. Environmental Protection Agency (EPA) promulgate regulations that subject wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy to the hazardous waste provisions of Subtitle C of the Resource Conservation and Recovery Act (RCRA). We submit this petition pursuant to 42 U.S.C. § 6974(a), seeking that EPA ensure safe management of these wastes throughout their life cycle from cradle to grave, including generation, transportation, treatment, storage and disposal. Reports concerning the toxicity of exploration, development and production wastes, their release into the environment, threats to human health, the increasing amount of these types of wastes being generated, the inadequacy of existing state regulations, enforcement and oversight, and the feasibility and economic benefits of using disposal techniques that are less harmful to the environment all support regulation under Subtitle C, as described in detail below.

A. The EPA Has Authority to Reconsider Its 1988 Regulatory Determination.

Congress gave EPA the authority to prescribe necessary regulations to carry out its functions under RCRA.[1] Congress charged EPA with the task of "assuring that hazardous waste management practices are conducted in a manner which protects human health and the environment."[2] Congress ensured that the public had a way to seek additional protections from hazardous wastes by allowing "[a]ny person . . . [to] petition the Administrator for the promulgation, amendment, or repeal of any regulation under" RCRA, and by requiring that "[w]ithin a reasonable time following receipt of such petition, the Administrator shall take action with respect to such petition and shall publish notice of such action in the Federal Register, together with the reasons therefor."[3]

With these provisions, Congress expressed its intent that RCRA would adapt to changing hazardous waste management needs. Foreseeing the need to update regulations promulgated under RCRA to account for changing circumstances,[4] Congress provided the public a way to bring about EPA review of its regulations.[5] These provisions authorize EPA to reconsider its current treatment of wastes associated with the exploration, development, or production of oil and gas (E&P wastes).

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[1] 42 U.S.C. § 6912(a)(1).
[2] 42 U.S.C. § 6902(a)(4).
[3] 42 U.S.C. § 6912(a)(1).
[4] 42 U.S.C. § 6912(b).
[5] 42 U.S.C. § 6912(a)(1).

Congress passed RCRA in 1976 as an amendment to the Solid Waste Disposal Act of 1965 in an effort to enact more comprehensive waste disposal standards nationwide.[6] Through RCRA, Congress declared that the "disposal of solid waste . . . without careful planning and management [was] a danger to human health and the environment."[7] Congress later amended RCRA with the Solid Waste Disposal Act Amendments of 1980.[8] One of the 1980 amendments, the so-called Bentsen Amendment, temporarily exempted "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas" from regulation under RCRA.[9]

Under the Bentsen Amendment, Congress directed EPA to conduct a study to determine whether or not E&P wastes should be regulated as hazardous wastes under RCRA.[10] EPA completed the required study and submitted a Report to Congress on the Management of Waste from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy.[11] Shortly after submitting its report to Congress, EPA issued its Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development, and Production Wastes, in which it decided that regulation of E&P wastes under Subtitle C of RCRA was unwarranted.[12]

In the more than twenty years that have passed since EPA issued its Regulatory Determination on E&P wastes, both the oil and gas industry and the risks associated with E&P wastes have expanded dramatically, making EPA's 1988 Regulatory Determination unjustified. While E&P wastes have always been hazardous to human health and the environment, the recent expansion of drilling operations to more densely populated areas places even more people at risk. EPA's reconsideration of its 1988 Regulatory Determination is especially necessary now that the basis for its Regulatory Determination no longer reflects current conditions. In its 1988 Regulatory Determination, EPA identified three factors as the basis for its decision not to regulate E&P wastes under Subtitle C. These factors included: (1) the infeasibility of implementing alternative regulations, (2) the adequacy of state regulations, and (3) the economic harm that would befall the oil and gas industry if additional regulatory controls were imposed.[13]

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[6] Joseph F. Scavetta, *RCRA 101: A Course in Compliance for Colleges and Universities*, 72 NOTRE DAME L. REV. 1647 (1997).

[7] Natasha Ernst, Note, *Flow Control Ordinances in a Post-*Carbone *World*, 13 PENN ST. ENVTL. L. REV. 53 (2004) (citing 42 U.S.C §§ 6901–6992k (2003)).

[8] Pub. L. 96-482; *see also* James R. Cox, *Revisiting RCRA'S Oilfield Waste Exemption as to Certain Hazardous Oilfield Exploration and Production Wastes*, 14 VILL. ENVTL. L.J. 1, 3 (2003).

[9] 42 U.S.C. § 6921(b)(2)(A).

[10] 42 U.S.C. § 6921(b)(2)(B).

[11] EPA, REPORT TO CONGRESS, MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT, AND PRODUCTION OF CRUDE OIL, NATURAL GAS, AND GEOTHERMAL ENERGY, Vols. 1–3 EPA530-SW-88-003 (1987) [hereinafter REPORT TO CONGRESS].

[12] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. 25446, 25447 (July 6, 1988).

[13] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25446.

As will be discussed at greater length below, new evidence clearly demonstrates that alternative disposal practices are feasible, state regulations remain inadequate, and the oil and gas industry is unlikely to be severely harmed by the imposition of more stringent waste disposal requirements. Because this evidence shows that the assumptions on which EPA's 1988 Regulatory Determination was based are no longer correct, EPA must revisit its decision.[14]

Nothing in RCRA prevents the EPA from reconsidering its 1988 Regulatory Determination. In *American Portland Cement Alliance*,[15] the court upheld EPA's authority to reconsider regulatory determinations made pursuant to the 1980 amendments to RCRA.[16] Moreover, statements made by EPA in its 1988 Regulatory Determination indicate that EPA never intended the Regulatory Determination to be its final word on E&P waste. Instead, EPA established a three-pronged plan and intended to take further action to fill in existing gaps in the regulations governing the disposal of E&P wastes.[17] To date this three-pronged plan has not been fulfilled. Gaps in the regulatory system governing E&P wastes have grown even wider and evidence of the substantial harm E&P wastes can cause to human health and the environment has continued to accumulate. EPA must revisit its 1988 Regulatory Determination to fulfill its obligations under the 1988 Regulatory Determination and protect human health and the environment from the significant risks posed by E&P wastes.

Unless EPA revisits its 1988 Regulatory Determination and recommends that E&P wastes be regulated under Subtitle C of RCRA, E&P wastes will continue to present substantial hazards to human health and the environment.[18]

B. EPA Should Regulate E&P Wastes Under Subtitle C of RCRA.

In light of the documented toxicity of contaminants found in E&P waste, the failure of states to adequately regulate the disposal of E&P wastes, the dramatic increase in oil and gas production that has occurred since 1988, and the availability of safer cost-effective disposal alternatives, EPA must take action in order to prevent further harm to human health and the

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[14] EPA Region 8 itself stated that "EPA may need to revisit the continued validity of the exemption in light of the advancements in practices." EPA REGION 8, AN ASSESSMENT OF THE ENVIRONMENTAL IMPLICATIONS OF OIL AND GAS PRODUCTION: A REGIONAL CASE STUDY 3-14 (Working Draft 2008).

[15] 101 F.3d 772 (D.C. Cir. 1996).

[16] *Id.*

[17] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25,447.

[18] [This footnote intentionally deleted in corrected copy.]

environment. EPA should reconsider its 1988 Regulatory Determination and regulate E&P wastes under Subtitle C of RCRA. Regulation under Subtitle C is not only appropriate, given that E&P wastes fall within the regulatory criteria for characteristic hazardous waste,[19] but necessary because, without such action, the oil and gas industry will lack the incentives to implement safer techniques as quickly as is necessary.[20]

1. E&P Waste Is Toxic.

E&P waste that is exempt from regulation under Subtitle C includes: drilling fluids and cuttings, produced water, used hydraulic fracturing fluids, rigwash, workover wastes, tank bottom sludge, glycol-based dehydration wastes, amine-containing sweetening wastes, hydrocarbon-bearing soil, and many other individual waste products.[21] In its 1988 Regulatory Determination, EPA admitted that E&P wastes contain toxic substances that endanger both human health and the environment.[22] Despite noting that benzene, phenanthrene, lead, arsenic, barium, antimony, fluoride, and uranium found in E&P wastes were of major concern and present at "levels that exceed 100 times EPA's health based standards,"[23] EPA declined to regulate these toxic substances under Subtitle C of RCRA. But EPA can no longer refuse to act: an ever-increasing amount of evidence demonstrates that E&P wastes are toxic, have had substantial negative effects on human health and the environment, and should be a major concern for EPA. Since 1988, numerous reports, studies, and cases have demonstrated that E&P wastes contain toxic substances that threaten both human health and the environment.

a. Contaminants Found in Different Types of E&P Wastes

E&P wastes are generally divided into three categories: produced water, drilling fluids and cuttings, and associated wastes.[24] All of these wastes contain a variety of toxic substances that present substantial risks to human health and the environment. Despite these risks, these E&P wastes are currently exempt from regulation under Subtitle C.

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[19] *See* notes 282–313 *infra* and accompanying text.

[20] Closing Argument of the New Mexico Citizens for Clean Air and Water, Dec. 2007, OCD Document Image No. 14015_648_CF[1] at 9-10; *see also* AMY MALL, DRILLING DOWN: PROTECTING WESTERN COMMUNITIES FROM THE HEALTH AND ENVIRONMENTAL EFFECTS OF OIL AND GAS PRODUCTION vi (2007) [hereinafter "DRILLING DOWN"].

[21] *See* RAILROAD COMMISSION OF TEXAS, *Hazardous and Nonhazardous Oil and Gas Waste* 3–6, *in* WASTE MINIMIZATION IN THE OIL FIELD (2001).

[22] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25448.

[23] *Id.*; *see also* Cox, *supra* note 8, at 9.

[24] CLAUDIA ZAGREAN NAGY, CALIFORNIA DEP'T OF TOXIC SUBSTANCES CONTROL, OIL EXPLORATION AND PRODUCTION WASTES INITIATIVE 6 (2002).

i. Produced Water & Hydraulic Fracturing Wastewater

Produced water, also known as brine, is generally—but erroneously—considered to be "relatively clean" and contain less contaminants than other E&P waste.[25] Despite this common misconception, a study sponsored by the U.S. Department of Energy demonstrated that oil production yields "environmentally hazardous" produced water.[26] The West Virginia Department of Environmental Protection (WVDEP) found many contaminants of concern present in oil and gas wastewaters,[27] including arsenic, lead, and hexavalent chromium, while EPA Region 8 identified the presence of barium, chloride, sodium, sulfates, and other minerals,[28] and the Oklahoma Corporation Commission Oil and Gas Conservation Division stated that produced water can contain high levels of boron.[29] In 2009, the Colorado Oil and Gas Conservation Commission (COCG) documented multiple spills of produced water containing benzene levels exceeding the state's water quality standards, at least one of which was confirmed to have impacted groundwater.[30]

Knowledge of the hazardous nature of produced water is not new. In 1972, Chevron Oil Field Research Company found that "oil field produced waters contain dissolved organic compounds that are toxic to marine life."[31] More than a decade later, the U.S. General Accounting Office (GAO) acknowledged that "[b]rines associated with oil and gas production contain very high levels of chlorides . . . . Brines may also contain . . . petroleum hydrocarbons and additives, such as corrosion inhibitors, . . . and other radioactive materials."[32] EPA was aware of these hazardous constituents when it issued its 1988 Regulatory Determination. In its 1987 Report to Congress, EPA knew that "PAHs [polycyclic aromatic hydrocarbons] are a typical component of some produced waters," that "very low concentrations . . . of PAH are lethal to some forms of aquatic wildlife," and that the practice of disposing of "produced water in

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[25] KELLY CORCORAN, KATHERINE JOSEPH, ELIZABETH LAPOSATA, & ERIC SCOT, UC HASTINGS COLLEGE OF THE LAW'S PUBLIC LAW RESEARCH INSTITUTE, SELECTED TOPICS IN STATE AND LOCAL REGULATION OF OIL AND GAS EXPLORATION AND PRODUCTION 31–32.

[26] C. TSOURIS, OAK RIDGE NATIONAL LABORATORY, EMERGING APPLICATIONS OF GAS HYDRATES 7.

[27] The contaminants of concern included: "sulfate, chloride, arsenic, titanium, cobalt, nickel, silver, zinc, vanadium, tin, cadmium, lead, chromium, hexavalent chromium, copper, fluoranthene, cyanide, mercury, selenium, antimony, beryllium, barium, ammonia nitrogen, fluoride, nitrite nitrogen, nitrate nitrogen, oil and grease, total suspended solids, iron, aluminum, chloroform, benzene, phthalate esters, strontium, strontium-90, boron, lithium, gross alpha radiation, gross beta radiation, radium 226+ [and] radium 228." Letter from West Virginia Department of Environmental Protection to William Goodwin, Superintendent Clarksburg Sanitary Board, July 23, 2009.

[28] EPA REGION 8, AN ASSESSMENT OF THE ENVIRONMENTAL IMPLICATIONS OF OIL AND GAS PRODUCTION: A REGIONAL CASE STUDY, WORKING DRAFT 3-11 (2008).

[29] OKLAHOMA CORPORATION COMMISSION OIL AND GAS CONSERVATION DIVISION, GUIDELINES FOR RESPONDING TO AND REMEDIATING NEW OR HISTORIC BRINE SPILLS 2 (2009).

[30] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1631502, 1631508 (groundwater impact confirmed).

[31] A.H. BEYER, CHEVRON OIL FIELD RESEARCH CO., TECHNICAL MEMORANDUM, PURIFICATION OF PRODUCED WATER, PART 1—REMOVAL OF VOLATILE DISSOLVED OIL BY STRIPPING 1 (1972).

[32] U.S. GENERAL ACCOUNTING OFFICE, RCED-89-97, SAFEGUARDS ARE NOT PREVENTING CONTAMINATION FROM INJECTED OIL AND GAS WELLS 11 (1989).

unlined percolation pits [allows] PAHs and other constituents to migrate into and accumulate in soils."[33]

In addition to containing dangerous contaminants, produced water can also be radioactive. This problem first attracted national attention 1988 in southern and Gulf Coast states.[34] Shortly thereafter, GAO's 1989 report openly acknowledged the hazard.[35] A more recent analysis of normally occurring radioactive materials (NORM) levels in produced waters from the Marcellus Shale indicates that the dangers may be greater than initially thought.[36] Samples of produced water in the Marcellus Shale analyzed by the New York State Department of Environmental Conservation (NYSDEC) were reported to contain "levels of radium 226, a derivative of uranium, as high as 267 times the limit safe for people to drink."[37]

Despite knowledge of these risks, the data currently available may underestimate the actual radiation levels in produced water. A common method used by industry and EPA to measure radiation levels in produced water has been criticized because of its tendency to underestimate actual radiation levels. In the late 1980s, Exxon Mobil, along with Rogers and Associates Engineers (RAE) and the American Petroleum Institute (API), formulated correlations that could be used to estimate NORM in levels of equipment used to hold produced water.[38] The external measurement process chosen by RAE to measure the NORM levels has since been challenged as "seriously flawed" and has resulted in the reporting of a "greatly reduced radioactivity concentration of 480 pCi/gm."[39] Accurate testing could reveal that the NORM levels in produced water are even higher than currently being reported.

Wastewaters from hydraulic fracturing, largely composed of used fracturing fluids, are also toxic. Common substances found in these wastewaters include: surfactants, friction reducing chemicals, biocides, scale inhibitors, polymers, cross linkers, pH control agents, gel breakers, clay control agents and propping agents.[40] Many of these substances are possible and probable carcinogens.[41] Analysis of fracturing fluid flowback waters from Pennsylvania and West Virginia found the known carcinogen benzene present in nearly half of all fracturing fluid flowback waters at average concentrations nearly one hundred times the maximum acceptable

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[33] EPA, REPORT TO CONGRESS, *supra* note 11, at II-44.
[34] Keith Schneider, *Radiation Danger Found in Oilfields Across the Nation*, N.Y. TIMES, Dec. 3, 1990, at A1.
[35] GAO, RCED-89-97, *supra* note 32.
[36] N.Y. DEP'T OF ENVTL. CONSERVATION, DRAFT SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM 6-130 (2009) [hereinafter DRAFT SGEIS].
[37] Abrahm Lustgarten, ProPublica, *Natural Gas Drilling Produces Radioactive Wastewater*, SCIENTIFIC AMERICAN, Nov. 9, 2009; *see also* DRAFT SGEIS, *supra* note 36, at app. 13.
[38] Motion in Limine to Exclude Rogers and Associates Engineering Reports, Lester v. Exxon Mobil Corp., No. 630-402 (La. 24th Jud. Dist. Ct. 2009), at 6–7.
[39] *Id.* at 7-8.
[40] Wilma Subra, Louisiana Environmental Action Network, Comments on Hydraulic Fracturing to the Louisiana Senate Environmental Quality Committee, Mar. 11, 2010.
[41] *Id.*

contaminant levels established by EPA.[42] While this information demonstrates that these wastes contain toxic compounds, the true extent of the risks associated with hydraulic fracturing wastewaters is currently unknown as many of the compounds used in fracturing fluids and returned in the wastewaters are not publically disclosed.[43]

ii. Drilling Fluids and Drill Cuttings

Drilling fluids and cuttings make up two to four percent of oil and gas wastes.[44] They include rock removed during drilling (drill cuttings) and drilling muds, also known as drilling fluids, which can be either water or oil-based and often contain various additives.[45] A joint EPA/API survey found drilling fluids in reserve pits to contain "chromium, lead and pentachlorophenol at hazardous levels."[46] The survey also found that "oil-based fluids may contain benzene"[47] and that when oil-based fluids are used, "potentially toxic hydrocarbons" will be present in greater quantities.[48] Drilling muds may also contain other "potentially hazardous substances including . . . cadmium, arsenic . . . mercury, copper . . . diesel oil; grease; and various other hydrocarbons and organic compounds (e.g., methanol, chlorinated phenols, formaldehyde, benzene, toluene, ethyl benzene, xylene, and acrylamide)," as well as additives including acids and caustics, corrosion inhibitors, bactericides and biocides, surfactants, defoamers, emulsifiers, filtrater

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[42] Susan Riha et al, *Comments on the Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program*, Jan. 2010, at 5; *see also* N.Y. DEP'T OF ENVTL. CONSERVATION, DRAFT SGEIS 5-104 (2009).

[43] Wilma Subra, Comments on Hydraulic Fracturing, *supra* note 40. *See also* DRAFT SGEIS, *supra* note 36, at 5-51 (stating that the fracturing fluid additives list "[c]hemical constituents are not linked to product names in Table 5.6 because a significant number of product composition and formulas have been justified as trade secrets as defined [under New York law] . . . .").

[44] U.S. CONGRESS, OFFICE OF TECHNOLOGY ASSESSMENT, MANAGING INDUSTRIAL SOLID WASTES FROM MANUFACTURING, MINING, OIL AND GAS PRODUCTION, AND UTILITY COAL COMBUSTION—BACKGROUND PAPER 67 (1992).

[45] *Id; see also* U.S. FISH & WILDLIFE SERV., REGION 6, ENVTL. CONTAMINANTS PROGRAM, RESERVE PIT MANAGEMENT: RISKS TO MIGRATORY BIRDS 4–5 (2009).

> "Water-based drilling muds can contain glycols, chromium, zinc, polypropylene glycol, and acrylamide copolymers. Synthetic-based muds contain mineral oil and oil-based muds can contain diesel oil, although diesel oil is being replaced by a palm oil derivative or hydrated caster [*sic*] oil. Other additives typically used in drilling fluids include: polymers (partially hydrolyzed polyacrylamide (PHPA) and polyanionic cellulose (PAC)); drilling detergents; and sodium carbonate (soda ash). PHPA is used to increase viscosity of fluid and inhibit clay and shale from swelling and sticking. PAC is used to increase the stability of the borehole in unconsolidated formations. Drilling detergents or surfactants are used with bentonite drilling fluids to decrease the surface tension of the drill cuttings. Soda ash is used to raise the pH of the water and precipitate calcium out of the water." *Id.* (internal citations omitted).

[46] U.S. CONGRESS, OFFICE OF TECHNOLOGY ASSESSMENT, MANAGING INDUSTRIAL SOLID WASTES FROM MANUFACTURING, MINING, OIL AND GAS PRODUCTION, AND UTILITY COAL COMBUSTION—BACKGROUND PAPER 5 (1992).

[47] *Id.*

[48] OIL & GAS ACCOUNTABILITY PROJECT, PIT POLLUTION—BACKGROUNDER ON THE ISSUES, WITH A NEW MEXICO CASE STUDY 6 (2004).

reducers, shale control inhibitors, thinners and dispersants, weighing materials, bentonite clay, and acrylamide.[49]

The use of these additives increases the risks associated with E&P waste, as many are hazardous compounds themselves.[50] EPA has already classified at least one additive, flocculant acrylamide, as a probable carcinogen.[51] Another frequently used additive, barite weighting agent, can contain cadmium and mercury.[52] When Greenpeace analyzed the heavy metal contents of one drilling fluid additive, SOLTEX® (a scale inhibitor used in both on- and off-shore drilling muds), it identified the presence of antimony, arsenic, barium, cadmium, chromium, cobalt, copper, fluoride, lead, mercury, nickel, vanadium, and zinc.[53] These reports alone create cause for concern; yet, the full extent of the risk these chemicals present is unknown, as the additives' formulas, and thus the concentrations of the various chemicals, are proprietary information and undisclosed by oil and gas companies.[54]

iii. Associated Wastes

Associated wastes include oily sludges, workover wastes, well completion and abandonment wastes and other small volume wastes associated with oil or gas production.[55] Oily sludges consist of "oily sands and untreatable emulsions segregated from the production stream, and sediment accumulated on the bottom of crude oil and water storage tanks."[56] Workover wastes include foam treatment wastes and stimulation fluids.[57] Of all the E&P wastes, associated wastes are generated in the lowest volume;[58] however, this does not mean that they are safe or that current regulations ensure they are disposed of properly. Indeed, "[a]lthough associated wastes constitute a relatively small proportion of total wastes, they are most likely to contain a range of chemicals and naturally occurring materials that are of concern to health and safety."[59] Several associated wastes identified in Colorado have the "potential to be ignitable" while others "can exhibit toxicity for heavy metals such as lead."[60]

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[49] *Id.*
[50] *Id.*
[51] U.S. EPA, *Technology Transfer Air Toxics: Acrylamide*.
[52] T.A. Kassim, *Waste Minimization and Molecular Nanotechnology: Toward Total Environmental Sustainability*, *in* 3 ENVIRONMENTAL IMPACT ASSESSMENT OF RECYCLED WASTES ON SURFACE AND GROUND WATERS: ENGINEERING MODELING AND SUSTAINABILITY 191, 204 (Tarek A. Kassim ed., 2005); Texas Railroad Commission, Waste Minimization in Drilling Operations.
[53] JONATHAN WILLS, MUDDIED WATERS, A SURVEY OF OFFSHORE OILFIELD DRILLING WASTES AND DISPOSAL TECHNIQUES TO REDUCE THE ECOLOGICAL IMPACT OF SEA DUMPING (2000).
[54] OIL & GAS ACCOUNTABILITY PROJECT, *supra* note 48, at 6–7.
[55] NAGY, *supra* note 24, at 6.
[56] *Id. at* 13.
[57] *Id.* at 14.
[58] *Id. at* 6; American Petroleum Institute, Waste Management.
[59] Dara O'Rourke & Sarah Connolly, *Just Oil? The Distribution of Environmental and Social Impacts of Oil Production and Consumption*, 28 ANNUAL REV. ENVTL. RESOURCES 587, 595 (2003).
[60] Testimony of Margaret A. Ash, OGCC Envtl. Supervisor, *In the Matter of Changes to the Rules and Regulations of the Oil and Gas Conservation Commission of the State of Colorado*, at 15.

b. Contaminants Found in Specific E&P Waste Disposal Sites

The hazardous contaminants used in oil and gas exploration and production and whose presence has been identified in E&P wastes end up being disposed of in a variety of methods. Pits, burial, land application, and injection wells are the methods most frequently used to dispose of E&P wastes. Wastewater treatment facilities are also increasing in use. Studies of some of these different types of common E&P waste disposal sites provide further evidence of the toxicity of E&P wastes.

Pits are a common E&P waste disposal method used both to store drilling muds and cuttings brought to the surface in drilling operations and to hold produced water, production fluids, used hydraulic fracturing fluid, and other wastes.[61] Numerous studies have found pits to contain toxic levels of many hazardous compounds. In 2007, an industry committee of oil and gas companies in New Mexico sponsored a sampling and analysis program of waste pits in the San Juan Basin.[62] Forty-two substances, including the "BTEX" chemicals[63] (benzene, toluene, ethylbenzene, and xylene), acetone, arsenic, barium, mercury, and radium were found in the samples.[64] Eleven of the chemicals were present at concentration levels above state limits.[65] A more recent sampling of an oilfield pit in Texas identified the presence of high levels of mercury and chromium.[66] Dirt removed from a pit in Oklahoma was contaminated with "high levels of arsenic, dioxins and total petroleum hydrocarbons."[67]

Analysis of land application sites, another method for disposing of E&P wastes, provides further evidence illustrating the hazards of E&P wastes. A study of landfarms conducted by the Arkansas Department of Environmental Quality (ADEQ) found that the substances in E&P wastes that were being land applied exceeded Arkansas' acceptable limits for chloride concentrations in most of the facilities it tested.[68] In addition, "[n]ine out of eleven facilities had

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[61] CORCORAN ET AL., *supra* note 25, at 20–21.

[62] The Endocrine Disruption Exchange, Potential Health Effects of Residues in 6 New Mexico Oil and Gas Drilling Reserve Pits Based on Compounds Detected in at Least One Sample, Nov. 15, 2007.

[63] SHANNON D. WILLIAMS, DAVID E. LADD & JAMES J. FARMER, U.S. GEOLOGICAL SURVEY, FATE AND TRANSPORT OF PETROLEUM HYDROCARBONS IN SOIL AND GROUND WATER AT BIG SOUTH FORK NATIONAL RIVER AND RECREATION AREA, TENNESSEE AND KENTUCKY, 2002–2003 10 (2006) ("The BTEX compounds . . . appear on The Clean Water Act Priority Pollutant list of 126 chemical substances (Office of the Federal Register, 2002)."). Testing obtained by individuals residing near the pits has also confirmed the presence of dangerous contaminants. DRILLING DOWN, *supra* note 20, at 26 n.156.

[64] The Endocrine Disruption Exchange, *supra* note 62.

[65] The Endocrine Disruption Exchange, Number of Chemicals Detected in Reserve Pits for 6 Wells in New Mexico That Appear on National Toxic Chemicals Lists: Amended Document, Nov. 15, 2007.

[66] Letter from Roy Staiger, District Office Cleanup Coordinator, Texas Railroad Commission, to Exxon Mobil Corporation, Dec. 31, 2009.

[67] OIL & GAS ACCOUNTABILITY PROJECT, SPRING/SUMMER 2006 REPORT (2006).

[68] Arkansas Dep't of Envtl. Quality, Report on Landfarms ("Four facilities had pond chlorides greater than 3,000 mg/L and the ponds were full . . . . Eight out of eleven facilities had soil concentrations greater than 1,000 mg/Kg on at least one application area. Most were several times higher than 1,000 mg/Kg . . . .").

TPH concentrations that would indicate the application of [oil-based drilling fluids] had taken place."[69] Analysis of soil samples taken from a residential property in Texas, where pit sludge had been land applied less than 300 feet from a residence, "confirmed the presence of numerous hydrocarbons identified as Recognized and Suspected human carcinogens and neurotoxins (1, 2, 4 Trimethylbenzene, 1, 3, 5 Trimethylbenzene, 4-Isopropyltoluene, Acetone, Benzene, Carbon disulfide, Ethylbenzene, Isopropylbenzene, m&m Xylene, n-Butylbenzene, n-Propylbenzene, o-Xylene, sec-Butylbenzene, tert-Butylbenzene, Toluene)."[70] The residents of this property all reported skin rashes after the waste was applied to their land.[71]

c. The risks associated with these contaminants

i. Substances in E&P Wastes Endanger Human Health.

Many of these substances identified in E&P wastes are known carcinogens.[72] The most prevalent contaminants found in E&P wastes are the "BTEX" chemicals:[73] benzene,[74] toluene,[75] ethylbenzene,[76] and xylene.[77] Exposure to benzene has been "associated with an increased risk of leukemia in industrial workers"[78] and other serious health conditions, exposure to toluene can cause nervous system damage,[79] while xylenes can "cause dizziness, headaches and loss of balance among other problems."[80]Many of the other chemicals found in E&P waste, including

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[69] *Id.*

[70] WOLF EAGLE ENVIRONMENTAL, ENVIRONMENTAL STUDIES: FUGITIVE AIR EMISSIONS TESTING, IMPACTED SOIL TESTING, MR. AND MRS. TIMOTHY RUGGIERO (2010).

[71] Eric Griffey, *Toxic drilling waste is getting spread all over Texas farmland*, FORT WORTH WEEKLY, May 12, 2010.

[72] *See* Cox, *supra* note 8, at 4.

[73] CORCORAN ET AL., *supra* note 25, at 21.; *see also* WILLIAMS ET AL., *supra* note 63, at 10 ("The BTEX compounds . . . appear on The Clean Water Act Priority Pollutant list of 126 chemical substances (Office of the Federal Register, 2002)."); U.S.G.S., TOXIC SUBSTANCE HYDROLOGY PROGRAM: BTEX.

[74] "Benzene is a known human carcinogen and causes leukemia." DRILLING DOWN, *supra* note 20, at vi; *see also* WILLIAMS ET AL., *supra* note 63, at 26. ("Because of the high degree of toxicity and mobility of benzene (compared to other petroleum hydrocarbons), it is commonly the main ground-water contaminant of concern at petroleum release sites.").

[75] "Toluene can cause fatigue, confusion, weakness, memory loss, nausea, hearing loss, central nervous system damage, and may cause kidney damage. It is also known to cause birth defects and reproductive harm." DRILLING DOWN, *supra* note 20, at vi (footnotes omitted).

[76] "Ethylbenzene can cause dizziness, throat and eye irritation, respiratory problems, fatigue, and headaches. It has been linked to tumors and birth defects in animals, as well as to damage in the nervous system, liver, and kidneys." *Id.* (footnote omitted).

[77] "Xylene can cause headaches; dizziness; confusion; balance changes; irritation of the skin, eyes, nose and throat; breathing difficulty; memory difficulties; stomach discomfort; and possibly changes in the liver and kidneys." *Id.* (footnote omitted).

[78] N.Y. DEP'T OF ENVTL. CONSERVATION, *supra* note 36, at 5-62 (2009).

[79] CORCORAN ET AL., *supra* note 25, at 21.

[80] *Id.*

acetone,[81] arsenic,[82] barium,[83] mercury,[84] and radium,[85] all found in E&P waste samples, also raise serious concerns for human health.

The impacts of these contaminants have been documented. In a 1997 Louisiana case against U.S. Liquids & Exxon, plaintiffs reported that shortly after the dumping of more than fifty million gallons of E&P waste containing benzene, toluene, and lead occurred at a facility located less than 500 feet from the nearest resident's home, "[a] strange smell blew over the community and . . . . [m]any people in the area felt sick . . . . For nearly three weeks, most residents, including children, suffered from stomach pains, sinus problems and other ailments."[86] Other evidence demonstrates that exposure to contaminants in E&P wastes can result in delayed and long-term health effects. One study conducted in the Amazon Basin of Ecuador found that pregnant women who resided in areas where there was discharge of untreated oilfield wastes into the environment experienced higher levels of spontaneous abortion.[87] Another epidemiological study in the same area showed "significantly higher incidence of cancer for all sites combined in both men and women living in proximity to oil fields . . . . [specifically,] [s]ignificantly higher incidences were observed for cancers of the stomach, rectum skin melanoma, soft tissue and

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[81] Acetone can cause nose, throat, lung and eye irritation, respiratory problems, fatigue and headaches. *See* AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR ACETONE (1995); DRILLING DOWN, *supra* note 20, at vi (footnote omitted).

[82] "Chronic arsenic exposure can cause damage to blood vessels, a sensation of 'pins and needles' in hands and feet, darkening and thickening of the skin, and skin redness. It is a known human carcinogen and can cause cancer of the skin, lung, bladder, liver, kidney, and prostate." DRILLING DOWN, *supra* note 20, at vi (footnote omitted); *see also* AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR ARSENIC (2007) ("Exposure to lower levels can cause nausea and vomiting, decreased production of red and white blood cells, abnormal heart rhythm . . . ."); SCIENCELAB.COM, CHEMICALS & LABORATORY EQUIPMENT, MATERIAL SAFETY DATA SHEET: ARSENIC MSDS 1 (2008), ("[Arsenic is] toxic to kidneys, lungs, the nervous system, mucous membranes.")

[83] "Ingesting drinking water containing levels of barium above the EPA drinking water guidelines for relatively short periods of time can cause gastrointestinal disturbances and muscle weakness. Ingesting high levels for a long time can damage the kidneys . . . . Some people who eat or drink amounts of barium above background levels found in food and water for a short period may experience vomiting, abdominal cramps, diarrhea, difficulties in breathing, increased or decreased blood pressure, numbness around the face, and muscle weakness. Eating or drinking very large amounts of barium compounds that easily dissolve can cause changes in heart rhythm or paralysis and possibly death. Animals that drank barium over long periods had damage to the kidneys, decreases in body weight, and some died." AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR BARIUM (2007).

[84] "Mercury can permanently damage the brain, kidneys, and developing fetus and may result in tremors, changes in vision or hearing, and memory problems. Even in low does, mercury may affect an infant's development, delaying walking and talking, shortening attention 'span,' and causing learning disabilities." DRILLING DOWN, *supra* note 20, at vi (footnote omitted).

[85] "Radium is a known human carcinogen, causing bone, liver, and breast cancer." *Id.* (footnote omitted); *see also* AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR RADIUM (1999).

[86] Chris Gray, *Pits Cause Stink in Lafourche*, TIMES-PICAYUNE, July 14, 1997, at A1.

[87] Miguel San Sebastian, Ben Armstrong, & Carolyn Stephens, *Outcomes of Pregnancy among Women Living in the Proximity of Oil Fields in the Amazon Basin of Ecuador*, 8 INTL. J. OF OCCUPATIONAL AND ECON. HEALTH 312 (2002).

kidney in men and for cancers of the cervix and lymph nodes in women.[88] As reports and first-hand accounts indicate, the risks posed by the contaminants found in E&P waste are not merely speculative. And the risks will not decrease anytime soon. As many pits containing E&P wastes are buried and forgotten, the buried E&P wastes have the potential to threaten future generations who will be unaware of the hazards just below the surface.

Human health can also be harmed by exposure to radiation in NORM-contaminated E&P wastes. Exposure can occur through inhalation of radium-bearing particles, through direct contact with NORM-contaminated soils and water, or through ingestion of radium-barium particles found in plants or animals exposed to NORM-contaminated soils or water.[89] Exposure to radium can result "in an increased risk of bone, liver, and breast cancer . . . . [it] has been shown to cause effects on the blood (anemia) and eyes (cataracts). It also has been shown to affect the teeth, causing an increase in broken teeth and cavities."[90] And the risks associated with NORM-contaminated soils and waters can persist for decades. In particular, land contaminated by radium 226, such as that found in produced water from the Marcellus Shale,[91] can pose a threat to "many generations of individuals living or working on NORM-contaminated land for a period covering nearing 20,000 years."[92]

ii. Substances in E&P Wastes Endanger Wildlife and Livestock.

In addition to harming human health, exposure to contaminants in E&P waste can sicken and kill wildlife. A recent report prepared by the U.S. Fish and Wildlife Service (USFWS) indicates that pits present significant risks to wildlife. Pits can "entrap and kill migratory birds and other wildlife . . . . Birds are attracted to reserve pits by mistaking them for bodies of water. . . . The sticky nature of oil entraps birds in the pits and they die from exposure and exhaustion."[93] In 2009, ExxonMobil pled guilty to violating the Migratory Bird Treaty Act,[94] after numerous birds (including mallard ducks, grebes, white-faced ibis, gadwell ducks, owls, Wilson pharalopes, Northern Shoveler ducks, avocets, curlew, a green-winged teal, a Cassin's sparrow, a purple

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[88] Anna-Karin Hurtig & Miguel San Sebastian, *Geographical Differences in Cancer Incidence in the Amazon Basin of Ecuador in Relation to Residence near Oil Fields*, 31 INT'L. J. OF EPIDEMIOLOGY 1021, 1025 (2002).

[89] Henry Spitz, Kennith Lovins & Christopher Becker, *Evaluation of Residual Soil Contamination From Commercial Oil Well Drilling Activities and Its Impact on the Naturally Occurring Background Radiation Environment*, 6 SOIL & SEDIMENT CONTAMINATION: AN INT'L J. 37, 43 (1997).

[90] AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, *supra* note 85.

[91] *See supra* note 37.

[92] Henry Spitz, Kennith Lovins & Christopher Becker, *Evaluation of Residual Soil Contamination From Commercial Oil Well Drilling Activities and Its Impact on the Naturally Occurring Background Radiation Environment*, 6 SOIL & SEDIMENT CONTAMINATION: AN INT'L J. 37, 41 (1997).

[93] U.S. FISH & WILDLIFE SERV., REGION 6, ENVTL. CONTAMINANTS PROGRAM, RESERVE PIT MANAGEMENT: RISKS TO MIGRATORY BIRDS i (2009).

[94] 16 U.S.C. §§ 703-708.

martin, and a hawk) were found sick and dead after being exposed to pit contents, including hydrocarbons, in multiple states.[95]

E&P wastes have the potential to destroy lands upon which wildlife depend, disrupt food chains, and prevent wildlife from reproducing.[96] The New Mexico Department of Game & Fish has expressed concern about the hazards of hydrocarbon toxicity to wildlife including "acute and chronic ingestion or absorption toxicity, loss of thermal stability from oiling of fur or feathers, and reproductive failure due to absorption of chemicals from the maternal bird body through the shell of eggs."[97] Other researchers are concerned about the bioaccumulation of E&P wastes in wildlife, a process that would cause their harmful effects to magnify as they progress up the food chain.[98] Wildlife habitat may also be harmed by E&P waste. The New Mexico Department of Game and Fish has stated that it "is concerned that chloride contamination of the soil vadose zone may permanently impact the ability of a closed pit location to support vegetation necessary for productive wildlife habitat."[99] Just as E&P wastes can harm humans in ways that are not immediately apparent but can cause harm to future generations, so too can they harm successive generations of wildlife.

Domesticated animals are also harmed by E&P wastes. The Pennsylvania Department of Agriculture quarantined cattle after they came into contact with hydraulic fracturing wastewater being stored in a pit that leaked into an adjacent field. The owners of the property where the pit was located noticed seepage from the pit for as long as two months prior to the leak. The Department stated that wastewater "contains dangerous chemicals and metals." Tests of the wastewater found that it contained strontium as well as other substances.[100] E&P waste is sometimes disposed of on land used for cattle grazing.[101] Residents of the Barnett Shale have reported seeing cattle drinking from sludge pits.[102] Cattle have been lost due to exposure to E&P waste in New Mexico[103] and 54 out of 56 hair samples from sick cattle analyzed by the Texas Veterinary Medical Diagnostic Laboratory contained petroleum.[104]

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[95] Joint Factual Statement, U.S. v. Exxon Mobil Corp., ¶¶ 10–27 (D.Col. 2009).

[96] BRYAN M. CLARK, DIRTY DRILLING: THE THREAT OF OIL AND GAS DRILLING IN LAKE ERIE 25 (2002).

[97] Letter from Lisa Kirkpatrick, Chief, New Mexico Dep't of Game & Fish, Conservation Services Division, to Florene Davidson, Commission Secretary, EMNRD Oil Conservation Division (Jan. 20, 2006); *see also* Letter from Lisa Kirkpatrick, Chief, New Mexico Dep't of Game & Fish, Conservation Services Division, to Florene Davidson, Commission Secretary, EMNRD Oil Conservation Division (Mar. 7, 2006).

[98] BRYAN M. CLARK, *supra* note 96, at 25.

[99] Letter from Lisa Kirkpatrick, Chief, New Mexico Dep't of Game & Fish, Conservation Services Division, to EMNRD Oil Conservation Division (Feb. 2, 2007).

[100] Press Release, Pa. Dep't of Envtl. Prot., *Cattle from Tioga County Farm Quarantined after Coming in Contact with Natural Gas Drilling Wastewater* (July 1, 2010).

[101] *See e.g.*, Amended Complaint, Sweet Lake Land and Oil Co. v. Exxon Mobil Corp., No. 209CV01100, at ¶ 32 (W.D. La. filed Sept. 14, 2009), 2009 WL 4701364.

[102] Bluedaze: Drilling Reform for Texas blog (July 25, 2008).

[103] DRILLING DOWN, *supra* note 20, at 26.

[104] Test results from Veterinary Medical Diagnostic Laboratory on July 26, 2005, August 18, 2005, and September 6, 2005; DRILLING DOWN, *supra* note 20, at 26.

In response to occurrences like these, cattle ranchers and others whose animals are at risk have sought to prevent E&P waste disposal facilities from opening near their properties.[105] Protecting cattle and other domesticated animals from exposure to E&P wastes is particularly important as the hazardous contaminants of E&P wastes have the potential to bioaccumulate in these animals and potentially make their way into the human food chain.[106]

2. Current State Regulations and Enforcement Are Inadequate and Allow E&P Waste to Be Released into the Environment.

Waste produced in E&P operations is disposed of in a variety of ways, with underground injection and burial of waste historically being the most widely used methods.[107] Wastewater treatment facilities are another growing disposal method. Even before EPA made its 1988 Regulatory Determination, data indicated that commonly used disposal practices failed to prevent E&P wastes from contaminating soil and groundwater.[108] A 1987 report documented "the migration of leachate 400 feet from reserve pits buried in . . . North Dakota and reported groundwater contamination 50 feet below the buried reserve pits."[109] Incidences of soil and groundwater contamination have continued to occur since then.

E&P wastes may leak, spill, or evaporate into the air, allowing the chemicals used in oil and gas operations to be released into the environment. These releases occur in large part because many states' regulations do not adequately account for all of these potential modes of contamination, despite the fact that releases are occurring with alarming regularity, or are not vigorously enforced. The regulations of the Railroad Commission (RRC) of Texas have been described as providing only weak assurance that the "quality of waters (and land) will not be impacted by a gas operator's activity."[110] Assurances are similarly minimal in other states where regulations provide virtually useless oversight of E&P waste disposal because they fail to "clearly indicate acceptable disposal practices for all drilling wastes."[111]

An Ohio resident with 23 years of experience in drilling oil and gas wells testified before the state legislature that existing regulations are inadequate and cannot be appropriately enforced: "… the [Ohio Department of Natural Resources] has a serious lack of ability to enforce their own regulations due to the way the current law and this bill are written."[112] A review of Tennessee oil

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[105] Susan Hylton, *Drilling Waste Feud, Neighbors of Maverick Energy Services Think Water is Being Polluted,* TULSA WORLD, Mar. 21, 2010, at A11

[106] DRILLING DOWN, *supra* note 20, at 26.

[107] *See* E&P FORUM, EXPLORATION AND PRODUCTION (E&P) WASTE MANAGEMENT GUIDELINES 5 (Report No. 2.58/196, 1993).

[108] U.S. FISH & WILDLIFE SERV., *supra* note 93, at 4.

[109] *Id.*

[110] League of Women Voters of Tarrant County, Gas Drilling Waste-Water Disposal (2008).

[111] BRYAN M. CLARK, *supra* note 96, at 35.

[112] Testimony of James E. McCartney to the 128th General Assembly, Ohio Senate Environmental and Natural Resources Committee. Opponent Testimony on Senate Bill 165, Oct. 28, 2009.

and gas regulations found that the state does not have technical criteria for E&P waste management practices or any certification for E&P haulers.[113] Although all pits must be lined in Tennessee, pits are not considered or tracked through the permitting process and there are no security or wildlife protection measures.[114]

A 2009 letter from the EPA to the RRC of Texas states that the Commission should have "more rigorous evaluation" of conditions for waste disposal wells.[115] Texas also "allows companies to hire their own environmental consultants to check for contamination."[116] These regulatory failures existed when EPA issued its 1988 Regulatory Determination, and have been exacerbated in the wake of EPA's decision not to regulate E&P wastes under Subtitle C of RCRA.

a. Pits

Pit construction requirements vary greatly across the country. While a few states, such as New Mexico and Colorado, have recently adopted stricter rules governing the disposal of E&P wastes in pits, other states have minimal regulations and often do not even require the use of pit liners.[117]

The open design of pits, combined with the often minimal regulatory requirements governing their construction and use, present greater opportunities for their dangerous contents to be released into the environment. Reports indicate that the release of E&P wastes from pits is far too common.

In September 2008, New Mexico compiled its data on cases where pit substances contaminated New Mexico's groundwater.[118] The numbers were staggering: More than 700 incidents of groundwater contamination by oilfield wastes or products were documented.[119] Elsewhere, in 2001, E&P wastes from the Black Mountain disposal facility in Colorado contaminated nearby soil and groundwater when its clay lined pits began to leak.[120] Since then, many more releases of E&P wastes have occurred in Colorado. The Colorado Oil and Gas Conservation Commission (COGCC) documented several pits at the same pad site in Garfield

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[113] TENNESSEE DEP'T OF ENV'T & CONSERVATION, STATE REVIEW OF OIL AND NATURAL GAS ENVIRONMENTAL REGULATIONS, INC., TENNESSEE STATE REVIEW 13, 19, 22, 24 (2007).

[114] *Id.* at 30.

[115] FY2008 EPA Region 6 End-of-year Evaluation of the Railroad Commission of Texas Underground Injection Control Program, with transmittal letter from Bill Luthans, Acting Director, Water Quality Protection Division, Region 6 to Tommie Seitz, Director, Oil and Gas Division (June 19, 2009).

[116] Joe Carroll, *Exxon's Oozing Texas Oil Pits Haunt Residents as XTO Deal Nears*, Bloomberg Businessweek, April 16, 2010.

[117] *See infra* notes 146–160 and accompanying text; *see also* OKLA. ADMIN. CODE § 165:10-7-16(b)(1)(B)(iii), (2)(b).

[118] NEW MEXICO ENERGY, MINERALS AND NATURAL RES. DEP'T, OIL CONSERVATION DIV., CASES WHERE PIT SUBSTANCES CONTAMINATED NEW MEXICO'S GROUND WATER (2008).

[119] Oil & Gas Accountability Project, Groundwater Contamination.

[120] Kim Weber, Regarding Support of HB 1414—Evaporative Waste Facilities Regulations.

County whose liners had torn and allowed wastes to be released on multiple occasions between April and August 2008.[121] The reports indicated that the pits were located on rocky terrain and that some of the liners had been torn by rocks on the site.[122] In total, more than 6,000 barrels of pit contents escaped the pits because of the tears.[123] In La Plata County, a landowner reported the possible contamination of his well by an unlined reserve pit located a mere 350 feet uphill from his well.[124] The COGCC eventually concluded that "it appear[ed] that fluids from the unlined reserve pit infiltrated into the shallow groundwater, flowed downhill and impacted the Thomson water well."[125] The COGCC has documented numerous other incidents where pits have leaked,[126] overflowed, [127] or been unlined,[128] thereby allowing their contents to be absorbed by unprotected ground.

In May, 2008, a Colorado citizen drank water from his spring and fell ill. The COGCC found benzene in the groundwater that exceeded standards by 32 times and benzene in faucet water that exceeded standards by 13 times, as well as elevated levels of toluene and xylenes. Although the COGCC began investigating this complaint in June, 2008, it wasn't until October, 2008, that the operator stated that it became aware that the production pit was never permitted. The state appears to have been unaware that the pit was never permitted even though it was investigating the pit as a possible source of groundwater contamination. In July, 2010, the COGCC found that the operator failed to properly permit, construct, maintain, and repair the pit, leading to a release or releases of E&P waste that impacted groundwater. The agency found that the liner had been stretched over rocks and had improperly sealed seams.[129]

In addition to the reports from New Mexico and Colorado, there have been many complaints by citizens of contamination reportedly caused by E&P wastes in other states. NYSDEC has received numerous reports of E&P waste releases, many of which have contaminated soil and

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[121] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1630424, 1630426, 1630427, 1630428, 1630429, 1630430.

[122] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NO. 1630428.

[123] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1630424 (714 bbls), 1630426 (2000 bbls), 1630427 (500 bbls), 1630428 (1250 bbls), 1630429 (204 bbls), 1630430 (2017 bbls).

[124] Oil & Gas Accountability Project, Contamination Incidents Related to Oil and Gas Development, Maralex Drilling Fluids in Drinking Water; COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORT, DOC. NO. 1953000.

[125] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, NOAV REPORT, DOC. NO. 200085988; *see also* Oil & Gas Accountability Project, Contamination Incidents Related to Oil and Gas Development, Maralex Drilling Fluids in Drinking Water.

[126] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1631518, 1631599, 2605176, 2605847.

[127] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 200225543, 200225547, 200225546.

[128] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NO.1632846.

[129] Colorado Oil and Gas Conservation Commission, Cause No. 1V, Order No. 1V, Docket No. 1008-OV-06

groundwater.[130] In June 1987, in West Seneca, N.Y., product from an open pit containing oil and other solvents was found running from the pit towards a nearby creek.[131] In November 1996, in Reading, N.Y., a produced water pit overflowed and spilled approximately two hundred gallons of produced water into a creek feeding into Seneca Lake.[132] NYSDEC determined that no cleanup was possible.[133] When a property owner in Bolivar, N.Y., called in June 2002 to report leaking oil wells, NYSDEC inspectors also found unlined leaking containment ponds.[134]

E&P wastes in pits have been released into the environment in other states as well. Pennsylvania's Department of Environmental Protection (PADEP) has documented several incidents of dangerous E&P waste releases into the environment. Notably, at two of Atlas Resources LLC's well sites in Pennsylvania, "compromised" pit liners allowed fracturing flowback fluids to escape.[135] In Ohio, a fracturing flowback pit was cut with a track hoe in 2010, causing more than 1.5 million gallons of fluid were spilled into the environment.[136] In 2008, the back wall of a pit in Ohio gave way, causing pit contents to spill and flow towards a creek.[137]

In addition to releases caused by torn liners and overflows, pits allow the hazardous contaminants in E&P wastes to be released into the environment through evaporation into the air. E&P wastes such as produced water stored in open pits can "release methane, toxic volatile organic chemicals and sulfur based compounds into the air."[138] Rocky Mountain Clean Air Action collected data showing that wastewater evaporation pits in Garfield County, Colorado are "major sources of air pollution and pose greater threats to human health than previously reported."[139] The data indicated that high levels of hydrocarbons and other hazardous air pollutants were being released into the air. [140] Also in Garfield County, beginning in October 2005, a resident repeatedly notified the COGCC that severe odors were emanating from an E&P waste pit located close to her home.[141] In early December 2005, the resident reported smelling "a different sort of stench . . . the 'Benzene smell'" to the COGCC and requested that the agency

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[130] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST (2009).
[131] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 37 (2009) (Spill Number: 8702469).
[132] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 53 (2009) (Spill Number: 9610217).
[133] *Id.*
[134] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 124-25 (2009) (Spill Number: 0275147).
[135] Consent Assessment of Civil Penalty, In re Atlas Resources LLC, Dancho-Brown 4, ¶¶ AV–AZ, Groves 8, ¶¶ BA–BE.
[136] Ohio Department of Natural Resources, Notice of Violation No. 1278508985, June 21, 2010.
[137] Ohio Department of Natural Resources, Notice of Violation No. 2016754140, May 16, 2008.
[138] Subra, *supra* note 43.
[139] Phillip Yates, *Clean Air Group Contends Evaporation Ponds in Garfield County More Dangerous than Previously Believed*, POST INDEPENDENT, Jan. 9, 2008.
[140] *Id.*
[141] Oil & Gas Accountability Project, Contamination Incidents Related to Oil and Gas Development.

install full-time air monitoring equipment.[142] At the end of the month, the resident learned that sampling of the air fairly close to the pit "showed that benzene and xylenes exceeded the [EPA's] 'non-cancer risk levels' for these compounds – at 67 µg/m3, benzene was present at more than double the risk level. Other detectable compounds included acetone, toluene and ethylbenzene."[143]

While some incidents are effectively reported and prosecuted by state authorities, many more incidents occur that are not addressed adequately by state officials. In these cases, the citizens affected by such releases into the environment have instead turned to the judicial system in order to hold the oil and gas companies accountable. John Preston Stephenson, Jr. sued Chevron U.S.A alleging that waste from Chevron oil pits contaminated his property with "hazardous toxic and carcinogenic chemicals."[144] Similarly, the Sweet Lake Land and Oil Company sued multiple defendants, including Exxon, Noble Energy, Inc., and Texas Eastern Skyline Oil Company, for contamination of "the soil and groundwater with produced water, oil, drilling muds, technologically enhanced naturally occurring radioactive materials (sometimes referred to as 'TENORM'), hydrocarbons, metals, and other toxic and/or hazardous substances, wastes and pollutants," claiming that the defendants knew the pits contents would contaminate the plaintiff's surface and subsurface soil and water.[145] Sweet Lake Land and Oil Company further alleged that "[t]he presence of the pits, substances and scrap on and under the Property constitutes a nuisance."[146] These claims are only a handful of many more by citizens who have been harmed by E&P wastes released from pits.[147]

These reports of contamination are at least partially attributable to inadequate state efforts to regulate E&P waste disposal in pits. Despite the fact that pit contents have been found to contain hazardous contaminants,[148] many states fail to require operators to use the most basic of precautions. Tennessee, for example, does not even take pits into account in its permitting process, thereby "making their management and disposal difficult to track" and increasing the

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[142] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, COMPLAINT REPORT, DOC. NO. 200081602.

[143] Oil &Gas Accountability Project, *supra* note 141.

[144] Amended Complaint at ¶ 9, Stephenson v. Chevron U.S.A, Inc., No. 209CV01454, (W.D. La. filed Sept. 11, 2009), 2009 WL 4701406.

[145] Sweet Lake Land and Oil Co. v. Exxon Mobil Corp., *supra* note 101, at ¶ 10.

[146] *Id.* at ¶ 27.

[147] *See also* Petition for Damages, Brownell Land Corp., LLC v. Honey Well Int'l., No. 08CV04988, ¶¶ 11-12 (E.D. La. filed Nov. 21, 2008), 2008 WL 5366168; Rice Agricult. Corp., Inc., v. HEC Petroleum Inc., 2006 WL 2032688 (E.D. La); Petition for Damages, Tensas Poppadoc, Inc. v. Chevron U.S.A., Inc., No. 040769, ¶ 8 (7th Judicial Court La. filed Sept. 21, 2005), 2005 WL 6289654; Petition for Damages to School Lands, Louisiana v. Shell Oil Co., No. CV04-2224 L-O, (W.D. La. filed Oct. 29, 2004), 2004 WL 2891505 (where the State of Louisiana and the Vermilion Parish School Board made similar allegations against Shell Oil, claiming they had contaminated school property. In July 2006, the case was remanded to state court).

[148] *See* notes 62–67 *supra*.

likelihood that the locations of the wastes will be forgotten in the future.[149] In addition, Tennessee has no freeboard or liner integrity requirements,[150] does not require testing or tracking of pit wastes,[151] and fails to require oil to be removed from pits.[152] Kentucky similarly turns a blind eye to the risks E&P wastes present to the public through its failure to require testing of E&P waste characteristics and its treatment of all E&P wastes except production brines and drilling muds as solid wastes, subject to less stringent disposal requirements "irrespective of the risk posed to human health or the environment from the waste."[153]

States also fail to take other simple steps that would dramatically decrease the likelihood of E&P wastes being released into the environment, for example, requiring pits to be lined with impermeable barriers. In Oklahoma, neither emergency pits nor pits holding water-based drilling fluids are required to have any lining.[154] This failure to require the use of a liner in pits holding water-based drilling fluids increases the risk that the "barite, clays, lignosulfonate, lignite, caustic soda and other specialty additives" found in water-based muds will contaminate the environment.[155] Kentucky's liner requirements are also inadequate. Kentucky does not require the use of liners in drilling pits that are used for less than thirty day storage and has "minimal liner requirements for holding pits" for storage over thirty days.[156]

Wildlife protection devices are another important and too often underused safety measure. Tennessee,[157] Louisiana,[158] and Kentucky all fail to require any "fencing, flagging or netting of pits," thereby increasing the risks the pits present to wildlife and domestic animals.[159] And according to a recent report prepared by Region 6 of the U.S. Fish & Wildlife Service, these three states are not alone.[160] As reported by Region 6, only thirteen states require pits or open tanks to be screened or netted to prevent wildlife from coming into contact with E&P wastes.[161] The failure to require pit operators to use even the most basic protection devices such as fencing or netting greatly increases the likelihood that wildlife will come into contact with E&P waste and suffer significant harm.

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[149] TENNESSEE DEP'T OF ENV'T & CONSERVATION, *supra* note 113, at 30.
[150] *Id.*
[151] *Id.* at 32.
[152] *Id.* at 31.
[153] STATE REVIEW OF OIL AND NATURAL GAS ENVIRONMENTAL REGULATIONS, INC., KENTUCKY STATE REVIEW 50–51 (2006).
[154] OKLA. ADMIN. CODE § 165:10-7-16(b)(1)(B)(iii), (2)(b).
[155] CORCORAN ET AL., *supra* note 25, at 20; *see also* U.S. FISH & WILDLIFE SERV., *supra* note 93, at 4–5 ("Water-based drilling muds can contain glycols, chromium, zinc, polypropylene glycol, and acrylamide copolymers.").
[156] KENTUCKY STATE REVIEW, *supra* note 153, at 54.
[157] TENNESSEE DEP'T OF ENV'T & CONSERVATION, *supra* note 113, at 30.
[158] STATE REVIEW OF OIL AND NATURAL GAS ENVIRONMENTAL REGULATIONS, INC., LOUISIANA STATE REVIEW 29 (2004).
[159] *Id.*
[160] U.S. FISH & WILDLIFE SERVICE, *supra* note 93, at 13 fig. 15.
[161] *Id.*

States also fail to regulate where pits may be located, allowing them to be placed near residences, schools, and other areas frequently used by the public. In some cases, homes are located so close to pits that residents have been forced indoors because of the foul odors and health symptoms emanating from the pits. One Pennsylvania family reported severe headaches caused by fumes from a pit less than 200 feet from their home.[162] As of 2005, when STRONGER, Inc. conducted a review of Indiana's E&P waste disposal practices and regulations, Indiana regulations had no requirements regarding "specifications for the location, orientation and construction of drilling pits. There [were] no required setbacks of minimum distances from buildings, homes or other structures for drilling pits." Since then, although Indiana has adopted a new rule requiring pits to be located at least one hundred feet from streams, rivers, lakes and drainage ways, it still does not specifically require pits to be setback from other structures.[163] By allowing pits to be sited close to where people live and children attend school, state regulators are bringing health risks literally closer to the citizens across the country.

b. Land application

EPA has stated that hazards also exist with land application of E&P wastes, finding that hydrocarbons, salts, and metals can all cause contamination when E&P wastes are land applied.[164] The Oil Industry International Exploration and Production Forum (E&P Forum), an international industry association, has also issued warnings, stating that land application may result in contaminants accumulating "in the soil [at] a level that renders the land unfit for further use."[165] New York State allows waste to be disposed of in municipal landfills.[166] Land where only oil and gas waste is applied is often called a "landfarm." Studies of landfarm conditions confirm that these hazards are real. When the Arkansas Department of Environmental Quality conducted a study of landfarms in Arkansas, it found that "all 11 sites that land applied fluids at some point had improperly discharged the fluids so as to cause runoff into the waters of the state."[167]

Land application sites outside of Arkansas are sources of similar concerns. Near Holdenville, Oklahoma, residents protested the opening of a landfarm because they were worried about

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[162] Christie Campbell, *Foul Odor from Impoundment Upsets Hopewell Woman*, OBSERVER-REPORTER, Apr. 14, 2010. June Chappel, who lives near a pit, stated that the odor "reminded her of a hair perm. It smelled like ammonia . . . [and] 'took your breath away.'" *Id.* Other times the fumes have smelled like gasoline, diesel fuel, and sewage. *Id.*

[163] 312 IND. ADMIN. CODE 16-5-13 (2010).

[164] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006, at 49 (2000).

[165] E&P FORUM, *supra* note 107, at 17.

[166] Letter from Gary M. Maslanka, New York State Division of Solid & Hazardous Materials, to Joseph Boyles, Casella (April 27, 2010).

[167] Press Release, Arkansas Dep't of Envtl. Quality, ADEQ Releases Landfarm Study Report (Apr. 20, 2009).

potential “water contamination and land spoilage.”[168] After the residents lost two appeals in which they tried to prevent its opening, the landfarm finally began operations and made the residents’ fears a reality. Claudia Olivo, who owns a cattle ranch adjacent to the landfarm, filed a complaint with EPA after she noticed “strange glistening spots in the water” on her property.[169] In response, EPA issued a cease-and-desist order against the landfarm after finding that it had made unauthorized discharges of drilling mud into a creek that ran through Olivo’s property, in violation of the Clean Water Act.[170] The Crouch Mesa landfarm in Aztec, New Mexico, is located directly across the street from a residential area and is the source of considerable visible dust observed blowing toward homes.[171]

Despite these risks, many states inadequately regulate land application. In Oklahoma, one-time land applications may occur as close as one hundred feet from any perennial stream, freshwater pond, lake or wetland.[172] Tennessee regulations fail to provide any explicit guidance regarding the use of land applications.[173] Meanwhile, Kentucky has no siting criteria for land application specific to E&P wastes.[174]

These lax regulations result in E&P wastes being land applied near, and in some cases, on residential property, increasing the likelihood that humans will be exposed to E&P waste’s toxic compounds.[175] In Martha, Kentucky, produced water and tank bottoms were land applied on farmland near where a family of two adults and two children lived.[176] The family grew the majority of the vegetables and meat they consumed on the farm,[177] and the portion of the family’s land used for storing E&P waste disposal was located a mere 100 feet from a small creek which “drains into a marsh, which then drains into a larger creek” from which the farm’s cattle drank.[178] The family no longer drinks from its well, which has been contaminated with benzene.[179] Lead and arsenic were found in soil samples.[180] In addition, areas of the farm where E&P wastes had been disposed were found to be NORM-contaminated sites which “will remain radioactive for many thousands of years,” “creating many opportunities for radium to enter the soil and be taken up by plants or cattle grazing on the land,” and threatening “[f]uture inhabitants or workers on the NORM-contaminated land [who] may also be directly exposed to ionizing

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[168] Susan Hylton, *supra* note 105, at A11.
[169] *Id.*
[170] *Id.*
[171] DRILLING DOWN, *supra* note 20, at 22.
[172] OKLA. ADMIN. CODE § 165:10-7-26(c)(6) (2009).
[173] TENNESSEE DEP’T OF ENV’T & CONSERVATION, *supra* note 113, at 32.
[174] KENTUCKY STATE REVIEW, *supra* note 153, at 50.
[175] *See* WOLF EAGLE ENVIRONMENTAL, *supra* note 70.
[176] Spitz et al., *supra* note 92, at, 45.
[177] *Id.* at 46.
[178] *Id.* at 45.
[179] *Id.*
[180] *Id.* at 55.

radiation or inhale radium-bearing particles."[181] As demonstrated by the contamination that occurred in Martha, Kentucky, inadequate state regulations too frequently fail to protect the public and the environment from the hazards associated with land application of E&P wastes.

A Texas resident lives fifty feet away from a 100-acre land farm, where the Texas Railroad Commission issued 22 minor permits for 22 different operations that are all located on one property. A second land farm is located just down the road.[182]

c. Injection Wells

Underground injection, the most widely used disposal method,[183] also poses concerns. If the formation into which E&P wastes are injected does not meet certain levels of permeability, porosity, and low reservoir pressure, the formations can form a poor seal around the E&P wastes and threaten nearby aquifers.[184] Under the Underground Injection Control (UIC) Program, E&P wastes may be injected in Class II wells, while wastes designated as hazardous under RCRA can only be disposed of in the more strictly regulated Class I wells.[185]

The lower standards applicable to Class II wells have proven inadequate to prevent E&P wastes from contaminating groundwater. In 1988, GAO released a report, *Safeguards Are Not Preventing Contamination from Injected Oil and Gas Wells*, which examined the effectiveness of EPA's UIC program.[186] Although GAO speculated that it was likely that more incidents had occurred, it reported that the EPA was aware of at least 23 cases across the country where Class II injection wells had contaminated drinking water supplies.[187] Since then more incidences of concern have occurred.

In September 2007, a state inspector in Texas inspected an underground injection disposal well site outside of Fort Worth and found no problems. Yet a resident complained of "spilled oil, overflowing dikes and green-colored fluid in standing puddles." Inspectors returned and found that "oil-stained soil" had seeped several inches into the ground, that the "containment dike will not hold estimated capacity," and that standing water had oil in it. State records showed that the well site was not being used, when in fact it was actively being injected with oil and gas waste.[188]

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[181] *Id.* at 57.

[182] *See* Griffey, *supra* note 71

[183] M.G. PUDER & J.A. VEIL, ARGONNE NATIONAL LABORATORY, OFFSITE COMMERCIAL DISPOSAL OF OIL AND GAS EXPLORATION AND PRODUCTION WASTE: AVAILABILITY, OPTIONS, AND COSTS, S-2 (2006) ("By far, the most common commercial disposal method for produced water is injection.").

[184] *See* E&P FORUM, *supra* note 107, at 15.

[185] DRILLING DOWN, *supra* note 20, at 17; *see also* 42 U.S.C § 300h-4; 42 U.S.C § 300h(b); 42 U.S.C. § 300(h)-1(c).

[186] U.S. GENERAL ACCOUNTING OFFICE, *supra* note 32, at 2.

[187] *Id.* at 3.

[188] Abrahm Lustgarten, *State Oil and Gas Regulators Are Spread Too Thin to Do Their Jobs*, ProPublica, December 30, 2009.

Residents in DeBerry, Panola County, Texas, first began complaining that their groundwater was contaminated in 1996.[189] An underground injection disposal facility began operations one-eighth of a mile away from the community in 1987, injecting produced water into the ground at depths between 1,080 and 1,110 feet.[190] In 1996, while the well was still in operation, DeBerry residents told an EPA Region 6 employee that their water was discolored, was staining their kitchen and bath fixtures, and that they were experiencing gastrointestinal problems.[191] The residents of DeBerry ultimately stopped using their drinking water and instead began to obtain water from other sources.[192] No government agency tested DeBerry's drinking water for several years after residents first complained. Not until 2002 did the site operator of the injection wells in DeBerry, Basic Energy, sample the drinking water.[193] When it did, the residents' suspicions were confirmed. The results showed the presence of contaminants above the EPA's maximum contaminant levels.[194] In 2003, the Texas RRC found benzene, barium, arsenic, cadmium, lead and mercury in wells at levels exceeding the state's drinking water standards.[195] Because the Texas RRC never completed a full assessment of the contamination, the source of the contamination is not definitively known; however, residents strongly believe the injection wells were the cause of the contamination, and EPA has been unable to rule this possibility out conclusively.[196]

Also in Texas, an underground injection disposal facility in Daisetta is linked to contamination of a fresh water aquifer. The EPA found a lack of compliance reviews, inappropriate monitoring, and incomplete record-keeping, as well as a lack of evidence that all problems were ever remedied. This problematic facility led to a surface collapse and a large sinkhole.[197]

The likelihood that similar incidents will continue to occur exists as long as underground injection associated with oil and gas exploration, production, and development only has to meet the requirements for Class II wells and states fail to require better monitoring.

In addition, a vast amount of E&P waste is being injected underground without any UIC regulation whatsoever. Used hydraulic fracturing fluid—perhaps millions of gallons per each

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[189] EPA OFFICE OF THE INSPECTOR GENERAL, COMPLETE ASSESSMENT NEEDED TO ENSURE RURAL TEXAS COMMUNITY HAS SAFE DRINKING WATER, NO. 2007-P-00034 2 (2007).
[190] *Id.* at 3.
[191] *Id.* at 2.
[192] *Id.*
[193] *Id.*
[194] *Id.*
[195] *Hearing Before the Subcomm. on Superfund and Environmental Health of the S. Comm. on Environment and Public Works* 12–13 (2007) (statement of Robert D. Bullard, Dir. Environmental Justice Resource Center).
[196] EPA, OFFICE OF THE INSPECTOR GENERAL, *supra* note 189, at 3.
[197] EPA, *supra* note 115.

well—remain underground permanently. It has been estimated that up to 90% of hydraulic fracturing fluids used in the Marcellus shale formation remain underground.[198] Yet this waste disposal and storage activity is not subject to any federal underground injection regulations.

d. Wastewater Treatment Facilities

In regions where underground injection is not readily available, hydraulic fracturing wastewater and produced water may be sent to wastewater treatment plants prior to release to surface water. The plants may be publicly owned treatment works (POTWs) that typically process municipal sewage or centralized wastewater treatment (CWT) facilities that process industrial wastes. None of the POTWs and few of the CWT plants currently in operation have the capacity to reduce to safe levels all of the chemical contaminants commonly found in E&P waste. As a result, toxins are released to surface water, with adverse impacts on drinking water quality. The very high concentrations of total dissolved solids (TDS)—principally salts—that are common in hydraulic fracturing wastewater and produced water present a particular problem for wastewater treatment facilities.

Without adequate pretreatment, pollutants in oil and gas waste will pass through a POTW into the receiving stream, and they may interfere with ordinary sewage treatment systems.[199] Even with pretreatment, POTWs are not effective in removing salts from those wastes.[200] The use of POTWs for treatment of E&P waste in western Pennsylvania produced TDS levels in the Monongahela River in excess of drinking water standards, forcing the Commonwealth to limit the waste to one percent of influent at nine plants along the river.[201] Unauthorized discharges of pollutants, including fecal matter, from a POTW into the Susquehanna River were attributed to the plant's acceptance of oil and gas wastes.[202] Even CWT plants rarely have the evaporation and crystallization technologies needed to reduce extremely high levels of TDS in hydraulic fracturing wastewater and produced water (up to 300,000 mg/l) to levels consistent with water quality standards (500 mg/l). There is not a single CWT facility with that capacity in all of New York or Pennsylvania.[203]

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[198] PROCHEMTECH INTERNATIONAL, INC., MARCELLUS GAS WELL HYDROFRACTURE WASTEWATER DISPOSAL BY RECYCLE TREATMENT PROCESS.

[199] N.Y. State Water Res. Inst., *Waste Management of Cuttings, Drilling Fluids, Hydrofrack Water and Produced Water*; Oh. Envtl. Prot. Agency, *Marcellus Shale Gas Well Production Wastewater*.

[200] *Id.*

[201] Joaquin Sapien, *With Natural Gas Drilling Boom, Pennsylvania Faces an Onslaught of Wastewater*, ProPublica, Oct. 4, 2009; *Municipal Authorities' Perspective: Marcellus Shale Natural Gas Wastewater Treatment, Hearing Before the S. Comm. on Envtl. Res. & Energy* (Pa. 2010) (statement of Peter Slack, Pennsylvania Municipal Authorities Ass'n).

[202] Press Release, Pa. Dep't Envtl. Prot., DEP Says Jersey Shore Borough Exceeds Wastewater Permit Limits (June 23, 2009).

[203] N.Y. State Water Res. Inst., *supra* note 199; Joaquin Sapien, *supra* note 201.

e. Other spills, leaks, and intentional dumping

In addition to those releases that commonly occur when these common E&P waste disposal methods are being used properly, many other spills and releases occur before E&P wastes reach these storage or disposal sites. These other releases can be the result of equipment failure, accidents, negligence, or intentional dumping. Consistent federal regulations for waste management, storage and disposal would help prevent them in the future.

For example, in Pennsylvania, Atlas Resources LLC "discharged residual and industrial waste, including diesel and production fluids, onto the ground at seven of the 13 well sites."[204] At three of the wells Atlas allowed produced water to be released into the environment.[205] Pennsylvania records also show that pipes used to transport waste, sometimes for miles, have leaked. In October, 2009, a pipe carrying diluted wastewater spilled about 10,500 gallons into a high-quality stream, killing about 170 small fish and salamanders. In December, 2009, a pipe failed in five places, spilling an estimated 67,000 total gallons of fluid, tests of which found elevated levels of salts, barium and strontium.[206]

NYSDEC has documented numerous other examples of releases. In October 1997, a produced water tank in Willing, New York, containing produced water from natural gas extraction overflowed and contaminated the surrounding soil and a nearby creek from which cows drank with fifteen thousand gallons of produced water.[207] The produced water killed vegetation in its path.[208] More recently, in September 2005, eight hundred gallons of production brine from another tank in Pine City, New York, overflowed when it was not emptied on schedule, causing an impact on nearby streams.[209] In July 1996, crude oil tank bottoms were dumped into a pit and set on fire.[210] In March 2003, a property owner in Ithaca, New York, called to report that a driller was dumping mud on his property.[211] In May 2007, NYSDEC received an anonymous tip indicating that produced water from a natural gas well was being

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[204] Press Release, Pa. Dep't Envtl. Prot., DEP Fines Atlas $85,000 for Violations at 13 Well Sites, Jan. 7, 2010.

[205] Consent Assessment of Civil Penalty, *In re Atlas Resources LLC*, Pevarnik 8, ¶¶ Z–AD, Willis 18, ¶¶ AE–AI, Thompson 33 ¶¶ AP–AU.

[206] Laura Legere, *Massive Use of Water in Gas Drilling Presents Myriad Chances for Pollution,* SCRANTON TIMES-TRIBUNE, June 22, 2010.

[207] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 3 (2009) (Spill Number: 9707892).

[208] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 4 (2009) (Spill Number: 9707892).

[209] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 8 (2009) (Spill Number: 0507041).

[210] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 23 (2009) (Spill Number: 9604701).

[211] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 68 (2009) (Spill Number: 0212276).

dumped on the ground near Cayuga Creek in Sheldon, New York.[212] In May 2009, eight hundred gallons of produced water contaminated soils in Westfield, New York, after equipment failed and allowed the fluids to be released into the environment a mere 1200 yards away from nearby homes.[213]

The COGCC has also documented incidents where tanks have been improperly sealed[214] or allowed to overflow,[215] where corroded equipment allowed produced water to contaminate the ground,[216] and where equipment failure has allowed produced water to escape from underground injection wells.[217] Between June 2002 and June 2006, 555 produced water spills were reported to the COGCC.[218]

In Texas, between 2001 and 2006, thirty percent of spill complaints were inspected "either late or not at all."[219] Most recently in the Texas town of Flower Mound, the Texas RRC sent out a notification stating that approximately 3,000 gallons of "flowback water containing fracturing fluid and associated additives" spilled out of gas well pad site.[220] To date, the RRC has not publically released either the cause of the spill or the exact contents of the flowback water.[221]

The mayor of West Union, West Virginia, wrote a letter to the WVDEP in October 2009 to express his concern over WVDEP's failure to notify the town until two months after a spill occurred.[222] The mayor was even more concerned about WVDEP's failure to have any emergency notification system in place, stating that the continued failure to establish such a system "will only result in less time for the water system to react [to future spills] and [result in] a greater chance of catastrophe."[223] Elsewhere in West Virginia, Luanne McConnell Fatora reported a release of between fifty and seventy barrels of some type of oil and gas waste in a

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[212] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 159 (2009) (Spill Number: 0750225).

[213] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 143 (2009) (Spill Number: 0902327).

[214] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORT, DOC. NO. 1630697.

[215] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1631155, 1631831, 1631794, 1632853.

[216] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1630885, 1631496, 1631519, 1632057, 2605191, 1632995.

[217] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 200226284, 200225725, 2605709.

[218] OIL & GAS ACCOUNTABILITY PROJECT, COLORADO OIL AND GAS INDUSTRY SPILLS: A REVIEW OF COGCC DATA (JUNE 2002-JUNE 2006) 1-2 (2006).

[219] Lustgarten, *supra* note 188.

[220] *Frac Fluid Spill Reported in Flower Mound*, CROSS TIMBERS GAZETTE, Mar. 17, 2010.

[221] *Id.*

[222] Letter from Robert F. Fetty, Mayor, Town of West Union, to Barbara Taylor, Director, WVBPH/Office of Environmental Health Services, Oct. 28, 2009.

[223] *Id.*

stream in Doddridge County.[224] Fatora's son discovered the spill when he tried to go fishing in the stream in late August 2009 and found the water to be "acrid" and covered with a "red/orange gel" that had an oily smell which got on his hands and did not "go away for some time despite repeated washing."[225] Although the Chief of the West Virginia Oil and Gas Office stated that the fluids were consistent with oil and gas waste, more than a month after the spill the WVDEP remained uncertain about what caused the release.[226]

These releases, and the undoubtedly numerous other unreported incidents, demonstrate that current regulations and regulatory enforcement is inadequate to prevent E&P wastes from being released into the environment.

3. Oil & Gas Production Has Increased Dramatically Since 1988.

When EPA released its 1988 Regulatory Determination, the domestic oil and natural gas industry was struggling. Since then, oil and natural gas production in the United States has increased dramatically. Tens of thousands of new oil wells have been drilled. According to the U.S. Energy Information Administration (US EIA), between 1989 and 2008 the number of producing gas wells nationwide almost doubled, increasing from roughly 262,000 to 479,000 wells.[227]

Bureau of Land Management (BLM) statistics also demonstrate the growth in oil and gas operations under its jurisdiction. In most years during the 1990s, there were less than four thousand applications for permits to drill (APDs) filed with the BLM.[228] BLM has stated that "[s]ince 1996, the number of new APDs has risen dramatically."[229] BLM received more than ten thousand APDs in 2006.[230] Although BLM projects that the number of APDs will decline by 2010,[231] BLM still expects to receive a staggering number, approximately 7,000, of APDs in 2010. Furthermore, BLM attributes this projected decrease to the fact that a larger percentage of proposed drilling is expected to occur on existing leases and not to a decrease in drilling.[232]

State agency statistics also demonstrate an increase in the amount of domestic drilling: one example is Texas, where the number of permits issued by the RRC for drilling in the Barnett

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[224] Ken Ward Jr., *What Caused Big Fracking Fluid Spill in Doddridge County?*, SUSTAINED OUTRAGE: A GAZETTE WATCHDOG BLOG (Oct. 2, 2009); *see also* Letter from Louanne McConnell Fatora to Gov. Manchin, West Highlands Conservancy (Aug. 30, 2009).
[225] Letter from Louanne McConnell Fatora to Gov. Manchin, (Aug. 30, 2009).
[226] Ward Jr., *supra* note 224.
[227] U.S. ENERGY INFO. ADMIN., NUMBER OF PRODUCING GAS WELLS (2009).
[228] BUREAU OF LAND MGT., BLM FY 2010 BUDGET JUSTIFICATIONS III-120 (2010).
[229] *Id.* at III-119.
[230] *Id.* at III-120.
[231] *Id.*
[232] *Id.* at III-122.

Shale increased from 273 in 2000 to 3,653 in 2007,[233] and 4,145 in 2008.[234] Industry-wide, API statistics confirm that these increases are not isolated incidents. The API reported that 2006 was a record year for gas drilling, in which more than 29,000 new wells were drilled.[235] The API expected that this trend would continue and it did: a new 21-year record was reached when 11,771 wells were drilled in the first-quarter of 2007.[236]

Along with this increase in drilling, there has been an associated increase in the amount of E&P waste produced. In Utah's Uintah County the amount of produced water generated from oil and gas operations increased from approximately 800,000 barrels per month in January 1999 to over 1,600,000 barrels per month in January 2007.[237] Even though some techniques have been implemented to reduce the amount of produced water generated from oil and gas extraction activities, EPA's Region 8 noted an overall two percent increase in the amount of produced water generated from 2002 to 2008.[238] The increases in both drilling and E&P waste that have occurred since 1988 indicate that the risks associated with E&P wastes have become even more substantial and that EPA must revisit its Regulatory Determination in light of these developments.

4. Regulation Under Subtitle C of RCRA Would Not Harm the Oil & Gas Industry.

In its 1988 Regulatory Determination, EPA placed significant weight on the potential harm that increased regulation of E&P waste could cause the oil and natural gas industry in making its determination not to regulate E&P wastes under Subtitle C of RCRA. EPA claimed that regulating E&P wastes under Subtitle C would be "extremely costly" for industry.[239] EPA also asserted that "[a]ny program to improve management of oil and gas wastes in the near term will be based largely on technologies and practices in current use."[240] While in 1988 EPA did not believe that the oil and gas industry would develop new waste management technologies, its belief has proved to be incorrect.

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[233] Hannah Wiseman, *Untested Waters: The Rise of Hydraulic Fracturing in Oil and Gas Production and the Need to Revisit Regulation*, 20 FORDHAM ENVTL. L. REV. 115, 124 (2009) (citing Texas Railroad Commission, Newark, East (Barnett Shale), Drilling Permits Issued (1993–2007)).

[234] Texas Railroad Commission, Newark, East (Barnett Shale) Field, Drilling Permits Issued (1993–2009).

[235] Daniel Cusick, *Industry Sets Record for Drilling, Well Completions*, LAND LETTER, Jan. 18, 2007.

[236] Am. Petroleum Inst., "U.S. Q1 drilling & completion estimates at 21-year high—API," Apr. 26, 2007.

[237] DIV. OF OIL, GAS AND MINING, UTAH DEP'T OF NATURAL RES., PRODUCED WATER DISPOSAL, graph slide 6 (2007).

[238] EPA REGION 8, *supra* note 28, at fig. 3-9.

[239] 53 FED. REG. at 25446-01, 25456.

[240] *Id.* at 25,451. EPA's Report to Congress indicates that EPA did not truly believe this assertion that it made in the 1988 Regulatory Determination: "Long-term improvements in waste management need not rely, however, purely on increasing the use of better existing technology. The Agency does foresee the possibility of significant technical improvements in future technologies and practices." EPA, REPORT TO CONGRESS, MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT, AND PRODUCTION OF CRUDE OIL, NATURAL GAS, AND GEOTHERMAL ENERGY III-2 (1987)

Evidence since 1988 demonstrates that new technologies and practices are available and that the use of these safer practices often results in significant cost savings. In 2008, EPA itself stated that "It has been 20 years since the RCRA exemption for oil and gas exploration and production was implemented, and many practices and chemicals used have changed during that time,"[241] and has noted that many safer drilling fluids have been developed[242] and the use of alternatives to pits has become increasingly practical.[243] In addition to the savings that can result from the use of these new disposal methods, companies using safer disposal practices also obtain cost benefits by preventing pollution in the first place, as opposed to being allowed to use "cheaper" practices and later required to clean up the damage they create.[244] The State of New Mexico found that drilling activity more than doubled in the year immediately following establishment of more protective rules for oil and gas waste pits.[245]

It is time for EPA to require oil and gas companies to use these new, safer technologies.

a. New Waste Disposal Technologies

Safer disposal methods for E&P wastes have been developed since 1988. Although EPA acknowledged that such developments were likely in its 1987 Report to Congress, it chose not to require the use of then-emerging safer technologies because it believed that requiring their use would be prohibitively expensive for the oil and gas industry. Recent cost analyses indicate that those fears were unfounded; in many instances, the use of more environmentally sound disposal practices actually saves oil and gas companies money. For example, a study conducted in New Mexico found that eliminating pits, traditionally considered the cheapest disposal method, is actually more cost-effective than their continued use.[246]

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[241] EPA REGION 8, *supra* note 28, at 3–13.

[242] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006, at 29 (2000).

[243] EPA, REGION 8, OIL AND GAS ENVIRONMENTAL ASSESSMENT REPORT 1996–2002 13 (2003).

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> [W]e've had testimony through here that the costs of remediation are, you know, in the hundreds of thousands to, typically millions of dollars. And there's a huge cost benefit to business to prevent pollution versus us allowing them to pollute water and then come back and require them to clean it up. I think that's really a disservice to industry, not to help them prevent that from occurring.

Statement of Commissioner William Olson before the New Mexico Oil Conservation Division, Apr. 16, 2008, OCD Document Image 14015_657_CF[1] at 30.

[245] Press Release, State of New Mexico, Governor Bill Richardson Announces Oil and Gas Drilling Activity in New Mexico Is Strong: Environmental regulations are not driving business away (May 19, 2010).

[246] DORSEY ROGERS, GARY FOUT & WILLIAM A. PIPER, NEW INNOVATIVE PROCESS ALLOWS DRILLING WITHOUT PITS IN NEW MEXICO (2006).

An Oil and Gas Accountability Project (OGAP) analysis demonstrates that closed-loop drilling systems, which use storage tanks and other equipment instead of pits, are cost-effective and can save money compared to conventional waste management with pits.[247] Mary Ellen Denomy, an expert in petroleum accounting, testified before the New Mexico Oil Conservation Division and reported her findings that the costs associated with a typical closed loop drilling system, also known as a pitless drilling system, are only 3.58% of total drilling costs, a significant reduction from the costs associated with typical on-site pit burial (6.58% of total drilling costs) and digging up and hauling wastes to a centralized facility (9.38% of total drilling costs).[248] While initial costs may be higher, closed-loop drilling systems create long-term savings because there is no need to construct pits, drilling waste can be dramatically reduced, water use can be reduced by as much as eighty percent, truck traffic is reduced by as much as seventy-five percent, and tanks can be reused.[249] Comparisons have found closed-loop drilling can result in a cost savings of up to $180,000 per pit,[250] and a project in New Mexico found that:

> [T]he average cost of using a pit and hauling the waste elsewhere for disposal is about 45% more compared to following the same process without a reserve pit. Moreover, the analysis showed that burying the waste on-site costs about 24% more when using a reserve pit as opposed to employing the closed-loop system.[251]

Individual case studies provide further support for these conclusions. A survey of Prima Energy Corporation's closed-loop system in Colorado indicated that closed-loop drilling could be more cost effective than conventional rotary drilling with reserve pits.[252] Prima Energy Corporation drilled over 68 wells in Colorado using closed-loop systems and compared their costs to the costs of using conventional rotary drilling with reserve pits.[253] The closed-loop drilling systems' average cost was $15,600 compared to conventional rotary drilling's cost of $17,020.[254] The study further demonstrated that closed-loop drilling systems result in significant waste minimization. Conventional rotary drilling was found to generate 5,200 barrels more barrels of produced water than closed-loop drilling.[255]

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[247] Oil & Gas Accountability Project, Alternatives to Pits.

[248] Oil & Gas Accountability Project, Closing Argument and Proposed Changes to Proposed Rule 50, *Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc.*, Dec. 10, 2007, at 10.

[249] Oil & Gas Accountability Project, *supra* note 247.

[250] *Id; see also* ROGERS ET AL., *supra* note 246, at 4–5.

[251] Dorsey Rogers, Dee Smith, Gary Fout & Will Marchbanks, *Closed-loop drilling system: A Viable Alternative to Reserve Waste Pits*, WORLD OIL, Dec. 2008, at 46.

[252] *See* Oil & Gas Accountability Project, *supra* note 247.

[253] Exhibit 8, Closed-Loop Drilling Case Studies, *Re: Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc.*, OCD Document Image No. 14015_637_[CF]1.

[254] *Id.*

[255] *Id.*

Similarly a study of two wells drilled two hundred feet apart in Matagorda County, Texas provides further support for assertions that closed-loop drilling systems can provide cost savings.[256] In Matagorda County, two wells were drilled two hundred feet apart "through the same formations, using the same rig crew, mud company and bit program."[257] One well used a closed-loop system while the other used traditional solids-control equipment. The closed-loop system "resulted in some significant savings" including: a forty-three percent savings in drilling fluid costs, twenty-three percent fewer rotating hours, fewer days to drill the wells to comparable depths, a thirty-seven percent reduction in bits used, and up to thirty-nine percent improvement in penetration rates.[258]

EPA's own studies confirm that closed-loop drilling systems are a safer and cost-saving waste disposal process.[259] Because of these types of findings, EPA has promoted the use of closed-loop drilling systems in Region 8.[260] The RRC of Texas has confirmed that closed-loop systems can result in significant cost savings;[261] and many other government agencies also support the use of closed-loop drilling systems.[262] In addition to the already demonstrated economic advantages of closed-loop systems, there is a great likelihood that the costs of constructing closed-loop systems will decrease even more in the future "as economies of scale and innovations in operations" continue to occur.[263] If these systems are manufactured in the United States, they add the benefit of new job creation in addition to lower environmental risk.

Although safer and economical, even closed loop systems can leak or spill. Strong regulations are required to govern the storage and transport of toxic waste. In some cases, waste may be transported via pipeline to storage or disposal sites. Yet in Texas, State officials declared at a public meeting that the state has no "rule-making authority" over such pipelines.[264]

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[256] *Id.*
[257] *Id.*
[258] *Id.*
[259] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006, at 69 (2000).
[260] EPA REGION 8, AN ASSESSMENT OF THE ENVIRONMENTAL IMPLICATIONS OF OIL AND GAS PRODUCTION: A REGIONAL CASE STUDY 4-4 (Working Draft 2008).
[261] Abrahm Lustgarten, *Underused Drilling Practices Could Avoid Pollution*, PROPUBLICA, Dec. 14, 2009.
[262] U.S. Fish & Wildlife Serv., *Wildlife Mortality Risk in Oil Field Waste Pits*, U.S. FWS CONTAMINANTS INFORMATION BULLETIN (2000) (recommending the use of closed loop containment systems and elimination of open pits and ponds); BUREAU OF LAND MGT, THE GOLD BOOK: SURFACE OPERATING STANDARDS AND GUIDELINES FOR OIL AND GAS EXPLORATION AND DEVELOPMENT (4th ed. 2007). "To prevent contamination of ground water and soils . . . it is recommended that operators use a closed-loop drilling system or line reserve pits with an impermeable liner." *Id.* at 17.
[263] Controlled Recovery Inc.'s Written Closing Argument, *Re: Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc*., Dec. 10, 2007, at 3.
[264] Lowell Brown, *Officials Give Few Answers to Argyle*, DENTON RECORD-CHRONICLE, Jan. 30, 2010.

b. Waste Minimization, Reuse, and Recycling Techniques

Waste minimization, reuse and recycling techniques also can be economical for companies. According to the RRC of Texas, "[w]aste minimization has been proven to be an effective and beneficial operating procedure," while recycling "is becoming a big business and more recycling options are available every day." [265] Both serve to reduce the total amount of E&P wastes that must be disposed and thereby decrease the risks associated with E&P wastes. In its manual *Waste Minimization in the Oilfield*, the RRC of Texas offers oil and gas companies more than one hundred ways to minimize wastes.[266] This manual, along with reports from individual companies implementing various waste minimization and recycling techniques, demonstrates that improved practices are possible.

Studies by the E&P Forum attest to the benefits of waste recycling[267] and identify several ways industry can reduce waste, "through process and procedure modifications . . . [For example,] improved solids control equipment and new technology can reduce the volumes [of drilling fluids] discharged to the environment, . . . more effective drillbits can reduce the need for chemical additions, [and] gravel packs and screens may reduce the volume of formation solids/sludge produced."[268] An analysis by OGAP found that the use of closed-loop drilling systems, in addition to providing cost benefits, maximizes the ability to reuse and recycle drilling fluids.[269] And waste reduction is not just beneficial from an environmental perspective. It can provide further opportunities for the oil and gas industry to save money. A study on land owned by the U.S. Army Corps of Engineers in Oklahoma found that a reduction in "wastes by close to 1.5 million pounds" resulted in "[a] material and disposal cost savings of $12,700."[270]

Both the government and industry are aware of the cost saving opportunities associated with the use of waste minimizing technologies and recycling and reuse projects. For example, STW Resources has developed a technology for use in the Barnett Shale that can reclaim approximately seventy percent of the flowback water produced by hydraulic fracturing operations in the region and thereby reduce the total amount of waste associated with hydraulic fracturing while also enabling the wastes to be reused.[271] And in July of 2008, the RRC of Texas approved Devon Energy's "third pilot program to treat and reuse frac fluid . . . . As a result of its water recycling efforts, Devon is the industry leader in water recycling and now used recycled

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[265] Railroad Commission of Texas, *supra* note 52.

[266] DRILLING DOWN, *supra* note 20, at 29.

[267] E&P FORUM, *supra* note 107, at14 ("There are potential benefits in the sale of recovered hydrocarbons. All hydrocarbon wastes should be returned to the production stream where possible.").

[268] UNEP E&P FORUM, ENVIRONMENTAL MANAGEMENT IN OIL AND GAS EXPLORATION AND PRODUCTION: AN OVERVIEW OF ISSUES AND MANAGEMENT APPROACHES 54 (1997).

[269] Oil & Gas Accountability Project, *supra* note 247.

[270] Exhibit 8, Closed-Loop Drilling Case Studies, *Re: Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc.*, OCD Document Image No. 14015_637_[CF]1.

[271] STW RES., INC., CONTAMINATED WASTE WATER RECLAMATION OPPORTUNITIES 2–3.

frac water at one out of every 10 frac jobs in its Barnett Shale operations."[272] Devon's wastewater recycling program "is projected to produce 75 percent reusable fracture fluid and 25 percent high concentrate and solids. The concentrate will be used as a drilling fluid or disposed of in an authorized facility."[273] Devon Energy Production Central Division's vice president estimated that "[a]t full treatment capacity, up to 85 percent of [the] water [Devon] recover[s] from fracture completions in the Barnett Shale could be reused." [274] And Devon Energy is not alone: Fountain Quail Water Management, DTE Gas Resources Inc., Burlington Resources, and Stroud Energy have all engaged in reuse and recycling efforts.[275]

New projects are underway at the national level: the U.S. Department of Energy's National Energy Technology Laboratory launched nine new projects in October 2009 focused on developing new technologies "to improve management of water resources, water usage, and water disposal."[276] These projects add to the fifteen already underway that are focused on "assess[ing] options and technologies for handling, cleaning, and reuse of produced and flowback water" in the Barnett and Appalachian shale plays.[277] When combined with pitless drilling through a closed-loop system, recycling of waste is clearly an effective, available, and economical way to manage E&P waste more safely and allow for compliance with stronger regulations.

c. <u>New Substitutes for Toxic Materials</u>

Studies indicate that the use of less toxic drilling and hydraulic fracturing fluids can both reduce the risks associated with E&P wastes and also reduce oil and gas companies' liability, thus potentially saving them money in the long run.[278] Other agencies confirm EPA's findings on the benefits of using safer cost effective alternatives. Numerous agencies encourage operators "to substitute less toxic, yet equally effective products for conventional drilling products."[279] And most recently, ExxonMobil announced that it "'supports the disclosure of the identity of the ingredients being used in fracturing fluids.'"[280] OGAP sees ExxonMobil's statement as a "significant step" and believes that "[o]nce the chemicals are widely known . . . companies will

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[272] News Release, Railroad Commission of Texas, Commissioners Approve of Devon Water Recycling Project for the Barnett Shale, July 29, 2008.
[273] *Id.*
[274] *Energy Companies Strive to Reuse Water*, WEATHERFORD TELEGRAM, July 25, 2007, at 3C.
[275] *Id.*
[276] U.S. Dep't of Energy, National Energy Technology Lab, *Nine New Projects*, OIL & GAS PROGRAM NEWSLETTER (Dep't), Winter 2009, at 8.
[277] *Id.* at 6.
[278] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006 (2000).
[279] BUREAU OF LAND MGT, THE GOLD BOOK: SURFACE OPERATING STANDARDS AND GUIDELINES FOR OIL AND GAS EXPLORATION AND DEVELOPMENT, at 39 (4th ed. 2007).
[280] Katie Burford, *ExxonMobil Favors Fracing Disclosure, Environmental Group Welcomes Position from Oil Industry Giant*, DURANGO HERALD, Apr. 19, 2010.

be more likely to use green alternatives" which will result in "a lessening of the toxicity of the fluids" over time.[281]

In addition, the search for chemicals with lower potential environmental impacts has "result[ed] in the generation of less toxic wastes . . . . [For] example . . . mud and additives that do not contain significant levels of biologically available heavy metals or toxic compounds."[282] These types of new synthetic drilling fluids already have been developed and are less toxic, "free of polynuclear aromatic hydrocarbons and have . . . faster biodegradability and lower bioaccumulation potential."[283] Safer alternatives to current drilling fluids are available—all that remains is for the oil and gas industry to adopt widespread use of them.

Industry has already proven itself to be capable of switching to less hazardous compounds in the past. In the 1990s many drilling companies voluntarily phased out the use of benzene in their operations.[284] EnCana stopped using a chemical, 2-Butoxyethanol, linked with reproductive problems in animals, while BJ Services, "one of the largest fracturing service providers in the world, has discontinued the use of fluorocarbons, a family of compounds that are persistent environmental pollutants." [285] Schlumberger has developed "GreenSlurry," which the company claims is "earth-friendly."[286] Antero Resources Corporation pledged to use only "green frac" materials in the communities of Rifle, Silt and New Castle in western Colorado.[287] Yet these reported less toxic fluids are not used everywhere. While the oil and gas industry clearly has the capability to adapt its operations to safer technologies, most companies have been reluctant to make such changes. EPA should thus act and require the oil and gas industry to expand the use of the safer, less toxic drilling fluids that are currently available.

5. Oil and Gas Waste Meets the Statutory and Regulatory Criteria for Hazardous Waste.

Absent their special exclusion from RCRA, E&P wastes would properly be regulated under Subtitle C of RCRA. Congress defined hazardous wastes under RCRA as:

> [A] solid waste, or combination of solid wastes, which because of its quantity, concentration, or physical, chemical or infectious characteristic may—

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[281] *Id.*
[282] E&P FORUM, *supra* note 107, at12-23.
[283] Drilling Waste Management Information System, Drilling Waste Management Fact Sheet: Using Muds and Additives with Lower Environmental Impacts.
[284] Susan Riha et al., *supra* note 42, at 6.
[285] Lustgarten, *supra* note 261.
[286] Schlumberger, "Earth-friendly GreenSlurry system for uniform marine performance," March, 2003.
[287] The Rifle, Silt, New Castle Community Development Plan, Jan. 1, 2006.

> (A) cause, or significantly contribute to an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness; or
> (B) pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, or disposed of, or otherwise managed.[288]

Under RCRA, Congress instructed EPA to "define hazardous waste using two different mechanisms: by listing certain specific solid wastes as hazardous . . . and by identifying characteristics . . . which, when exhibited by a solid waste, make it hazardous."[289] Under RCRA, "[c]haracteristic wastes are wastes that exhibit measurable properties which indicate that a waste poses enough of a threat to warrant regulation as a hazardous waste."[290] The four technical criteria EPA uses to determine if a waste is a characteristic waste include:[291] ignitability, corrosivity, reactivity, and toxicity.[292] Waste will be considered hazardous if it exhibits *any* of the four characteristics.[293] Because various types of E&P wastes exhibit several of these characteristics, E&P wastes should properly be regulated under Subtitle C of RCRA as characteristic hazardous wastes.

a. Ignitability

Ignitability is a criterion used to identify wastes that "can readily catch fire and sustain combustion."[294] A substance's flashpoint is indicative of its ignitability.[295] A waste's flash point is "the lowest temperature at which the fumes above a waste will ignite when exposed to flame."[296] Eleven percent of oily sludges sampled in California had a flash point exceeding the regulatory threshold.[297]

The risks associated with E&P wastes having hazardous flashpoints under RCRA's criteria have been demonstrated in the past decade. In January 2003, a fire occurred when hydrocarbon vapor from basic sediment and water, a type of E&P waste, ignited at a Texas open area collection pit.[298] Three people were killed in the fire and four others were severely burned.[299] In

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[288] 42 U.S.C. § 6903(5).
[289] EPA, RCRA ORIENTATION MANUAL, CHAPTER III: RCRA SUBTITLE C—MANAGING HAZARDOUS WASTE, at III-17.
[290] *Id.* at III-22.
[291] Hazardous Waste Treatment Council v. U.S. EPA, 861 F.2d 277, 279 (D.C. Cir. 1988).
[292] *See* 40 CFR § 261.20 et seq.
[293] *Id.*
[294] EPA, *supra* note 2899, at III-22.
[295] NAGY, *supra* note 24, at 36.
[296] EPA, *supra* note 2899, at III-23.
[297] NAGY, *supra* note 24, at 31.
[298] U.S. Dep't. of Labor, Occupational Safety & Health Admin., Potential Flammability Hazard Associated with Bulk Transportation of Oilfield Exploration and Production (E&P) Waste Liquids, SHIB-03-24-2008.
[299] *Id.*

May 2006, a natural gas condensate tank and pit caught on fire in Colorado.[300] Nearby residents were described as "'terrified' by the 200-foot flames."[301] Residents were also concerned because they were not able to learn what potential health impacts they were exposed to from the burning waste "since neither the company nor local or state authorities bothered taking air quality samples during the blaze."[302]

More recently, a wastewater impoundment pond in Washington County, Pennsylvania caught fire.[303] George Zimmerman reported seeing "flames shooting 100 feet in the air" at the fire that occurred at the hydraulic fracturing site located on his property.[304] A state police fire marshal determined that the fire was an accident caused by "a malfunction [that] ignited fumes [most likely in the frac tank] and caused $375,000 in damages."[305] The fire also "badly damaged" the frac pit liner, causing a spokeswoman from the Pennsylvania DEP to be concerned that the pit's contents might escape.[306] Instances such as these fires and the sampling data from California indicate that E&P wastes are ignitable, and that this characteristic of E&P wastes has resulted in serious harm. E&P wastes with these flash points would appropriately be regulated as characteristic hazardous wastes under Subtitle C of RCRA. Such regulation is necessary to prevent future incidents similar to the January 2003 and March 2010 fires.

b. Corrosivity

Waste is corrosive if "it is acqueous and has a pH less than or equal to 2 or greater than or equal to 12.5" or if "[i]t is a liquid and corrodes steel . . . at a rate greater than 6.35 mm per year."[307] Drilling wastes sampled in California had elevated pH levels approaching the 12.5 regulatory limit.[308] In addition, corrosive chemicals are frequently found in E&P wastes. For example, hydrogen sulfide is a corrosive and "toxic gas occurring naturally in some oil and gas reservoirs."[309] The corrosive characteristics of E&P wastes have already been responsible for many incidents where E&P wastes have been improperly released. On numerous occasions, spills of E&P wastes have been reported as originating from corroded equipment that had begun to leak because of corrosion attributed to the substances the equipment contained.[310] Again, because a waste is properly regulated under Subtitle C of RCRA when it exhibits *any* of the four

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[300] OIL & GAS ACCOUNTABILITY PROJECT, SPRING/SUMMER 2006 REPORT (2006).
[301] *Id.*
[302] *Id.*
[303] Janice Crompton, *Residents Reported Gas Odors Before Explosion*, PITTSBURGH POST-GAZETTE, Apr. 1, 2010, at B-1.
[304] Kathie O. Warco, *Fumes Ignite at Gas Well*, OBSERVER-REPORTER, Apr. 1, 2010.
[305] *Id.*
[306] *Id.*
[307] 40 CFR § 261.22.
[308] NAGY, *supra* note 24, at 37.
[309] E&P FORUM, *supra* note 107, at28.
[310] *See supra* note 216 and accompanying text.

criteria of characteristic hazardous wastes, corrosive E&P wastes should be regulated under Subtitle C.

c. Reactivity

A waste is reactive if "(1) it is normally unstable and readily undergoes violent change without detonating, (2) [i]t reacts violently with water, (3) [i]t forms potentially explosive mixtures with water, (4) [w]hen mixed with water, it generates toxic gases, vapors or fumes in a quantity sufficient to present a danger to human health or the environment, (5) [i]t is a cyanide or sulfide bearing waste which, when exposed to pH conditions between 2 and 12.5, can generate toxic gases, vapors or fumes in a quantity sufficient to present a danger to human health or the environment, (6) [i]t is capable of detonation or explosive reaction if it is subjected to a strong initiating source or if heated under confinement, (7) [i]t is readily capable of detonation or explosive decomposition or reaction at standard temperature and pressure, [or] (8) [i]t is a forbidden explosive . . . ."[311]

Out of the four criteria for determining characteristic hazardous wastes, reactivity is the most difficult to test: "In many cases, there is no reliable test method to evaluate a waste's potential to explode, react violently, or release toxic gas under common waste handling conditions."[312] In some cases, a waste's reactivity can be evaluated by a releasable sulfide test.[313] Although no regulatory threshold valuable for releasable sulfides has been established, EPA established an interim guidance value.[314] Testing of E&P wastes in California found samples of sludge and tank bottoms exceeding EPA's interim guidance value.[315]

d. Toxicity

The Code of Federal Regulations describes the specific levels/concentrations at which various chemicals will be considered toxic for the purposes of RCRA. To determine whether a chemical meets the required level, EPA uses the Toxicity Characteristic Leaching Procedure (TCLP). Many E&P wastes would be considered toxic under this test. The New Mexico Oil Conservation Division (OCD) found that several samples taken from E&P waste disposal pits in the state contained levels of chemicals that failed the TCLP test.[316] Specifically, the OCD found pits that contained levels of arsenic, lead, mercury, 2,4-Dinitrotoluene, and 2-Methylnaphthalene that exceeded TCLP levels.[317] Its report indicated that the levels of lead they found alone would have allowed the wastes to be considered characteristically hazardous if not for the RCRA

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[311] 40 CFR § 261.23.
[312] EPA, *supra* note 2899, at III-23.
[313] NAGY, *supra* note 24, at 38.
[314] *Id.*
[315] *Id.* at 38–39.
[316] *See* Earthworks, OCD's 2007 Pit Sampling Program: What Is in that Pit?, at 31.
[317] *Id.* at 34.

exemption.[318] Analysis of E&P waste in California determined that both produced water and oily sludge met the federal toxicity characteristic and would be considered hazardous, again, if not for the RCRA exemption.[319] Because of this evidence, and the multitude of evidence discussed above indicating that E&P wastes have caused, and present substantial risk of continuing to cause, hazards to human health and the environment, EPA should reconsider its 1988 Regulatory Determination and regulate E&P wastes under Subtitle C of RCRA, as would be proper given the fact that they frequently exhibit the same traits as characteristic hazardous wastes.

II. REQUEST FOR PROMULGATION OF REGULATIONS

The Petitioner, the Natural Resources Defense Council, respectfully requests that the EPA promulgate regulations classifying wastes from the exploration, development and production of oil and natural gas as hazardous waste subject to provisions of Subtitle C of RCRA. This request is based on overwhelming evidence that waste from the exploration, development and production of oil and natural gas is hazardous, taking into account its toxicity, corrosivity, and ignitability, that it is released into the environment where it can cause harm, that state regulations are inadequate, and that there are numerous methods available to manage it as hazardous waste. As set forth in this Petition, evidence exists for EPA to document that, because of its quantity, concentration, and chemical characteristics, E&P waste may cause or significantly contribute to an increase in mortality and serious incapacitating illness and that it may pose a substantial present or potential hazard to wildlife and the environment when improperly treated, transported or disposed of, or otherwise managed, as is occurring throughout the U.S. in the absence of sufficient mandatory federal oversight. *See* 42 U.S.C. § 6902(4)-(5).

The Petitioner requests that the EPA consider the relevant statutory and regulatory factors, as well as the factors set forth in the July 1988 Regulatory Determination, and promulgate regulations applying to wastes from the exploration, development and production of oil and natural gas under Subtitle C of RCRA.

Respectfully submitted this 8th day of September, 2010.

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Ohio Quakes Probably Triggered by Waste Disposal Well, Say Seismologists

January 6, 2012

A tower for removing gas at the Marcellus Shale Formation in Pennsylvania. Credit: Ruhrfisch/Wikimedia Commons.

Earthquakes that have shaken an area just outside Youngstown, Ohio in the last nine months—including a substantial one on New Year's Eve—are likely linked to a disposal well for injecting wastewater used in the hydraulic fracturing process, say seismologists at Columbia University's **Lamont-Doherty Earth Observatory** who were called in to study the quakes. Ohio Gov. John Kasich has shut down the injection well and put four other proposed wells on hold. In the meantime, steps have been taken to ease pressure in the well to avert further rumblings.

The concern comes as natural gas drilling in shale formations that underlie much of the Northeast grows. To extract the gas, a mix of water, sand and chemicals is pumped under high pressure into shale rocks, in a process called hydraulic fracturing, or fracking. Once the gas has been removed, wastewater is either recycled or trucked off-site and injected deep underground. As the pressurized water seeps through cracks deep below ground, it can sometimes cause earthquakes on ancient fault lines.

Ohio is home to 177 such disposal wells, including the Youngstown well, which lies in a seismically dormant region bordering Pennsylvania. The first rumblings surfaced in March, several months after injection of fracking waste from Pennsylvania began. Nine small temblors followed. In late November, Ohio authorities asked Lamont scientists to monitor the area with mobile instruments that could provide a more accurate location of subsequent earthquakes. On Dec. 24, the four instruments recorded a magnitude 2.7 quake 2.2 miles below the surface–a half-mile away and about 2,000 feet below the 1.7 mile deep well.

"The location of the earthquake was sufficient evidence that there could be a link," Lamont seismologist **John Armbruster** told **NPR's All Things Considered**. Later in the week, D&L Energy, which owns the site, agreed to shut down the well. Then, on Dec. 31, a magnitude 4.0 quake struck. The Lamont instruments located it at about 300 feet east, and some 500 feet under the previous event. A 4.0 is about 40 times more powerful than a 2.7. At that point, the state put a moratorium on activity on four other wells within a five-mile radius, all of them already inactive.

Hydrofracking by its nature causes tiny earthquakes, because it involves fracturing of rock—but these are largely imperceptible, as the process takes place in relatively weak, shallow shales that crack before building up much strain. Quakes triggered by waste injection wells can be potentially more powerful because more fluid is usually being pumped underground at a site for longer periods, said **Roger Anderson**, an energy geophysicist at Lamont-Doherty who is not involved in the study. Once fluid enters a preexisting fault, it can pressurize the rocks enough to move; the more stress placed on the rock formation, the more powerful the earthquake. The Lamont data suggests that the Dec. 31 movement near the Ohio well was a strike-slip motion, in which one rock face slides across the other horizontally.

The chance of triggering an ancient fault by injecting fluid underground is relatively slim—maybe one in 200, said Lamont seismologist **Won-Young Kim**, who heads the **Lamont-Doherty Cooperative Seismic Network**. But, he said, the potential damage and injuries from an earthquake could far outweigh the cost of closing the well. "Once you get one earthquake, it's better to stop then, because you may get another," he said. That point was echoed by Armbruster on NPR: "I would advocate monitoring of wells to know when triggering of earthquakes first begins," he said. "Then you can decide whether to continue using that well."

Seismologists have known about the potential for injection wells to trigger earthquakes since the 1960s, when injected wastewater from weapons production at the Rocky Mountain Arsenal in Colorado was tied to a **series of earthquakes** including several of magnitude 5.0 or greater that caused minor damage in Denver and other cities. Earthquakes in Arkansas, Texas, Oklahoma and the United Kingdom have been linked in recent years to disposal of fracking fluids. In 2001, scientists linked a magnitude 4.2 quake in Ashtabula, Ohio to a waste disposal well there, a "carbon copy" of the recent activity near Youngstown, said Kim.

After the New Year's quake, Kim said that the risk could continue for another year or two, as it could take that long for pressurized fluid to dissipate. To minimize that risk, Ohio officials announced Jan. 5 that they would start letting the injected fluids bubble back into storage tanks at the surface rather than capping the well under standard procedures.
The Lamont-Doherty scientists will continue to monitor the area with colleagues from Youngstown State University and Ohio Geological Survey. They are also talking with the university about upgrading its own seismic station.

More:
Watch how injected fluids trigger an earthquake in **this video** from Next media Animation.
For ongoing coverage of the scientific debate over hydrofracking see Scientific American's **Storify blog.**

Related Projects:

Lamont Cooperative Seismographic Network (LCSN)

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BUSINESS | November 3, 2011

Study Ties Fracking to Quakes in England

By ALEXIS FLYNN

LONDON—The company leading efforts to unlock the U.K.'s potentially vast shale-gas reserves suffered a setback Wednesday after a report found it was "highly probable" a controversial production technique caused two small earthquake tremors in the country earlier this year.

The report, which was financed by U.K. energy company Cuadrilla Resources Ltd., pointed to "strong evidence" that the two minor earthquakes and 48 weaker seismic events resulted from Cuadrilla's pumping drilling fluids used in hydraulic fracturing, or "fracking." At the same time, the report said the events were the result of a "rare combination of geological factors."

Bloomberg News

Cuadrilla Resouces' shale gas exploration site, in July.

The report could complicate efforts by privately held Cuadrilla to resume hydraulic-fracturing activity that was halted after the two seismic incidents.

The company said the report concluded that none of the events recorded, including one in April of 2.3 and one in May of 1.5 on the Richter scale, had any structural impact on the surface above.

The U.K. has become the latest venue in Europe to see shale gas spur major debate over fracking, which has been heavily criticized by environmental groups. In June, France became the first country to ban shale-gas exploration.

The Staffordshire, England-based company said the report vindicated its stance that its operations pose "no threat to people or property in the local area," but it pledged to implement an early-warning system and other recommendations to mitigate the risk.

Cuadrilla in September announced a big shale-gas discovery, but development is on hold after the company and government agreed in June to stop its shale-gas test drilling until its potential consequences were better understood.

More

Cuadrilla statement

Earlier: U.K. Gets Big Shale Find

EXPERIENCE WSJ PROFESSIONAL

Editors' Deep Dive: Shale Rush Hits Hurdles

PLATTS COMMODITY NEWS
US Interior To Issue Frack Fluid Disclosure Rule

ENERGY WASHINGTON WEEK
Gas Industry Criticizes EPA Fracking Well Air Rules

U.K. regulators said they would review the findings before shifting policy. Leading environmental groups and local-government officials also called for caution on fracking, which has been a key component in the rise of shale gas in the U.S. and other areas.

The U.K. Department of Energy and Climate Change will study the implications of the report, a department spokesman said. "The implications of this report will be reviewed very carefully—in consultation with the British Geological Survey, independent experts, and the other key regulators," said the spokesman.

The report found that the combination of geological factors that caused the quakes was rare and would be unlikely to occur together again at future well sites.

"If these factors were to combine again in the future, local geology limits seismic events to around magnitude 3 on the Richter scale as a worst-case scenario," the report said.

The Richter scale measures magnitude, which is expressed in whole numbers and decimal fractions, and not damage caused. Each whole number represents a tenfold increase in measured amplitude, so a 5.3 tremor might be rated moderate, while a strong earthquake could be recorded at 6.3.

Cuadrilla said the report was overseen by an independent team of seismic experts and was prepared in consultation with the Department of Energy and Climate Change. A department spokesman said the report was commissioned by the company and that it would comment on the substance of the conclusions after it studied the report's findings.

An earlier study by the British Geological Survey put the epicenter for each earthquake as being 500 meters (1,650 feet) away from the Preese Hall-1 well, at Weeton, near Blackpool, England.

British Geological Survey Earthquake Seismologist Dr. Brian Baptie said Wednesday's report confirmed his organization's own initial conclusion that fracking was responsible for the earthquakes. "It seems quite possible, given the same injection scheme in the same well, that there could be further earthquakes," he said.

Dr. Baptie said a way to minimize future risks could include the type of traffic-light monitoring system proposed by Cuadrilla but pointed out that even an "acceptable magnitude 2.6 earthquake might, at a depth of three kilometers (1.9 miles), result in an intensity of shaking that would not be expected to cause any damage but would be widely felt by people indoors and out, and may displace objects on shelves."

Spotting these types of seismic events could also be tricky, explained Dr. Baptie. "Earthquakes such as this result from very small movements on small faults that may be very difficult to identify," he said.

Nick Molho, head of energy policy at environmental group WWF-UK, said the findings "are worrying, and are likely to add to the very real concerns that people have about fracking and shale gas."

Local Liberal Democrat Councillor Sue McGuire, who also leads a residents' group opposed to fracking, said that if Cuadrilla drilled the 400 to 800 wells proposed than "we cou ld be looking at significant seismic activity in the area, which could have major impact on peoples' homes and businesses in the area, not to mention the impact on the environment."

"A moratorium would give the government time to ensure that industry specific legislation can be put in place," she said.

Cuadrilla has said some 200 trillion cubic feet of shale gas may be contained in northwest England,enough to meet the country's gas demand for 64 years, although it has cautioned the actual recoverable figure may be much lower.

—Guy Chazan contributed to this article.

Write to Alexis Flynn at alexis.flynn@dowjones.com

Corrections & Amplifications

An earlier version of this story erroneously referred to a Cuadrilla estimate of 200 million feet of gas in northwest England; the estimate is for 200 trillion cubic feet of gas.

FINAL

RULE H-1 - CLASS II DISPOSAL AND CLASS II COMMERCIAL DISPOSAL WELL PERMIT APPLICATION PROCEDURES

a) Definitions:

1) "Class II Disposal Well"-- means:

A) A permitted Class II well in which Class II Fluids are injected into zones not productive of oil and gas, and brine used to produce bromine, within the field boundary established by an order of the Commission for the production of liquid hydrocarbons or brine used to produce bromine, where the well is located or will be located, for the purpose of disposal of those fluids; or

B) A permitted Class II well in which Class II Fluids are injected into a zone or zones~~,~~ which are not commercially productive of dry gas, within the same common source of supply, where the well is located or will be located, for the purpose of disposal of those fluids.

2) “Class II Commercial Disposal Well"-- means a permitted Class II well in which Class II Fluids are injected, for which the Permit Holder receives deliveries of Class II Fluids by tank truck from multiple oil and gas well operators, and either charges a fee at the disposal well facility or purchases the Class II Fluids at the source for subsequent transport to the disposal well facility for the specific purpose of disposal of the delivered Class II Fluids.

3) "Class II Fluids" means:

A) Produced water and/or other fluids brought to the surface in connection with drilling, completion, or fracture treatments, workover or recompletion and plugging of oil and natural gas wells;~~,~~ Class II or wells that are required to be permitted as water supply wells by the Commission; enhanced recovery operations; or natural gas storage operations; or

B) Produced water and/or other fluids from (A) above, which prior to re-injection have been used on site for purposes integrally associated to oil and natural gas well drilling, completion, or fracture treatments, workover or recompletion and plugging of oil and natural gas wells; Class II or wells that are required to be permitted as water supply wells by the Commission; enhanced recovery operations; or natural gas storage operations, or chemically treated or altered to the extent necessary to make them usable for purposes integrally related to oil and natural gas well drilling, completion, workover and plugging, oil and gas production, enhanced recovery operations, or natural gas storage operations, or commingled with fluid wastes resulting from fluid treatments outlined above, and including any other exempted oil and gas related fluids under the Resource Conservation and Recovery Act, provided the commingled fluid wastes do not constitute a hazardous waste under the Resource Conservation and Recovery Act; or

C) Waste fluids from gas plants (including filter backwash, precipitated sludge, iron sponge, hydrogen sulfide and scrubber liquid) which are an integral part of oil and gas production operations; and waste fluids from gas dehydration plants (including glycol-based compounds and filter backwash), unless the gas plant or gas dehydration plant wastes are classified as hazardous under the federal Resource Conservation and Recovery Act.

4) "Confining layer" means a geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above an injection zone. It is composed of rock layers that are impermeable or distinctly less permeable than the injection zone beneath it. There may be multiple confining layers above an injection zone.

5) "Permit Holder" means the entity or person to whom the permit is issued and who is responsible for all regulatory requirements relative to the Class II Disposal or Class II Commercial Disposal Well.

6) "USDW" means Underground Source of Drinking Water which is defined in Title 40, Code of Federal Regulations (40 CFR) Section 144.3, as an aquifer or its portion which:

A) Supplies any public water system (see 40 CFR); or

B) Contains a sufficient quantity of groundwater to supply a public water system (see 40 CFR) and currently supplies drinking water for human consumption; or

C) Contains fewer than 10,000 mg/l total dissolved solids (see 40 CFR); and

D) Which is not an exempted aquifer (see 40 CFR)

b) No person shall drill, deepen, re-enter, recomplete or operate any well for use as a Class II Disposal or Class II Commercial Disposal Well or inject into any well, without the applicable permits from the Commission, application for which shall be made on forms prescribed by the Director. Permits are valid only for the Permit Holder stated on the permit, and shall remain valid only with ongoing compliance with established operating requirements specified in General Rule H-2 or H-3, except that permits to drill, deepen, or re-enter shall automatically expire six (6) months from the date of issuance, unless commencement of the drilling, deepening or re-entry of plugged well operations authorized by the permit has occurred, which are to be continued with due diligence, but not to exceed one (1) year from the date of commencement of the drilling, deepening or re-entry of plugged well operations authorized by the permit, at which time the well shall be plugged, injection casing set, or a new permit application, along with a new permit fee and plat, must be filed. Failure to comply with the operating requirements in General Rule H-2 or H-3 may result in revocation of the Class II Disposal Well or Class II Commercial Disposal Well permit in accordance with subparagraph q) below.

1) Authority to conduct an injectivity test, step rate test or trial injection test prior to, or after the issuance of a permit may be approved as follows:

A) An injectivity test, step rate test or trial injection test of less than twelve (12) hours duration may be approved by the Director upon review of the well construction to determine well mechanical integrity for the protection of the USDW's and oil and gas resources during the test. The Director shall establish the protective parameters of the test, require the submittal of any information or test data deemed necessary and may require the witnessing by Commission staff of the test.

B) An Applicant may request approval from the Commission, by filing an application in accordance with General A-2 and A-3 and other applicable hearing procedures, of an injectivity test, step rate test or trial injection test of twelve (12) hours or more in duration.

2) No Class II Disposal or Class II Commercial Disposal Well may be drilled at a surface location other than that specified on the permit, except that if a permit holder has commenced drilling operations and the Class II Disposal or Class II Commercial Disposal Well is lost due to adverse drilling conditions prior to surface casing being set, the permit holder may request an amendment of the permit without a fee for the new location, provided the Class II Disposal or Class II Commercial Disposal Well remains on the same surface owners property where the Class II Disposal or Class II Commercial Disposal Well was originally permitted and all other aspects of the permit request remain the same. Movement of the Class II Disposal or Class II Commercial Disposal Well location off the original surface owners' property, or after surface casing has been set, will require the filing of a new permit application, along with a new permit fee and plat. Drilling may not commence prior to the issuance of a new permit.

3) Permits to recomplete or operate shall automatically expire one year from the date of issuance, unless commencement of the operations authorized by the permit has occurred, or a new permit application, along with a new permit fee has been filed.

4) Upon issuance of a permit, a copy of the permit shall be displayed at the site where the Class II Disposal or Class II Commercial Disposal Well is being drilled for review by Commission staff.

5) Permits to drill, deepen, or re-enter a Class II Disposal or Class II Commercial Disposal Well may only be issued if the location complies with General Rule B-3.

c) The application to drill, deepen, re-enter, recomplete or operate a Class II Disposal or Class II Commercial Disposal Well shall include at a minimum:

1) The information required by subparagraph (h) below, for the existing or proposed well and any additional information deemed necessary by the Director for the protection of USDWs; and

2) Accompanied by a permit fee in the amount of $300.00 if the Class II Disposal or Class II Commercial Disposal Well is drilled, deepened, or re-entered; and

3) Accompanied by a non-refundable fee of $100.00 for a Class II Disposal Well or $500.00 for a Class II Commercial Disposal Well to recomplete or operate the Class II Disposal or Class II Commercial Disposal Well; and

4) Accompanied by the required financial assurance in accordance with General Rule B-2; and

    5) Accompanied by a Form 1 Organizational Report in accordance with General Rule B-13; and

    6 Be executed under penalties of perjury; and

    7) If the applicant is a corporation, limited liability company, limited liability partnership or other business entity, it must be incorporated, organized, or authorized to do business in the State of Arkansas, and by filing an application, the applicant irrevocably waives, to the fullest extent permitted by law, any objection to a hearing before the Commission or in a court of competent jurisdiction in Arkansas; and

    8) If the applicant is an individual, partnership, or other entity that is not a resident of Arkansas, the applicant must be authorized to do business in Arkansas, and by filing an application, the applicant irrevocably waives, to the fullest extent permitted by law, any objection to a hearing before the Commission or in a court of competent jurisdiction in Arkansas; and

    9) Proof that the Class II Disposal or Class II Commercial Well location complies with General Rule B-3.

d) No person shall inject into USDWs or be issued a permit to inject into USDWs unless an aquifer exemption has been granted in accordance with US Environmental Protection Agency procedures.

e) Unless otherwise approved by the Commission, no person shall inject into a well which does not have at a minimum, five hundred (500) feet for a Class II Disposal Well or seven hundred-fifty (750) feet for a Class II Commercial Disposal Well, of confining layers between the base of the lowermost USDWs and the top of the injection interval, with no individual confining layer being less than 50 feet in thickness. A lesser amount of confining layer(s) may be approved, provided the Applicant provides substantial information as to the integrity of the confining layers to inhibit the upward migration of the injection fluids so as not to endanger the lowermost USDW in the area of the well.

f) If the application does not contain all of the required information or documents, the Director shall notify the Applicant in writing. The notification shall specify the additional information or documents necessary for an evaluation of the application and shall advise the Applicant that the application will be deemed denied unless the information or documents are submitted within sixty (60) days following the date of notification.

g) Applications for a Class II Disposal Well shall contain the names of all permit holders who are to utilize the proposed disposal well.

h) Contents of Application

    1) A specification as to the type of Class II well being permitted as a Class II Disposal Well or a Class II Commercial Disposal Well.

    2) The Applicant shall provide the name, address, phone, fax and e-mail (if available) of the local or on-site supervisory or field personnel responsible for the disposal well.

3) If the well is not located within the boundaries of an operating oil and gas leasehold or drilling unit, the Applicant shall provide documentation, in the form of a surface use agreement or an affidavit of a surface use agreement, indicating the Applicant’s right to drill and to operate the proposed disposal well. If the well is located within the boundaries of an operating oil and gas leasehold or drilling unit, and the Applicant is someone other than the operator of the leasehold or drilling unit, the Applicant shall provide documentation, in the form of a surface use agreement, or an affidavit of a surface use agreement, indicating the Applicant's right to drill and to operate the proposed disposal well.

4) A survey plat of the location and ground elevation of the proposed disposal well or if the application is for an existing well, the well name and permit number of the existing well. A new survey is not required for a well to be converted or deepened well or a plugged well to be re-entered, if the original well location was surveyed, a copy of which shall be submitted with the application.

5) The name, geologic description and the approximate top and bottom elevation, from sub-sea, of the formation (indicating the perforated or open hole interval) into which fluid will be injected and the geologic description and top and bottom elevation, from sub-sea, of the above confining layers, in the proposed or existing disposal well. If an existing well is to be converted, a geophysical log of the well shall be submitted showing the above information. For a proposed well, an induction log from a well in the immediate vicinity of the proposed disposal well shall be submitted. If the geologic name of the interval is unclear include any additional geological evidence such as a cross section, structure or isopach map that may be necessary to adequately define the proposed injection interval.

6) A well bore diagram of the proposed or existing well showing casing for the injection well, indicating from the well head to total depth of the well, all casings and cementing of casings, any obstructions within well, all plugs set, tubing and packer setting depth, and all perforations and or open hole intervals. If application is for an existing well, a cement bond log (CBL) shall be submitted with the application, or if submitted after the application is filed, the CBL shall be submitted prior to commencement of operations as a condition of the permit.

7) The proposed daily amounts to be injected, the source and the type of fluid to be injected, and standard laboratory report from an accredited laboratory reporting the laboratory results of a representative sample of the proposed disposal fluids for the following parameters: chloride, pH, specific gravity, total dissolved solids (TDS) and total percent hydrocarbon (TPH). The sample shall be obtained and analyzed no earlier than one hundred-eighty (180) days prior to the date of filing of the application and analyzed in a timely fashion after collection.

8) The maximum injection pressure.

    A) The Director shall determine the maximum permitted injected pressure, measured at the wellhead, by multiplying the results of the formula below by ninety percent (90%):

        i) A maximum fracture gradient not to exceed 1.1 psi/ft (x) depth to injection formation (-)weight of fluid column (specific gravity of injection fluid) (+) injection tubing friction loss in Ashley, Bradley, Calhoun, Columbia, Hempstead, Lafayette Miller, Nevada, Ouachita, and Union counties for injection into formations below the Midway Shale Formation; or

ii) A maximum fracture gradient not to exceed 1.0 psi/ft**(**x**)** depth to injection formation (-)weight of fluid column (specific gravity of injection fluid) (+) injection tubing friction loss in all other counties for injection into formations below the Fayetteville Shale Formation in the areas covered by General Rule B-43 (c) and (d), General Rule B-44, and the portions of Franklin, Logan, Scott, Sebastian, and Yell Counties not covered by General Rule B-44; or

iii) A maximum fracture gradient not to exceed 0.73 psi/ft**(x)** depth to injection formation (-)weight of fluid column (specific gravity of injection fluid) (+) injection tubing friction loss for all other formations and/or counties.

The following calculation is included only as an example, and for informational and demonstrative purposes only. For purposes of this example, assume the well is in ColumbiaCounty, the total depth to the injection formation is 2,500 feet, the specific gravity is 1.085, and the injection tubing friction loss is 250 psi. Using the formula provided above, the maximum permitted injection pressure for the well would be 1,642 psig, calculated as follows:

Step 1: 0.9 x [(1.1 psi/ft x 2500 ft) – [0.433psi/ft x 2500 ft) x 1.085 (specific gravity)] + 250 tubing friction loss]

Step 2: 0.9 x [2750 psi – 1175 + 250 tubing friction loss]

Step 3: 0.9 x [1825]

Step 4: Result = 1642 psig

B) An Applicant may request an increase in the maximum injection pressure specified in subparagraph h) 8) A) above, or appeal a Director’s decision to issue a permit utilizing a fracture gradient less than the maximum fracture gradient specified in subparagraph h) 8) A) above, by filing an application in accordance with General A-2, A-3 and other applicable hearing procedures. Any increase in the maximum injection pressure may be granted if the Applicant presents sufficient evidence to justify the requested increased injection pressure will not initiate or propagate fractures in the overlying confining layer(s) that could enable the injection fluid or the fluid in the injection interval to leave the permitted injection intervals or cause movement of the injection fluid or formation fluids into USDWs.

9) A map showing:

A) The surveyed location of the well proposed to be drilled, deepened or converted, showing distances to the nearest property or lease lines; and

B) The location of all known plugged and unplugged wells, which penetrate the proposed injection interval, within the 1/2 mile radius from the proposed disposal well, and showing the status of each well as producing, shut-in, disposal, enhanced recovery, plugged and abandoned, or other status.

10) The Applicant shall submit evidence, where available, that all plugged and unplugged wells which penetrate the injection formation, within the ½ mile radius shown on the above plat in subparagraph h) 9) B), contain an adequate amount of cement and are constructed or plugged in a manner which will prevent the injection fluid and the fluid in the injection formation from entering USDWs. The types of evidence that will be considered acceptable include, but are not limited to: well completion reports, cementing records, well construction records, cement bond logs, tracer surveys, oxygen activation logs, and plugging records.

11) The Applicant shall submit evidence and/or information showing that the proposed injection interval or formation is not a USDW.

12) The Applicant shall submit information as to the depth (subsea) of the fresh water supply in the nearest known private water well and in the nearest known public water system water well.

13) If the application is for a Class II UIC Commercial Disposal Well, a listing of all previous and current violations of any statute, rule, regulation, permit condition, or order of the Commission, the Arkansas Department of Environmental Quality, the Arkansas Pollution Control and Ecology Commission, or any other state or federal environmental regulatory agency, including those of other states, regarding oil or gas related activities.

i) Notice of the application shall be given by the Applicant by one (1) publication in a legal newspaper having a general circulation in the county, or in each county, if there shall be more than one, in which the one-half mile radius from the proposed disposal well is situated, and by mailing via certified mail, FedEx,UPS,or other method that provides proof of mailing and delivery, a copy of the application to each permit holder of all permitted, drilling or producing wells within a one-half mile radius of the proposed disposal well. Such notice shall be published or mailed no more than thirty (30) days, prior to the date on which the application is filed with the Commission. The cost of such notice and mailing of the application shall be paid for by the Applicant. Attached to the application shall be evidence that the application was mailed or sent asrequired and a proof of publication of the application from the newspaper.

j) If notice is for a commercial disposal well, in addition to compliance with subparagraph i) above, the commercial disposal well application shall also be sent via certified mail, FedEx, or UPS to the County Judge of the county where the well is located and to the landowner (surface owner) where the well is located. In addition, the public notice should be large font and surrounded by a printed border to highlight the published notice.

k) Objections received by the Director, must be received by the Director within fifteen (15) days after the publication date of the notice and the date of mailing or sending to all parties specified in subparagraphs i) and j) above.

l) If an objection is received the application shall be deemed denied. If the application is denied under this section, the Applicant may request to have the application referred to the Commission for determination, in accordance with General Rules A-2 and A-3, and other applicable hearing procedures, except that no additional filing fee is required.

m) If an objection is not received by the Director and the application is deemed complete, the permit shall be issued following the required notice period specified in subparagraph i) above, unless the Director deems it necessary, for the purpose of protecting USDWs or oil and gas resources, that the application may be referred to the Commission for determination, and no additional filing fee is required from the applicant.

n) If the application does not satisfy the requirements of this Rule, the application shall be denied. If the application is denied under this section, the Applicant may request to have the application referred to the Commission for determination, in accordance with General Rules A-2 and A-3, and other applicable hearing procedures.

o) If the Applicant satisfies the requirements of all applicable statutes and this Rule, a permit shall be issued, unless:

  1) The Applicant has falsified or otherwise misstated any material information on or relative to the permit application; or

  2) For purposes of Class II Commercial Disposal Wells, the Applicant:

    A) Has an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest in the entity exceeding 5%;

      i) That has failed to abate an outstanding violation of the oil and gas statutes or rules, regulations, or comply with an orders of the Commission as specified in a final administrative decision of the Commission; or

      ii) For which funds have been obligated and remain outstanding from the Plugging and Restoration Fund to plug wells, under General Rule G-1 or G-2; or

      iii) Who is delinquent in payment of any annual well fees under General Rule B-2.

    B) Was an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest exceeding 5%;

      i) That has failed to abate an outstanding violation of the oil and gas statutes or rules, regulations, or comply with an orders of the Commission as specified in a final administrative decision of the Commission; or

      ii) For which funds have been obligated and remain outstanding from the Plugging and Restoration Fund to plug wells, under General Rule G-1 or G-2; or

      iii) Who is delinquent in payment of any annual well fees under General Rule B-2.

C) Is a Permit Holder or an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest exceeding 5%;

i) That has failed to abate an outstanding violation of the oil and gas statutes or rules, regulations, or comply with an orders of the Commission as specified in a final administrative decision of the Commission; or

ii) For which funds have been obligated and remain outstanding from the Plugging and Restoration Fund to plug wells, under General Rule G-1 or G-2; or

iii) Who is delinquent in payment of any annual well fees under General Rule B-2.

D) If the Director determines that the applicant, or an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest exceeding 5% in the applicant, has a history of violating an oil and gas statute, rule, regulation, permit condition or order of the Commission, the Arkansas Department of Environmental Quality, the Arkansas Pollution and Ecology Commission, or any other state or federal environmental regulatory agency, including those of other states, regarding oil or gas related activities, which pose a potential danger to the environment and public health and safety. In making the determination, the Director may consider:

i) The danger to the environment and public health and safety if the applicant's proposed activity is not conducted in a competent and responsible manner; and

ii) The degree to which past and present oil and gas related activities directly bear upon the reliability, competence, and responsibility of the applicant.

E) If a permit is not issued in accordance with subparagraph o) 2) above, the Applicant may request to have the permit application referred to the Commission for determination, in accordance with General Rules A-2 and A-3, and other applicable hearing procedures, except that no additional filing fee is required.

p) The Commission retains jurisdiction to determine zones suitable for disposal injection based on the porosity, permeability, fluid capacity, structure, geology and overall suitability of the zone as a disposal injection interval with respect to protection of USDWs and oil and gas resources.

q) Class II Disposal or Class II Commercial Disposal Well Drilling Permit or Transfer Revocation Procedures

1) The Director may revoke a Class II Disposal or Class II Commercial Disposal Well permit or transfer approval if the Permit Holder fails to meet permit conditions as specified in the Class II Disposal or Class II Commercial Disposal Well permit or transfer approval, the Class II Disposal or Class II Commercial Disposal Well permit or transfer

approval was issued in error, or the Permit Holder falsified or otherwise misstated any material information in the application form.

2) The Director shall notify the Permit Holder of the Class II Disposal or Class II Commercial Disposal Well permit or transfer revocation in writing. Following the revocation notice the Permit Holder is required to plug the Class II Disposal or Class II Commercial Disposal Well. The Permit holder shall have thirty (30) days from the date of the Class II Disposal or Class II Commercial Disposal Well permit or transfer revocation to appeal the Director's Decision to revoke the Class II Disposal or Class II Commercial Disposal Well permit or transfer approval in accordance with General Rule A-2, A-3 and other applicable hearing procedures. Operations may not commence or continue during the appeal process. A revocation of a Class II Disposal or Class II Commercial Disposal Well permit or transfer approval for which an appeal has not been filed, shall become a final administrative decision of the Commission thirty (30) days following the date of the revocation.

r) Class II Disposal or Class II Commercial Disposal Well Transfer Procedures

1) Definitions

A) "Current Permit Holder" means the individual or entity required to hold the permit or to whom the permit was issued and who is the owner of the right to operate said Class II Disposal or Class II Commercial Disposal Well(s), possesses the full rights and responsibilities for operating the Class II Disposal or Class II Commercial Disposal Well(s) in accordance with applicable Arkansas law and has the current obligation to plug said Class II Disposal or Class II Commercial Disposal Well(s), who is the assignor, transferor or seller (whether voluntary or involuntary) of the Class II Disposal or Class II Commercial Disposal Well(s).

B) "New Permit Holder" means the individual or entity acquiring the Class II Disposal or Class II Commercial Disposal Well(s) and the right to operate said Class II Disposal or Class II Commercial Disposal Well(s), who obtains the full rights and responsibilities for operating the Class II Disposal or Class II Commercial Disposal Well(s) in accordance with applicable Arkansas law and/or rule, regulation, or order of the Commission, who~~m~~ will obtain the obligation to plug said Class II Disposal or Class II Commercial Disposal Well(s), and who as owner or operator in accordance with applicable Arkansas law and/or rule, regulation, or order of the Commission is required to hold the permit.

C) "Transfer" means any assignment, devise, release, transfer, takeover, buyout, merger, sale, conveyance, or other transfer of any kind, whether voluntarily or involuntarily.

2) The provisions of this subparagraph apply to all transfers of the interest of the individual or entity required to hold and to whom the Class II Disposal or Class II Commercial Disposal Well transfer approval is issued (Permit Holder), including but not limited to:

A) a change of ownership of the right to drill and/or operate said Class II Disposal or Class II Commercial Disposal Well(s), along with the full rights and responsibilities for operating the Class II Disposal or Class II Commercial

Disposal Well(s) and the obligation to ultimately plug said Class II Disposal or Class II Commercial Disposal Well(s); or

B) a change in the designation of the owner or operator under an operating or other similar agreement; or

C) a change pursuant to the action of the owners of separate interests who designate an owner to be Permit Holder; or

D) a change required by the appointment, by a court of competent jurisdiction, of a trustee or a receiver to exercise custody and control over the Class II Disposal or Class II Commercial Disposal Well(s), including the right to drill and/or operate said well(s) along with the full right and responsibilities for operating the well(s).

3) The provisions of this subparagraph shall not apply to the transfer of working interests not affecting the rights or responsibilities of the Permit Holder.

4) The provisions of this subparagraph shall not apply to transfers of Class II Disposal or Class II Commercial Disposal Well(s) abandoned or orphaned in accordance General Rule G-1 or G-2. Transfers of Class II Disposal or Class II Commercial Disposal Wells deemed abandoned or orphaned are subject to the transfer provisions in General Rule G-3.

5) Notification of a transfer shall be given to the Director, or his designee, by the Current Permit Holder, on a form prescribed by the Director, of the transfer of any Class II Disposal or Class II Commercial Disposal Well or any Class II Disposal or Class II Commercial Disposal Well required to be permitted within thirty (30) days after the effective date of the transfer.

6) A separate form shall be completed for each lease, Class II Disposal or Class II Commercial Disposal Well, or other unit transferred.

7) The notification shall be signed by the Current Permit Holder and the New Permit Holder, or by authorized representatives specified on the Organizational Report filed in accordance with General Rule B-13, except as follows:

A) In lieu of the signature of the Current Permit Holder, the New Permit Holder may submit a court order or other legal document evidencing ownership of the lease or unit to be transferred in the event that the Current Permit Holder cannot be located or refuses to sign the notification of transfer form.

B) In lieu of the signature of the New Permit Holder, the Current Permit Holder may submit documentation evidencing transfer of the ownership of the Class II Disposal or Class II Commercial Disposal Well, lease, or unit in the event the New Permit Holder refuses to sign the notification of transfer form.

8) A New Permit Holder may operate Class II Disposal or Class II Commercial Disposal Wells covered by the Class II Disposal or Class II Commercial Disposal Well transfer request, until such time as the transfer request has been approved or denied by the Director or his designee, provided the request was submitted within thirty (30) days of the actual transfer of the Class II Disposal or Class II Commercial Disposal Well.

However, Class II Disposal or Class II Commercial Disposal Wells may not be operated by the New Permit Holder, until a Class II Disposal or Class II Commercial Disposal Well transfer request is approved, if the request was received by the Director, or his designee, more than thirty (30) days after the actual transfer of the Class II Disposal or Class II Commercial Disposal Well.

9) A New Permit Holder that acquires the right to operate a Class II Disposal or Class II Commercial Disposal Well(s) pursuant to a transfer shall apply for and must receive transfer approval from the Director, or his designee, prior to operating the Class II Disposal or Class II Commercial Disposal Well(s) beyond the timeframe specified in subparagraph (r)(8) above.

10) Prior to the Director, or his designee, approving the transfer request, the New Permit Holder shall provide the required financial assurance, if applicable, in accordance with General Rule B-2, and file the required organizational report, if applicable, in accordance with General Rule B-13.

11) A transfer to a New Permit Holder may be denied by the Director, or his designee, if the New Permit Holder meets any of the conditions specified in subparagraph o) above.

12) The New Permit Holder shall be responsible for all regulatory requirements relative to all Class II Disposal or Class II Commercial Disposal Wells and all other surface production facilities in existence at the time of the transfer related to the Class II Disposal or Class II Commercial Disposal Wells. The New Permit Holder shall not be responsible for regulatory requirements relative to spills of crude oil or other production fluids which occurred prior to the date of the transfer, unless the New Permit Holder has otherwise agreed with the Current Permit Holder.

13) If any Class II Disposal or Class II Commercial Disposal Well, or any lease or other unit associated with the Class II Disposal or Class II Commercial Disposal Well, is in violation at the time of the transfer request to the New Permit Holder, the transfer request shall be denied pending abatement of all violations by the Current Permit Holder. However, if the New Permit Holder, after being notified of the violation(s), agrees in writing to the transfer approval including conditions to abate all violations, the transfer may be approved by the Director, or his designee. Failure to abate the violations within the time period specified by the Director or his designee may result in revocation of the transfer approval in accordance with subparagraph q) above, and/or other applicable enforcement actions in accordance with General Rule A-5.

14) The Current Permit Holder is not responsible for any regulatory violation caused by the actions of the New Permit Holder during the permit transfer process, after notice is given to the Director, or his designee, by the Current Permit Holder of the pending transfer if the transfer is approved. However, if the transfer is denied by the Director or his designee, the Current Permit Holder assumes all responsibility for the violations caused by the New Permit Holder. Nothing in this subsection shall affect the contractual rights and obligations between the person or entity transferring the Class II Disposal or Class II Commercial Disposal Well(s) and the person or entity acquiring the Class II Disposal or Class II Commercial Disposal Well(s).

15) The transfer approval pursuant to this subparagraph shall not affect the rights of the Commission, or any obligation or duty of the Current Permit Holder arising under any

applicable Arkansas laws, or rules, regulations, or orders of the Commission. Any cause of action accruing or any action or proceeding which has commenced, whether administrative, civil or criminal, may be instituted or continued without regard to the transfer approval.

16) The Director shall notify the Current and New Permit Holder of the transfer approval or denial in writing. Following the approval or denial of the transfer approval request, the Current or New Permit holder shall have thirty (30) days from the date of the approval or denial to appeal the Director's Decision in accordance with General Rule A-2, A-3 and other applicable hearing procedures. A transfer request approval or denial, for which an appeal has not been filed, shall become a final administrative decision of the Commission thirty (30) days following the date of the approval or denial.

s) Miscellaneous Provisions and Requirements for Class II Disposal or Class II Commercial Disposal Wells Within General Rule B-43 Section c) lands.

1) Definitions:

a. "Regional Fault" means the identified fault zones named by the Arkansas Geological Survey as the Clinton, Center Ridge, Heber Springs, Enders and Morrilton Fault zones; and which are part of a general east-west turning north-east (approximately N55ºE to N75ºE) trending, down thrown to the south, fault system generally occurring below the Fayetteville Shale Formation displacing the Lower Mississippian through Precambrian strata and truncating upward at the unconformity between the Mississippian and Pennsylvanian age strata; and which are identified on the Arkansas Geological Survey map attached hereto as Exhibit 1 to this Rule; and as updated for purposes of this Rule following notice and a hearing in accordance with General Rule A-2.

b. "Moratorium Zone Deep Faults" means deeper faults associated with the Guy-Greenbrier Earthquake Swarm; and which are part of a general northeast-southwest (approximately N30ºE) trending deeper fault system displacing the Lower Ordovician through Precambrian strata occurring in the general B-43 Section c) lands area.

2) Unless otherwise approved by the Commission after notice and a hearing, no permit to drill, deepen, re-enter, recomplete or operate a Class II Disposal or Class II Commercial Disposal Well may be granted for any Class II or Class II Commercial Disposal wells in any formation within the following area ("Moratorium Zone")located in Cleburne, Conway, Faulkner, Van Buren, and White Counties:

Sections	**Township**	**Range**
ALL	4N	13W
ALL	5N	12W
ALL	5N	13W
ALL	5N	14W
ALL	6N	12W
ALL	6N	13W
ALL	7N	11W
ALL	7N	12W
ALL	7N	13W
ALL	8N	11W
ALL	8N	12W
ALL	8N	13W
ALL	9N	10W
ALL	9N	11W
ALL	9N	12W
ALL	10N	10W
ALL	10N	11W
ALL	11N	10W
ALL	11N	11W
1-12, 14-23, 27-33	4N	12W
1-30, 35-36	4N	14W
1-2, 10-15, 23-25	4N	15W
4-9, 17-20, 30-31	5N	11W
25, 35-36	5N	15W
6	6N	10W
1-23, 26-34	6N	11W
1-4, 9-36	6N	14W
24-25, 36	6N	15W
3-9, 16-20, 29-31	7N	10W
1, 11-14, 22-27, 34-36	7N	14W
6-7	8N	9W
1-24, 26-35	8N	10W
25, 36	8N	14W
3-10, 15-21, 29-32	9N	9W
1-5, 7-36	9N	13W
1-23, 27-34	10N	9W
1-3, 9-17, 19-36	10N	12W
25, 33, 34, 36	10N	13W
17-22, 27-35	11N	9W
13, 23-27, 34-36	11N	12W

3) Unless otherwise approved by the Commission after notice and a hearing, no permit to drill or re-enter, a new Class II Disposal or Class II Commercial Disposal Well may be granted within one (1) mile of a Regional Fault or within five (5) miles of a known or identified Moratorium Zone Deep Fault within any remaining B-43 Section c) lands.

4) Unless otherwise approved by the Commission after notice and a hearing, no permit to deepen or re-complete any existing Class II Disposal or Class II Commercial Disposal Well in a zone stratigraphically below the Fayetteville Shale formation, may be granted within one (1) mile of a Regional Fault or within five (5) miles of a known or identified Moratorium Zone Deep Fault within any remaining B-43 Section c) lands.

5) Unless otherwise approved by the Commission after notice and a hearing, the following provisions shall apply to any permit to drill, deepen, or operate a new Class II Disposal or Class II Commercial Disposal Well proposed to be located within in any remaining B-43 Section c) lands:

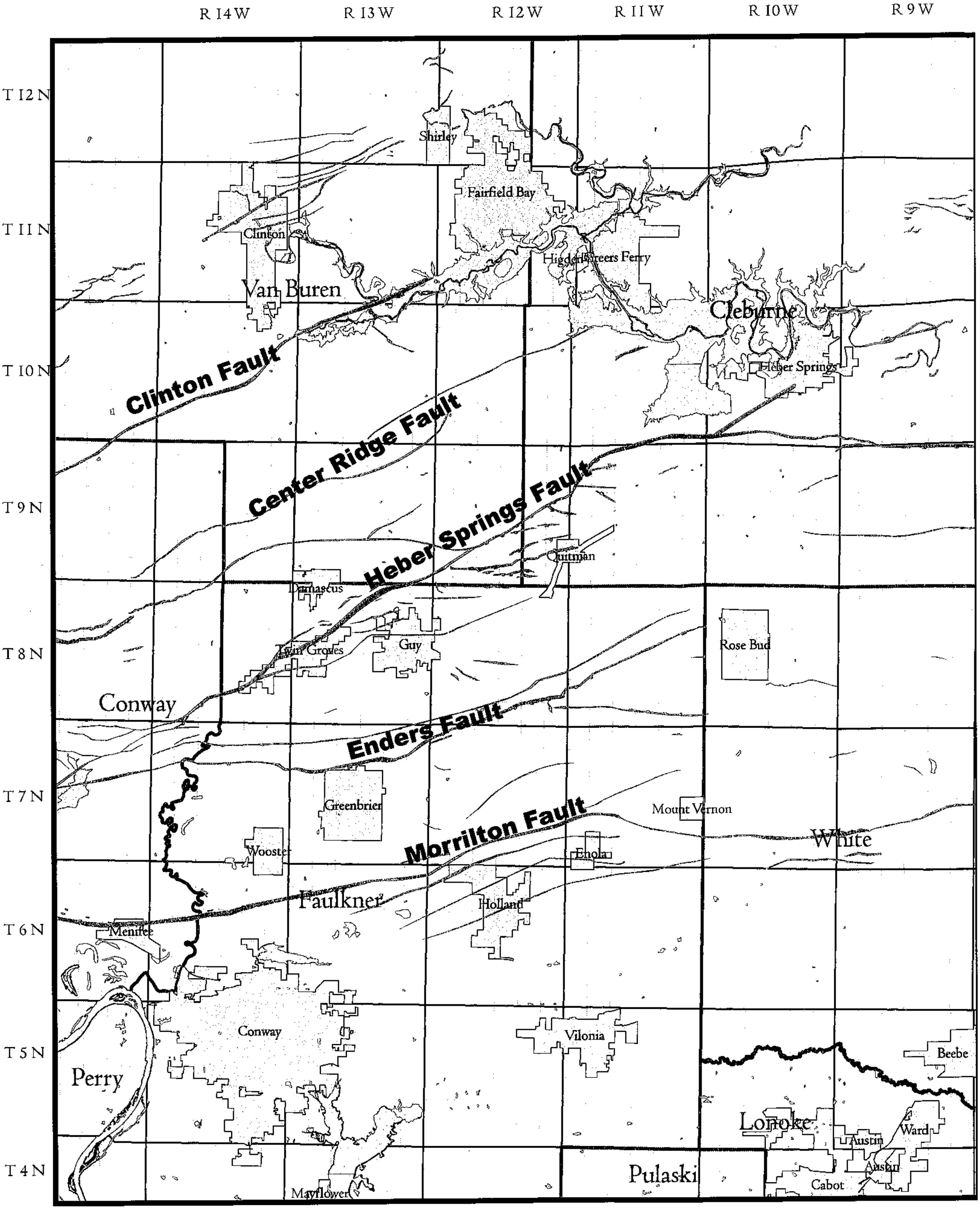
    a) No Class II Disposal or Class II Commercial Disposal Well disposing in a zone occurring stratigraphically below the Fayetteville Shale formation shall be located within five (5) miles of another Class II Disposal or Class II Commercial Disposal Well disposing in a zone occurring stratigraphically below the Fayetteville Shale formation.

    b) No Class II Disposal or Class II Commercial Disposal well disposing in a zone occurring stratigraphically above the Fayetteville Shale formation shall be located within one-half (1/2) mile of another Class II Disposal or Class II Commercial Disposal Well disposing in a zone occurring stratigraphically above the Fayetteville Shale formation.

6) The Applicant shall provide technical information to the Director in support of the application. The technical justification shall include information related to the location of any Moratorium Zone Deep Fault within five (5) miles or Regional Fault within two miles (2) of the proposed location of the Class II Disposal or Class II Commercial Disposal Well, with special emphasis on identifying any deep faults occurring below the Fayetteville Shale formation which extend to the basement rock.

7) Flow meters, or other measuring devices approved by the Director, shall be installed on all Class II Disposal and Class II Commercial Disposal Wells and Permit Holders shall submit accurate injection volume and pressure information, on no less than a daily basis, on a form prescribed by the Director.

Named Regional Faults



SSA 2012

Session: The M5.8 Central Virginia and the M5.6 Oklahoma Earthquakes of 2011

ARE SEISMICITY RATE CHANGES IN THE MIDCONTINENT NATURAL OR MANMADE?

ELLSWORTH, W. L., US Geological Survey, Menlo Park, CA; HICKMAN, S. H., US Geological Survey, Menlo Park, CA; LLEONS, A. L., US Geological Survey, Menlo Park, CA; MCGARR, A., US Geological Survey, Menlo Park, CA; MICHAEL, A. J., US Geological Survey, Menlo Park, CA; RUBINSTEIN, J. L., US Geological Survey, Menlo Park, CA

A remarkable increase in the rate of M 3 and greater earthquakes is currently in progress in the US midcontinent. The average number of M >= 3 earthquakes/year increased starting in 2001, culminating in a six-fold increase over 20th century levels in 2011. Is this increase natural or manmade? To address this question, we take a regional approach to explore changes in the rate of earthquake occurrence in the midcontinent (defined here as 85° to 108° West, 25° to 50° North) using the USGS Preliminary Determination of Epicenters and National Seismic Hazard Map catalogs. These catalogs appear to be complete for M >= 3 since 1970. From 1970 through 2000, the rate of M >= 3 events averaged 21 +- 7.6/year in the entire region. This rate increased to 29 +- 3.5 from 2001 through 2008. In 2009, 2010 and 2011, 50, 87 and 134 events occurred, respectively. The modest increase that began in 2001 is due to increased seismicity in the coal bed methane field of the Raton Basin along the Colorado-New Mexico border west of Trinidad, CO. The acceleration in activity that began in 2009 appears to involve a combination of source regions of oil and gas production, including the Guy, Arkansas region, and in central and southern Oklahoma. Horton, et al. (2012) provided strong evidence linking the Guy, AR activity to deep waste water injection wells. In Oklahoma, the rate of M >= 3 events abruptly increased in 2009 from 1.2/year in the previous half-century to over 25/year. This rate increase is exclusive of the November 2011 M 5.6 earthquake and its aftershocks. A naturally-occurring rate change of this magnitude is unprecedented outside of volcanic settings or in the absence of a main shock, of which there were neither in this region. While the seismicity rate changes described here are almost certainly manmade, it remains to be determined how they are related to either changes in extraction methodologies or the rate of oil and gas production.

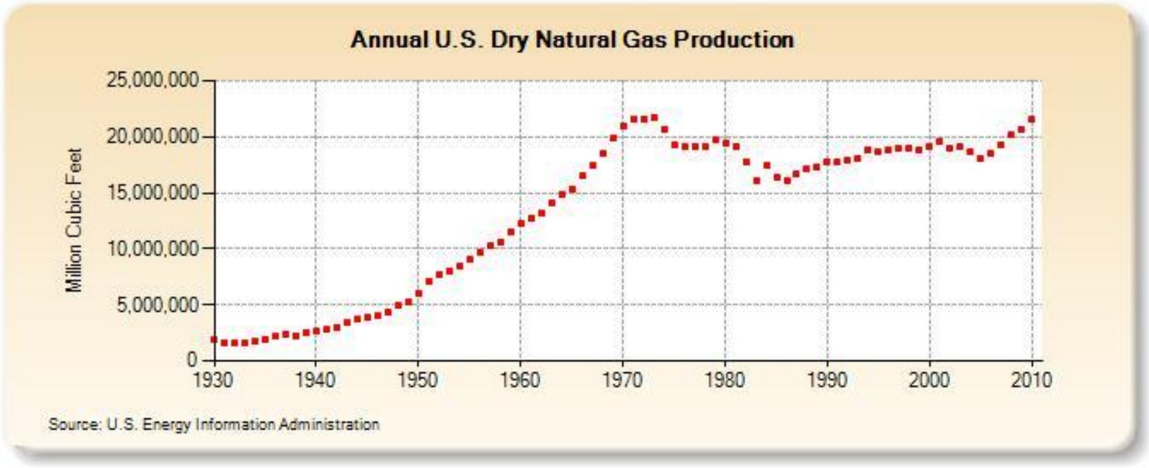
Wednesday, April 18th / 3:45 PM Oral / Pacific Salon 4 & 5

Using GPCM® to Model LNG Exports from the US Gulf Coast

Robert Brooks, Ph.D., President, RBAC, Inc.

March 2, 2012

As the gas industry rolled into the 21st century, natural gas production was beginning to decline and the outlook for production looked rather bleak. A small upsurge due to the advent of coal-bed methane development had begun to play out and it looked like the future lay in LNG imports. Billions of dollars were spent in designing and getting permitted dozens of new LNG import terminals. Ten new terminals and two offshore receiving stations were actually built. As it turned out, the companies that lagged behind and didn't actually build these expensive terminals were the winners, because the industry as a whole did not predict an upstream revolution which was quietly occurring at the same time. A breakthrough in horizontal drilling combined with hydro-fracturing and advanced 3D imaging finally made it possible to economically develop the enormous gas and oil resources long known to exist in vast shale formations throughout much of North America.



Source: U.S. Energy Information Administration

Figure 1: US Dry Natural Gas Production 1930-2010

A drilling boom began which completely turned the US production graph around. (See Figure 1.) All of a sudden there was more gas than could be easily absorbed in a recession-bound market. Natural gas prices began to erode, moving from the $6/mmbtu range to under $4/mmbtu (Figure 2), and the new challenge became "what are we going to do with all this gas?"

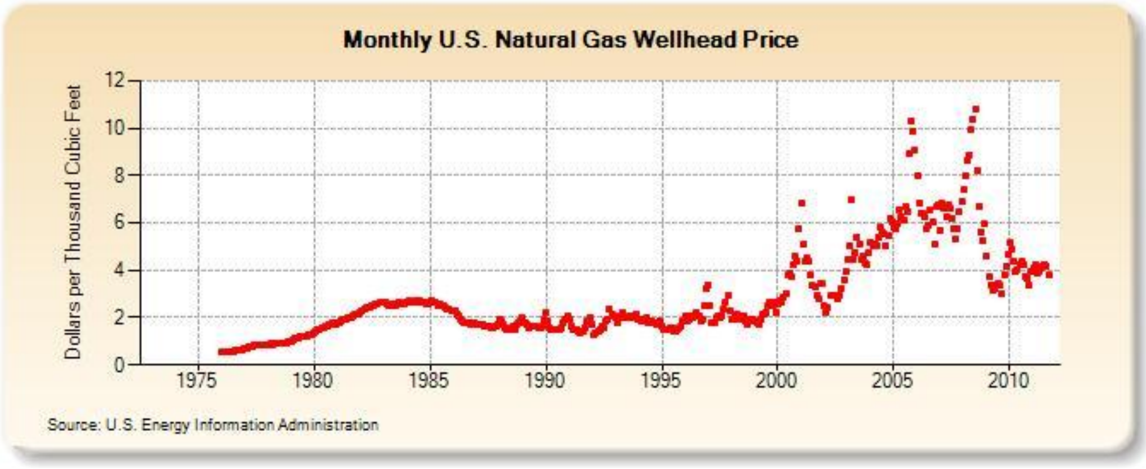


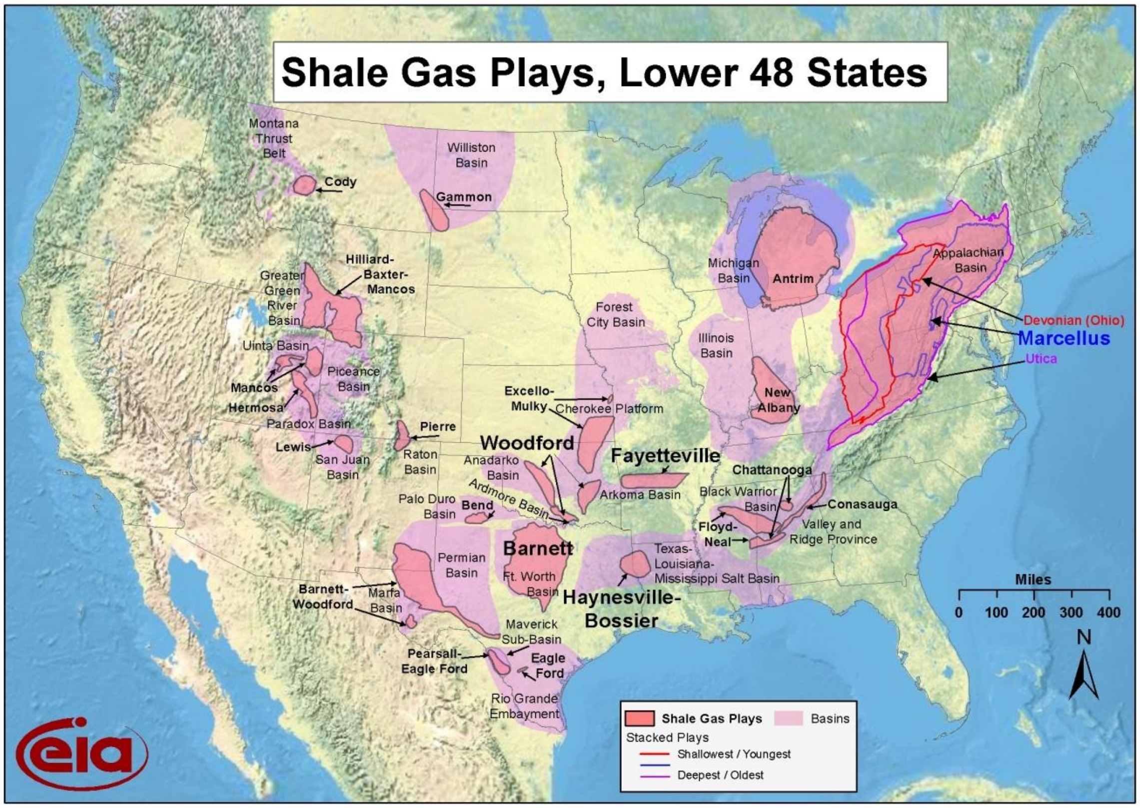
Figure 2: Monthly Natural Gas Wellhead Prices 1975-2010

Five answers have been put forward: redirect drilling from dry gas plays to plays having higher concentrations of more profitable natural gas liquids, replace coal with natural gas in electricity generation; build new fleets of natural gas powered trucks, buses, and cars; convert the gas into liquids for use in transportation; and, most recently, liquefy the gas and export it to other countries willing to pay much higher prices, notably Japan, China, Korea, and India.

As of year-end 2011 redirection to wetter gas plays has not solved the problem because the wetter gas plays have proven to be even more prolific gas producers than the dry gas plays drilled earlier. Replacing coal with gas in electricity production has been occurring but is a slow process which will take decades to unfold. Similarly, the natural gas vehicle market is growing, but from such a small base that it will take a very long time to have an impact on gas price, if ever. Gas-to-liquids is a mature technology, but is expensive, and its future in North America is still quite uncertain.

Up until very recently, the idea of liquefying excess North American natural gas and exporting it to overseas markets did not appear to be likely of success. That was before late 2011 when Cheniere Energy, owner of the Sabine Pass LNG terminal in Louisiana, announced the completion of agreements with UK-based BG Group and Spain's Gas Natural Fenosa to export LNG to Europe and Latin America and with GAIL (India) Limited for similar exports to India. Each of these agreements is for 3.5 million tons of LNG per year. In January 2012, Cheniere and Korea Gas Corporation (KOGAS) announced a similar agreement for another 3.5 million tons per year. 14 million tons per year of LNG would require almost 2 billion cubic feet per day (bcf/day) of production.

Much or most of the gas to be liquefied into LNG would be produced out of the nearby Haynesville-Bossier Shale play of northern Louisiana and east Texas. Following upon these deals, Cheniere announced plans to convert its planned Corpus Christi LNG import terminal into a second liquefaction and export terminal, this one located near the prolific Eagle Ford Shale wet gas play in South Texas.



Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010

Figure 3: Shale Gas Plays in the United States

Some concern has been expressed by end-users of natural gas that these export projects would increase natural gas prices in the United States. Cheniere estimated that exports of 2 bcf/day could raise gas prices by as much as 10%. DOE's Energy Information Administration was requested by Congress to make its own projection. DOE assumed a much more extreme range of exports between 6 and 12 bcf/day with two different ramp-up rates (1 bcf/day per year and 3 bcf/day per year). In their 6 bcf/day scenario with 2 year ramp-up, the so-called "low, rapid" scenario, EIA projected an average price increase at the Henry Hub in Southern Louisiana of $0.60 per million btu (mmbtu) over the period 2016-2035.

Using its WGM model with the assumption of a 6 bcf/day export volume, consultant Deloitte MarketPoint LLC projected an average increase of only $0.22 mmbtu at the Henry Hub in Southern Louisiana over the same time period as EIA. Deloitte attributed the tiny magnitude of this price impact to the ability of the North American gas market to quickly and efficiently adjust to the prospect of an export market.

Using the GPCM model RBAC has produced its own analysis to address this question. Starting with RBAC's GPCM 11Q3 Base Case released in October 2011, which assumed Gulf LNG exports of 0.7 bcf/day, we have created five new scenarios: 1) no LNG exports from the US lower-48 states, 2) 1 bcf/day, 3) 2 bcf/day, 4) 4 bcf/day, and 5) 6 bcf per day. Each of the

LNG scenarios took 3 years to ramp up to maximum by 2018 and continued at that level through 2035.

The following figures show the results from these scenarios and the impact of various volumes of LNG exports on prices at Henry Hub.

Figure 4 shows Henry Hub price forecasts for the five scenarios. Prices are expected to be in the sub-$4 range from 2012-2015 for all scenarios, varying from that point depending on the volume of LNG exports in each.

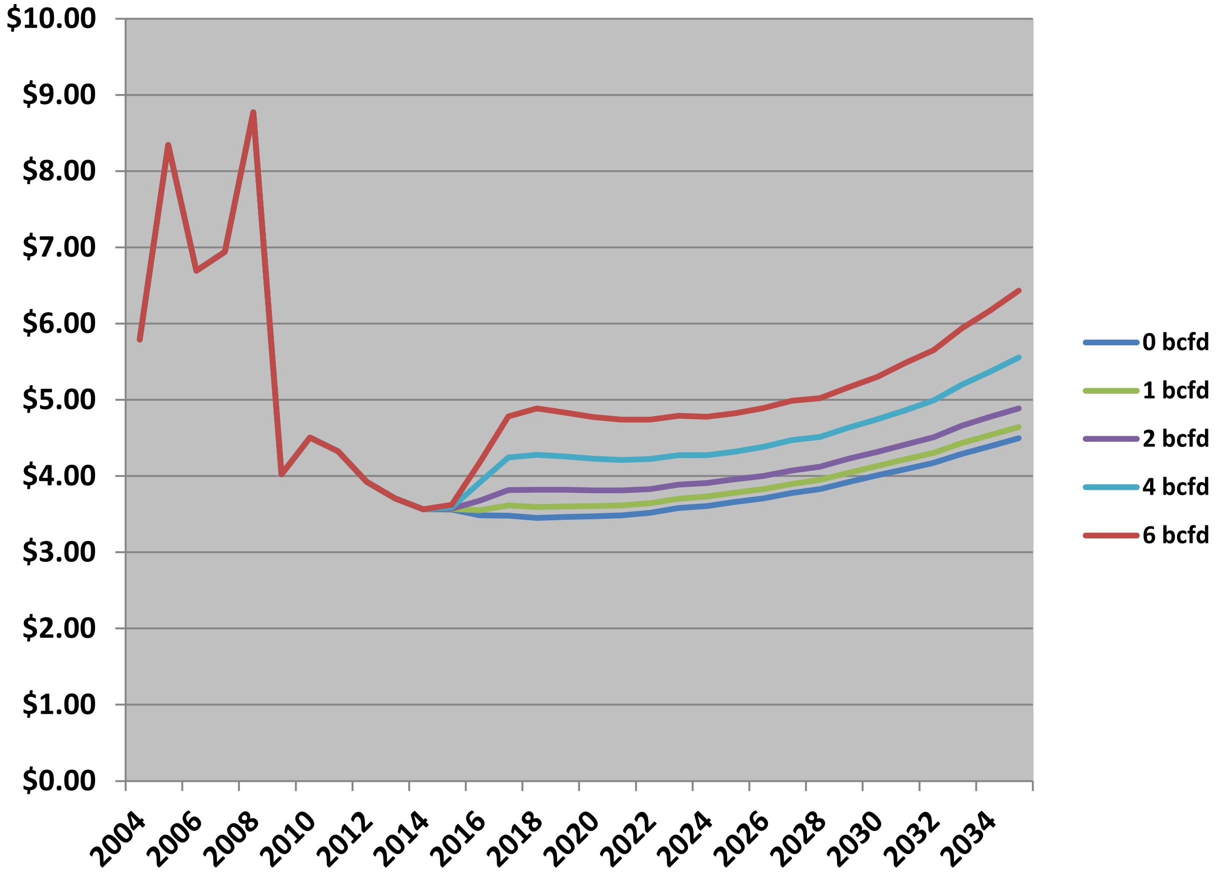


Figure 4: Annual Average Henry Hub Gas Price Forecast: 0, 1, 2, 4, and 6 bcf/day exports

Figure 5 shows the price difference between the no-LNG and the 1, 2, 4, and 6 bcf/day scenarios.

Figure 6 shows the average price impact over the 20 year 2016-2035 time period of each of the LNG export scenarios versus a zero-LNG export scenario.

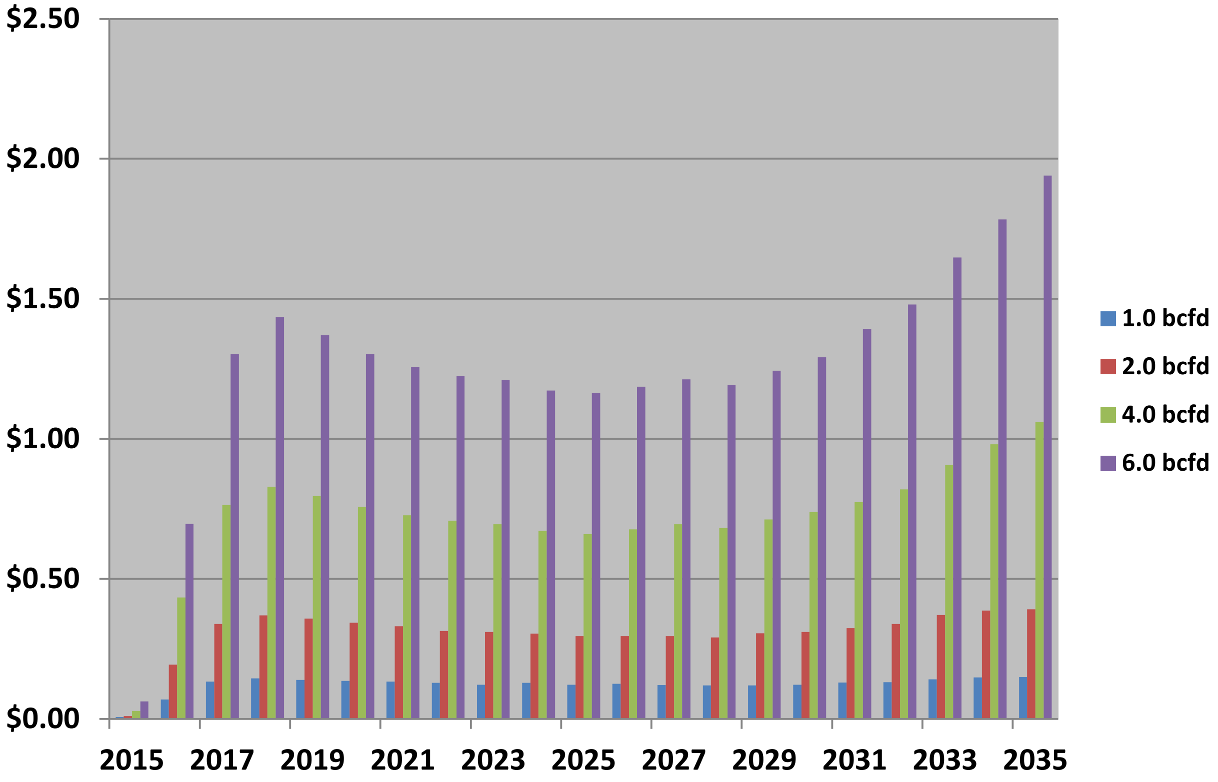


Figure 5: Price Impact at Henry Hub Due to Various Levels of Gulf Coast LNG Exports

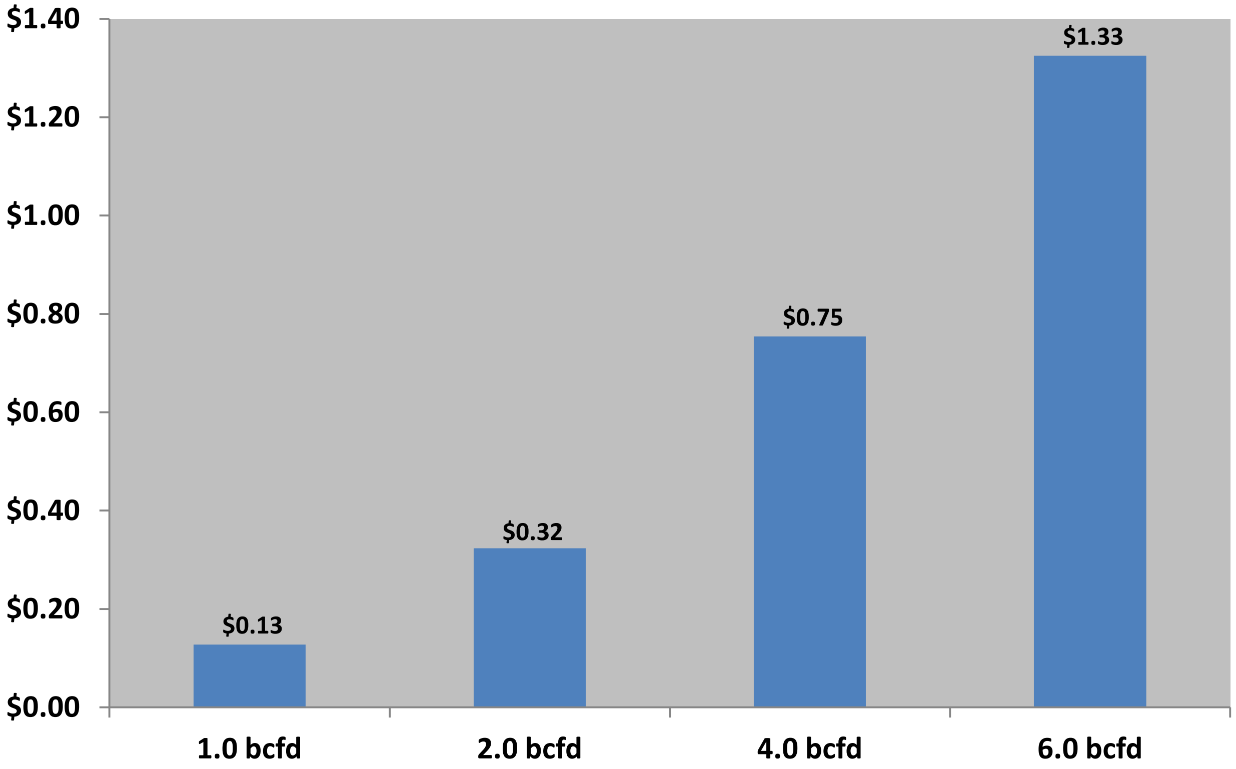


Figure 6: Average Price Impact at Henry Hub 2016-2035 of Different Gulf LNG Export Levels

The price impact of this level of LNG exports predicted using RBAC's GPCM model is about the same as Cheniere for the 2 bcf/day scenario ($0.32), but much greater for the more extreme 6 bcf/day scenario than that estimated by EIA ($0.60) or Deloitte ($0.22). It averages about $1.33 per mmbtu over the forecast horizon, a 30% increase at Henry Hub. RBAC's 6 bcf/day scenario does not forecast that the industry will respond with speed and efficiency with an insignificant gas-price increase as does the Deloitte model. The flexibility of the industry to respond to this large and sudden increase in demand comes at a price.

The following figure shows the effect of this extreme level of LNG exports and resulting higher prices on domestic gas deliveries.

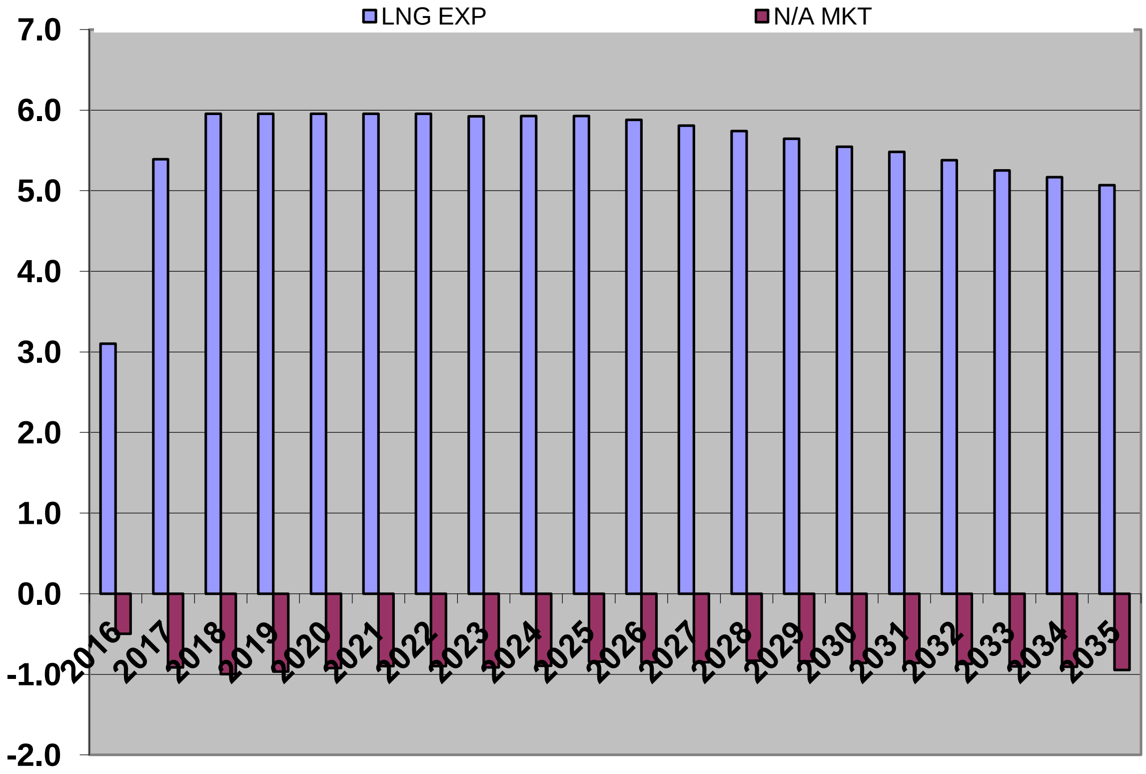


Figure 7: Impact of LNG Exports on Deliveries to the North American Market

First note that the scenario as designed ran into difficulty exporting 6 BCF/day after 2025. The amount available for export slowly fell to about 5 BCF/day by 2035. The 6 bcf/day scenario assumes 3 bcf/day from Louisiana and 3 bcf/day from Texas. In the longer run, it is more difficult to supply 3 bcf/day for LNG exports from Texas due to competition with Mexico. On average the LNG exports were about 5.5 BCF/day in this scenario.

The addition of 5.5 BCF/day LNG export demand raises prices enough to reduce deliveries to the domestic North American market by almost 0.8 BCF/day. Most of this reduction is felt by the industrial market, the most price sensitive sector in the US. Thus the net additional production required by the new LNG export market is about 4.7 BCF/day.

Perhaps one reason why EIA's price response is less than RBAC's is that EIA assumes an increase in production of only 3.8 bcf/day will be required to supply 6 bcf/day in exports. This surprising result comes about because EIA's result shows a 2.1 bcf/day decrease in gas available to consumers in the US. Their demand model is much more price-sensitive than RBAC's.

Figure 8 shows where the additional supply will originate in the 6 bcf/day RBAC scenario. About 10% of the required new supply comes from coal-bed methane and a small uptick in LNG imports. The latter is due to the fact that the Mexican market is dependent on imports from the US as well as LNG. With less pipeline gas available to Mexico from South Texas, more local gas must be produced and more LNG imported.

One surprise is that conventional sources will initially provide about 50% of the incremental supply needed for the net increase in demand with shale providing about 40%. However, as shale becomes the predominant source of production, it also takes over as the primary source of incremental supply for exports, reaching more than 60% by year 2035. This may be more a result of the fact that GPCM models physical gas flows. How gas is contracted could be quite different.

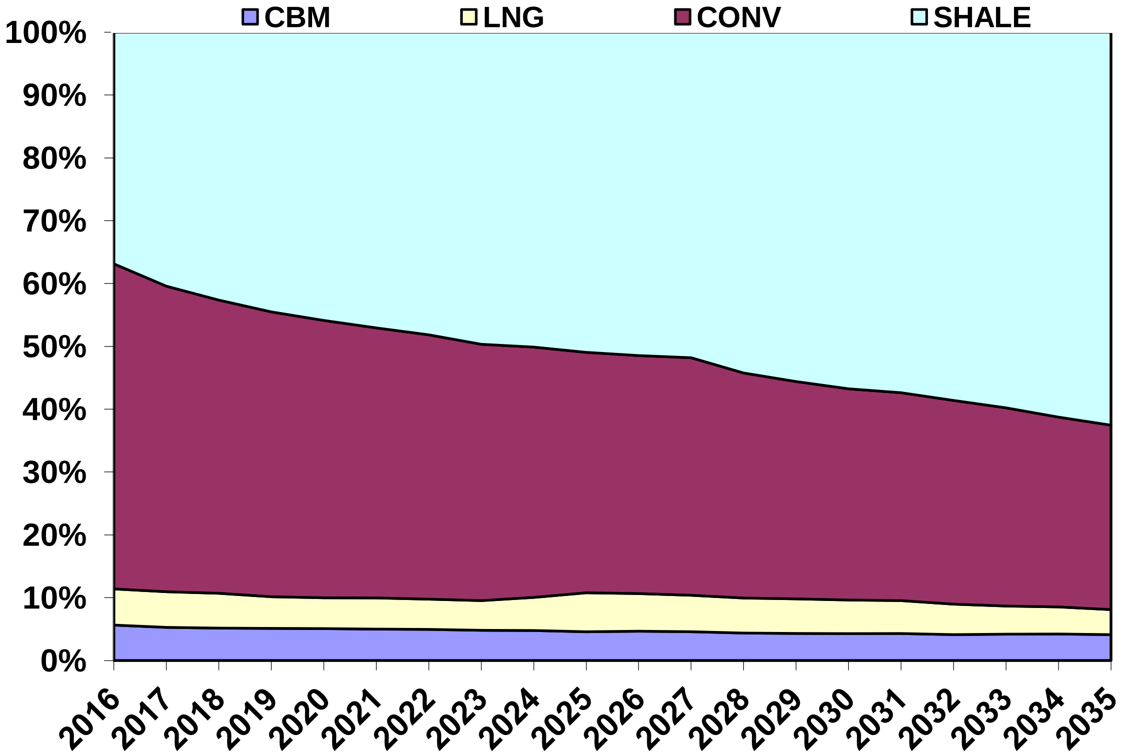


Figure 8: Share of New Supply Required in 6 bcf/day LNG Exports Scenario

Sensitivity of Results to Supply Assumptions

A sixth scenario was run to test the sensitivity of these results to the base case assumption of supply responsiveness to changes in demand. By raising price sensitivity of supply for prices higher than about $4/mmbtu, production capacity grows faster than in the original 6 bcf/day LNG exports scenario. By 2035 capacity is about 4 BCF/day (3%) higher for the same price.

Figure 9 shows the effect of this higher production sensitivity case on Henry Hub price.

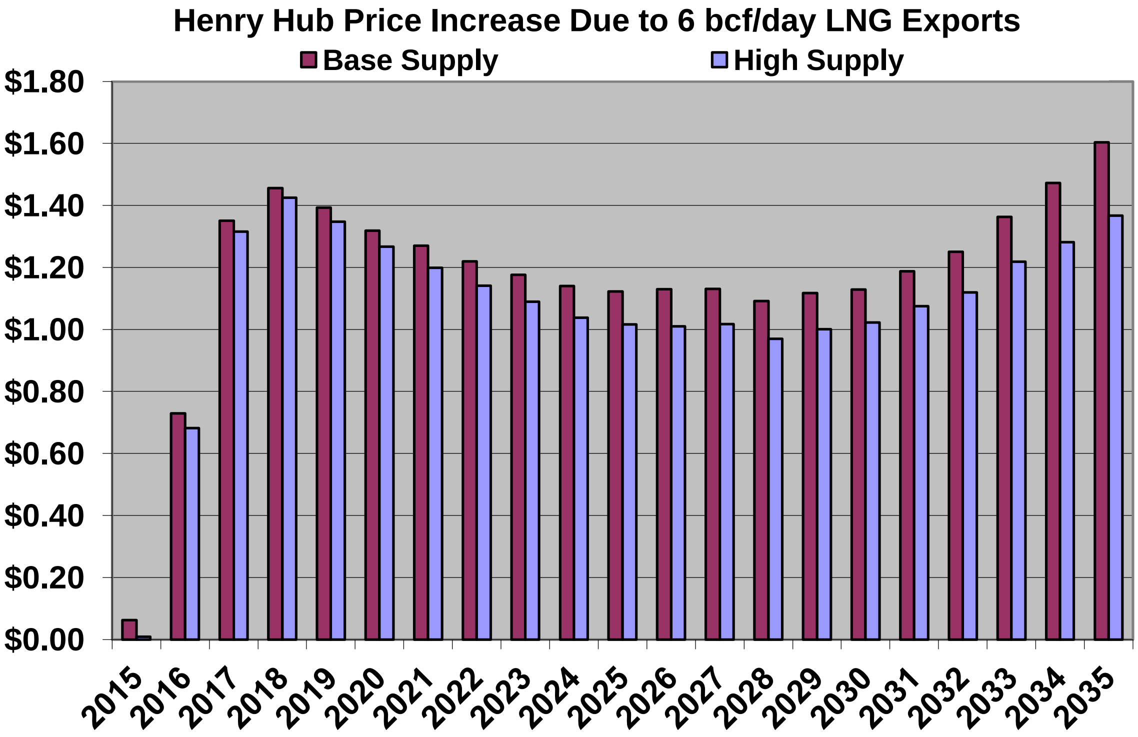


Figure 9: Sensitivity of Henry Hub Price Effect to Supply Capacity Growth

The price effect of LNG exports is reduced by about $0.05 in 2016 growing to almost $0.25 by 2035. The average price effect in the sensitivity case is $1.13, about $0.10 less than the original 6 bcf/day exports case. These results suggest that both EIA and Deloitte models may substantially underestimate the price effect of 6 bcf/day LNG exports of the magnitude reported in their studies. The adjustments which the industry makes to meet the challenge of this large new demand are not likely to be made so quickly and with so little impact on price.

Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of January 11, 2013)

All Changes Since January 4, 2013 Update Are In Red

Company	Quantity (a)	FTA Applications (b) (Docket Number)	Non-FTA Applications (c) (Docket Number)
Sabine Pass Liquefaction, LLC	2.2 billion cubic feet per day (Bcf/d) (d)	Approved (10-85-LNG)	Approved (10-111-LNG)
Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC	1.4 Bcf/d (d)	Approved (10-160-LNG)	Under DOE Review (10-161-LNG)
Lake Charles Exports, LLC	2.0 Bcf/d (e)	Approved (11-59-LNG)	Under DOE Review (11-59-LNG)
Carib Energy (USA) LLC	0.03 Bcf/d: FTA 0.01 Bcf/d: non-FTA (f)	Approved (11-71-LNG)	Under DOE Review (11-141-LNG)
Dominion Cove Point LNG, LP	1.0 Bcf/d (d)	Approved (11-115-LNG)	Under DOE Review (11-128-LNG)
Jordan Cove Energy Project, L.P.	1.2 Bcf/d: FTA 0.8 Bcf/d: non-FTA (g)	Approved (11-127-LNG)	Under DOE Review (12-32-LNG)
Cameron LNG, LLC	1.7 Bcf/d (d)	Approved (11-145-LNG)	Under DOE Review (11-162-LNG)
Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC (h)	1.4 Bcf/d (d)	Approved (12-06-LNG)	Under DOE Review (11-161-LNG)
Gulf Coast LNG Export, LLC (i)	2.8 Bcf/d(d)	Approved (12-05-LNG)	Under DOE Review (12-05-LNG)
Gulf LNG Liquefaction Company, LLC	1.5 Bcf/d(d)	Approved (12-47-LNG)	Under DOE Review (12-101-LNG)
LNG Development Company, LLC (d/b/a Oregon LNG)	1.25 Bcf/d(d)	Approved (12-48-LNG)	Under DOE Review (12-77-LNG)
SB Power Solutions Inc.	0.07 Bcf/d	Approved (12-50-LNG)	n/a
Southern LNG Company, L.L.C.	0.5 Bcf/d(d)	Approved (12-54-LNG)	Under DOE Review (12-100-LNG)
Excelerate Liquefaction Solutions I, LLC	1.38 Bcf/d(d)	Approved (12-61-LNG)	Under DOE Review (12-146-LNG)
Golden Pass Products LLC	2.6 Bcf/d(d)	Approved (12-88 -LNG)	Under DOE Review (12-156-LNG)
Cheniere Marketing, LLC	2.1 Bcf/d(d)	Approved (12-99-LNG)	Under DOE Review (12-97-LNG)
Main Pass Energy Hub, LLC	3.22 Bcf/d	Approved (12-114-LNG)	n/a
CE FLNG, LLC	1.07 Bcf/d(d)	Approved (12-123-LNG)	Under DOE Review (12-123-LNG)
Waller LNG Services, LLC	0.16 Bcf/d	Approved (12-152-LNG)	n/a
Pangea LNG (North America) Holdings, LLC	1.09 Bcf/d[d]	Pending Approval (12-174-LNG)	Under DOE Review (12-184-LNG)
Magnolia LNG, LLC	0.54 Bcf/d	Pending Approval (12-183-LNG)	n/a

Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of January 11, 2013)

All Changes Since January 4, 2013 Update Are In Red

Company	Quantity [a]	FTA Applications [b] (Docket Number)	Non-FTA Applications [c] (Docket Number)
Trunkline LNG Export, LLC	2.0 Bcf/d	Pending Approval (13-04-LNG)	n/a
Gasfin Development USA, LLC	0.2 Bcf/d	Pending Approval (13-06-LNG)	n/a
Total of all Applications Received		**31.41 Bcf/d**	**24.80 Bcf/d**

(a) Actual applications were in the equivalent annual quantities.

(b) FTA – Applications to export to free trade agreement (FTA) countries. The Natural Gas Act, as amended, has deemed FTA exports to be in the public interest and applications shall be authorized without modification or delay.

(c) Non-FTA applications require DOE to post a notice of application in the Federal Register for comments, protests and motions to intervene, and to evaluate the application to make a public interest consistency determination.

(d) Requested approval of this quantity in both the FTA and non-FTA export applications. Total facility is limited to this quantity (i.e., FTA and non-FTA volumes are not additive at a facility).

(e) Lake Charles Exports, LLC submitted one application seeking separate authorizations to export LNG to FTA countries and another authorization to export to Non-FTA countries. The proposed facility has a capacity of 2.0 Bcf/d, which is the volume requested in both the FTA and Non-FTA authorizations.

(f) Carib Energy (USA) LLC requested authority to export the equivalent of 11.53 Bcf per year of natural gas to FTA countries and 3.44 Bcf per year to non-FTA countries.

(g) Jordan Cove Energy Project, L.P. requested authority to export the equivalent of 1.2 Bcf/d of natural gas to FTA countries and 0.8 Bcf/d to non-FTA countries.

(h) DOE/FE received a new application (11-161-LNG) by FLEX to export an additional 1.4 Bcf/d of LNG from new trains to be located at the Freeport LNG Terminal, to non-FTA countries, and a separate application (12-06-LNG) to export this same 1.4 Bcf/d of LNG to FTA countries (received January 12, 2012). This 1.4 Bcf/d is in addition to the 1.4 Bcf/d FLEX requested in dockets (10-160-LNG and 10-161-LNG).

(i) An application was submitted by Gulf Coast on January 10, 2012, seeking one authorization to export LNG to any country not prohibited by U.S. law or policy. On September 11, 2012, Gulf Coast revised their application by seeking separate authorizations for LNG exports to FTA countries and Non-FTA countries.

U.S. Energy Information Administration

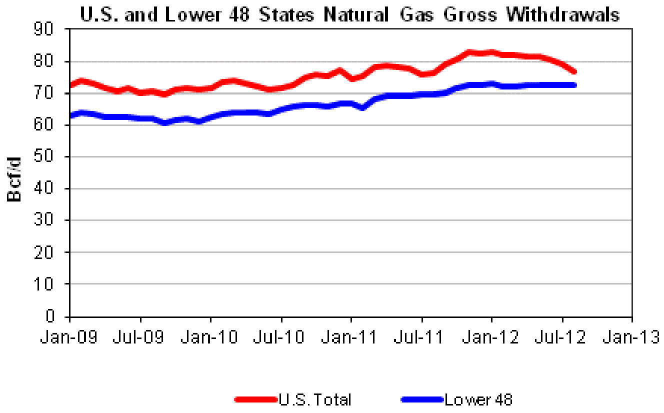
NATURAL GAS

Monthly Natural Gas Gross Production Report

Data Files **Methodology and Analysis** **Form and Instructions**

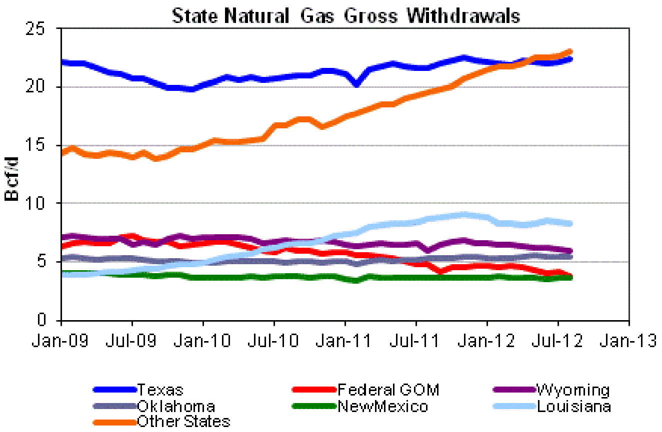
Monthly Natural Gas Gross Production Report with data for August 2012
Released: November 2, 2012
Next Release: November 30, 2012

The two graphs below show total U.S. and Lower 48 natural gas production on one and the individual State production on the other.



Source: Energy Information Administration

Figure Data



Source: Energy Information Administration

Figure Data

In August, Lower 48 States production decreased 0.2 percent or 0.11 billion cubic feet per day (Bcf/d). The Gulf of Mexico and Louisiana had the largest decreases at 9.5 percent or 0.39 Bcf/d and 1.9 percent or 0.16 Bcf/d, respectively as many operators reported shut-ins due to Hurricane Isaac. Wyoming production also decreased 2.1 percent or 0.13 Bcf/d due to maintenance. Increases in production were reported in Texas and Other States at 1.0 percent or 0.23 Bcf/d and 1.6 percent or 0.37 Bcf/d respectively, which primarily can be explained by new wells coming on-line in several shale plays.

Gross Withdrawals of Natural Gas[1], August 2011 through August 2012
(Billion Cubic Feet per Day)

Area	Federal Offshore Gulf of Mexico		Louisiana		New Mexico		Oklahoma		Texas[2]	
Report Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month
Aug-11	4.82	1.5	8.66	3.0	3.69	0.0	5.28	1.3	21.69	0.0
Sep-11	4.12	-14.5	8.86	2.3	3.68	-0.3	5.37	1.7	22.02	1.5
Oct-11	4.58	11.2	8.97	1.2	3.66	-0.5	5.36	-0.2	22.29	1.2
Nov-11	4.58	0.0	9.09	1.3	3.63	-0.8	5.38	0.4	22.49	0.9
Dec-11	4.66	1.7	8.97	-1.3	3.57	-1.7	5.40	0.4	22.22	-1.2
Jan-12	4.63	-0.6	8.81	-1.8	3.67	2.8	5.37	-0.6	22.16	-0.3
Feb-12	4.53	-2.2	8.26	-6.2	3.71	1.1	5.32	-0.9	22.02	-0.6
Mar-12	4.69	3.5	8.26	0.0	3.62	-2.4	5.31	-0.2	21.91	-0.5
Apr-12	4.54	-3.2	8.20	-0.7	3.57	-1.4	5.43	2.3	22.26	1.6
May-12	4.29	-5.5	8.32	1.5	3.59	0.6	5.53	1.8	22.15	-0.5
Jun-12	3.99	-7.0	8.49	2.0	3.52	-1.9	5.48	-0.9	22.04	-0.5
Jul-12	R 4.09	2.5	R 8.47	-0.2	3.61	2.6	5.50	0.4	R 22.18	0.6
Aug-12	3.70	-9.5	8.31	-1.9	3.60	-0.3	5.48	-0.4	22.41	1.0

Area	Wyoming		Other States[3]		Lower 48 States		Alaska State Data[4]		U.S. Total	
Report Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month	Gross Withdrawals (Bcf/day)	% Change from Last Month
Aug-11	6.01	-8.7	19.53	1.4	69.68	0.1	6.79	12.6	76.47	1.1

Sep-11	6.51	8.3	19.76	1.2	70.32	0.9	8.73	28.6	79.05	3.4
Oct-11	6.70	2.9	20.13	1.9	71.69	1.9	8.82	1.0	80.51	1.8
Nov-11	6.83	1.9	20.68	2.7	72.68	1.4	10.09	14.4	82.77	2.8
Dec-11	6.59	-3.5	21.08	1.9	72.49	-0.3	9.98	-1.1	82.47	-0.4
Jan-12	6.65	0.9	21.45	1.8	72.74	0.3	10.32	3.4	83.06	0.7
Feb-12	6.46	-2.9	21.72	1.3	72.02	-1.0	10.04	-2.7	82.06	-1.2
Mar-12	6.43	-0.5	21.70	-0.1	71.92	-0.1	9.99	-0.5	81.91	-0.2
Apr-12	6.30	-2.0	22.08	1.8	72.38	0.6	9.18	-8.1	81.56	-0.4
May-12	6.19	-1.7	22.48	1.8	72.55	0.2	9.12	-0.7	81.67	0.1
Jun-12	6.17	-0.3	22.60	0.5	72.29	-0.4	8.43	-7.6	80.72	-1.2
Jul-12	6.10	-1.1	R 22.71	0.5	R 72.66	0.5	6.67	-20.9	R 79.33	-1.7
Aug-12	5.97	-2.1	23.08	1.6	72.55	-0.2	4.05	-39.3	76.60	-3.4

Source: EIA-914 and EIA Natural Gas Annual

Note: Data presented in the table are monthly natural gas gross withdrawals estimated from data collected on the EIA-914 survey. In 2010 data are from the *EIA Natural Gas Annual*. Gross withdrawals are converted to marketed natural gas production which is reported on the EIA website in the Natural Gas Data Tables, and in the *Natural Gas Monthly* and *Natural Gas Annual* reports. Marketed production is calculated by subtracting gas used for repressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations from gross withdrawals.

[1] The EIA-914 estimates are based on the simple ratio method, explained in the *Methodology*.

[2] Texas gross withdrawals data do not include CO_2 production associated with injection projects. Texas CO_2 Adjustment Article

[3] Monthly Other States total estimates are determined by applying the ratio of 2010 gross natural gas production published at http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm to the 2010 reported EIA-914 survey production.

[4] Alaska data is from the State of Alaska, not the EIA-914. It's included here for completeness.

R=Revised data. It is EIA-914's revision policy to revise the prior month's data for any change when the latest month's data is released. Earlier months are only revised when a current estimate differs by the amount specified in the Revision Policy.

Notes: New Mexico EIA-914 gross withdrawals estimates now include CO_2 production in the same manner as it is reported by the State of New Mexico. All associated EIA-914 Data Files have been updated. Area estimates may not add to the lower 48 estimate due to independent rounding.

All estimates, except as footnoted, are based on the simple ratio estimate method, which is explained in the Methodology. Readers are encouraged to review these reports to better understand all aspects of the EIA-914 survey. The Data Files contain initial and revised production estimates for each month (revisions are based on company resubmissions and late reports) and response rates by month. Data and graphs showing comparisons between EIA-914 estimates and other sources can also be found here.

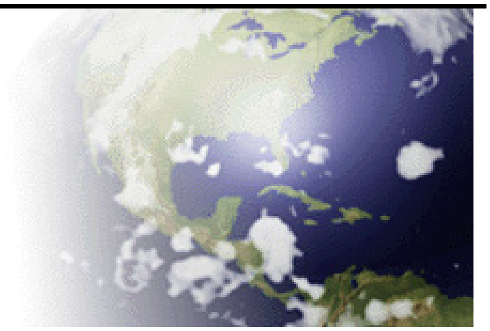
http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html
Last updated on Wednesday, October 17, 2012

Clean Energy

You are here: EPA Home Climate Change Clean Energy Energy and You How does electricity affect the environment? Air Emissions

Air Emissions

Electricity generation is the dominant industrial source of air emissions in the United States today. Fossil fuel-fired power plants are responsible for 67 percent of the nation's sulfur dioxide emissions, 23 percent of nitrogen oxide emissions, and 40 percent of man-made carbon dioxide emissions. These emissions can lead to smog, acid rain, and haze. In addition, these power plant emissions increase the risk of climate change. Congress is currently considering proposals to require further reductions of emissions from power plants, including the President's Clear Skies Initiative. However, renewable energy is receiving increased attention by environmental policymakers because renewable energy technologies have significantly lower emissions than traditional power generation technologies. To find out more about the air emissions generated by U.S. power plants, you can use EPA's Emissions and Generated Resource Integrated Database, or eGRID. eGRID provides emissions data on virtually every power plant and company that generates electricity in the United States.



Various Energy Resources

- Air Emissions
- Water Resource Use
- Water Discharges
- Solid Waste Generation
- Land Resource Use

The air emissions impacts of electricity generation vary from technology to technology, as described below.

Natural Gas

At the power plant, the burning of natural gas produces nitrogen oxides and carbon dioxide, but in lower quantities than burning coal or oil. Methane, a primary component of natural gas and a greenhouse gas, can also be emitted into the air when natural gas is not burned completely. Similarly, methane can be emitted as the result of leaks and losses during transportation. Emissions of sulfur dioxide and mercury compounds from burning natural gas are negligible.

The average emissions rates in the United States from natural gas-fired generation are: 1135 lbs/MWh of carbon dioxide, 0.1 lbs/MWh of sulfur dioxide, and 1.7 lbs/MWh of nitrogen oxides.[1] Compared to the average air emissions from coal-fired generation, natural gas produces half as much carbon dioxide, less than a third as much nitrogen oxides, and one percent as much sulfur oxides at the power plant. In addition, the process of extraction, treatment, and transport of the natural gas to the power plant generates additional emissions.[2]

Coal

When coal is burned, carbon dioxide, sulfur dioxide, nitrogen oxides, and mercury compounds are released. For that reason, coal-fired boilers are required to have control devices to reduce the amount of emissions that are released.

The average emission rates in the United States from coal-fired generation are: 2,249 lbs/MWh of carbon dioxide, 13 lbs/MWh of sulfur dioxide, and 6 lbs/MWh of nitrogen oxides.[3]

Mining, cleaning, and transporting coal to the power plant generate additional emissions. For example, methane, a potent greenhouse gas that is trapped in the coal, is often vented during these processes to increase safety.

Oil

Burning oil at power plants produces nitrogen oxides, sulfur dioxide, carbon dioxide, methane, and mercury compounds. The amount of sulfur dioxide and mercury compounds can vary greatly depending on the sulfur and mercury content of the oil that is burned.

The average emissions rates in the United States from oil-fired generation are: 1672 lbs/MWh of carbon dioxide, 12 lbs/MWh of sulfur dioxide, and 4 lbs/MWh of nitrogen oxides.[4]

In addition, oil wells and oil collection equipment are a source of emissions of methane, a potent greenhouse gas. The large engines that are used in the oil drilling, production, and transportation processes burn natural gas or diesel that also produce emissions.

Nuclear Energy

Nuclear power plants do not emit carbon dioxide, sulfur dioxide, or nitrogen oxides. However, fossil fuel emissions are associated with the uranium mining and uranium enrichment process as well as the transport of the uranium fuel to the nuclear plant.

Municipal Solid Waste

Although municipal solid waste (MSW) includes renewable resources, its use as a source of energy has been met with controversy. Despite recent toughening of emission standards for MSW combustion, the process creates significant emissions, including trace amounts of hazardous air pollutants.

Burning MSW produces nitrogen oxides and sulfur dioxide as well as trace amounts of toxic pollutants, such as mercury compounds and dioxins. Although MSW power plants do emit carbon dioxide, the primary greenhouse gas, the biomass-derived portion is considered to be part of the Earth's natural carbon cycle. The plants and trees that make up the paper, food, and other biogenic waste remove carbon dioxide from the air while they are growing, which is returned to the air when this material is burned. In contrast, when fossil fuels are burned, they release carbon dioxide that has not been part of the Earth's atmosphere for a very long time (i.e., within a human time scale).

The average air emission rates in the United States from municipal solid waste-fired generation are: 2988 lbs/MWh of carbon dioxide, (it is estimated that the fossil fuel-derived portion of carbon dioxide emissions represent approximately one-third of the total carbon dioxide emissions) 0.8 lbs/MWh of sulfur dioxide, and 5.4 lbs/MWh of nitrogen oxides.[5]

The variation in the composition of MSW raises concerns. For example, if MSW containing batteries and tires are burned, toxic materials are released into the air. A variety of air pollution control technologies are used to reduce most toxic air pollutants from MSW power plants.

If MSW were to be incinerated anyway, little or no environmental impact would be attributable to using the resulting heat to generate electricity. However, there are alternatives to incineration, such as recycling waste, storing waste in landfills, and source reduction.

Hydroelectricity

Hydropower's air emissions are negligible because no fuels are burned. However, if a large amount of vegetation is growing along the riverbed when a dam is built, it can decay in the lake that is created, causing the buildup and release of methane, a potent greenhouse gas.

Non-Hydroelectric Renewable Energy

Solar

Emissions associated with generating electricity from solar technologies are negligible because no fuels are combusted.

Geothermal

Emissions associated with generating electricity from geothermal technologies are negligible because no fuels are combusted.

Biomass

Biomass power plants emit nitrogen oxides and a small amount of sulfur dioxide. The amounts emitted depend on the type of biomass that is burned and the type of generator used. Although the burning of biomass also produces carbon dioxide, the primary greenhouse gas, it is considered to be part of the natural carbon cycle of the earth. The plants take up carbon dioxide from the air while they are growing and then return it to the air when they are burned, thereby causing no net increase. Biomass contains much less sulfur and nitrogen than coal;[6] therefore, when biomass is co-fired with coal, sulfur dioxide and nitrogen oxides emissions are lower than when coal is burned alone.[7] When the role of renewable biomass in the carbon cycle is considered, the carbon dioxide emissions that result from co-firing biomass with coal are lower than those from burning coal alone.[8]

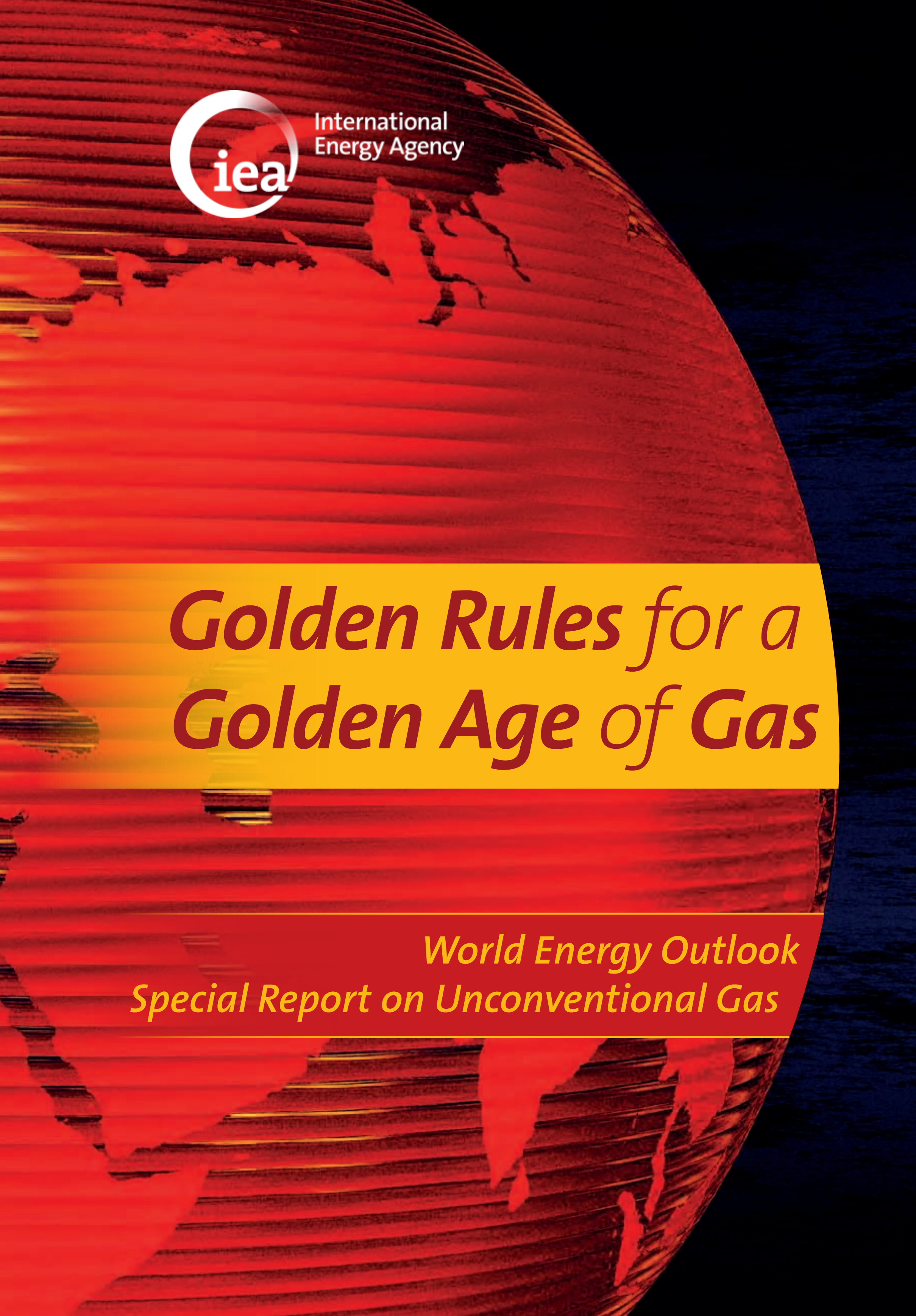
Landfill Gas

Burning landfill gas produces nitrogen oxides emissions as well as trace amounts of toxic materials. The amount of these emissions can vary widely, depending on the waste from which the landfill gas was created. The carbon dioxide released from burning landfill gas is considered to be a part of the natural carbon cycle of the earth. Producing electricity from landfill gas avoids the need to use non-renewable resources to produce the same amount of electricity. In addition, burning landfill gas prevents the release of methane, a potent greenhouse gas, into the atmosphere.

Wind

Emissions associated with generating electricity from wind technology are negligible because no fuels are combusted.

1. U.S. EPA, eGRID 2000.
2. Ibid.
3. Ibid.
4. Ibid.
5. U.S. EPA, Compilation of Air Pollutant Emission Factors (AP-42).
6. U.S. Department of Energy, Energy Efficiency and Renewable Energy Clearinghouse, Biomass Cofiring: A Renewable Alternative for Utilities. June 2000. DOE/GO-102000-1055.
7. Ibid.
8. Ibid.



International
Energy Agency

Golden Rules for a Golden Age of Gas

World Energy Outlook Special Report on Unconventional Gas

Golden Rules for a Golden Age of Gas

World Energy Outlook Special Report on Unconventional Gas

Natural gas is poised to enter a golden age, but this future hinges critically on the successful development of the world's vast unconventional gas resources. North American experience shows unconventional gas – notably shale gas – can be exploited economically. Many countries are lining up to emulate this success.

But some governments are hesitant, or even actively opposed. They are responding to public concerns that production might involve unacceptable environmental and social damage.

This report, in the *World Energy Outlook* series, treats these aspirations and anxieties with equal seriousness. It features two new cases: a Golden Rules Case, in which the highest practicable standards are adopted, gaining industry a "social licence to operate"; and its counterpart, in which the tide turns against unconventional gas as constraints prove too difficult to overcome.

The report:

- Describes the unconventional gas resource and what is involved in exploiting it.
- Identifies the key environmental and social risks and how they can be addressed.
- Suggests the Golden Rules necessary to realise the economic and energy security benefits while meeting public concerns.
- Spells out the implications of compliance with these rules for governments and industry, including on development costs.
- Assesses the impact of the two cases on global gas trade patterns and pricing, energy security and climate change.

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International
Energy Agency

Golden Rules *for a* Golden Age *of* Gas

World Energy Outlook
Special Report on Unconventional Gas

INTERNATIONAL ENERGY AGENCY

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Natural gas is poised to enter a golden age, but will do so only if a significant proportion of the world's vast resources of unconventional gas – shale gas, tight gas and coalbed methane – can be developed profitably and in an environmentally acceptable manner. Advances in upstream technology have led to a surge in the production of unconventional gas in North America in recent years, holding out the prospect of further increases in production there and the emergence of a large-scale unconventional gas industry in other parts of the world, where sizeable resources are known to exist. The boost that this would give to gas supply would bring a number of benefits in the form of greater energy diversity and more secure supply in those countries that rely on imports to meet their gas needs, as well as global benefits in the form of reduced energy costs.

Yet a bright future for unconventional gas is far from assured: numerous hurdles need to be overcome, not least the social and environmental concerns associated with its extraction. Producing unconventional gas is an intensive industrial process, generally imposing a larger environmental footprint than conventional gas development. More wells are often needed and techniques such as hydraulic fracturing are usually required to boost the flow of gas from the well. The scale of development can have major implications for local communities, land use and water resources. Serious hazards, including the potential for air pollution and for contamination of surface and groundwater, must be successfully addressed. Greenhouse-gas emissions must be minimised both at the point of production and throughout the entire natural gas supply chain. Improperly addressed, these concerns threaten to curb, if not halt, the development of unconventional resources.

The technologies and know-how exist for unconventional gas to be produced in a way that satisfactorily meets these challenges, but a continuous drive from governments and industry to improve performance is required if public confidence is to be maintained or earned. The industry needs to commit to apply the highest practicable environmental and social standards at all stages of the development process. Governments need to devise appropriate regulatory regimes, based on sound science and high-quality data, with sufficient compliance staff and guaranteed public access to information. Although there is a range of other factors that will affect the development of unconventional gas resources, varying between different countries, our judgement is that there is a critical link between the way that governments and industry respond to these social and environmental challenges and the prospects for unconventional gas production.

We have developed a set of "Golden Rules", suggesting principles that can allow policy-makers, regulators, operators and others to address these environmental and social impacts.[1] We have called them Golden Rules because their application can bring a level of environmental performance and public acceptance that can maintain or earn the industry a "social licence to operate" within a given jurisdiction, paving the way for the widespread development of unconventional gas resources on a large scale, boosting overall gas supply and making the golden age of gas a reality.

The Golden Rules underline that full transparency, measuring and monitoring of environmental impacts and engagement with local communities are critical to addressing public concerns. Careful choice of drilling sites can reduce the above-ground impacts and most effectively target the productive areas, while minimising any risk of earthquakes or of fluids passing between geological strata. Leaks from wells into aquifers can be prevented by high standards of well design, construction and integrity testing. Rigorous assessment and monitoring of water requirements (for shale and tight gas), of the quality of produced water (for coalbed methane) and of waste water for all types of unconventional gas can ensure informed and stringent decisions about water handling and disposal. Production-related emissions of local pollutants and greenhouse-gas emissions can be reduced by investments to eliminate venting and flaring during the well-completion phase.

We estimate that applying the Golden Rules could increase the overall financial cost of development a typical shale-gas well by an estimated 7%. However, for a larger development project with multiple wells, additional investment in measures to mitigate environmental impacts may be offset by lower operating costs.

In our Golden Rules Case, we assume that the conditions are in place, including approaches to unconventional gas development consistent with the Golden Rules, to allow for a continued global expansion of gas supply from unconventional resources, with far-reaching consequences for global energy markets. Greater availability of gas has a strong moderating impact on gas prices and, as a result, global gas demand rises by more than 50% between 2010 and 2035. The increase in demand for gas is equal to the growth coming from coal, oil and nuclear combined, and ahead of the growth in renewables. The share of gas in the global energy mix reaches 25% in 2035, overtaking coal to become the second-largest primary energy source after oil.

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[1] Consultations with a range of stakeholders when developing these Golden Rules included a high-level workshop held in Warsaw on 7 March 2012, which was organised by the IEA, hosted by the Polish Ministry of Economy and co-hosted by the Mexican Ministry of Energy. In addition to the input received during this workshop, we have drawn upon the extensive work in this area undertaken by many governments, non-governmental and academic organisations, and industry associations.

Production of unconventional gas, primarily shale gas, more than triples in the Golden Rules Case to 1.6 trillion cubic metres in 2035. This accounts for nearly two-thirds of incremental gas supply over the period to 2035, and the share of unconventional gas in total gas output rises from 14% today to 32% in 2035. Most of the increase comes after 2020, reflecting the time needed for new producing countries to establish a commercial industry. The largest producers of unconventional gas over the projection period are the United States, which moves ahead of Russia as the largest global natural gas producer, and China, whose large unconventional resource base allows for very rapid growth in unconventional production starting towards 2020. There are also large increases in Australia, India, Canada and Indonesia. Unconventional gas production in the European Union, led by Poland, is sufficient after 2020 to offset continued decline in conventional output.

Global investment in unconventional production constitutes 40% of the $6.9 trillion (in year-2010 dollars) required for cumulative upstream gas investment in the Golden Rules Case. Countries that were net importers of gas in 2010 (including the United States) account for more than three-quarters of total unconventional upstream investment, gaining the wider economic benefits associated with improved energy trade balances and lower energy prices. The investment reflects the high number of wells required: output at the levels anticipated in the Golden Rules Case would require more than one million new unconventional gas wells worldwide between now and 2035, twice the total number of gas wells currently producing in the United States.

The Golden Rules Case sees gas supply from a more diverse mix of sources of gas in most markets, suggesting growing confidence in the adequacy, reliability and affordability of natural gas. The developments having most impact on global gas markets and security are the increasing levels of unconventional gas production in China and the United States, the former because of the way that it slows the growth in Chinese import needs and the latter because it allows for gas exports from North America. These developments in tandem increase the volume of gas, particularly liquefied natural gas (LNG), looking for markets in the period after 2020, which stimulates the development of more liquid and competitive international markets. The share of Russia and countries in the Middle East in international gas trade declines in the Golden Rules Case from around 45% in 2010 to 35% in 2035, although their gas exports increase by 20% over the same period.

In a Low Unconventional Case, we assume that – primarily because of a lack of public acceptance – only a small share of the unconventional gas resource base is accessible for development. As a result, unconventional gas production in aggregate rises only slightly above current levels by 2035. The competitive position of gas in the global fuel mix deteriorates as a result of lower availability and higher prices, and the share of gas in global energy use increases only slightly, from 21% in 2010 to 22% in 2035, remaining well behind that of coal. The volume of inter-regional trade is higher than in the Golden Rules Case and some patterns of trade are reversed, with North America requiring significant quantities of imported LNG. The Low Unconventional Case reinforces the preeminent position in global supply of the main conventional gas resource-holders.

Energy-related CO_2 emissions are 1.3% higher in the Low Unconventional Case than in the Golden Rules Case. Although the forces driving the Low Unconventional Case are led by environmental concerns, this offsets any claim that a reduction in unconventional gas output brings net environmental gains. Nonetheless, greater reliance on natural gas alone cannot realise the international goal of limiting the long-term increase in the global mean temperature to two degrees Celsius above pre-industrial levels. Achieving this climate target will require a much more substantial shift in global energy use. Anchoring unconventional gas development in a broader energy policy framework that embraces greater improvements in energy efficiency, more concerted efforts to deploy low-carbon energy sources and broad application of new low-carbon technologies, including carbon capture and storage, would help to allay the fear that investment in unconventional gas comes at their expense.

Measure, disclose and engage

- Integrate engagement with local communities, residents and other stakeholders into each phase of a development starting prior to exploration; provide sufficient opportunity for comment on plans, operations and performance; listen to concerns and respond appropriately and promptly.
- Establish baselines for key environmental indicators, such as groundwater quality, prior to commencing activity, with continued monitoring during operations.
- Measure and disclose operational data on water use, on the volumes and characteristics of waste water and on methane and other air emissions, alongside full, mandatory disclosure of fracturing fluid additives and volumes.
- Minimise disruption during operations, taking a broad view of social and environmental responsibilities, and ensure that economic benefits are also felt by local communities.

Watch where you drill

- Choose well sites so as to minimise impacts on the local community, heritage, existing land use, individual livelihoods and ecology.
- Properly survey the geology of the area to make smart decisions about where to drill and where to hydraulically fracture: assess the risk that deep faults or other geological features could generate earthquakes or permit fluids to pass between geological strata.
- Monitor to ensure that hydraulic fractures do not extend beyond the gas-producing formations.

Isolate wells and prevent leaks

- Put in place robust rules on well design, construction, cementing and integrity testing as part of a general performance standard that gas bearing formations must be completely isolated from other strata penetrated by the well, in particular freshwater aquifers.
- Consider appropriate minimum-depth limitations on hydraulic fracturing to underpin public confidence that this operation takes place only well away from the water table.
- Take action to prevent and contain surface spills and leaks from wells, and to ensure that any waste fluids and solids are disposed of properly.

Treat water responsibly

- Reduce freshwater use by improving operational efficiency; reuse or recycle, wherever practicable, to reduce the burden on local water resources.
- Store and dispose of produced and waste water safely.
- Minimise use of chemical additives and promote the development and use of more environmentally benign alternatives.

Eliminate venting, minimise flaring and other emissions

- Target zero venting and minimal flaring of natural gas during well completion and seek to reduce fugitive and vented greenhouse-gas emissions during the entire productive life of a well.
- Minimise air pollution from vehicles, drilling rig engines, pump engines and compressors.

Be ready to think big

- Seek opportunities for realising the economies of scale and co-ordinated development of local infrastructure that can reduce environmental impacts.
- Take into account the cumulative and regional effects of multiple drilling, production and delivery activities on the environment, notably on water use and disposal, land use, air quality, traffic and noise.

Ensure a consistently high level of environmental performance

- Ensure that anticipated levels of unconventional gas output are matched by commensurate resources and political backing for robust regulatory regimes at the appropriate levels, sufficient permitting and compliance staff, and reliable public information.
- Find an appropriate balance in policy-making between prescriptive regulation and performance-based regulation in order to guarantee high operational standards while also promoting innovation and technological improvement.
- Ensure that emergency response plans are robust and match the scale of risk.
- Pursue continuous improvement of regulations and operating practices.
- Recognise the case for independent evaluation and verification of environmental performance.

Technology is opening up possibilities for unconventional gas to play a major role in the future global energy mix, a development that would ease concerns about the reliability, affordability and security of energy supply. In North America, production of unconventional gas – notably shale gas – has risen rapidly in recent years and is expected to dominate growth in overall US natural gas production in the coming years and decades. Naturally, there is keen interest in replicating this success in other parts of the world, where sizeable resources of unconventional gas are known to exist. This could give a major boost to gas supply worldwide and help take us into a "Golden Age of Gas" – the subject of a special *WEO* report released last year (IEA, 2011) (Box).

Box ▻ Linking the Golden Rules to a "Golden Age of Gas"

The IEA released an analysis in June 2011 whose title asked the question "Are We Entering a Golden Age of Gas?" (IEA, 2011). How does this report link back to that analysis?

The Golden Age of Gas Scenario (GAS Scenario) in 2011 built a positive outlook for the future role of natural gas on four main pillars: more ambitious assumptions about gas use in China; greater use of natural gas in transportation; an assumption of slower growth in global nuclear power capacity; and a more optimistic outlook for gas supply – primarily though the availability of additional unconventional gas supplies at relatively low cost. In the GAS Scenario, as a result, natural gas increased its role in the future global energy mix from 21% to 25% over the period to 2035.

However, the question mark in the title of this publication was not accidental. It reflected continued uncertainties over the future of natural gas, in particular those connected with the potential for growth in unconventional gas supply. The present analysis zooms in on the environmental impacts of unconventional gas supply, how they are being, and might be, addressed and what the consequences might be. It should therefore be understood as a more detailed examination of a key pre-condition for a golden age of gas.

A range of factors will affect the pace of development of this relatively new industry over the coming decades. In our judgement, a key constraint is that unconventional gas does not yet enjoy, in most places, the degree of societal acceptance that it will require in order to flourish. Without a general, sustained and successful effort from both governments and operators to address the environmental and social concerns that have arisen, it may be impossible to convince the public that, despite the undoubted potential benefits, the impact and risks of unconventional gas development are acceptably small. The IEA offers this special report as a contribution to the solution of this dilemma. The objective is to suggest what might be required to enable the industry to maintain or earn a "social licence to operate".

In Chapter 1 of this special report, we analyse the specific characteristics of each type of unconventional gas development and their environmental and social impacts, examining the technologies and their associated risks, why they have raised public anxiety and why and how they require special attention from policy-makers, regulators and industry. This chapter develops a set of "Golden Rules", the application of which would reduce the impact of unconventional gas developments on land and water use, on the risk of water contamination, and on methane and other air emissions. It also analyses the implications of compliance with the Golden Rules for governments and for industry.

In Chapter 2, we set out the results of two sets of projections of future energy demand, supply and energy-related CO_2 emissions, which explore the potential impact of unconventional gas resources on energy markets. The first of these, to which the main part of this chapter is devoted, is a *Golden Rules Case*, which assumes that the conditions are put in place to allow for a continued expansion of gas supply from unconventional gas resources, including the effective application of the Golden Rules. This situation allows unconventional output to expand not only in North America but also in other countries around the world with major resources. A *Low Unconventional Case*, examined at the end of this chapter, considers the opposite turn of events, in which Golden Rules are not observed, opposition to unconventional gas hardens and the constraints prove too difficult to overcome.

Chapter 3 takes a closer look at unconventional gas in four key regions and countries: North America (United States, Canada and Mexico), China, Europe and Australia. The prospect of increased unconventional gas production is prompting many countries to review their regulatory frameworks to accommodate (or, in some cases, to restrict) the development of these resources. This chapter provides an overview of the main debates and challenges around unconventional production in the selected countries and regions, presented together with our projections for future output.

Chapter 1

Addressing environmental risks

Why do we need "Golden Rules"?

Highlights

- Unconventional gas resources are trapped in very tight or low permeability rock and the effort required to extract them is greater than for conventional resources. This means higher intensity of drilling, entailing more industrial activity and disruption above ground. Producing gas from unconventional formations in many cases involves the use of hydraulic fracturing to boost the flow of gas from the well.
- The environmental and social hazards related to these and other features of unconventional gas development have generated keen public anxiety in many places. Means are available to address these concerns. "Golden Rules", as developed here, provide principles that can guide policy-makers, regulators, operators and other stakeholders on how best to reconcile their interests.
- Critical elements are: full transparency, measuring, monitoring and controlling environmental impacts; and early and sustained engagement. Careful choice of drilling sites can reduce the above-ground impacts and most effectively target the productive areas, while minimising any risk of earthquakes or of fluids passing between geological strata.
- Sound management of water resources is at the heart of the Golden Rules. Alongside robust rules on well design, construction, cementing and integrity testing to prevent leaks from the well into aquifers, this requires rigorous assessment, monitoring and handling of water requirements (for shale and tight gas), of the quality of produced water (for coalbed methane) and of waste water (in all cases).
- Unconventional gas has higher production-related greenhouse-gas emissions than conventional gas, but the difference can be reduced and emissions of other pollutants lowered by eliminating venting and minimising flaring during the well completion phase. Releases of methane, wherever they occur in the gas supply chain, are particularly damaging, given its potency as a greenhouse gas.
- The potential environmental impacts and the scale of unconventional gas development make it essential for policy-makers to ensure that effective and balanced regulation is in place, based on sound science and high-quality data, and that adequate resources are available for enforcement.
- Operators have to perform to the highest standards in order to win and retain the "social licence to operate". Application of the Golden Rules does affect costs, with an estimated 7% increase for a typical individual shale gas well. However, when considered across a complete licensing area, additional investment in measures to mitigate environmental impact can be offset in many cases by lower operating costs.

The environmental impact of unconventional gas production

Although known about for decades, the importance of global unconventional gas resources and their full extent has only recently been appreciated. Allowing for the uncertainties in the data, stemming, in part, from difficulties in distinguishing and categorising different types of gas (Box 1.1), we estimate that the remaining technically recoverable resources of unconventional gas worldwide approach the size of remaining conventional resources (which are 420 trillion cubic metres [tcm]). Remaining technically recoverable resources of shale gas are estimated to amount to 208 tcm, tight gas to 76 tcm and coalbed methane to 47 tcm. The economic and political significance of these unconventional resources lies not just in their size but also in their wide geographical distribution, which is in marked contrast to the concentration of conventional resources.[1] Availability of gas from a diverse range of sources would underpin confidence in gas as a secure and reliable source of energy.

Box 1.1 ▻ Unconventional gas resources

Unconventional gas refers to a part of the gas resource base that has traditionally been considered difficult or costly to produce. In this report, we focus on the three main categories of unconventional gas:

- **Shale gas** is natural gas contained within a commonly occurring rock classified as shale. Shale formations are characterised by low permeability, with more limited ability of gas to flow through the rock than is the case with a conventional reservoir. These formations are often rich in organic matter and, unlike most hydrocarbon reservoirs, are typically the original source of the gas, *i.e.* shale gas is gas that has remained trapped in, or close to, its source rock.
- **Coalbed methane**, also known as coal seam gas in Australia, is natural gas contained in coalbeds. Although extraction of coalbed methane was initially undertaken to make mines safer, it is now typically produced from non-mineable coal seams.
- **Tight gas**[2] is a general term for natural gas found in low permeability formations. Generally, we classify as tight gas those low permeability gas reservoirs that cannot produce economically without the use of technologies to stimulate flow of the gas towards the well, such as hydraulic fracturing.

Although the development cycle for unconventional gas and the technologies used in its production have much in common with those used in other parts of the upstream industry, unconventional gas developments do have some distinctive features and requirements, particularly in relation to the perceived higher risk of environmental damage and adverse

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[1] The extent and distribution of recoverable resources of unconventional gas is discussed in more detail in Chapter 2.

[2] Tight gas is often a poorly defined category with no clear boundary between tight and conventional, nor between tight gas and shale gas.

social impacts. This helps to explain why the issue of unconventional gas exploitation has generated so much controversy.

This chapter addresses these issues by examining in some depth what is involved in exploiting each category of unconventional gas and the associated hazards. It then proposes a set of principles, the "Golden Rules", applicable to future operations in this sector. The objective is to define the conditions which might enable the industry to gain or retain a "social licence to operate". The consequences for the energy sector of securing such an outcome are discussed in Chapters 2 and 3, together with the possible consequences of failing to do so.

The main reason for the potentially larger environmental impact of unconventional gas operations is the nature of the resources themselves: unconventional resources are less concentrated than conventional deposits and do not give themselves up easily. They are difficult to extract because they are trapped in very tight or low permeability rock that impedes their flow. Since the resources are more diffuse and difficult to produce, the scale of the industrial operation required for a given volume of unconventional output is much larger than for conventional production. This means that drilling and production activities can be considerably more invasive, involving a generally larger environmental footprint.

One feature of the greater scale of operations required to extract unconventional gas is the need for more wells. Whereas onshore conventional fields might require less than one well per ten square kilometres, unconventional fields might need more than one well per square kilometre (km^2), significantly intensifying the impact of drilling and completion activities on the environment and local residents.[3] A satellite image from Johnson County in Texas, United States illustrates this point, showing the density of well sites producing from the Barnett shale (Figure 1.1). This image highlights 37 well sites in an area of around 20 km^2, with each well site potentially having more than one well. Another important factor is the need for more complex and intensive preparation for production. While hydraulic fracturing is already used on occasions to stimulate conventional reservoirs, tight gas and shale gas developments almost always require the use of this technique in order to generate adequate flow rates into the well. The same technique is also often used, albeit less frequently, to produce coalbed methane. The associated use and release of water gives rise to a number of environmental concerns, including depletion of freshwater resources and possible contamination of surface water and aquifers.

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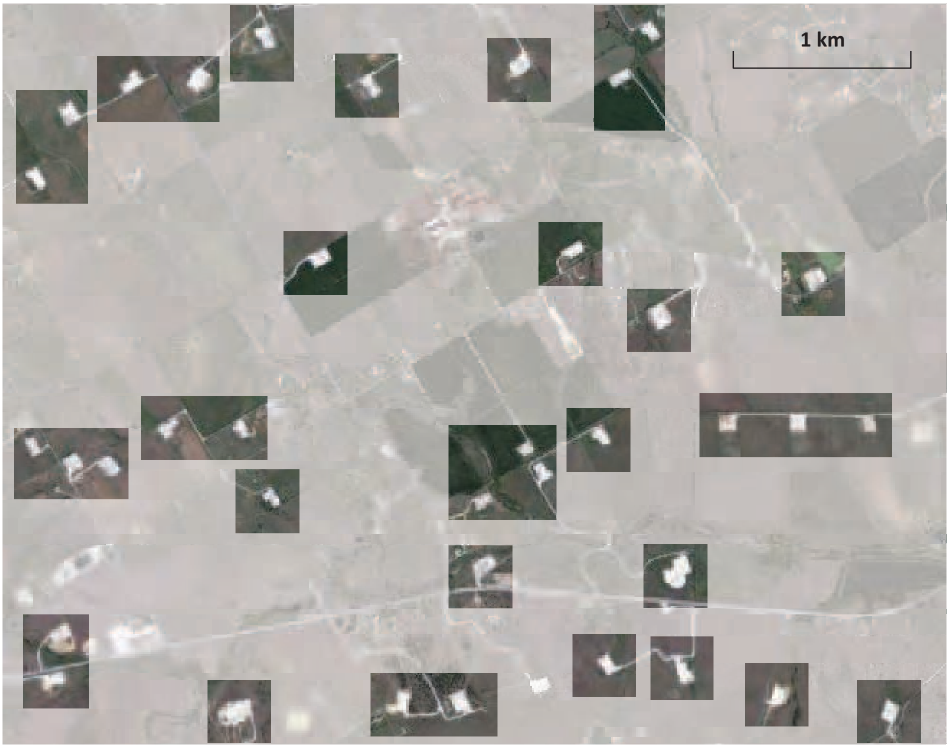
3. It should be noted that conventional gas fields in mature areas, such as onshore United States or Canada, often have well densities (number of wells per unit area) comparable to those of unconventional gas. However, burgeoning unconventional gas production today tends to replace production that would have come from offshore locations or countries rich in conventional gas, such as Russia or Qatar, in which the well densities are much smaller.

Figure 1.1 ▷ **Drilling intensity in Johnson County, Texas**



Source: © 2012 Google, DigitalGlobe, GeoEye, Texas Orthoimagery Program, USDA Farm, Farm Service Agency source. Google Maps, http://g.co/maps/j9xws, with well sites highlighted.

The production of unconventional gas also contributes to the atmospheric concentration of greenhouse gases and affects local air quality. In some circumstances, unconventional gas production can result in higher airborne emissions of methane, a potent greenhouse gas, of volatile organic compounds (VOCs) that contribute to smog formation, and of carbon dioxide (CO_2) (from greater use of energy in the production process, compared with conventional production). Just how much greater these risks may be is uncertain: it depends critically on the way operations are carried out. On the other hand, there are potential net benefits from unconventional gas production, to the extent that, having been produced and transported to exacting environmental standards, it leads to greater use of gas instead of more carbon-intensive coal and oil.

In addition to the smaller recoverable hydrocarbon content per unit of land, unconventional developments tend to extend across much larger geographic areas. The Marcellus Shale in the United States covers more than 250 000 km^2, which is about ten times larger than the Hugoton Natural Gas Area in Kansas – the country's largest conventional gas producing zone. Moreover, areas with high unconventional potential are not always those with a strong or recent tradition of oil and gas industry activity; they are not necessarily rich in conventional hydrocarbons and in some cases there may have been little or no recent hydrocarbon production (and none expected). This tends to exacerbate the problem of public acceptance.

Shale and tight gas developments

Characteristics of the resource

By contrast to conventional gas reservoirs, shale gas reservoirs (Box 1.2) have very low permeability due to the fine-grained nature of the original sediments (gas does not flow easily out of the rock), fairly low porosities (relatively few spaces for the gas to be stored, generally less than 10% of the total volume), and low recovery rates (because the gas can be trapped in disconnected spaces within the rock or stuck to its surface). The last two factors (low porosity and low recovery) are responsible for the fact that the volume of recoverable hydrocarbons per square kilometre of area at the surface is usually an order of magnitude smaller than for conventional gas. Low permeability is responsible for shale gas requiring specific technologies, such as hydraulic fracturing, to achieve commercial flow rates.

Tight gas reservoirs originate in the same way as conventional gas reservoirs: the rock into which the gas migrates after being expelled from the source rock just happens to be of very low permeability. As a result, tight gas reservoirs also require special techniques to achieve commercial flow rates. On the other hand, they tend to have better recovery factors than shale gas deposits and, therefore, higher density of recoverable hydrocarbons per unit of surface area.

Box 1.2 ▷ What are shales and shale gas?

Shales are geological rock formations rich in clays, typically derived from fine sediments, deposited in fairly quiet environments at the bottom of seas or lakes, having then been buried over the course of millions of years. When a significant amount of organic matter has been deposited with the sediments, the shale rock can contain organic solid material called kerogen. If the rock has been heated up to sufficient temperatures during its burial history, part of the kerogen will have been transformed into oil or gas (or a mixture of both), depending on the temperature conditions in the rock. This transformation typically increases pressure within the rock, resulting in part of the oil and gas being expelled from the shale and migrating upwards into other rock formations, where it forms conventional oil and gas reservoirs. The shales are the source rock for the oil and gas found in such conventional reservoirs. Some, or occasionally all, of the oil and gas formed in the shale can remain trapped there, thus forming shale gas or light tight oil reservoirs.[4]

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[4] Terminology in this area remains to be standardised (see Box 1.1). Previous WEOs have classified light tight oil from shales as conventional oil. Note that the term light tight oil is preferred to that of shale oil, as the latter can bring confusion with oil shales, which are kerogen-rich shales that can be mined and heated to produce oil (IEA, 2010; IEA, 2011a).

Shales are ubiquitous in sedimentary basins: they typically form about 80% of what a well will drill through. As a result, the main organic-rich shales have already been identified in most regions of the world. Their depths vary from near surface to several thousand metres underground, while their thickness varies from just a few metres to several hundred.[5] Often, enough is known about the geological history to infer which shales are likely to contain gas (or oil, or a mixture of both). In that sense there is no real "exploration" required for shale gas. However, the amount of gas present and particularly the amount of gas that can be recovered technically and economically cannot be known until a number of wells have been drilled and tested. Each shale formation has different geological characteristics that affect the way gas can be produced, the technologies needed and the economics of production.[6] Different parts of the (generally large) shale deposits will also have different characteristics: small "sweet spots" or "core areas" may provide much better production than the rest of the play, often because of the presence of natural fractures that enhance permeability. The amount of natural gas liquids (NGLs) present in the gas can also vary considerably, with important implications for the economics of production. While most dry gas plays in the United States are probably uneconomic at the current low natural gas prices, plays with significant liquid content can be produced for the value of the liquids only (the market value of NGLs is correlated with oil prices, rather than gas prices), making gas an essentially free by-product.

Well construction[7]

The drilling phase is the most visible and disruptive in any oil and gas development – particularly so in the case of shale gas or tight gas because of the larger number of wells required. On land, a drilling rig, associated equipment and pits to store drilling fluids and waste typically occupy an area of 100 metres by 100 metres (the well site). Setting up drilling in a new location might involve between 100 and 200 truck movements to deliver all the equipment, while further truck movements will be required to deliver supplies during drilling and completion of the well.

Each well site needs to be chosen taking account not only of the subsurface geology, but also of a range of other concerns, including proximity to populated areas and existing infrastructure, the local ecology, water availability and disposal options, and seasonal restrictions related to climate or wildlife concerns. In North America, there has recently

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[5] Thin shales are generally considered as not exploitable. Depth can cut both ways: shallower shales require shallower, *i.e.* cheaper, wells, but deeper shales have higher pressures, which increases the areal density of recoverable gas (which is measured at surface conditions, while the gas in the shale is compressed by the formation pressure).

[6] For example, horizontal wells with multi-stage hydraulic fracturing have been pivotal to the economic success of shale gas in the United States, while in Argentina, YPF has recently reported successful tests with vertical wells with only three or four hydraulic fractures (YPF, 2012).

[7] The construction of a well to access unconventional gas deposits is divided into two phases: the drilling phase, where the hole is drilled to its target depth in sections that are secured with metal casing and cement; and the completion phase, where the cemented casing across the reservoir is perforated and the reservoir stimulated (generally by hydraulic fracturing) in order to start the production of hydrocarbons.

been a move towards drilling multiple wells from a single site, or pad, in order to limit the amount of disruption and thereby the overall environmental impact of well construction.[8] In 2011, according to industry sources, around 30% of all new shale and tight gas wells in the United States and Canada were multiple wells drilled from pads.

Once drilling starts, it is generally a 24-hour-per-day operation, creating noise and fumes from diesel generators, requiring lights at night and creating a regular stream of truck movements during mobilisation/demobilisation periods. Drilling operations can take anything from just a few days to several months, depending on the depth of the well and type of rock encountered. As the drill bit bores through the rock, drilling fluid known as "mud" is circulated through the wellbore in order, among other tasks, to control pressure in the well and remove cuttings created by the drill bit from the well. This lubricating "mud" consists of a base fluid, such as water or oil, mixed with salts and solid particles to increase its density and a variety of chemical additives. Mud is stored either in mobile containers or in open pits which are dug into the ground and lined with impermeable material. The volume of material in the pits needs to be monitored and contained to prevent leaks or spills. A drilling rig might have several hundred tonnes of mud in use at any one time, which creates a large demand for supplies. Once used, the mud must be either recycled or disposed of safely. Rock cuttings recovered from the mud during the drilling process amount to between 100 and 500 tonnes per well, depending on the depth. These, too, need to be disposed of in an environmentally acceptable fashion.

A combination of steel casing and cement in the well (Figure 1.2) provides an essential barrier to ensure that high-pressure gas or liquids from deeper down cannot escape into shallower rock formations or water aquifers. This barrier has to be designed to withstand the cycles of stress it will endure during the subsequent hydraulic fracturing, without suffering any cracks. The design aspects that are most important to ensure a leak-free well include the drilling of the well bore to specification (without additional twists, turns or cavities), the positioning of the casing in the centre of the well bore before it is cemented in place (this is done with centralisers placed at regular intervals along the casing as it is run in the hole, to keep it away from the rock face) and the correct choice of cement. The cement design needs to be studied both for its liquid properties during pumping (to ensure that it gets to the right place) and then for its mechanical strength and flexibility, so that it remains intact. The setting time of the cement is also a critical factor – cement that takes too long to set may have reduced strength; equally, cement that sets before it has been fully pumped into place requires difficult remedial action.

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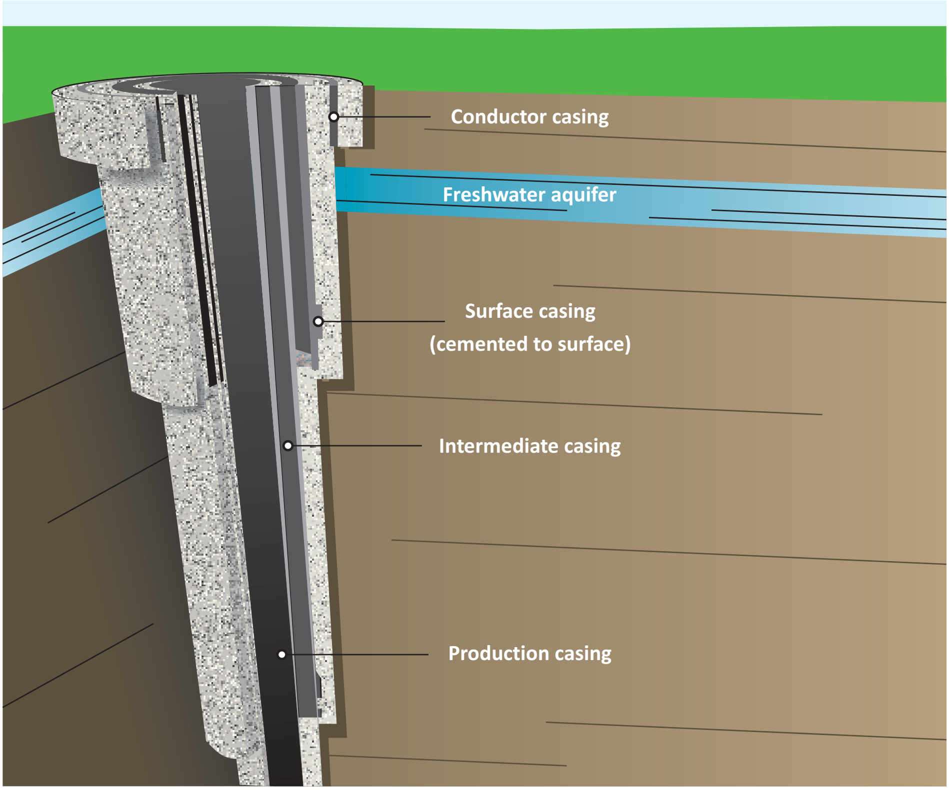
[8] Pad drilling has long been used in northern areas, such as Alaska and in Russia, but the introduction of this practice to places such as Texas is relatively new.

Figure 1.2 ▷ Typical well design and cementing



Source: Adapted from ConocoPhillips.

Well completion

Once the well has been drilled, the final casing cemented in place across the gas-bearing rock has to be perforated in order to establish communication between the rock and the well.[9] The pressure in the well is then lowered so that hydrocarbons can flow from the rock to the well, driven by the pressure differential. With shale and tight gas, the flow will be very low, because of the low permeability of the rock. As the rate of hydrocarbon flow determines directly the cash flow from the well, low flow rates can mean there is insufficient revenue to pay for operating expenses and provide a return on the capital invested. Without additional measures to accelerate the flow of hydrocarbons to the well, the operation is then not economic.

Several technologies have been developed over the years to enhance the flow from low permeability reservoirs. Acid treatment, involving the injection of small amounts of strong acids into the reservoir to dissolve some of the rock minerals and enhance the permeability

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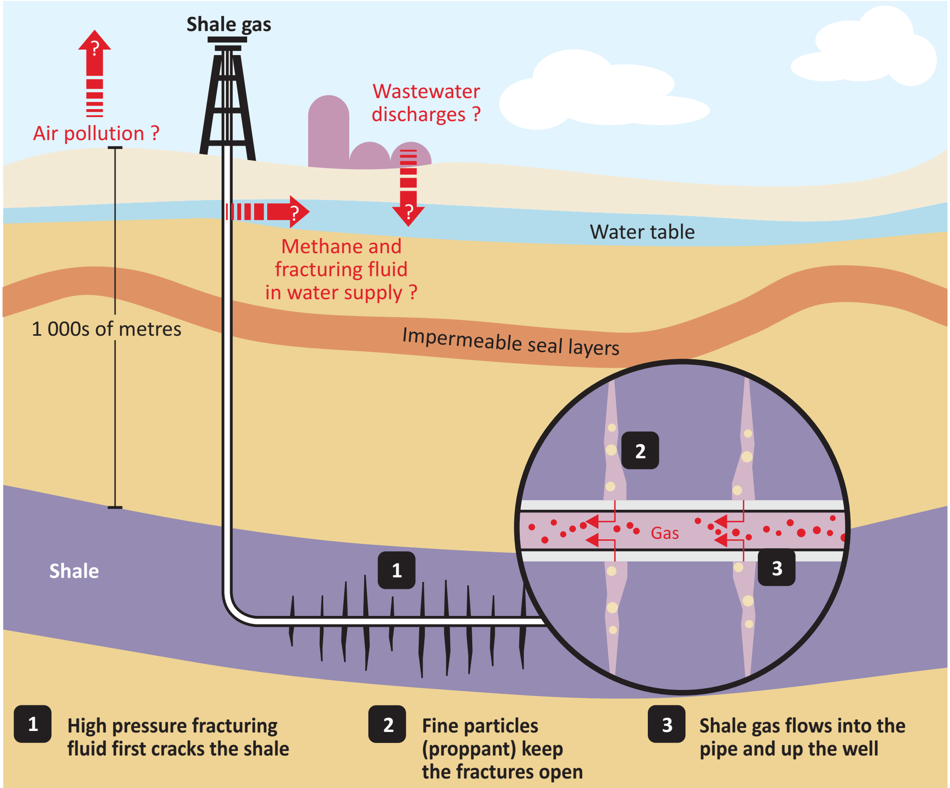
[9] Some wells are completed "open-hole", in which there is no casing in the final part of the well in the gas-bearing rock; this is not uncommon in horizontal wells.

of the rock near the wellbore, is probably the oldest and is still widely practised, particularly in carbonate reservoirs. Wells with long horizontal or lateral sections (known as horizontal wells) can increase dramatically the contact area between the reservoir rock and the wellbore, and are likewise effective in improving project economics. Hydraulic fracturing, developed initially in the late 1940s, is another effective and commonly-practised technology for low-permeability reservoirs. When rock permeability is extremely low, as in the case of shale gas or light tight oil, it often takes the combination of horizontal wells and hydraulic fracturing to achieve commercial rates of production (Figure 1.3). Advances in the application of these two techniques, in combination, largely explain the surge in shale gas production in the United States since 2005.

Figure 1.3 ▷ Shale gas production techniques and possible environmental hazards



Source: Adapted from Aldhous (2012).

Note: The possible environmental hazards discussed in the text are shown with red arrows. Although the figure illustrates a shale gas well with multi-stage hydraulic fracturing, some similar hazards are present with conventional gas wells, and with tight gas developments.

Hydraulic fracturing involves pumping a fluid – known as fracturing fluid – at high pressure into the well and then, far below the surface, into the surrounding target rock. This creates fractures or fissures a few millimetres wide in the rock. These fissures can extend tens or, in some cases, even hundreds of metres away from the well bore. Once the pressure is released, these fractures would tend to close again and not produce any lasting improvement in the flow of hydrocarbons. To keep the fractures open, small particles, such as sand or ceramic beads, are added to the pumped fluid to fill the fractures and to act as proppants, *i.e.* they prop open the fractures thus allowing the gas to escape into the well.

Box 1.3 ▻ Unconventional gas production and earthquake risks

There have been instances of earthquakes associated with unconventional gas production, for example the case of the Cuadrilla shale gas operations near Blackpool in the United Kingdom, or a case near Youngstown, Ohio, in the United States, which has been provisionally linked to injection of waste water, an operation that is similar in some respects to hydraulic fracturing. The registered earthquakes were small, of a magnitude of around two on the Richter scale, meaning they were discernible by humans but did not create any surface damage.

Because it creates cracks in rocks deep beneath the surface, hydraulic fracturing always generates small seismic events; these are actually used by petroleum engineers to monitor the process. In general, such events are several orders of magnitude too small to be detected at the surface: special observation wells and very sensitive instruments need to be used to monitor the process. Larger seismic events can be generated when the well or the fractures happen to intersect, and reactivate, an existing fault. This appears to be what happened in the Cuadrilla case.

Hydraulic fracturing is not the only anthropogenic process that can trigger small earthquakes. Any activity that creates underground stresses carries such a risk. Examples linked to construction of large buildings, or dams, have been reported. Geothermal wells in which cold water is circulated underground have been known to create enough thermally-induced stresses to generate earthquakes that can be sensed by humans (Cuenot, 2011). The same applies to deep mining (Redmayne, 1998). What is essential for unconventional gas development is to survey carefully the geology of the area to assess whether deep faults or other geological features present an enhanced risk and to avoid such areas for fracturing. In any case, monitoring is necessary so that operations can be suspended if there are signs of increased seismic activity.[10]

In many cases, a series of fractures is created at set intervals, one after the other, about every 100 metres along the horizontal well bore. This multi-stage fracturing technique has played a key role in unlocking production of shale gas and light tight oil in the United States and promises to do likewise elsewhere in the world. A standard single-stage hydraulic fracturing may pump down several hundred cubic metres of water together with proppant and a mixture of various chemical additives. In shale gas wells, a multi-stage fracturing

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[10] Detailed recommendations, following analysis of the Cuadrilla event, are under consideration by the United Kingdom Department of Energy and Climate Change (DECC, 2012).

would commonly involve between ten and twenty stages, multiplying the volumes of water and solids by 10 or 20, and hence the total values for water use might reach from a few thousand to up to twenty thousand cubic metres of water per well and volumes of proppant of the order of 1 000 to 4 000 tonnes per well. The repeated stresses on the well from multiple high-pressure procedures increase the premium on good well design and construction to ensure that gas bearing formations are completely isolated from other strata penetrated by the well.

Once the hydraulic fracturing has been completed, some of the fluid injected during the process flows back up the well as part of the produced stream, though typically not all of it – some remains trapped in the treated rock. During this flow-back period, typically over days (for a single-stage fracturing) to weeks (for a multi-stage fracturing), the amount of flow back of fracturing fluid decreases, while the hydrocarbon content of the produced stream increases, until the flow from the well is primarily hydrocarbons.

Best practice during this period is to use a so-called "green completion" or "reduced-emissions completion", whereby the hydrocarbons are separated from the fracturing fluid (and then sold) and the residual flow-back fluid is collected for processing and recycling or disposal. However, while collecting and processing the fluid is standard practice, capturing and selling the gas during this initial flow-back phase requires investment in gas separation and processing facilities, which does not always take place. In these cases, there can be venting of gas to the atmosphere (mostly methane, with a small fraction of VOCs) or flaring (burning) of hydrocarbon or hydrocarbon/water mixtures. Venting and/or flaring of the gas at this stage are the main reasons why shale and tight gas can give rise to higher greenhouse-gas emissions than conventional production (see the later section on methane and other airborne emissions).

Production

Once wells are connected to processing facilities, the main production phase can begin. During production, wells will produce hydrocarbons and waste streams, which have to be managed. But the well site itself is now less visible: a "Christmas tree" of valves, typically one metre high, is left on top of the well, with production being piped to processing facilities that usually serve several wells; the rest of the well site can be reclaimed. In some cases, the operator may decide to repeat the hydraulic fracturing procedure at later times in the life of the producing well, a procedure called re-fracturing. This was more frequent in vertical wells but is currently relatively rare in horizontal wells, occurring in less than 10% of the horizontal shale-gas wells drilled in the United States.

The production phase is the longest phase of the lifecycle. For a conventional well, production might last 30 years or more. For an unconventional development, the productive life of a well is expected to be similar, but shale gas wells typically exhibit a burst of initial production and then a steep decline, followed by a long period of relatively low production. Output typically declines by between 50% and 75% in the first year of production, and most recoverable gas is usually extracted after just a few years (IEA, 2009).

Well abandonment

At the end of their economic life, wells need to be safely abandoned, facilities dismantled and land returned to its natural state or put to new appropriate productive use. Long-term prevention of leaks to aquifers or to the surface is particularly important. Since much of the abandonment will not take place until production has ceased, the regulatory framework needs to ensure that the companies concerned make the necessary financial provisions and maintain technical capacity beyond the field's economic life to ensure that abandonment is completed satisfactorily, and well integrity maintained over the long term.

Coalbed methane developments

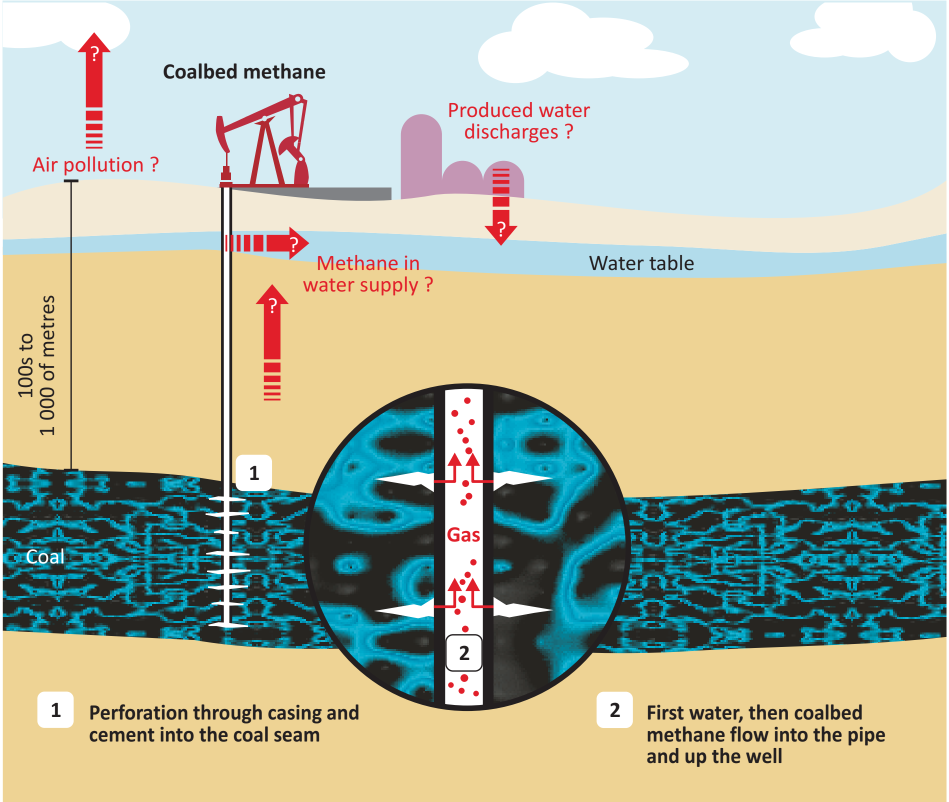
Coalbed methane refers to methane (natural gas) held within the solid matrix of coal seams. Some of the methane is stored within the coal as a result of a process called adsorption, whereby a film of methane is created on the surface of the pores inside the coal. Open fractures in the coal may also contain free gas or water. In some cases, methane is present in large volumes in coalbeds and can constitute a serious safety hazard for coal-mining operations. Significant volumes of CO_2 may also be present in the coal.

There are both similarities and differences between coalbed methane and the two other main types of unconventional gas discussed, which are linked to the way in which coalbed methane is extracted, the associated costs and the impact on the environment. The main similarity is the low permeability of the gas-bearing reservoir – a critical factor for the technical and economic viability of extraction. Virtually all the permeability of a coalbed is due to fractures, in the form of cleats and joints. These fractures tend to occur naturally so that, within a small part of the seam, methane is able to flow through the coalbed. As with shale and tight gas deposits, there are major variations in the concentration of gas from one area to another within the coal seams. This, together with variations in the thickness of the seam, has a significant impact on potential production rates.

Above ground, coalbed methane production involves disruption to the landscape and local environment through the construction of drilling pads and access roads, and the installation of on-site production equipment, gas processing and transportation facilities. As is often the case with shale gas and tight gas, coalbed methane developments require the drilling of more wells than conventional oil and gas production; as a result, traffic and vehicle noise levels, noise from compressors, air pollution and the potential damage to local ecological systems are generally more of an issue than for conventional gas output.

There are some important differences between coalbed methane and shale or tight gas resources. Coalbed methane deposits can be located at shallow depths (these are predominantly the deposits that have been exploited thus far), whereas shale and tight gas are usually found further below the surface. Water is often present in the coalbed, which needs to be removed to allow the gas to flow to the well. In addition, coalbed methane contains very few heavier liquid hydrocarbons (natural gas liquids or gas condensate), which means the commercial viability of production depends heavily on the price at which the gas itself can be sold; in the case of shale gas produced together with large volumes of associated natural gas liquids, the price of oil plays a very important role in determining the overall profitability of the development project.

Figure 1.4 ▷ Coalbed methane production techniques and possible environmental hazards



Source: Adapted from Aldhous (2012).

Note: The possible environmental hazards discussed in the text are shown with red arrows.

Considerable progress has been made over the last 25 years in honing techniques to extract coalbed methane on a commercial basis, paving the way to production on a significant scale, initially in North America and, since the mid-1990s, in Australia. Coalbed methane can be produced from vertical or horizontal wells. The latter are becoming increasingly common, though less so than for shale gas. Generally, the thinner the coal seam and the greater the depth of the deposit, the more likely it is that a horizontal well will be drilled. Although a depth of 800 to 1 200 metres is typical, in some cases coalbed methane is located in shallow formations as little as 100 metres below the surface, making it more economical to drill a series of vertical wells, rather than a horizontal well with extended reach along the coal seam. For shallow deposits, wells can often be drilled using water-well drilling equipment, rather than rigs designed for conventional hydrocarbon extraction, with commensurately cheaper costs (US EPA, 2010). For deeper formations (400 to 1 200 metres), both vertical and horizontal wells are used and custom-built small drilling rigs, capable of handling blow-out risks, have been developed.

Once a well is drilled, the water in the coalbed is extracted, either under natural pressure or by using mechanical pumping equipment – a process known as dewatering (water use and contamination risks are discussed in more detail in the next section). As subsurface pressure drops with dewatering, the flow of natural gas previously held in place by water pressure increases initially as it is released from the natural fractures or cleats within the coalbed. The gas is separated from the water at the surface and is then compressed and injected into a gas-gathering pipeline for onward transportation.

As in the case of shale gas, the rate of production of coalbed methane is often significantly lower than that achieved in conventional gas reservoirs; it also tends to reach a peak quickly as water is extracted, before entering a period of decline as the well pressure drops further. A well's typical lifespan is between five and fifteen years, with maximum gas production often achieved after one to six months of water removal (Horsley & Witten, 2001). In most cases, the low natural permeability of the coal seam means that gas can flow into the well from only a small segment of the coal seam – a characteristic shared with shale and tight gas. As a result, a relatively large number of wells is required over the area of the coalbed, especially if they are drilled vertically.

In some cases, it may also be necessary to use hydraulic fracturing to increase the permeability of the coal seam in order to stimulate the release of water and gas. This is normally practised only in deeper wells, typically at several hundred metres below the ground. The decision to proceed with hydraulic fracturing needs to be made before drilling begins, as the well and surface facilities need to be designed accordingly. The approach is similar to that described above, but in contrast to current practice with shale gas and tight gas wells, fracturing for coalbed methane production is frequently a single-stage process, *i.e.* one fracturing job per well, rather than multi-stage. Since wells are often drilled in batches, the water required for hydraulic fracturing can be sourced from neighbouring wells that are being de-watered. The flow-back fluids recovered from the well are pumped to lined containment pits or tanks for treatment or offsite disposal.

Water use

The extent of water use and the risk of water contamination are key issues for any unconventional gas development and have generated considerable public concern. In the case of a shale gas or tight gas development, though some water is required during the drilling phase, the largest volumes of water are used during the hydraulic fracturing process: each well might need anything between a few thousand and 20 000 cubic metres (between 1 million and 5 million gallons). Efficient use of water during fracturing is essential. Average water use per well completion in the Eagle Ford play in west Texas has been reduced from 18.5 to 13.6 thousand cubic metres since mid-2010, primarily through increased recycling of waste water from flow-back of fracturing fluid, an important step forward, given that more than 2 800 drilling permits were issued by the Railroad Commission of Texas for Eagle Ford wells in 2011 (RCT, 2012).[11] The amount of water required for shale gas or tight gas developments, calculated per unit of energy produced, is higher than for conventional gas but comparable to the amount used for the production of conventional oil (Table 1.1).

Table 1.1 ▷ **Ranges of water use per unit of natural gas and oil produced** (cubic metres per terajoule)

	Water consumption	
	Production	Refining
Natural gas		
Conventional gas	0.001 - 0.01	
Conventional gas with fracture stimulation	0.005 - 0.05	
Tight gas	0.1 - 1	
Shale gas	2 - 100	
Oil		
Conventional oil*	0.01 - 50	5 - 15
Conventional oil with fracture stimulation*	0.05 - 50	5 - 15
Light tight oil	5 - 100	5 - 15

Source: IEA analysis.

* The high end of this range is for secondary recovery with water flood; the low end is primary recovery.

Note: Coalbed methane is not included in this table as it tends to produce water, rather than require it for production (but see below for the discussion of waste water disposal).

Water for fracturing can come from surface water sources (such as rivers, lakes or the sea), or from local boreholes (which may draw from shallow or deep aquifers and which may already have been drilled to support production operations), or from further afield (which generally requires trucking). Transportation of water from its source and to disposal locations can be a large-scale activity. If the hydraulic fracturing of a well requires 15 000 cubic metres, this amounts to 500 truck-loads of water, on the basis that a typical truck can hold around 30 cubic metres of water. Such transportation congests local roads, increases wear and tear to roads and bridges and, if not managed safely, can increase road accidents.

In areas of water-scarcity, the extraction of water for drilling and hydraulic fracturing (or even the production of water, in the case of coalbed methane) can have broad and serious environmental effects. It can lower the water table, affect biodiversity and harm the local

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[11] If these 2 800 wells each require 13.6 thousand cubic metres for well completion, the water requirement of 38 million cubic metres represents 0.2% of annual water consumption of the state of Texas, or 12% of the annual water consumption of the city of Dallas, Texas.

ecosystem. It can also reduce the availability of water for use by local communities and in other productive activities, such as agriculture.

Limited availability of water for hydraulic fracturing could become a significant constraint on the development of tight gas and shale gas in some water-stressed areas. In China, for example, the Tarim Basin in the Xinjiang Uyghur Autonomous Region holds some of the country's largest shale gas deposits, but also suffers from severe water scarcity. Although not on the same scale, in terms of either resource endowment or water stress, a number of other prospective deposits occur in regions that are already experiencing intense competition for water resources. The development of China's shale gas industry has to date focused on the Sichuan basin, in part because water is much more abundant in this region.

Hydraulic fracturing dominates the freshwater requirements for unconventional gas wells and the dominant choice of fracturing fluid for shale gas, "slick-water", which is often available at the lowest cost and in some shale reservoirs may also bring some gas-production benefits, is actually the most demanding in terms of water needs. Much attention has accordingly been given to approaches which might reduce the amount of water used in fracturing. Total pumped volumes (and therefore water volumes required) can be decreased through the use of more traditional, high viscosity, fracturing fluids (using polymers or surfactants), but these require a complex cocktail of chemicals to be added. Foamed fluids, in which water is foamed with nitrogen or CO_2, with the help of surfactants (as used in dish washing liquids), can be attractive, as 90% of the fluid can be gas and this fluid has very good proppant-carrying properties. Water can, indeed, be eliminated altogether by using hydrocarbon-based fracturing fluids, such as propane or gelled hydrocarbons, but their flammability makes them more difficult to handle safely at the well site. The percentage of fracturing fluid that gets back-produced during the flow-back phase varies with the type of fluid used (and the shale characteristics), so the optimum choice of fluid will depend on many factors: the availability of water, whether water recycling is included in the project, the properties of the shale reservoir being tapped, the desire to reduce the usage of chemicals and the economics.

Treatment and disposal of waste water

Waste water from hydraulic fracturing

The treatment and disposal of waste water are critical issues for unconventional gas production – especially in the case of the large amounts of water customarily used for hydraulic fracturing. After being injected into the well, part of the fracturing fluid (which is often almost entirely water) is returned as flow-back in the days and weeks that follow. The total amount of fluid returned depends on the geology; for shale it can run from 20% to 50% of the input, the rest remaining bound to the clays in the shale rock. Flow-back water contains some of the chemicals used in the hydraulic fracturing process, together with metals, minerals and hydrocarbons leached from the reservoir rock. High levels of salinity are quite common and, in some reservoirs, the leached minerals can be weakly radioactive, requiring specific precautions at the surface.[12] Flow-back returns (like waste water from drilling) requires secure storage on site, preferably fully contained in stable, weather-proof storage facilities as they do pose a potential threat to the local environment unless handled properly (see next section).

Once separated out, there are different options available for dealing with waste water from hydraulic fracturing. The optimal solution is to recycle it for future use and technologies are available to do this, although they do not always provide water ready for re-use for hydraulic fracturing on a cost-effective basis. A second option is to treat waste water at local industrial waste facilities capable of extracting the water and bringing it to a sufficient standard to enable it to be either discharged into local rivers or used in agriculture. Alternatively, where suitable geology exists, waste water can be injected into deep rock layers.

Box 1.4 ▷ What is in a fracturing fluid?

Environmental concerns have focused on the fluid used for hydraulic fracturing and the risk of water contamination through leaks of this fluid into groundwater. Water itself, together with sand or ceramic beads (the "proppant"), makes up over 99% of a typical fracturing fluid, but a mixture of chemical additives is also used to give the fluid the properties that are needed for fracturing. These properties vary according to the type of formation. Additives (not all of which would be used in all fracturing fluids) typically help to accomplish four tasks:

- To keep the proppant suspended in the fluid by gelifying the fluid while it is being pumped into the well and to ensure that the proppant ends up in the fractures being created. Without this effect, the heavier proppant particles would tend to be distributed unevenly in the fluid under the influence of gravity and would, therefore, be less effective. Gelling polymers, such as guar or cellulose (similar to those used in food and cosmetics) are used at a concentration of about 1%. Cross-linking agents, such as borates or metallic salts, are also commonly used at very low concentration to form a stronger gel. They can be toxic at high concentrations, though they are often found at low natural concentrations in mineral water.
- To change the properties of the fluid over time. Characteristics that are needed to deliver the proppant deep into subsurface cracks are not desirable at other stages in the process, so there are additives that give time-dependent properties to the fluid, for example, to make the fluid less viscous after fracturing, so that the hydrocarbons flow more easily along the fractures to the well. Typically, small concentrations of chelants (such as those used to de-scale kettles) are used, as are small concentrations of oxidants or enzymes (used in a range of industrial processes) to break down the gelling polymer at the end of the process.

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[12] These naturally occurring radioactive materials, or NORMs, are not specific to unconventional resources; some conventional reservoirs are also known to produce them.

- To reduce friction and therefore reduce the power required to inject the fluid into the well. A typical drag-reducing polymer is polyacrylamide (widely used, for example, as an absorbent in baby diapers).
- To reduce the risk that naturally occurring bacteria in the water affect the performance of the fracturing fluid or proliferate in the reservoir, producing hydrogen sulphide; this is often achieved by using a disinfectant (biocide), similar to those commonly used in hospitals or cleaning supplies.

Until recently, the chemical composition of fracturing fluids was considered a trade secret and was not made public. This position has fallen increasingly out of step with public insistence that the community has the right to know what is being injected into the ground. Since 2010, voluntary disclosure has become the norm in most of the United States.[13] The industry is also looking at ways to achieve the desired results without using potentially harmful chemicals. "Slick-water", made up of water, proppant, simple drag-reducing polymers and biocide, has become increasingly popular as a fracturing fluid in the United States, though it needs to be pumped at high rates and can carry only very fine proppant. Attention is also being focused on reducing accidental surface spills, which most experts regard as a more significant risk of contamination to groundwater.

Produced water from coalbed methane production[14]

In the case of coalbed methane, additional water supplies are rarely required for the production process, but the satisfactory disposal of water that has been extracted from the well during the dewatering process is of critical importance. The produced water is usually either re-injected into isolated underground formations, discharged into existing drainage systems, sent to shallow ponds for evaporation or, once properly treated, used for irrigation or other productive uses. The appropriate disposal option depends on several factors, notably the quality of the water. Depending on the geology of the coal deposit and hydrological conditions, produced water can be very salty and sodic (containing high concentrations of sodium, calcium and magnesium) and can contain trace amounts of organic compounds, so it often requires treatment before it can be used for irrigation or other uses. Using saline water for irrigation can inhibit germination and plant growth, while excessively sodic water can change the physical properties of the soil, leading to poor drainage and crusting and adversely affecting crop yields.

The potential cost of water disposal depends on both the extent to which treatment is required and the volume of water produced. In practice, the total amount of water that must be removed from each well to allow gas to be produced varies considerably. It can be very large; for example, an estimated 65 cubic metres of water (17 000 gallons) are

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13. See the voluntary disclosure web site FracFocus (www.fracfocus.org).

14. Both conventional gas and other types of unconventional gas production can also be accompanied by produced water, but the flow rates involved are normally much smaller than for coalbed methane.

pumped from each coalbed methane well every day on average in the Powder River Basin in Montana and Wyoming. For the United States as a whole, it is estimated that, in 2008, more than 180 million cubic metres (47 billion gallons) of produced water were pumped out of coal seams (US EPA, 2010), equivalent to the annual direct water consumption of the city of San Francisco. In principle, produced water can be treated to any desired quality. This may be costly, but the treated water may have economic value for productive uses – as long as the cost of transporting the water is not excessive.

The options for treatment and disposal of produced water and the market value of water in the near vicinity are often key factors in the economics of coalbed methane developments. Many of the areas where coalbed methane is produced today, or where prospects for production are good, are arid or semi-arid and could benefit from additional freshwater supplies. For now, evaporation or discharge into drainage systems (in some cases, after treatment) are still the most common methods in North America (reuse of treated water is growing in Australia) because of the high cost of purifying the water for irrigation or reinjection into a deeper layer. In the United States, approximately 85 million cubic metres (22 billion gallons) of produced water, or about 45% of the total, were discharged to surface waters in 2008 with little or no treatment (US EPA, 2010).

There is limited experience of assessing the actual environmental impacts of produced water from coalbed methane production. A recent study by the US National Research Council found that the eventual disposal or use of produced water can have both positive and negative impacts on soil, ecosystems, and the quality and quantity of surface water and groundwater (NRC, 2010). Although the study found no evidence of widespread negative effects, allowance must be made for the fact that the industry is relatively young and that few detailed investigations into local impacts have been carried out yet.

The risk of water contamination

Significant concern has been expressed about the potential for contamination of water supplies, whether surface supplies, such as rivers or shallow freshwater aquifers, or deeper waters, as a result of all types of unconventional gas production. Water supplies can be contaminated from four main sources:

- Accidental spills of fluids or solids (drilling fluids, fracturing fluids, water and produced water, hydrocarbons and solid waste) at the surface.
- Leakage of fracturing fluids, saline water from deeper zones or hydrocarbons into a shallow aquifer through imperfect sealing of the cement column around the casing.
- Leakage of hydrocarbons or chemicals from the producing zone to shallow aquifers through the rock between the two.
- Discharge of insufficiently treated waste water into groundwater or, even, deep underground.

None of these hazards is specific to unconventional resources; they also exist in conventional developments, with or without hydraulic fracturing. However, as noted, unconventional developments occur at a scale that inevitably increases the risk of incidents occurring. Public concern has focused on the third source of potential contamination, *i.e.* the possibility that hydrocarbons or chemicals might migrate from the produced zone into aquifers through the intervening rock. However, this may actually be the least significant of the hazards, at least in the case of shale gas and tight gas production; in some cases a focus on this risk may have diverted attention, including the time of regulators, away from other more pressing issues.

Box 1.5 ▻ Coalbed methane production and effects on groundwater

There are concerns about the impact of coalbed methane production on groundwater flows and the supply and purity of water in aquifers adjacent to the coal seams being exploited. The extent to which this can occur is very location specific and depends on several factors, the most important of which are the overall volume of water initially in the coalbed and the hydrogeology of the basin; the density of the coalbed methane wells; the rate of water pumping by the operator; the connectivity of the coalbed and aquifer to surrounding water sources and, therefore, the rate of recharge of the aquifer; and the length of time over which pumping takes place.

In the United States, various agencies now monitor water in producing areas in order to learn more about this process. Depletion of aquifers because of coalbed methane production has been well-documented in the Powder River Basin: in the Montana portion of the basin, 65% to 87% recovery of coalbed groundwater levels has occurred after production ceased (NRC, 2010). However, the extent to which water levels in shallow alluvial and water table aquifers have dropped has not been measured (recent legislation in Queensland in Australia now requires such measurements to be performed). There is evidence that groundwater movement provoked by dewatering during coalbed methane production has increased the amount of dissolved salt and other minerals in some areas.

Because productive coal seams are often at shallower depths than tight or shale gas deposits, there is also a greater risk that fracturing fluids might find their way into an aquifer directly or via a fracture system (either a natural system or one that is created through fracturing). This risk is mitigated in part by the fact that, in contrast to shale or tight gas, the dewatering required for production of coalbed methane means that less water may be left in the ground in aquifers near the vicinity of the well, limiting the potential for contamination. As with shale or tight gas production, the flow-back fluids removed from the well after fracturing need to be treated before disposal.

The first hazard – the risk of spills at the surface – can be mitigated through rigorous containment of all fluid and solid streams. Accidents can always happen but good procedures, training of personnel and availability of spill control equipment can ensure they have a limited impact. As discussed below, greater use of pipelines to move liquids can reduce the risks associated with trucking movements.

Controlling the second hazard – leakage into a shallow aquifer behind the well casing – requires use of best practice in well design and well construction, particularly during the cementing process, to ensure a proper seal is in place, systematic verification of the quality of the seal and ensuring the seal does not deteriorate through the life of a well. This is a particular issue for wells in which multi-stage hydraulic fracturing is performed: the repeated cycles of high pressure pumping can apply repeated stress to the casing and to the cement column, potentially weakening them; selection of an appropriate strength of casing is therefore important.

The third hazard – leakage through the rock from the producing zone – is unlikely in the case of shale gas or tight gas because the producing zone is one to several thousand metres below any relevant aquifers and this thickness of rock usually includes one or several very impermeable layers. For example, the deepest potential underground sources of drinking water in the Barnett shale are at a depth of 350 metres, whereas the shale layer is at 2 000 to 2 300 metres. However, the hazard may be encountered if the producing zone is shallower or if there are shallow pockets of naturally occurring methane above the target reservoir. It is also theoretically possible if there are no identified impermeable layers in between or if deep faults are present that can act as a conduit for fluids to move from the deep producing zone towards the surface (such fluid movements are generally slow, but can occur on time scales of tens of years). One particular possibility is that hydraulic fractures may not be contained in the targeted rock layer and may break through important rock barriers or connect to deep faults. This is a rare occurrence because hydraulic fracturing is designed to avoid this (potentially costly) situation[15], but it cannot be completely excluded when the local geology is insufficiently understood.

Appropriate prior studies of the local geology to identify such situations are therefore a must before undertaking significant developments. Indeed, methane seeps to the surface have long been known (for example, the flame that has been burning for centuries in the village of Mrapen in Central Java, Indonesia, or the gas that fuels the "Eternal Flame Falls" in New York State, United States) and they have been used as a way to identify the presence of hydrocarbon deposits underground, showing that perfect rock seals do not always exist. On the other hand, the existence of seeps, and for that matter the presence of methane in many aquifers (Molofsky, 2011), shows that not all contamination is linked to industrial activity; it can also occur as a result of natural geological or biological processes.

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[15] This would increase losses of fracturing fluid and could mean in turn that the fracturing does not translate into the desired increase in gas production.

Addressing the fourth hazard – discharge of insufficiently treated waste water into groundwater or, even, deep underground – requires a regulatory response including appropriate tracking and documentation of waste water volumes and composition, how they are transported and disposed.

Methane and other air emissions

Shale gas and tight gas have higher production-related greenhouse-gas emissions than conventional gas. This stems from two effects:

- More wells and more hydraulic fracturing are needed per cubic metre of gas produced. These operations use energy, typically coming from diesel motors, leading to higher CO_2 emissions per unit of useful energy produced.
- More venting or flaring during well completion. The flow-back phase after hydraulic fracturing represents a larger percentage of the total recovery per well (because of more hydraulic fracturing, the flow-back takes longer and the total recovery per well is typically smaller due to the low permeability of the rock).

We have previously released estimates of these effects both in the case of flaring and for venting during flow-back, based on EPA data, in order to see what difference these practices make (IEA, 2011b). In the case of flaring, total well-to-burner emissions are estimated to be 3.5% higher than for conventional gas, but this figure rises to 12% if the gas is vented. Eliminating venting, minimising flaring and recovering and selling the gas produced during flow-back, in line with the Golden Rules, would reduce emissions below the lower figure given here.

Similar concerns about emissions attach to coalbed methane production, where significant volumes of methane can be vented into the atmosphere during the transition phase from dewatering to gas production and, where hydraulic fracturing is applied, during the well completion phase. Careful management of drilling, fracturing and production operations is essential to keep such emissions to a minimum.[16] This requires specialised equipment to separate gas from the produced water (and fracturing fluids) before injecting it into a gas-gathering system (or into temporary storage). If this is not possible for technical, logistical or economic reasons, it is preferable that the gas should be flared rather than vented for safety reasons and because the global-warming effect is considerably less.

The general issue of greenhouse-gas emissions from the production, transportation and use of natural gas, as well as the additional emissions from unconventional gas compared with conventional gas, has been the subject of some controversy. Some authors (Howarth, 2011) have argued that emissions from using natural gas as a source of primary energy have been significantly underestimated, particularly for unconventional gas. It has even been argued that full life-cycle emissions from unconventional gas can be higher than from

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[16] Coalbed methane production can reduce methane emissions if the gas would in any case have been released by subsequent coal-mining activities.

coal. The main issue revolves around methane emissions not only during production, but also during transportation and use of natural gas.

Methane is a more potent greenhouse gas than CO_2 but has a shorter lifetime in the atmosphere – a half-life of about fifteen years, versus more than 150 years for CO_2. As a result, there are different possible ways to compare the effect of methane and CO_2 on global warming. One way is to evaluate the Global Warming Potential (GWP) of methane, compared to CO_2, averaged over 100 years. The 4th Assessment report of the IPCC (IPCC, 2007) gives a value of 25 (on a mass basis) for this 100-years GWP, revised up from their previous estimate of 21. This value is relevant when looking at the long-term relative benefits of eliminating a temporary source of methane emissions versus a CO_2 source.

Averaged over 20 years, the GWP, estimated by the IPCC, is 72. This figure can be argued to be more relevant to the evaluation of the significance of methane emissions in the next two or three decades, which will be the most critical to determine whether the world can still reach the objective of limiting the long-term increase in average surface temperatures to 2 degrees Celsius (°C). Moreover, some scientists have argued that interactions of methane with aerosols reinforce the GWP of methane, possibly bringing it to 33 over 100 years and 105 over 20 years (Shindell, 2009): these recent analyses are under review by the IPCC. Such higher values would, of course, have implications not only for methane emissions from the gas chain but also for all other methane emissions, from livestock, landfills, rice paddies and other agricultural sources, as well as from natural sources (Spotlight).

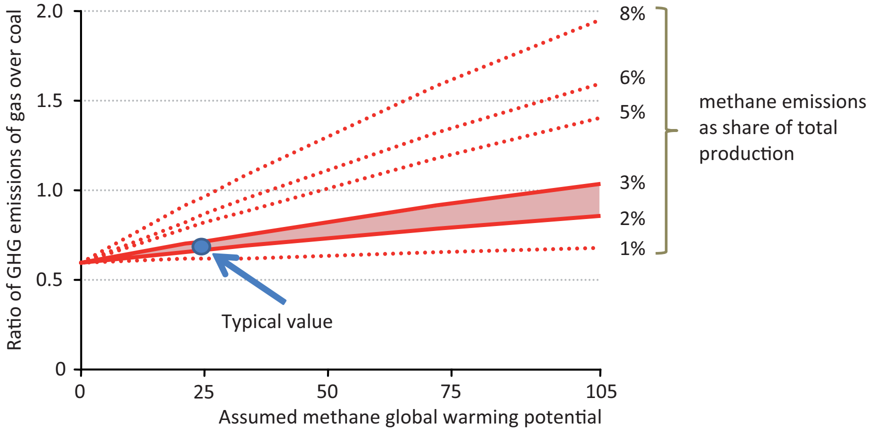
Methane emissions along the gas value chain (whether conventional or unconventional) come from four main sources:

- Intentional venting of gas for safety or economic reasons. Venting during well completions falls into this category, but venting can also take place as part of equipment maintenance operations.
- Fugitive emissions. These might be leaks in pipelines, valves or seals, whether accidental (*e.g*. corrosion in pipelines) or built into the equipment design (*e.g.* rotating seals, open tanks).
- Incidents involving rupture of confining equipment (pipelines, pressurised tanks, well isolation).
- Incomplete burning. The effectiveness of gas burning in gas flares varies according to wind and other conditions and is typically no better than 98%. (A similar effect can be seen when starting a gas stove: it can take a few seconds before a steady flame is established).

By their very nature, these emissions are difficult to quantify. Most estimates are based on emission factors for various parts of the chain (wells, various equipment, pipelines and so on), derived from studies conducted in the United States by the EPA and the Gas Research Institute in the 1990s (US EPA and GRI, 1996). It is by no means clear that these studies give a good indication for emissions in other parts of the world, or for the possible evolution of methane emissions in the future. Estimates of methane emissions from the gas chain at the global level vary between 1% and 8% of produced natural gas volumes (Howarth, 2011 and references therein; Petron, 2012; Cathles, 2012; Jiang 2011; and Skone 2011). The most comprehensive projections of future emissions, from the EPA (US EPA, 2011), assume no change in emission factors, for want of a better approach, and project a 26% increase in methane emissions from the oil and gas industry between 2010 and 2030.

Different assumptions about the level and impact of methane emissions can have a profound effect on the perception of gas as a "cleaner" fossil fuel. Figure 1.5 shows the well-to-burner emissions of natural gas compared to coal, as a function of various assumptions on GWP and average methane emissions. As seen from this figure, standard values (25 GWP, 2% to 3% methane emissions as a share of total production) substantiate the widely accepted advantage of gas, thanks to its lower combustion CO_2 emissions per unit of energy; but it is clear that more pessimistic assumptions can make gas a worse greenhouse-gas emitter than coal. It is very important that additional scientific work should pinpoint the most relevant GWP value and that efforts are redoubled to measure methane emissions more systematically.[17]

Figure 1.5 ▷ The impact of changing assumptions about methane on comparative well-to-burner greenhouse-gas emissions of natural gas versus coal



Note: Values below 1.0 on the vertical axis show points at which gas has lower well-to-burner emissions than coal. The comparison is for equivalent volumes of primary energy; however, gas also tends to be transformed, into other energy carriers (such as electricity) with higher efficiency than coal, so the ratio can be lower when calculated for the same end-use energy.

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[17] See, for example, a recent paper included in the Proceedings of the US National Academy of Sciences on methane leakage from natural gas infrastructure (Alvarez *et al.*, 2012)

One advantage attributable to expanded unconventional gas production and use over production and use of conventional gas is the distance to market; in general, unconventional resources are developed closer to the point of consumption, thereby reducing the distance required for transportation. All else being equal, this tends to reduce the level of fugitive emissions, as well as CO_2 emissions from the energy used for transportation.

SPOTLIGHT

How large are global methane emissions?

It is estimated that about 550 million tonnes (Mt) of methane (IPPC, 2007) are released into the atmosphere every year, but data on global methane emissions are poor. Converted into CO_2 equivalent (using the standard IPCC 100-years Global Warming Potential of 25), this amounts to about 14 gigatonnes CO_2-eq, roughly one-fourth of global greenhouse-gas emissions. Natural emissions (not related to man's activities) represent about 40% of total methane emissions. They come from natural seeps, wetlands, animals, such as termites, and vegetation decay. In addition, massive amounts of methane are stored in permafrost in Arctic regions and in underwater methane hydrates deposits. Some of this stored methane is released by natural processes, which are considered likely to accelerate with global warming: there is a risk of natural emissions increasing dramatically over the coming decades.

Non-energy related anthropogenic emissions come mostly from livestock, agriculture, landfills and wastewater. These represent about 38% of total methane emissions (64% of anthropogenic methane emissions). Energy-related methane emissions come from oil, gas and coal production, transportation, distribution and use as well as some biomass combustion: together they are estimated to be 125 Mt per year, about 20% of global methane emissions (36% of anthropogenic methane emissions). The gas and oil industry account for the lion's share of this: 70%, or 90 Mt per year, representing about 15% of total methane emissions (26% of anthropogenic emissions).

If current emissions are poorly known and the numbers above mere estimates, projecting future methane emissions is fraught with even more uncertainties. Natural emissions could be dramatically altered by the evolution of the climate. For anthropogenic emissions, activity levels in the energy and other industries as well as in livestock and agriculture can be projected, based on econometric analysis and assumptions on GDP and population growth, but the evolution of emission factors (volume of methane emitted per unit of activity) is very uncertain.[18] Many mitigation measures are considered to have low or even negative costs: reducing leaks in a gas

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[18] The IEA model (developed in collaboration with the OECD, using the ENV-linkages OECD model) uses the costs of mitigation measures (as derived from EPA studies; EPA, 2006) and a pseudo-price of carbon (whether coming from taxes, a carbon market or from regulations) to determine the likely evolution of emissions from an economic point of view. EPA has recently released draft updated costs of mitigation (EPA, 2012).

distribution system, for example, can allow more gas to be sold; the gas collected from a landfill can be marketed; changing the feed given to livestock to reduce methane production can allow more of the energy content of the feed to be transformed into marketable meat or milk. On the other hand, because of the very (spatially) distributed nature of most methane emission sources, it is not obvious that economic considerations alone will be sufficient to induce change. To achieve the trajectories of methane emissions consistent with the internationally agreed goal to limit the rise in global mean temperature to 2°C above pre-industrial levels, additional policy measures will be needed.

Golden Rules to address the environmental impacts

The outlook for unconventional gas production around the world depends critically on how the environmental issues described earlier are addressed. Society needs to be adequately convinced that the environmental and social risks will be well enough managed to warrant consent to unconventional gas production, in the interests of the broader economic, social and environmental benefits that the development of unconventional resources can bring. The Golden Rules, which are set out below with some explanatory background, suggest principles that can allow policy-makers, regulators, operators and others to address these environmental and social impacts in order to earn or retain that consent. We have called them Golden Rules because they can pave the way for the widespread and large-scale development of unconventional gas resources, boosting overall natural gas supply so as to realise a Golden Age of Gas (IEA, 2011b).

Abiding by these Golden Rules – or any rules – cannot reduce to zero the impacts on the environment associated with unconventional gas production. In any such undertaking, there are inevitable trade-offs between reducing the risks of environmental damage, on the one hand, and achieving the benefits that can accrue to society from the development of economic resources. In designing an appropriate regulatory framework, policy-makers need to set the highest reasonable social and environmental standards, assessing the cost of any residual risk against the cost of still higher standards (which could include the abandonment of resource exploitation). What is reasonable will evolve over time, as technology and industrial best practice evolve: in this spirit, these are not rigid rules, set in stone, but principles intended to guide regulators and operators. The format of regulation is also critical to achieving the intended result: it may include some specific and inflexible requirements but it should also encourage and reward performance to the highest standards, not supporting the notion that enough has been done if the instructions of others are mechanically observed, however meticulously. Ultimately, operators are responsible for the results of their operations. In framing these Golden Rules, we find that both governments and industry need to intensify their associated work if public confidence in this new industry is to be gained and retained.

Measure, disclose and engage

- ***Integrate engagement with local communities, residents and other stakeholders into each phase of a development, starting prior to exploration; provide sufficient opportunity for comment on plans, operations and performance, listen to concerns and respond appropriately and promptly.*** Simply providing information to the public is not enough; both the industry and the public authorities need to engage with local communities and other stakeholders and seek the informed consent that is often critical for companies to proceed with a development. Operators need to explain openly and honestly their production practices, the environmental, safety, and health risks and how they are addressed. The public needs to gain a clear understanding of the challenges, risks and benefits associated with the development. The primary role of the public authorities in this context is to provide credible, science-based background information that can underpin an informed debate and provide the necessary stimulus for joint endeavour between the stakeholders.
- ***Establish baselines for key environmental indicators, such as groundwater quality, prior to commencing activity, and continue monitoring during operations.*** This is a shared responsibility between the regulatory authorities, industry and other stakeholders. The data gathered needs to be made public and opportunities provided for all stakeholders to address any concerns raised, as an essential part of earning public trust. At a minimum, resource management or regulatory agencies must have groundwater quality information (and, for coalbed methane production, information on groundwater levels) in advance of new drilling activities, so as to provide a baseline against which changes in water level and quality can be compared.
- ***Measure and disclose operational data on water use, on the volumes and characteristics of waste water and on methane and other air emissions, alongside full, mandatory disclosure of fracturing fluid additives and volumes.*** Good data, measurement and transparency are vital to public confidence. For example, effective tracking and documentation of waste water is necessary to incentivise and ensure its proper treatment and disposal. Reluctance to disclose the chemicals used in the hydraulic fracturing process and the volumes involved, though understandable in terms of commercial competition, can quickly breed mistrust among local citizens and environmental groups.
- ***Minimise disruption during operations, taking a broad view of social and environmental responsibilities, and ensure that economic benefits are also felt by local communities.*** Existing legislation and regulations usually require operators to act in an environmentally and socially responsible manner, but operators need to go beyond minimally satisfying legal requirements in demonstrating their commitment to local development and environmental protection, for example through attention to local concerns about the volume and timing of truck traffic. Particularly in jurisdictions where mineral rights are owned by the state (rather than as in parts of the United States, where surface landowners might also be subsurface mineral rights holders,

entitled to royalty payments), it is essential that tangible benefits are evident at the local level, where production occurs. This can be difficult to achieve in a timely manner, given the delay between the start of a development project and the moment at which revenues start to flow, whether to government, the mineral rights' owner or the operator. Early public commitment by authorities and developers to expand local infrastructure and services in step with exploration and production activities can help. Governments need to be willing to consider using part of the revenues (from taxes, royalties, etc.) to invest in the development of the areas in question.

Watch where you drill

- ***Choose well sites so as to minimise impacts on the local community, heritage, existing land use, individual livelihoods and ecology.*** The choice of well site is a moment when engagement with local stakeholders and regulators needs to be handled with the utmost care. Each well site needs to be chosen based on the subsurface geology, but also taking into consideration populated areas, the natural environment and local ecology, existing infrastructure and access roads, water availability and disposal options and seasonal restrictions caused by climate or wildlife concerns. Sensitivity at this stage to a range of above-ground concerns can do much to mitigate or avoid problems later in a development.
- ***Properly survey the geology of the area to make smart decisions about where to drill and where to hydraulically fracture: assess the risk that deep faults or other geological features could generate earthquakes or permit fluids to pass between geological strata.*** Careful planning can greatly improve the productivity and recovery rates of wells, reducing the number of wells that need to be drilled and minimising the intensity of hydraulic fracturing and the associated environmental impact. Although the risk of triggering an earthquake is small, even minor earth tremors can easily undermine public confidence in the safety of drilling operations. A careful study of the geology of the area targeted for drilling is necessary to allow operators to avoid operations in areas where deep faults or other characteristics create higher risks. Producers also need to survey for the presence of old boreholes or naturally occurring methane in shallow pockets above the source rock and adjust drilling sites (or the pathway of the wellbore) to avoid these areas.
- ***Monitor to ensure that hydraulic fractures do not extend beyond the gas-producing formations.*** The risk of leakage of the fracturing fluid used for shale and tight gas production through the rock from the producing zone into aquifers is minimal because the aquifers are located at much shallower depths; but such migration is theoretically possible in certain exceptional circumstances (described in the preceding section). A good understanding of the local geology and the use of micro-seismic (or other) measuring techniques for monitoring fractures is necessary to minimise the residual risk.

Isolate wells and prevent leaks

- ***Put in place robust rules on well design, construction, cementing and integrity testing as part of a general performance standard that gas bearing formations must be completely isolated from other strata penetrated by the well, in particular freshwater aquifers.*** Regulations need to ensure wells are designed, constructed and operated so as to ensure complete isolation. Multiple measures need to be in place to prevent leaks, with an overarching performance standard requiring operators to follow systematically all recommended industry best practices. This applies up to and including the abandonment of the well, *i.e.* through and beyond the lifetime of the development.
- ***Consider appropriate minimum-depth limitations on hydraulic fracturing to underpin public confidence that this operation takes place only well away from the water table.*** Alongside measures to ensure that wells are designed, built and cemented to a high standard, the regulator may choose to define an appropriate depth limitation for shale and tight gas wells, based on local geology and any risk of communication with freshwater aquifers, above which hydraulic fracturing is prohibited.
- ***Take action to prevent and contain surface spills and leaks from wells, and to ensure that any waste fluids and solids are disposed of properly.*** This requires both stringent regulations and a strong performance commitment by all companies involved in drilling and production-related activities to carry out operations to the highest possible standard. Good procedures, training of personnel and ready availability of spill-control equipment are essential to prevent and limit the impact of accidents if they do occur. Upgrading fluid-disposal systems so that storage and separation tanks replace open pits (closed-loop systems) can reduce the risk of accidental discharge of wastes during drilling.

Treat water responsibly

- ***Reduce freshwater use by improving operational efficiency; reuse or recycle, wherever practicable, to reduce the burden on local water resources.*** Regulations covering shale and tight gas production (coalbed methane operations are net producers of water) need to be designed to encourage operators to use water efficiently and to reuse and recycle it. The largest volumes of water are required for hydraulic fracturing: where the necessary economies of scale are present, it should be feasible to reuse and recycle significant volumes of the flow-back water from fracturing operations, reducing the issues and costs associated with truck traffic and with securing water supplies and wastewater disposal.
- ***Store and dispose of produced and waste water safely.*** Within an overarching performance framework, rigorous and consistent regulations are needed to cover safe storage of waste water, with measures to ensure the robust construction and lining of open pits or, preferably, the use of storage tanks. Technology exists to treat produced and waste water to any standard, with the cost varying accordingly. It is

the responsibility of regulators to set and enforce appropriate standards based on local factors, including the availability of freshwater supplies and options for disposal, without diminishing the operators' ultimate responsibility for operation in accordance with evolving best practice standards. The least-cost solution for producers may not be the most economically optimal solution, when the potential long-term benefits of using treated water and the wider social and environmental costs of discharges into water courses or evaporation ponds are taken into consideration.

- ***Minimise use of chemical additives and promote the development and use of more environmentally benign alternatives.*** Disclosure of fracturing fluid additives can and should be compatible with continued incentives for innovation. The industry should commit to the development of fluid mixtures that, if they inadvertently migrate or spill, do not impair groundwater quality, or adopt techniques that reduce the need to use chemical additives.

Eliminate venting, minimise flaring and other emissions

- ***Target zero venting and minimal flaring of natural gas during well completion and seek to reduce fugitive and vented greenhouse-gas emissions during the entire productive life of a well.*** Best practice is to recover and market gas produced during the completion phase of a well, and public authorities need to consider imposing restrictions on venting and flaring and specific requirements for installing equipment to help minimise emissions. Measures in this area will also lower emissions of conventional pollutants, including VOCs. Operators should consider setting targets on emissions as part of their overall strategic policies to win public confidence that they are acting to minimise the environmental impact of their activities, taking into account the financial benefits of commercialising the gas that would otherwise be vented or flared. The gas industry as a whole, including conventional gas producers and companies operating in the midstream and downstream, needs to demonstrate that they are just as concerned by methane emissions beyond the production stage, for example in transportation and distribution.
- ***Minimise air pollution from vehicles, drilling rig engines, pump engines and compressors.*** Pollution from vehicles and equipment is often controlled by existing environmental and fuel-efficiency standards (it is a responsibility of governments to ensure that appropriate standards are in place). Operators and service providers should consider the advantages of deploying the cleanest vehicles and equipment available, for example, electric vehicles and gas-powered rig engines, to reduce both local air and noise pollution.

Be ready to think big

- ***Seek opportunities for realising the economies of scale and co-ordinated development of local infrastructure that can reduce environmental impacts.*** Investments in infrastructure to reduce environmental impacts that may be commercially impossible to justify for an individual well can be justified for a larger development. Good regulation can help to realise these gains by ensuring appropriate spatial planning of licensing areas and of the associated infrastructure (such as access roads, water resources and disposal facilities, gas processing units, compression stations and pipelines). The concept of utility corridors and multi-use rights of way can be useful to concentrate infrastructure development and so limit the wider environmental impacts. Operators can realise these gains in various ways, for example by drilling multiple wells from a single pad (with horizontal bores tapping different parts of the reservoirs): this may result in greater disruption in the immediate vicinity of the site but can significantly reduce the wider environmental footprint. Another example is the construction of a pipeline network for water that requires upfront investment but obviates the need for many thousands of truck movements over the duration of a project and can lower unit costs.[19] Good project and logistical planning by operators needs to go hand-in-hand with early strategic assessments and timely interventions by public authorities.
- ***Take into account the cumulative and regional effects of multiple drilling, production and delivery activities on the environment, notably on water use and disposal, land use, air quality, traffic and noise.*** Development of any hydrocarbon resource involves a large amount of activity to build the necessary infrastructure, bring in supplies, drill wells, extract the resource, process it and transport it to market. This activity is enhanced for unconventional developments, because of the larger number of wells required. As a result, the level of activity that might be tolerable for individual wells, such as volumes of road traffic, land and water use or noise from drilling activity, can increase by orders of magnitude. Regulators need to assess the cumulative impact of these effects and respond appropriately. Assessment on a regional basis is particularly important in the case of water requirements.

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[19] See the next sub-section for an assessment of the impact of such infrastructure developments on project costs; this is also covered in a recent paper on water management economics for shale gas developments (Robart, 2012).

Ensure a consistently high level of environmental performance

- ***Ensure that anticipated levels of unconventional gas output are matched by commensurate resources and political backing for robust regulatory regimes at the appropriate level, sufficient permitting and compliance staff, and reliable public information.*** An important focus for governments should be on ensuring there is a sufficient knowledge base on all environmental and technical aspects of unconventional gas development, that high-quality data are available and that sound science is being applied and promoted. Well-funded, suitably skilled and motivated regulators, in sufficient numbers, are essential to the responsible development of an unconventional resource.
- ***Find an appropriate balance in policy-making between prescriptive regulation and performance-based regulation in order to guarantee high operational standards while also promoting innovation and technological improvement.*** In some areas, detailed rules and checks are indispensable to guarantee environmental performance; but it is not always possible, or desirable, to regulate every aspect of a process in which technology is moving rapidly. Setting performance criteria and allowing operators to find the best way to meet them can often provide a better outcome than a prescriptive approach. Examples of performance criteria might be a mandated minimum level of improvement in water usage or a requirement that a "best-in-class" cement quality measurement is run, the burden being on the operator to prove the use of best-in-class. Whichever approach or combination of methods is chosen, there needs to be strict enforcement and penalties in the case of non-compliance, ultimately including loss of the licence to operate.
- ***Ensure that emergency response plans are robust and match the scale of risk.*** Operators and local emergency services should have robust plans and procedures in place to respond quickly and effectively to any accident, including appropriate training and equipment.
- ***Pursue continuous improvement of regulations and operating practices.*** Technology and best practice are constantly evolving. While respecting the advantages of clarity and stability in regulation, governments must be ready to incorporate lessons learned from experience in a dynamic industrial sector. For industry, following best practice means constant readiness to raise standards and providing the means to meet them.
- ***Recognise the case for independent evaluation and verification of environmental performance.*** Credible, third-party certification of industry performance can provide a powerful tool to earn and maintain public acceptance, as well as providing a powerful tool to assist companies to adhere to best practices. These independent assessments should come from institutions that enjoy public trust, whether academic or research institutes or independent regulatory or certification bodies.

Complying with the Golden Rules

Application of these Golden Rules requires action to be taken by both governments and industry. While the ultimate responsibility for sustaining public confidence rests with the industry, it is governments that that need to set the regulatory framework, promulgate the required principles and provide support through many related activities, *e.g.* scientific research. Trying to specify precisely the roles of governments, gas producers and other private sector operators in each area is not practicable on a global scale. Conditions vary from country to country, including the legal, geological, social and political background, farming/land-use practices, water availability and many others.[20] But the general principles are clear and, in the sections that follow which examine the implications of the Golden Rules for governments and for industry, we have included some observations on the allocation of responsibilities between the public authorities and operators.

Implications for governments

Ensuring responsible development of unconventional gas resources, in line with these Golden Rules, puts substantial demands on policy-makers and regulators. First and foremost, the intensive nature of unconventional gas developments – and the scope for rapid growth in unconventional supply discussed in Chapter 2 – means that existing regulatory arrangements may have to be revised and licensing, compliance and enforcement staff reinforced. The need for new regulatory bodies may need to be considered or, more likely, existing ones may require new resources, functions and powers. This reinforcement of capacity needs to anticipate the expansion of industrial activity, so an appropriate regulatory regime is in place in good time. In keeping with regulatory best practice, such regulators will need to be independent of industry (although this certainly does not exclude ongoing consultation with industry), and have the right (often new) skills and funding. Scope exists to secure the necessary funding from industry in advance of development, for example through fees attached to the award of exploration rights.

The overarching challenge for policy-makers, to find the right balance between the need to minimise adverse environmental and social impacts while encouraging the responsible development of resources for the benefit of the local and national economy, will require judgement at the highest political level. Once that judgement is made, operational decisions of considerable weight remain to be made, for example as to the level of detail required in regulating industry operations – detailed or prescriptive provisions may be necessary, but they can also deny legitimate scope for operators to minimise costs and can impose onerous monitoring and enforcement responsibilities on regulators; performance-based regulation can work better in many areas, particularly for an industry in which technology is changing quickly.

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[20] Examples of regulation and best practice, from different countries, in areas covered by these Golden Rules are available on the IEA website at http://www.worldenergyoutlook.org/goldenrules.

In a number of jurisdictions, significant advances have been made in regulatory arrangements in recent years. However, the situation is very dynamic and industry has the capacity to expand rapidly; governments in resource-rich areas need to act quickly to anticipate future needs and to put the necessary measures in place. The challenge for governments and regulators can be acute in relation to water resources and the risk of water contamination. Rigorous data collection, assessment and monitoring of water requirements (for shale and tight gas), and measurement of the quality of produced water (for coalbed methane) and of waste water (in all cases) are needed to allow informed decisions to be made. Existing users are deeply suspicious that their rights and water availability might be compromised. There is a need, among other things, for transparent, speedy and equitable procedures for compensating existing users who suffer loss.

Box 1.6 ▻ Getting the market setting right

Alongside attention to environmental issues, there are many other policy areas that affect the prospects for unconventional gas development, including: the terms for access to resources; clarity on mineral rights; a consistent fiscal and overall investment framework; the provision of infrastructure; and the structure and regulatory framework in a given market (see also the assumptions underpinning the projections in Chapter 2). Market developments are at varying stages in different countries and regions. North America has well-functioning gas markets and, to take one example, many observers consider reliable third-party access to pipelines has been a pivotal part in its unconventional gas development by giving gas producers confidence that their new gas output will be able to reach market. Other key supportive market or regulatory conditions for gas production (both conventional and unconventional) include: the removal of wellhead price controls; the absence of undue restrictions on trade and export; a competitive upstream environment that encourages innovation; and efficiency and market-based pricing for gas. While these market conditions have been under discussion for many years in most OECD jurisdictions, implementation of the necessary reforms remains at best incomplete; and the challenges are greater in many non OECD countries.

Governments everywhere have a central role in ensuring a sound, scientific, credible, knowledge base is publicly available prior to widespread development. Policy-makers and regulators themselves need access to the necessary expertise in order to understand and mitigate the environmental risks.[21] Baselines for various indicators, water in particular, are critical in this regard, but this requirement also encompasses basic geological and geophysical information. Good quality data are essential, not just as an input to good

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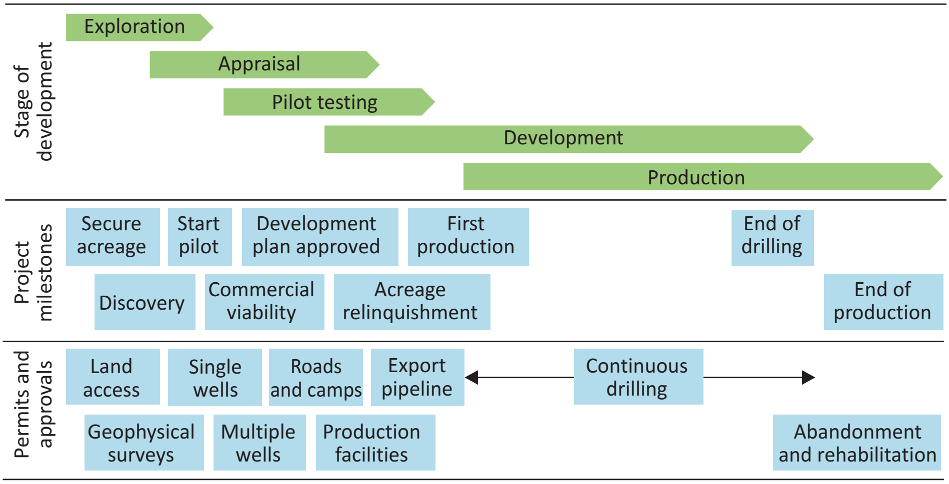
[21] An example is the decision of the Australian Government in late 2011 to establish an expert Scientific Committee, funded with AUD 150 million ($150 million) over four years, to oversee regional assessments and research on water-related impacts in areas where coalbed methane developments are proposed.

policy-making, but also to make it possible to demonstrate that the regulatory system is functioning effectively and to identify areas where improvements are needed.

Within large federal systems (for example the United States, Canada and Australia) environmental powers are usually exercised at state or provincial level, facilitating approaches that respond to local factors, such as the geology, the chosen technology and specific environmental risk factors. Local social and environmental concerns are often best dealt with at local levels. Clarity is often required as to the division of responsibilities between different levels of government, with the national authorities responsible for ensuring reasonable consistency of regulation and that adequate funding is available for region-wide work (for example, in river systems that cross internal or international boundaries).

Figure 1.6 ▻ **Stages in an unconventional gas development**



Note: The stages, milestones and permits shown here are not unique to unconventional developments, but the distinctive element is the overlap between stages of development, as opposed to a more sequential pattern for a typical conventional project.

Differences between the way in which conventional and unconventional resources are developed need to be taken into account in designing an effective legal and regulatory system. Conventional oil and gas developments generally follow a fairly well-defined sequence, but the distinctions between the phases of an unconventional development can be much less clear-cut – development generally proceeds in a more incremental fashion (Figure 1.6).[22] At any given time an operator may be exploring or appraising part of a

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[22] Often, the initial question is not whether the unconventional resource exists but whether the gas or liquids can be produced in a particular location at economic flow rates. Whereas each appraisal well of a conventional reservoir tends to increase knowledge about the overall reservoir structure and its limits, it is much more difficult with an unconventional play to extrapolate the results of individual appraisal wells to the acreage as a whole.

licence area, developing another part and producing from a third, with different regulatory approvals and permits applying at each stage. The blurred lines between the stages of an unconventional resource project development increase the complexity of the interactions between operator and regulators (and between the operator and local communities) throughout the life cycle of the development. For example, the regulatory system in most jurisdictions requires the submission and approval of a detailed field development plan at the end of the exploration phase. However, the longer learning curve for unconventional plays makes it much more difficult to develop comprehensive plans at this stage, with the risk that relatively small subsequent alterations might trigger the need to resubmit and re-approve the entire development plan – a lengthy and burdensome process for both sides.

Beyond their focus on the proper construction of individual wells and installations, regulators also need to take a broader view of the impact of multiple projects and wells over time. This broader scope is essential when it comes to assessments of water use and disposal and of future water requirements, but can be also required in other areas, including land use, air quality, traffic and noise. In general, a regulatory system that focuses primarily on well-by-well approvals rather than project level authorisations, can fail to provide for some environmental risks and miss opportunities to relieve them. For example, there are investments in infrastructure that may not proceed for an individual well but which would serve appreciably to reduce the cumulative environmental impacts of large-scale development, such as centralised water treatment plants or pipeline networks for water supply or removal (see below). One of the ways that a regulatory framework can facilitate this sort of investment is through issuing licences for sufficiently large areas and durations.

Governments are usually instrumental in promoting the co-ordinated and timely expansion of regional infrastructure alongside a gas development, including either directly putting in place alternatives to road transportation or ensuring that the regulatory framework serves to encourage or require the construction of gas transportation capacity or an expansion of local power supply. Either way, strong co-ordination and communication is necessary between different branches and levels of government, as the rapid growth of a new industry puts pressure not only on the local physical infrastructure, but also on local social services.

Implications for industry

All parts of the unconventional gas industry have to contribute to proving to society that the benefits of unconventional gas development more than offset the costs in social and environmental terms. This entails, among other things, demonstrating that environmental and social risks are being properly addressed at all stages of a development: adoption and application in full of these Golden Rules is one way to support and accelerate this process. Elements of these Golden Rules are already being applied today, incorporated into best practice or embodied in regulation. The challenge is to ensure that the highest reasonable standards are in place and are applied and enforced in a consistent and credible way across the industry. Companies have to convince society that they have both the interest and the incentive to constantly seek ways of improving their performance.

There is a cost entailed. Compliance with these Golden Rules can in many cases increase the overall financial cost of development. How much will vary, depending on the starting point and on how each jurisdiction formulates its rules but, based on our analysis of the impact on the costs of a typical 2011 shale gas well (presented below), the additional costs are likely to be limited. For a single well, application of the Golden Rules can add around 7% to the overall cost of drilling and completion. The increase in costs could be significantly lower when considered across a full development project, as additional upfront capital costs incurred to reduce environmental impacts can, in many cases, be offset by lower operating costs.

Major cost elements in a shale gas well

The major cost elements in the drilling and completion of a shale gas well are the rig and associated drilling services, and the hydraulic fracturing stage of well completion. Well construction costs are primarily influenced by the geographical location, the well depth and, to some extent, reservoir pressure, and by the market and infrastructure conditions in the country or region under consideration. For example, a typical onshore shale gas well in the Barnett shale in Texas may currently cost $4 million to construct, while a similar well in the Haynesville shale costs twice as much, because of the depth and pressure. A similar well in Poland might cost $10 million to $12 million, because the current size of the market means that the drilling and service industry is much less developed in Poland than in the United States.

In general, more technical services are required during drilling and completing a shale or tight gas well than for a similar onshore conventional gas well, which makes it more expensive. The cost of multi-stage hydraulic fracturing can add anything between $1 million and $4 million to the construction costs of a well in the United States, depending on location, depth and the number of stages. In a shale reservoir, when drilling a well with a long lateral section, roughly 40% of the total cost goes toward the drilling and associated hardware and the remaining 60% to well completion, of which multi-stage hydraulic fracturing is the largest component. In a conventional well, the completion cost would be only about 15% of the overall well cost.

Break-even costs of shale-gas production in the United States have fallen sharply in recent years, thanks to an increase in the proportion of horizontal wells, the length of horizontal sections and the number of hydraulic fracturing stages per well, as well as the benefits of ever-better knowledge and experience of the various resource plays. The share of horizontal wells in the total number of shale-gas wells drilled increased from less than 10% in 2 000 to well over 80% today. Over the same period, the average length of the lateral sections has increased from around 800 metres to well over 1 200 metres and the typical number of hydraulic fracturing stages has risen from single figures to around 20.[23]

Operational costs, similarly, vary with local conditions: for example, just as for drilling, operating costs in Europe are expected to be 30% to 50% higher than in the United States for a similar shale gas operation. Dry gas requires less processing than wet gas (gas containing a small fraction of liquid hydrocarbons), but also has lower market value, particularly in the current context of very high oil-to-gas price ratios in some markets.

It is worth noting that two of the key subsurface drivers of well cost – depth and well pressure – are expected to be higher in many of the areas being explored outside North America. On the other hand, for all unconventional deposits, there is considerable potential for cost savings through organising development so as to exploit economies of scale, learning, and optimising well selection and locations for hydraulic fracturing.

Impact on the cost of a single well

The typical shale gas well that we use as a basis for this analysis is not a "worst case" but rather a well of the type that was regularly drilled in 2011 into deep shale reservoirs (such as the Haynesville and Eagle Ford shale plays) in the United States, taking in many industry best practices that were not always systematically followed in the previous decade. The well is assumed to reach a vertical depth of the order of 3 000 metres, have a horizontal section of around 1 200 metres and be completed with 20 fracture stages using a total of 2 000 tonnes of proppant and 15 000 cubic metres of water (requiring 500 trucks). This type of well would typically be drilled in three sections of successively smaller diameter, each one being lined with steel casing and cemented in place before the next section is drilled.[24] The well considered is a development well rather than an exploratory well.

Such a well might be expected to cost $8 million, take a month to drill and a further month to complete. The hydraulic fracturing process accounts for around 40% of the total well cost – around twice as much as the second most expensive item, the rig itself. By comparison, a typical onshore conventional vertical gas well in the same area would cost around $3 million, with 40% being spent on the rig.

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[23] Some wells have lateral sections reaching up to 3 000 metres in length, with up to 40 individual geological zones for hydraulic fracturing, carried out one at a time. However, there are practical mechanical limits to the length of horizontal sections and multi-stages due to the pressure and temperature effect on the casing which mean that laterals longer than 1 800 metres or more than 20 fracture stages carry more mechanical risk (Holditch, 2010).

[24] Since the well being considered already had two barriers over the shallow aquifer region with hydrocarbons being produced through production tubing, we did not include an additional casing string in our calculation of the additional costs of compliance.

Applying the Golden Rules to this well would be expected to have the following effects on costs, summarising various elements of the Rules under four indicative headings:

- **Isolate wells and prevent leaks:** measures in this area could include increased spending on cement design, selection and verification, coupled with a slight increase in drilling time to ensure the quality of the well-bore and provide a contingency for remedial cementing, if required. For the purposes of our analysis, we have assumed that the cement would be designed to withstand all expected stresses over the life span of the well, including the stresses induced during the 20 stages of hydraulic fracturing. The well would be drilled with appropriate tools and mud to produce a smooth and regular well-bore, to ensure that the cement bonds tightly with the wall of the well. Flexible cements or cements incorporating other technical advances that give better performance against the design criteria would be used. The cement would be pressure-tested and measurements taken to validate the quality of the cement bond on the exterior casing wall, with a contingency for remedial work if required. The American Petroleum Institute (API) publishes comprehensive standards and best practices pertaining to the construction of wells to ensure their integrity so that they are leak-free. In our analysis, 10% was estimated as the increment to drilling and cementing service costs needed to take account of these measures.
- **Eliminate venting, minimise flaring and other emissions:** this could be achieved by installing separator equipment for the hydrocarbons when they are brought to surface. For the purposes of our analysis, we have estimated a 10% addition to the cost of services required during the flow-back phase (but have not assumed that it is offset by sales of the recovered oil or gas[25]).
- **Treat water responsibly:** measures in this area could involve upgrading of fluid-disposal systems to ensure zero discharge at any stage and maximum re-use of water, as well as the use of green fracturing fluids with minimum chemical additives. In our analysis, 10% has been added to the cost of hydraulic fracturing on this basis, and a further 10% to the cost of rig fluids and disposal.
- **Disclose and engage:** responsiveness to local community concerns might involve reducing the noise from rig operations by cladding the rig with sound-proof material or imposing trucking restrictions at times at which they would otherwise cause greatest local disturbance or risk of accident. $20 000 has been added to the rig cost to cover sound-proofing of the rig and 10% to the logistics cost to cover some trucking restrictions.

In addition to these measures, we have included other actions that would add little to the cost of operations but would increase understanding of the environmental impact of shale-gas operations and facilitate dialogue with stakeholders. Simple measurement of airborne

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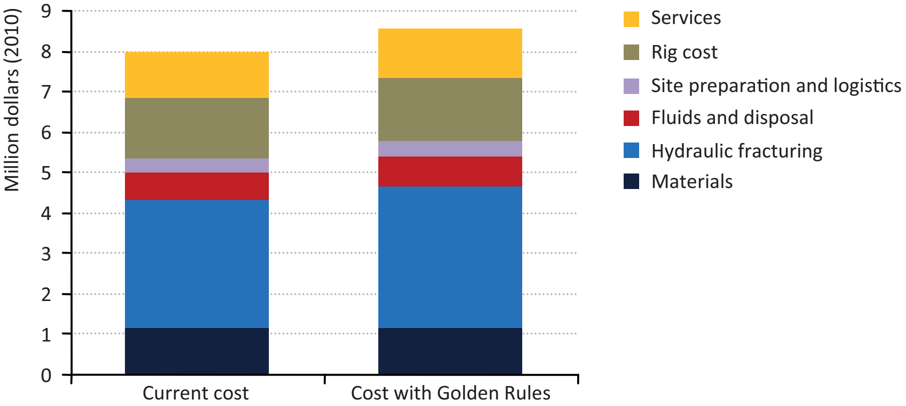
[25] According to the US EPA (EPA, 2011), general adoption of this type of "green completion" could also cut emissions of VOCs from new hydraulically fractured gas wells by 95%. The EPA further estimates that operators could expect to recover the additional cost associated with green completions within 60 days through the sale of captured hydrocarbons.

emissions at well sites in a consistent manner would provide valuable information to narrow the uncertainty around the extent of fugitive emissions of methane. Similarly, tests of local water wells that draw from an aquifer being drilled through would determine if there was contamination from any source. In total, we estimate that all the measures listed above would add around $580 000, or 7%, to the overall cost of drilling and completing this shale-gas well (Figure 1.7).

Figure 1.7 ▷ Impact of the Golden Rules on the cost of a single deep shale-gas well



Notes: Materials include all tangible material that is used in the well construction and remains in the well when it is completed, such as steel casing, valves and plugs.

Services include various services, other than hydraulic fracturing services, that are used in well construction: directional drilling services, cementing services, casing services, wire line and testing services.

Source: IEA analysis.

Impact on larger-scale developments

In practice, within a single licensing area, each operator typically drills a large number of wells at different sites. Applying the Golden Rules to entire unconventional gas developments could diminish the impact on overall production costs, because of economies of scale. While many of the environmental impacts discussed earlier in this chapter demand action chiefly where the scale of operations is large, large-scale operations also provide opportunities to minimise or eliminate environmental risks by optimising the process of drilling and completing each well. As the size of a development increases, measures to reduce environmental effects become both necessary and economically feasible (Figure 1.8), in a way that may not be possible for a single well.[26] In the case of gas, water and potentially

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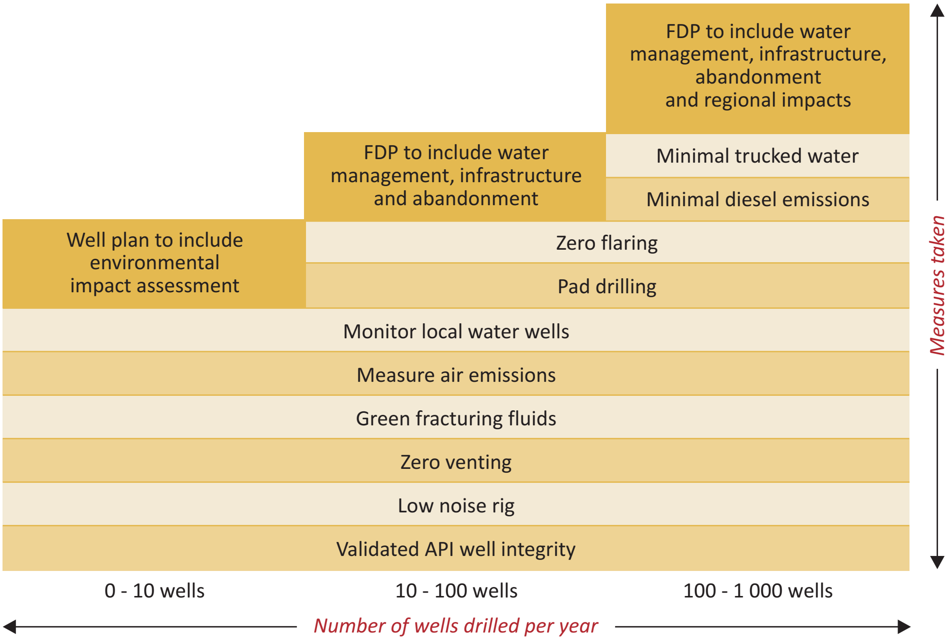
[26] Many best practices can and should be applied to all wells, regardless of the size of the development. However, practices such as pad drilling, zero flaring and the minimisation of diesel emissions or trucked water involve the installation of infrastructure that, as well as not being cost effective, might even cause more environmental disruption if serving only single wells. For example, the number of truck journeys required to install water pipelines to a single isolated well would probably be more than the number of truck journeys required for the water itself.

electricity networks, greater upfront capital expenditure is required, but operating costs can be reduced, leaving the overall economics of a large-scale development no worse and in some cases improved.

Figure 1.8 ▻ **Indicators of best practice as unconventional gas developments grow in size**



Notes: FDP = Field Development Plan; API = American Petroleum Institute Standards.

A well thought-out field development plan, based on a thorough environmental impact assessment, can help to capture these economies of scale and ensure that the hazards are well identified and that preventative or mitigating measures are in place. A key assumption in our analysis is that operators are able to plan developments optimally, both in space and in time. For this, licensing areas need to be large enough and be held for periods that are long enough for efficient development planning and the sharing of infrastructure. This needs a supportive regulatory framework.[27] Realising these gains also tends to rely on early investment in project infrastructure, often before production comes on stream and revenues start to flow: this can be a constraint for smaller companies, particularly where they are investing in marginal developments.

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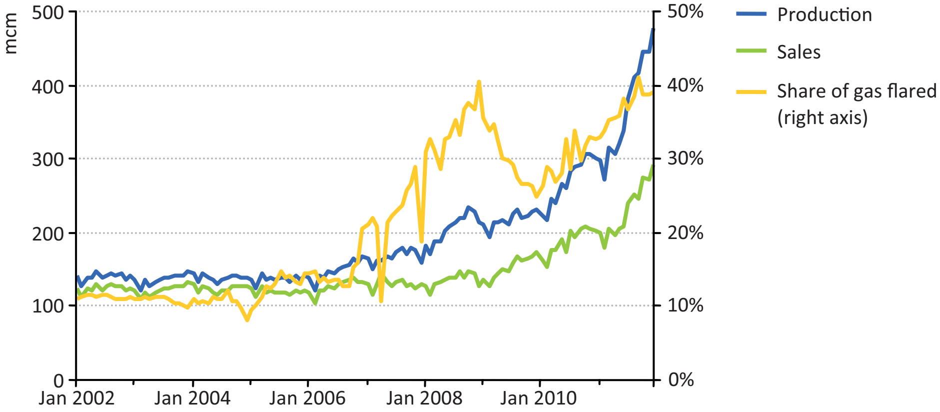
[27] In certain regions of the United States, this is not possible due to smaller acreage blocks and lease expiration acting as a driver for development planning.

Good logistics and project planning is essential, both from the industry and from the public authorities, in view of the envisaged scale of a development. It is particularly important that infrastructure development keeps pace with upstream activity as the consequences of failure to do so can fall on the environment. For example, Figure 1.9 illustrates how the rapid development of light tight oil production in the Bakken shale was accompanied by a rise in the flaring of associated gas, as the necessary increase in gas transport infrastructure did not occur at the same pace as the increase in drilling.

Figure 1.9 ▷ Monthly natural gas production and flaring in North Dakota



Source: North Dakota Mineral Resources Department.

For the purposes of our analysis of the implications of applying the Golden Rules at scale, we considered a development of 120 wells per year.[28] In order to be able to plan and implement the types of measures described in Figure 1.8, the licensing area would need to comprise contiguous blocks and be held for at least a ten-year period, with freedom to develop according to the best environmental plan (rather than drilling to retain leases or avoid relinquishment clauses).

For this scale of development, we envisaged the following:

- **Zero venting or flaring of gas at all stages of operations:** this would require the installation of test equipment and gas-gathering infrastructure before any wells are completed. The scale of operation would mean that it would be economically viable to have this equipment dedicated to the development, although it remains challenging to estimate expected production rates with sufficient accuracy to ensure that the infrastructure is correctly sized. The early installation of gas-gathering infrastructure would bring forward capital expenditure, but would not increase the net cost, as any additional charges, including interest charges, would probably be offset by the value of the gas captured. *Estimated cost impact on a large-scale development: neutral.*

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[28] We considered ten rigs drilling eight wells from each pad, where the drilling phase of each well lasts 30 days, including the rig move. Thus, each rig would move every eight months to a new pad location.

- **Zero in-field trucking of water within the concession area:** this is an area where regulation and licensing requirements can play an important role. If these facilitate the necessary investment, capital expenditure on building water supply pipelines could be offset over the ten-year period by the reduction in truck movements. *Estimated cost impact: neutral.*
- **Central purpose-built water-treatment facilities:** these facilities, allowing closed-loop recycling of waste water, could be linked by pipeline to each pad location. They would reduce the overall water supply required for operations and minimise the need for off-site disposal, thereby reducing total transportation, water and disposal costs. Based on industry case studies, *we estimate savings at $100 000 to $150 000 per well*.
- **A long-term monitoring program for the development:** this could take different forms but might include performing a 3-D seismic survey over the licensing area before drilling commences to establish a geological baseline for the location of faults and sweet spots, as well as the temporary or permanent installation of micro-seismic monitoring to monitor seismic events and the propagation of fractures, and the installation of equipment to monitor the quality of water in aquifers that are being drilled through. *We estimate the additional cost of these three measures at between $100 000 and $150 000 per well.*
- **Systematic learning about the shale:** this could involve taking the opportunity provided by each well to learn more about the reservoir by capturing data (typically by using down-hole measuring instruments) that will enable the character and behaviour of the shale to be better understood. This understanding is an important contributory factor in improving the operational performance (and therefore the environmental impact per unit of production) of each well drilled and in eliminating wells and fracture stages that do not contribute significantly to production. *We estimate the additional cost at $200 000 per well.*

Most of these measures would involve a marginal increase in the overall cost of a large-scale development. But there is potential for reducing costs through better planning of operations, which would also reduce environmental risks:

- **Exploiting economies of scale:** pad drilling and the associated ability to carry out simultaneous operations on more than one well has been shown to bring significant cost savings as well as reducing the total surface footprint. Typically the drilling phase of a number of wells on the pad would be finished first, enabling the completion phase to be carried out for multiple wells in parallel. "Simultaneous operations" of this sort can allow for more efficient use of equipment for hydraulic fracturing. The US company, Continental Resources, has reported a 10% drop in average well cost in the Bakken Shale, from $7.2 million to $6.5 million, by using such an approach at eight well pads. Other industry sources report savings of up to 30%, due to a combination of economies of scale and improvements in operational efficiency. *On this basis, we have estimated savings of 10% per well.*

- **Optimising the number of fracture stages:** this can achieved by acquiring better information about where the sweet spots are likely to be and fracturing only in those zones, rather than simply fracturing every 100 metres, with no science applied. Industry data from different shale plays in the United States show that, on average, between 30% and 40% of fractures do not contribute any production at all. We have assumed conservatively that at least two hydraulic fracturing stages out of twenty could be saved as a result of better reservoir characterisation by systematically learning about the shale. *This would represent a cost saving of around $400 000 per well or equivalent gains in production for the same number of stages.*
- **Learning from experience:** there is a learning curve associated with the drilling and completion of shale-gas wells that, on a large scale of development, can bring significant cost savings as time goes on: these savings are often quoted in conjunction with economies of scale and the optimisation of fracture stages. *For the purposes of our analysis, we have not added any additional saving related to the learning curve.*

Summing up the effects of the more stringent environmental measures applied to the development and the efficiency savings from better planning yields an overall net cost saving of approximately 5%. Most of these savings come from economies of scale and reduced hydraulic fracturing, which more than offset the additional cost of implementing well-specific measures and monitoring environmental effects.

There is potential for even larger cost savings in large-scale developments by optimising the number and location of wells drilled. Given the enormous variability in geology, there are significant variations in the economics of unconventional gas wells, driven largely by differences in the expected cumulative output of each one (referred to as Estimated Ultimate Recovery [EUR]). The ability of operators to locate sweet spots within an unconventional gas play, where output is particularly high, (or their good fortune in doing so) explains a large part of the difference in EUR between wells. The adoption of advanced technologies in drilling and completing wells can also help to increase EUR.

At present, in the vast majority of shale gas developments wells are drilled and hydraulically fractured "geometrically", that is to say at regular intervals, without regard for the changing geology between those intervals. Some wells give very good initial production and others close to zero. A detailed study of more than 7 000 wells in the Barnett Shale in *WEO-2009* showed that half of the horizontal wells drilled were unprofitable, even at the 2009 gas price of $6 per MBtu, while some others were profitable at much lower prices (IEA, 2009). This reflects differences in the amount of gas produced, itself a reflection of the local geology of the formation, but also of differences in the suitability and effectiveness of the well design and hydraulic fracturing operations. Reservoir characterisation and modelling techniques for shales is applied only in a limited manner at present. It is not unreasonable to expect that, had there been smarter selection of drilling targets, the least profitable 20% of wells in our sample would not have been drilled at all. Better understanding of the science of hydrocarbon flows within unconventional gas reservoirs is needed for improved reservoir characterisation and modelling to be achieved (Box 1.7).

Box 1.7 ▷ The potential benefits of better petroleum science

For all the advances that have been made in shale gas production in the United States in recent years, a large number of wells that prove to be very unproductive are still being drilled. Often, the value of the gas and liquids they yield is insufficient to cover the cost, the losses on such wells generally being offset by other wells that prove to be very productive. In addition, recovery factors for shale gas and light tight oil are very low, compared to conventional reservoirs: estimates in most cases do not exceed 15% of the original oil and gas in place. A better scientific understanding of both the geological structure and hydrocarbon flows within shale and tight gas rock should allow producers to target better and to refine their drilling and well-completion operations, driving down the number of unproductive wells and pushing up the estimated ultimate recovery – a tremendous prize for all stakeholders.

Thus far, improvements in unconventional gas technology have largely been concerned with how, on a cost-effective basis, to pump more fluid into more fracture stages in longer horizontal sections in order to increase reservoir contact, and how to better manage the environmental effects. But while advances in drilling and hydraulic fracturing technology have unlocked unconventional reserves that were previously uneconomic, the science of the behaviour of the reservoirs is still not well understood. This makes it very hard to predict decline rates and the ultimate production potential of each play and individual areas and wells. Traditional methods of computer modelling and simulation of oil and gas reservoirs do not work well in the case of shale gas or light tight oil.

This scientific challenge has attracted a significant research effort from industry experts and academia. Breakthroughs in understanding the behaviour of shale and tight-gas reservoirs are expected and are likely to trigger a shift from the current "brute force" approach to production towards a more scientific one, enabling operators to avoid drilling poor wells and using ineffective well-completion methods. This would allow for more efficient use of water and other resources, minimising the environmental footprint and lowering production costs.

Chapter 2

The Golden Rules Case and its counterpart

How might unconventional gas re-shape energy markets?

Highlights

- In a Golden Rules Case, we assume that the conditions are in place, including the application of the Golden Rules, to allow for an accelerated global expansion of gas supply from unconventional resources, with far-reaching consequences for global energy markets. Greater availability of gas supply has a strong moderating impact on gas prices and, as a result, demand for gas grows by more than 50% to 2035 and the share of gas in the global energy mix rises to 25% in 2035, overtaking that of coal.
- Production of unconventional gas, primarily shale gas, more than triples in the Golden Rules Case to 1.6 tcm in 2035. The share of unconventional gas in total gas output rises from 14% today to 32% in 2035. Whereas unconventional gas supply is currently concentrated in North America, in the Golden Rules Case it is developed in many other countries around the world, notably in China, Australia, India, Canada, Indonesia and Poland.
- The Golden Rules Case sees a more diverse mix of sources of gas in most markets, suggesting an environment of growing confidence in the adequacy, reliability and affordability of natural gas supplies. An increased volume of gas, particularly LNG, looking for markets in the period after 2020 stimulates the development of more liquid and competitive international markets. The projected levels of output in the Golden Rules Case would require more than one million new unconventional gas wells to be drilled worldwide between now and 2035.
- In a Low Unconventional Case, we assume that – primarily because of a lack of public acceptance – only a small share of unconventional gas resources is accessible for development and, as a result, global unconventional gas production rises only slightly above 2010 levels by 2035. The competitive position of gas in the global fuel mix deteriorates as a result of lower availability and higher prices, and the share of gas in global energy use remains well behind that of coal. The requirement for imported gas is higher and some patterns of trade are reversed, with North America needing significant quantities of imported LNG, and the preeminent position in global supply of the main conventional gas resource-holders is reinforced.
- Although the forces driving the Low Unconventional Case are led by environmental concerns, it is difficult to make the case that a reduction in unconventional gas output brings net environmental gains. The effect of replacing gas with coal in the Low Unconventional Case is to push up energy-related CO_2 emissions, which are 1.3% higher than in the Golden Rules Case. Reaching the international goal to limit the long-term increase in the global mean temperature to two degrees Celsius would, in either case, require strong additional policy action.

Paths for unconventional gas development

There are factors on both the demand and supply sides pointing to a bright future for natural gas, but the key element in the supply outlook is the growth in production of – and expectations for – unconventional gas resources. For the moment, production of unconventional gas is still overwhelmingly a North American phenomenon: in 2010, 76% of global unconventional gas output came from the United States (360 billion cubic metres [bcm]) and a further 13% from Canada (60 bcm). Outside North America, the largest contribution to unconventional gas production came from China and Australia, producing around 10 bcm and 5 bcm of coalbed methane, respectively.[1] But, in light of the North American experience and with evidence of a large and widely dispersed resource base, there has been a surge of interest from countries all around the world in improving their security of supply and gaining economic benefits from exploitation of domestic unconventional resources.

Box 2.1 ▻ Overview of cases

This chapter sets out projections from two cases, for the period to 2035, which explore the potential impact and implications of different trajectories for unconventional gas development.

- A ***Golden Rules Case***, to which the main part of this chapter is devoted, assumes that the conditions are put in place to allow for a continued global expansion of gas supply from unconventional resources. This allows unconventional gas output to expand not only in North America but also in other countries around the world with major resources.
- A ***Low Unconventional Case*** considers the opposite turn of events, where the tide turns against unconventional gas, as environmental and other constraints prove too difficult to overcome.

These projections are assessed against an updated ***baseline***, which takes as its starting point the central scenario (the New Policies Scenario) from the most recent *World Energy Outlook*, *WEO-2011*. The two main cases test a range of favourable and unfavourable assumptions about the future of unconventional gas. A necessary, but not sufficient, condition of the Golden Rules Case is the effective application of the Golden Rules, in order to earn or maintain the "social licence" for the industry to operate. Neither case is advanced as more probable; they are rather designed to inform the debate about the implications of different policy choices for energy markets, energy security and for climate change and the environment.

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[1] A proportion of gas production in Russia is classified as unconventional, tight gas.

The potential is there for unconventional gas supply to grow rapidly in the coming decades, but the speed at which this supply will grow is still highly uncertain. Outside North America, the unconventional gas business is in its formative years, with major questions still to be answered about the extent and quality of the resource base and the ability of companies to develop it economically. Moreover, as discussed in Chapter 1, social concerns about the impact of producing unconventional gas, particularly the threat of unacceptable environmental damage, have risen as production has grown. Reports of water contamination, earthquakes, and other disruptions to local communities have given unconventional gas production, and the practice of hydraulic fracturing in particular, a bad name in many countries.

It remains to be seen how this social and environmental debate will play out in different parts of the world. In parts of Canada, the United States and Australia, moratoria have been placed on hydraulic fracturing, pending the results of additional studies on the environmental impact of the technology. Even in advance of any commercial production, similar prohibitions are already in force in parts of Europe. There is a distinct possibility that, if these concerns are not directly and convincingly addressed, then the lack of public acceptance in some countries could mean that unconventional production is slow to take off, or, indeed, falters at the global level.

This chapter examines two scenarios, the Golden Rules Case and the Low Unconventional Case (Box 2.1), in the first of which these challenges are overcome and a second in which they are not successfully addressed. The difference in outcomes between them posits a critical link between the way governments and operators respond to these social and environmental challenges and the prospects for unconventional gas production. The strength of this link differs among countries depending on the ways that public concerns and perceptions of risk affect political decision-making. But the assumptions underlying these cases reflect our judgement that the development of this relatively new industry is contingent, in many places, on a degree of societal consent that in some places has yet to be achieved. Moreover, the perception of the industry as a whole is likely to be cast by the performance of its weakest players, not its strongest. Without a general and sustained effort from both governments and operators, the public may not be convinced that the undoubted benefits outweigh potential risks.

Golden Rules and other policy conditions

The Golden Rules, presented and discussed in Chapter 1, are principles designed to minimise the undesirable effects of unconventional gas production on society and the environment. Implementing such principles is in many cases a question of appropriate regulation; but this is not the whole story. The task for policy-makers and regulators is to find the right equilibrium that deals convincingly with social and environmental concerns without removing the economic incentives for developing an important national resource. This balance will vary from country to country, given differing energy security, economic and environmental priorities.

In the Golden Rules Case, we assume that all resource-rich countries formulate their approach to environmental regulation of unconventional gas production in line with these principles and thereby achieve a level of environmental performance and public acceptance that provides the industry with a "social licence to operate". In that sense, the Golden Rules become a necessary (but not sufficient) condition for a wide expansion of unconventional gas supply.

In the Low Unconventional Case, this balance is not found and the Golden Rules are either not adopted or inadequately applied. Whether in response to new incidents of environmental damage or evidence of poor industry performance, the potential social and environmental threats are deemed to be too significant in some countries or regions, to the extent that there are substantial obstacles to developing the resource. Longer-lasting prohibitions are imposed in some countries on technologies that are essential to unconventional gas development, such as hydraulic fracturing, or exclusion zones are created and tight restrictions applied to drilling locations that restrict access to all or part of the resource. Alternatively, either a combination of very strict and detailed regulation imposes prohibitive compliance costs or fears about future regulatory change deter investment.

The application of these Golden Rules is not sufficient in itself to determine successful resource development in countries with unconventional gas potential. Based on experience in the United States, other key factors include:

- **Access to resources:** these considerations include access to geological data on a reasonable and transparent basis, the size of the area covered by a licence and the duration of the licence, and freedom for companies to engage in upstream activities on a competitive basis.
- **The fiscal and regulatory framework:** some countries have high potential in terms of resources but unattractive overall conditions for investment, such as unpredictable fiscal regimes or weak institutions.
- **Availability of expertise and technology:** not least because unconventional gas production requires a large number of wells, the industry needs a skilled and experienced workforce and a well-developed service sector with access to the necessary equipment.
- **Existing infrastructure:** although there are possibilities for small-scale gas gathering arrangements and direct conversion to power (or liquefied natural gas [LNG]), the density of the gas transport infrastructure in areas targeted for unconventional development is an important consideration, as is the existence of guaranteed access to this infrastructure.
- **Markets and pricing:** gas is relatively expensive to transport (compared with its well-head production costs and also with the cost of transporting oil) so companies will be attracted to resources with reliable, proximate markets that offer the necessary

incentives to develop the gas. The absence of market pricing in the host market can eliminate the commercial case for unconventional gas development.

- **Water availability:** water is essential to the production process for shale gas and tight gas (see Chapter 1), and competition with established users in water-stressed areas may constrain unconventional developments.[2]

Experience in the United States points to additional factors such as the number of entrepreneurial and independent companies willing to take the risk of venturing into a new industrial sector, which is coupled with their ability to mitigate market risk via well-developed financial markets. In the absence of widespread examples outside the United States, it is impossible for the moment to say which of the ingredients listed above are essential for large-scale unconventional gas development, which of them are merely desirable, and which might play only a limited role. What can be said, though, is that the mix of conditions and constraints varies by country: in some, environmental and social issues will be decisive; in others, the quality of the resource, the nature of the upstream supply chain, market conditions and prices, or the overall legal system and investment security, may be more significant.

Our general assumption in the Golden Rules Case is that all of the potential obstacles listed are either overcome or do not prove a serious constraint on unconventional gas development. A major motivation for supportive policies is assumed to be the desire of countries to secure the economic benefits of a valuable indigenous resource and, in many cases, also to improve energy security by reducing dependence on imported gas. The essence of the Golden Rules is that they bolster public confidence in the determination of public authorities and operators alike to overcome the social and environmental hazards, thereby creating a political environment that allows for the enactment of other policies encouraging investment in this sector. In the Low Unconventional Case, weak or absent political support deters the implementation of supportive measures for unconventional gas development, such as attractive fiscal and investment terms.

In the projections for the different cases, which are presented later in this chapter, the results of adopting the Golden Rules, in the Golden Rules Case, and the results of failing to do so, in the Low Unconventional Case, are compared against the outcome in a baseline case. This baseline case uses the central scenario of the *WEO-2011* (the New Policies Scenario) as its starting point, but incorporates more recent data, where these have become available, and certain new assumptions, such as the rate of GDP growth, which are described more fully later in the chapter. The baseline case sees natural gas prices converge towards the levels assumed in the *WEO-2011* New Policies Scenario, whereby prices in the United States reach $8.2 per million British thermal units (MBtu) in 2035 (in year-2010 dollars) and average import prices into Europe and Japan reach $12.2/MBtu and $14.2/MBtu respectively. However, the baseline case excludes the application in full of the

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[2] The *WEO-2012* will include a dedicated chapter on the links between energy and water use.

Golden Rules and the other supportive policies that generate faster growth in natural gas production in the Golden Rules Case.

Unconventional gas resources

Our projections depend, first, on the size of the available resource. Drawing on data from a variety of sources, we estimate that remaining technically recoverable resources of shale gas amount to 208 trillion cubic metres (tcm), tight gas 76 tcm and coalbed methane 47 tcm (Table 2.1). Russia and countries in the Middle East are the largest holders of conventional gas resources (and Russia has by a distance the largest overall gas resources). However, a large part of the world's remaining recoverable unconventional gas lies in countries or regions that are currently net gas importers and face increasing import dependency, such as China, and the United States, which before the recent boom in unconventional gas in North America was looking at the prospect of rising LNG imports (Figure 2.1). Different assumptions about the terms of access to the unconventional resource base in China and in the United States, and in other unconventional resource-rich countries around the world, are a main determinant of the variations between levels of production in the Golden Rules Case and the Low Unconventional Case.

Table 2.1 ▷ Remaining technically recoverable natural gas resources by type and region, end-2011 (tcm)

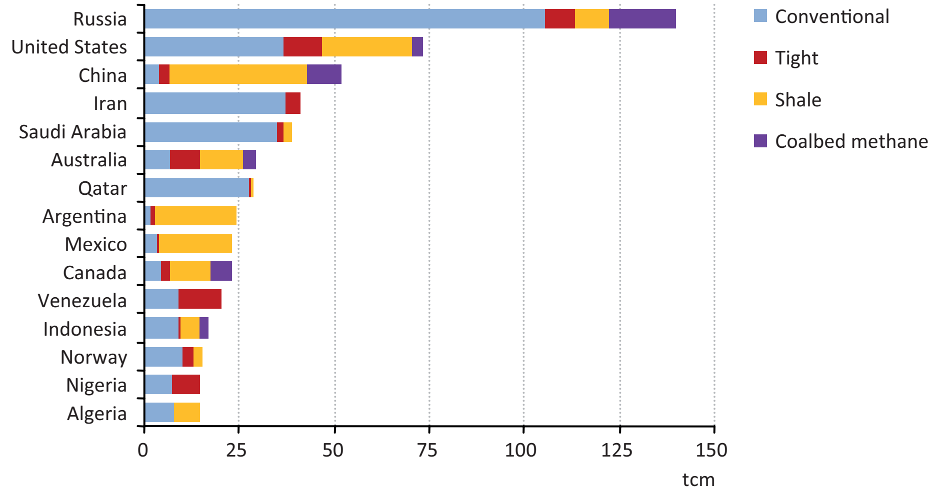
	Total		Unconventional		
	Conventional	Unconventional	Tight Gas	Shale Gas	Coalbed methane
E. Europe/Eurasia	131	43	10	12	20
Middle East	125	12	8	4	-
Asia/Pacific	35	93	20	57	16
OECD Americas	45	77	12	56	9
Africa	37	37	7	30	0
Latin America	23	48	15	33	-
OECD Europe	24	21	3	16	2
World	**421**	**331**	**76**	**208**	**47**

Source: IEA analysis.

Note: The resource estimate for coalbed methane in Eastern Europe and Eurasia replaces a figure given in the *WEO-2011* and in the *Golden Age of Gas* publications (IEA, 2011a and 2011b), which included a "gas-in-place" estimate for Russia instead of the estimate for technically recoverable resources.

Although they are undoubtedly large, unconventional gas resources are still relatively poorly known, both in terms of the extent of the resource in place and judgements about how much might be economically extracted. The industry is still in the learning phase when it comes to many resources outside North America: each unconventional resource play brings with it distinctive challenges and it has not yet been demonstrated that technologies well adapted to existing production areas can unlock the resource potential in all areas.

Figure 2.1 ▷ Remaining recoverable gas resources in the top fifteen countries, end-2011



Source: IEA analysis.

In particular for shale gas, our analysis and projections in this report rely on estimates from the pioneering work of Rogner (Rogner, 1997) and the landmark study from Advanced Resources International (ARI), published by the US Energy Information Administration (EIA) in 2011 (US DOE/EIA, 2011a); these are distinctive in applying consistent standards of evaluation to a large number of countries. On the one hand, resources could easily be even larger than indicated in these studies, as they do not examine all possible shale gas reservoirs around the world. On the other hand, several publications have provided estimates significantly lower than the ARI study: the United States Geological Survey (USGS), whose resource assessments are generally among the most authoritative, has recently published several regional studies indicating lower resources. This is the case, for example, for the Krishna-Godavari shale gas basin in India (USGS, 2012) for which they report a mean estimate of 116 bcm (4.1 trillion cubic feet [tcf]), compared with the ARI estimate of 765 bcm (27 tcf); this much more conservative estimate can be traced back to a smaller estimate for the productive area of the shale and to a smaller mean recovery per well (assuming the same drainage area).[3] Studies by the Polish Geological Institute with support from USGS also give a much lower estimate (a range of 346 bcm to 768 bcm versus the 5.3 tcm given in the ARI study[4]) for shale gas resources in Poland (PGI, 2012). China has

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[3] The methodologies used for the two studies are different. ARI first estimates gas-in-place and then applies a recovery factor. USGS estimates directly the recoverable resources based on recovery per well and well drainage areas derived by analogy with reservoirs in the United States for which data is available. The methodology used to determine well drainage areas has not been published yet by USGS, making it difficult to compare with industry-accepted values.

[4] The different resource estimates can have a substantial impact on the outcome of our projections: see the references to Poland in Chapter 3.

also released new estimates of shale gas resources that are about 20% lower than those given by ARI (MLR, 2012). The much talked-about USGS study of the Marcellus shale in the northeast United States estimated the undiscovered shale resources there at 2.4 tcm (84 tcf), much lower than the 11.6 tcm (410 tcf) recoverable resources reported by the US EIA in 2011 (USGS, 2011).[5] US EIA subsequently reduced their estimate for recoverable gas in the Marcellus to 4 tcm (141 tcf) (US DOE/EIA, 2012).

Estimates of coalbed methane resources are drawn from the German Federal Institute for Geosciences and Natural Resources (BGR, 2011) and US EIA. Tight gas resources are generally poorly defined and known: the exceptions are the United States, Canada and Australia, for which national resource data are used. Tight gas resource estimates for other countries are derived from Rogner.

In the Golden Rules Case, the entire resource base for unconventional gas is assumed to be accessible for development, including in countries and regions where moratoria or other restrictions are currently in place. In the Low Unconventional Case, however, the constraints imposed by the absence of supportive policies (in particular the Golden Rules themselves) and the uncertainties over the size and quality of the resource base were modelled by assuming that only a small part of the ultimately recoverable unconventional resource base is accessible for development. The key assumptions by country or region for the Low Unconventional Case are:

- **United States**: only 65% of tight gas, 45% of coalbed methane and 40% of shale gas resources are accessible. For shale gas, this could, as an example, correspond to excluding all new developments in the northeast United States[6], in California and in the Rocky Mountains, while the more traditional oil and gas producing regions, such as Texas, Oklahoma or the Gulf Coast, would continue to develop their shale resources. Alternatively, restrictions could apply to some parts of the prospective acreage in all regions, such as the more densely populated parts, or those with serious competition in uses for water. For coalbed methane, this could essentially restrict developments to regions that are already producing. Tight gas has been produced for many years in numerous traditional hydrocarbon-producing regions, so tight gas production is not assumed to be restricted as much as the other categories.

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[5] Strictly speaking, the USGS and US EIA numbers cannot be compared as USGS reports undiscovered gas resources while US EIA reports total recoverable resources, which differ from undiscovered by proven reserves and discovered-but-undeveloped resources. However, neither organisation has provided a breakdown of these three categories. Overall, unconventional gas challenges the usual definitions, as there is no real discovery process (the locations of most gas bearing shales in the world are already known); it is more an appraisal process: the process of establishing that a given shale, and/or what part of the shale, can produce economically. As a result the difference between undiscovered and discovered-but-not-developed is blurred and it is important to clarify the assumption used in various resources estimates.

[6] The *World Energy Model* (*WEM*) currently uses the US EIA 2011 resources numbers (US DOE/EIA, 2011b), before their downward revision for the Marcellus shale, pending publication of more details for the background of this revision. So the northeast United States, and the Marcellus shale in particular, represents about half of the estimated resources. Note that *WEM* treats the United States as a single region, so there is no projection of production by basin.

- **China**: only 40% of the coalbed methane and 20% of the shale gas resources are assumed to be accessible. Public acceptance is likely to be a lesser influence in China than in other countries (although we are looking forward 25 years and, if the changes that have occurred in the last 25 years in China are any guide, public sensitivity to environmental issues could become significantly greater during the projection period), but other factors could restrict the ambitious official plans for unconventional gas production (Box 2.4).
- **India**: only 30% of the coalbed methane and 20% of the shale gas resources are assumed to be accessible. The large projected gas import requirements of India make it unlikely that public opposition would force a complete ban. On the other hand, on current estimates, unconventional gas resources in India are not sufficient to make more than a dent in these imports and our assumption is consistent with a political decision to restrict development of all but the less contentious resource areas.
- **Australia**: only 40% of coalbed methane and none of the shale gas resources are assumed to be accessible. Development of both types of resources has already become controversial in Australia. About 5 bcm of coalbed methane was produced in Australia in 2010 and there are three large-scale projects underway to build LNG plants fed by coalbed methane. The restriction to 40% of available resources essentially amounts to no new projects being authorised beyond those announced.
- **Rest of the world**: no new unconventional gas resources are assumed to be developed outside Canada (for which we use percentages about half of those in the United States, to reflect similar dynamics, but the smaller part of the resources so far developed) and Russia (where, in any event, unconventional resources are not expected to play a significant role).[7]

Development and production costs

The costs of developing and producing unconventional gas are made up of several elements: capital costs, operational costs, transportation costs, and taxes and royalties. Capital costs, often called finding and development costs, are usually dominated by the costs of constructing wells. As discussed in Chapter 1 (under "Implications for Industry"), shale gas wells do cost more than conventional gas wells in the same conditions, because of the additional costs of multistage hydraulic fracturing; the same consideration applies to tight gas wells, for the same reason. Coalbed methane wells have so far been relatively cheap, compared with conventional gas wells, because production has been at shallow depths in regions with well-developed markets. Operational costs, also called lifting costs, are those variable costs that are directly linked to the production activity: they may differ according to local conditions (but not necessarily between conventional and

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[7] This assumption about the rest of the world (with the partial exception of Canada and Russia) has the virtue of simplicity, although it is a little extreme in some countries that are already producing coalbed methane without any controversy; however, the amounts involved are too small to have any impact on prices or energy security.

unconventional gas produced under similar conditions). The cost of bringing gas to market is distance-dependent and is identical for conventional and unconventional gas.

The final element, taxes and royalties, varies greatly between jurisdictions; in addition to a profit tax component, it very often includes fixed or production-related taxes (paid to governments) and/or royalties (paid to the resource owner, which may or may not be governments). Countries or regions that have higher capital and operating costs, due to their geography or market conditions, often create a more attractive fiscal regime in order to attract investment. This can go as far as offering subsidies: China provides subsidies for coalbed methane and shale gas production.

On the basis of these costs, one can estimate a “break-even cost”, or “supply cost”, the market value required to provide an adequate real return on capital for a new project (normally taken to be 10% for a project categorised as risk-free and rising with incremental risk). This break-even cost does not apply to legacy production from largely depreciated installations. Lifting costs, transport costs, and taxes and royalties are usually directly expressed in US dollars per unit of gas produced. The significance of capital costs is very dependent on the amount of gas recovered per well. This also varies greatly: the best shale gas wells in the United States are reported to have Estimated Ultimate Recovery (EUR) of 150 to 300 million cubic metres (mcm) (5 to 10 billion cubic feet [bcf]); but many shale gas wells have EUR that is 10 or 100 times less. The average EUR varies from one shale to another, but also depends on the experience of the industry in a given shale: with time, the industry optimises the technologies used and extracts more gas from each well. Outside the United States, there is essentially no experience so far, but drilling longer horizontal wells should help improve EUR per well (in many jurisdictions in the United States, horizontal well length is limited by acreage unit size regulations).

It follows from the discussion of costs that the break-even costs for gas can vary greatly from one location to the next, or within a single country (Table 2.2). For example in the United States, break-even costs for dry gas wells probably range from $5/MBtu to $7/MBtu; gas containing liquids has a lower (gas) break-even cost, which can be as low as $3/MBtu, as the liquids add considerable value for a small increase in costs (associated gas from wells producing predominantly oil can have an even lower break-even cost). Since conventional gas resources are already fairly depleted onshore and most future conventional gas production will therefore come from more expensive offshore locations, the range of break-even costs for conventional and unconventional gas in the United States is fairly similar.

In Europe, the costs of production are expected to be about 50% higher, with a range of break-even costs between $5/MBtu and $10/MBtu. Conventional and unconventional gas are expected to be in the same range, as conventional resources are depleted and new projects are moving to the more expensive Norwegian Arctic. China has a cost structure similar to that of the United States, but shale reservoirs there tend to be deeper and more geologically complex; similarly, coalbed methane reservoirs in China tend to be in remote locations, so we estimate the break-even cost range to be intermediate between that of the United States and that of Europe – from $4/MBtu to $8/MBtu (although there are production subsidies in place that can bring this figure down). This estimate for China applies to both conventional and unconventional gas, as the easy conventional gas is depleting and production is moving to offshore or more remote regions. In countries that have large, relatively easy, remaining conventional gas, such as the Middle East, with break-even costs of less than $2/MBtu, the break-even cost range for unconventional gas is expected to be higher (similar to that for unconventional gas in the United States).

Table 2.2 ▻ Indicative natural gas well-head development and production costs in selected regions (in year-2010 dollars per MBtu)

	Conventional	Shale gas	Coalbed methane
United States	3 - 7	3 - 7	3 - 7
Europe	5 - 9	5 - 10	5 - 9
China	4 - 8	4 - 8	3 - 8
Russia	0 - 2, 3 - 7*	-	3 - 5
Qatar	0 - 2	-	-

* The lower range for Russia represents production from the traditional producing regions of Western Siberia and the Volga-Urals; the higher range is for projects in new onshore regions such as Eastern Siberia, offshore and Arctic developments.

In the Golden Rules Case, the development and production cost assumptions are not increased because of the application of the Golden Rules; as discussed in Chapter 1, the application of the Golden Rules does have some cost impact, but not sufficient to push up the costs of production significantly (and, possibly, not at all). The same starting point is used for development and production costs in the Low Unconventional Case; costs in this case, though, are subject to the general assumption (built into the modelling) that production tends to become more costly as a given resource starts to become scarcer. Since access to unconventional gas resources is limited in this case, the rate of increase in the costs of production is higher than in the Golden Rules Case.

Natural gas prices

The price assumptions in the Golden Rules Case and in the Low Unconventional Case vary substantially, reflecting the different regional and global balances between supply and demand in each case (Table 2.3). The price assumptions in the Golden Rules Case reflect the favourable outlook for unconventional gas supply that results from successfully addressing the potential barriers to its development. Greater availability of gas supply has a strong moderating impact on gas prices. Conversely, lower production of unconventional gas in the Low Unconventional Case means that higher natural gas prices are required to bring the different regional markets into balance.

Table 2.3 ▷ Natural gas price assumptions by case
(in year-2010 dollars per MBtu)

		Golden Rules Case		Low Unconventional Case	
	2010	2020	2035	2020	2035
United States	4.4	5.4	7.1	6.7	10.0
Europe	7.5	10.5	10.8	11.6	13.1
Japan	11.0	12.4	12.6	14.3	15.2

Note: Natural gas prices are expressed on a gross calorific value basis. Prices are for wholesale supplies exclusive of tax. The prices for Europe and Japan are weighted average import prices. The United States price reflects the wholesale price prevailing on the domestic market

North America is the region where the unconventional gas industry has grown most rapidly and, unsurprisingly, is also the region where the impact on markets and prices has thus far been greatest. Historically low prices are being obtained for natural gas, relative to other energy forms such as oil. More surprisingly, given the relative isolation of North American markets from other major gas-using regions, this development has already had profound international impacts. These have arisen because North America has become almost self-sufficient in gas, whereas many LNG investments in the decade 2000 to 2010 were made in the expectation that the North American region would be a substantial net LNG importer. Import infrastructure in excess of 100 bcm was built in the United States alone in this period, with matching LNG supply investments in major producers, such as Qatar. However, in 2011, net LNG imports to North America were less than 20 bcm, out of a total market exceeding 850 bcm: 8 bcm into the United States and 9 bcm into Mexico and Canada. Hence, major quantities of LNG supply became available for other global markets, including Asia and Europe.

Natural gas prices in the United States are assumed to rise from today's historic lows in both cases, but they increase much more quickly in the Low Unconventional Case. The contrasting future roles of North America in global gas trade in the two cases help to explain these different price trajectories. In the Golden Rules Case, the region becomes a significant net LNG exporter, on the back of continued increases in unconventional gas output in the United States and Canada and an expansion in LNG export capacity. Natural gas prices in the United States are assumed to reach a plateau of between $5.5/MBtu and $6.5/MBtu during the 2020s (the levels which we assume are sufficient to support substantial volumes of dry gas production) before rising to $7.1/MBtu in 2035. Exports at the levels anticipated in this case are relatively small, compared with the overall size of the United States' gas market, and do not play a decisive role in domestic price-setting (although they are significant for other markets). By contrast, in the Low Unconventional Case, North America remains a net importer of gas, with imports growing rapidly after 2025. With the region needing to draw its incremental gas supply from international markets, the natural gas price in the United States is pushed up much more quickly than in the Golden Rules Case, reaching $10/MBtu in 2035.

The weighted average import price assumptions for Europe and for Japan are likewise lower in the Golden Rules Case than in the Low Unconventional Case. Within this basic trend, differences between the two markets reflect the different balances between gas supply and demand in each case, as well as the various pricing mechanisms present and how these mechanisms are assumed to evolve. At present, gas prices are set freely in several markets, including North America, the United Kingdom and, to a somewhat lesser extent, Australia, an approach known as gas-to-gas competition. However, much of the gas traded across borders in the Asia-Pacific region is sold under long-term contracts, with linkages to the price of oil or refined products. Prices in continental Europe are predominantly oil-linked, though in recent years a mixture of the two systems (and many variations in between) has emerged, with oil-indexed prices co-existing – often uneasily – with prices set by gas-to-gas competition. We assume that pressure to move away from prices set by oil-indexation and towards those established through gas-to-gas competition is significantly greater in the Golden Rules Case than in the Low Unconventional Case.

In the Golden Rules Case, the United States is expected to play an important role in the evolution of international natural gas pricing mechanisms. Initial contracts for United States LNG exports have been written on the basis of the price at the main domestic natural gas trading hub (Henry Hub), plus liquefaction and transport costs, plus profit, rather than the traditional oil-price indexation prevailing in many of the markets where this gas will be sold. In the Golden Rules Case, this is assumed to put pressure on oil-indexed price formulas for natural gas, moderating gas price increases and provoking a greater degree of convergence in international prices towards those set by gas-to-gas competition. We do not, though, assume that this process of creating a single, liquid or competitive international gas market is completed in the Golden Rules Case (a situation in which natural gas price differentials between regions would reflect only the costs of transportation between them). An important moderating factor in importing regions, especially in Asia, is that most existing natural gas import contracts will continue to remain in force for many years and are based on oil indexation, so average prices cannot be expected to fall dramatically. In addition, some major new export projects (including, for example, from Canadian plants) are greenfield LNG operations, likely to push for traditional pricing arrangements. Hence, while the rise of North American LNG exports in the Golden Rules Case is a major development in global gas markets, we anticipate that wholesale prices in the United States remain at least \$5 to \$6 below Japanese import prices, with European import prices between these two.

Other assumptions

Both cases include updated assumptions on GDP, compared with the *WEO-2011*, with average annual GDP growth of 3.5% for the period 2012 to 2035, compared with 3.4% in *WEO-2011* for the same period (this allows the global economy in 2035 to reach the same overall size as assumed in *WEO-2011*). World population is assumed to expand from an estimated 7.0 billion in 2012 to 8.6 billion in 2035, as in *WEO-2011*. The projections for natural gas incorporate new demand and supply data by country and region for 2011, where these are available. Prices for oil, coal and carbon-dioxide (CO_2) are likewise updated to include new data for 2011, but they still converge towards the levels assumed in the central scenario of the *WEO-2011,* the New Policies Scenario. This means that the average IEA crude oil import price – a proxy for international oil prices – reaches $120/barrel in 2035 in year-2010 dollars (a nominal oil price of $212/barrel). The IEA steam coal import price increases to $112/tonne in 2035.

In the Golden Rules Case, to complement the impact on gas demand arising from lower prices that improve the competitive position of gas compared with other fuels, we also assume intervention by governments to foster demand growth in countries experiencing a large rise in indigenous gas production. In the United States, for example, supportive policies are assumed to facilitate increased use of natural gas in the road-transport sector, in particular for the commercial fleet. These additional demand-side policies are not included in the baseline case nor in the Low Unconventional Case, because the motivation for their adoption, *i.e.* higher indigenous production and lower prices, is absent.

Another notable change in policy assumptions, compared with the *WEO-2011*, occurs in Japan, where, pending the outcome of the ongoing review of Japan's Strategic Energy Plan, the future contribution of the nuclear sector to power generation is revised downwards in all cases.

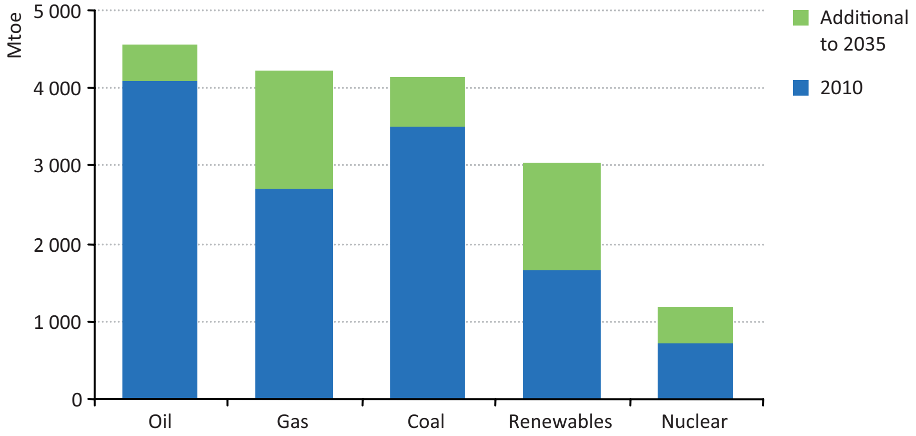
Otherwise, all assumptions remain constant from the New Policies Scenario of the *WEO-2011* (which takes into account policies and declared future intentions as of mid-2011), including the assumption that new measures are introduced to implement announced policy commitments, but only in a relatively cautious manner. These commitments include national pledges to reduce greenhouse-gas emissions and, in certain countries, plans to phase out fossil-fuel subsidies.

The Golden Rules Case

Demand

Global primary energy demand in the Golden Rules Case rises from around 12 700 million tonnes of oil equivalent (Mtoe) in 2010 to 17 150 Mtoe in 2035, an increase of 35%. Natural gas demand increases in the period to 2020 by more than 700 bcm (compared with 2010 levels), the equivalent of adding another United States to the global demand balance, and by a further 1.1 tcm in the period from 2020 to 2035, reaching a total of 5.1 tcm (4 230 Mtoe) in 2035. This is around 300 bcm, or 6%, higher than in the baseline case in 2035, with average annual growth over the projection period of 1.8%, compared with 1.5%. In the Golden Rules Case, gas accounts for about one-third of the overall increase in primary energy demand, a larger contribution than that made by any other fuel and equivalent to the growth in demand for coal, oil and nuclear combined (Figure 2.2). By 2035, natural gas has overtaken coal to become the second most important fuel in the energy mix.

Figure 2.2 ▷ **World primary energy demand by fuel in the Golden Rules Case**



Different rates of gas demand growth, albeit less pronounced than in the exceptional year of 2011[8], are expected to characterise gas markets in the longer term (Table 2.4). In the Golden Rules Case, 80% of the growth in gas demand comes from outside the OECD; China, India and the countries of the Middle East require an additional 900 bcm of gas in 2035, compared with consumption in 2010. In China and India and other emerging economies, natural gas at present often has a relatively low share of total energy consumption and its use is being specifically promoted as a way to diversify the fuel mix and reap some environmental benefits, often displacing coal as the preferred fuel to supply fast-growing urban areas. While growth in gas demand is healthy even in many of the more mature OECD gas markets – a development that is encouraged by the lower prices for natural gas in the Golden Rules Case – the growth in China alone is more than the anticipated growth in all of the OECD countries put together. Gas demand in China grows over the period 2010 to 2035 by 480 bcm, reaching a total of around 590 bcm in 2035 (larger than current gas demand in the European Union), meaning that developments on both the supply and demand sides in China will continue to have a substantial impact not just in the Asia-Pacific region but – via the wider effects on trade and prices – in markets around the world.

Gas used for generating power and heat is the single largest component of gas demand, accounting for around 40% of total gas consumed. Alongside the lower perceived risk of building gas-fired plants and the lower environmental impact, compared with other fossil fuels, the natural gas prices assumed in the Golden Rules Case improve the competitive

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[8] Preliminary data suggest that gas consumption in Europe declined by around 11% compared with the previous year, pulled down by warm weather, a sluggish European economy and a weak competitive position in the power sector compared with coal. This was in marked contrast to developments in the Asia-Pacific region: Korea and Japan showed a dramatic upsurge in demand for LNG, the latter linked to reduced output of nuclear energy following Fukushima, and Chinese gas demand continued its meteoric rise, becoming a larger gas consumer than any OECD country except the United States. The United States also saw growth in consumption, of around 2.5%, spurred by low prices that neared $2/MBtu in late 2011.

position of natural gas and push up gas demand for power generation to more than 2 tcm by 2035. The role of gas in power generation increases from 22% to 24%, with coal and oil (the latter a marginal fuel in power generation) ceding share in response. Gas use in buildings and in industry also increases substantially, reaching 1 060 bcm and 970 bcm respectively by the end of the projection period.

Table 2.4 ▻ Natural gas demand by region in the Golden Rules Case (bcm)

	2010	2020	2035	2010-2035*
OECD	**1 601**	**1 756**	**1 982**	**0.9%**
Americas	841	921	1 051	0.9%
United States	*680*	*717*	*787*	*0.6%*
Europe	579	626	692	0.7%
Asia Oceania	180	209	239	1.1%
Japan	*104*	*130*	*137*	*1.1%*
Non-OECD	**1 670**	**2 225**	**3 130**	**2.5%**
E. Europe/Eurasia	662	736	872	1.1%
Russia	*448*	*486*	*560*	*0.9%*
Asia	398	705	1 199	4.5%
China	*110*	*323*	*593*	*7.0%*
India	*63*	*100*	*201*	*4.7%*
Middle East	365	453	641	2.3%
Africa	101	130	166	2.0%
Latin America	144	200	252	2.3%
World	**3 271**	**3 982**	**5 112**	**1.8%**
European Union	*547*	*592*	*644*	*0.7%*

* Compound average annual growth rate

Although volumes are small compared with the other end-use sectors, the Golden Rules Case sees strong growth in gas use in the transport sector. This is encouraged both by lower prices, compared with oil, and also by government policies, for example support for developing the necessary refuelling infrastructure. Use of natural gas for road transportation increases by more than six times in the period to 2035, reaching close to 150 bcm in 2035. For the moment, transport is the only major end-use sector where gas is not widely used: although there are viable natural gas vehicle technologies, there are only a few countries where these are deployed at scale. More than 70% of all natural gas vehicles and half of all fuelling stations are found in just five countries: Pakistan, Iran, Argentina, Brazil and India. In our projections, India and the United States lead the growth in natural gas consumption for transport, primarily in commercial fleets, buses and municipal vehicles that can use central depots for refuelling.

Implications for other fuels

The implications of applying the Golden Rules to unconventional natural gas extend beyond gas to other competing fuels. As the share of gas rises from 21% of global primary energy consumption in 2010 to 25% by 2035 (compared with 23% in the baseline case), growth in demand for oil and coal is constrained and, marginally, also demand for nuclear and renewable energy (Table 2.5).

Table 2.5 ▷ World primary energy demand by fuel in the Golden Rules Case

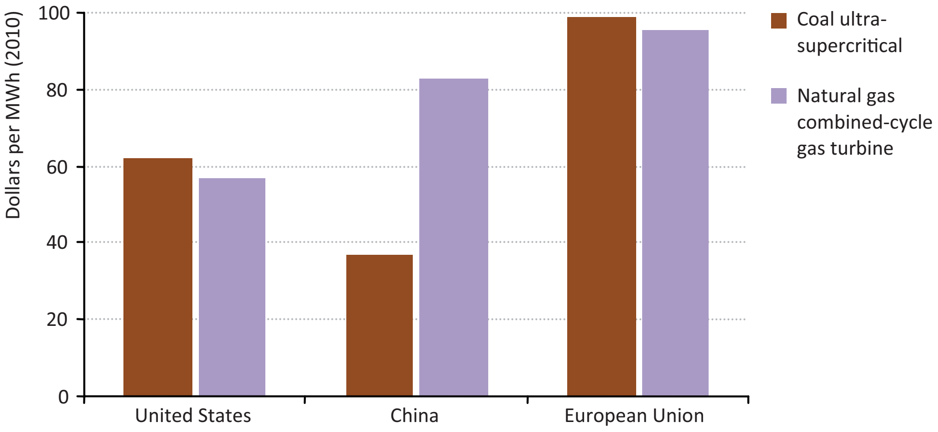
	Demand (Mtoe)			Share		
	2010	2020	2035	2010	2020	2035
Coal	3 519	4 109	4 141	28%	28%	24%
Oil	4 094	4 381	4 548	32%	29%	27%
Gas	2 700	3 291	4 228	21%	22%	25%
Nuclear	719	927	1 181	6%	6%	7%
Hydro	295	376	472	2%	3%	3%
Biomass	1 262	1 496	1 896	10%	10%	11%
Other renewables	110	287	676	1%	2%	4%

Oil continues to be the dominant fuel in the primary energy mix, with demand increasing from about 4 100 Mtoe in 2010 to 4 550 Mtoe in 2035, but its share in the primary energy mix drops from 32% in 2010 to 27% in 2035. Compared with the baseline case, lower gas prices promote substitution for oil in the transport and power sectors, resulting in global oil demand being reduced by some 2 million barrels per day (mb/d) in 2035.

Primary coal consumption in the Golden Rules Case rises until around 2025 and then levels off. Its share in the energy mix declines from 28% in 2010 to 24% in 2035. In that year, coal demand is around 3% lower (115 Mtoe) than in the baseline case, an amount greater than total current European imports of hard coal. Three-quarters of coal demand growth stems from the power sector. Lower gas prices favour gas over coal for new builds in most countries (Figure 2.3). However, in some countries, such as China, coal remains cheaper than gas, in the absence of prices that internalise environmental externalities, such as local pollution or CO_2 emissions. In this situation, Chinese government policies aimed at increasing gas use are crucial to its development. Globally, excluding China, 3.5 units of gas-fired electricity generation are added for each new unit of coal-fired electricity generation.

Over the *Outlook* period, nuclear output grows, but it is marginally below our baseline case in 2035. Gas prices have a direct influence on new nuclear construction in liberalised markets, mostly in OECD countries, where we expect nuclear output to grow 12% less than our baseline. However, most of the global growth in nuclear will occur in non-OECD countries, where specific national plans to expand nuclear capacity are less likely to be affected by changing market conditions.

Figure 2.3 ▷ **Electricity generating costs for new coal- and natural gas-fired power plants in selected regions in the Golden Rules Case, 2020**



The global outlook for renewable sources of energy is not affected substantially by the increased use of gas in the Golden Rules Case, with volumes and shares of output remaining very close to those in the baseline case. Due to lower gas (and consequently electricity) prices, the growth of electricity output from non-hydro renewables is reduced globally by 5% compared with our baseline. This global average figure hides some larger differences in specific countries, where the impact is stronger, due to the price levels and to the type of support policies in place. This is, for example, the case in the United States, where the growth of electricity from non-hydro renewables is some 10% lower with respect to the baseline.

There are factors working both against, and in favour of, renewables in a world of more abundant gas supplies. Depending on the type of policies in place, an abundance of natural gas might diminish the resolve of governments to support low and zero-carbon sources of energy: lower gas prices (and therefore lower electricity prices) can postpone the moment at which renewable sources of energy become competitive without subsidies and, all else being equal, therefore make renewables more costly in terms of the required levels of support. However, an expansion of gas in the global energy mix can also facilitate greater use of renewable energy, if policies are in place to support its deployment, given that gas-fired power generation can provide effective back-up to variable output from certain renewable sources. Moreover, lower electricity prices can encourage customer acceptance of a higher component of electricity from renewable sources. Ultimately, the way that renewables retain their appeal, in a gas-abundant world, will depend on the resolve of governments. We assume that existing policies and support mechanisms remain in place as part of the efforts by governments to address the threat of a changing climate.

Supply

In the Golden Rules Case, total gas production grows by around 55%, from 3.3 tcm in 2010 to 5.1 tcm in 2035. Over the same period, unconventional gas production increases from around 470 bcm in 2010 to more than 1.6 tcm in 2035. Although unconventional gas output grows relatively slowly in the early part of the projection period, reflecting the time required for new producing countries to develop commercial production, for the projection period as a whole, unconventional gas represents nearly two-thirds of incremental gas supply (Table 2.6).

Table 2.6 ▻ Natural gas production by region in the Golden Rules Case (bcm)

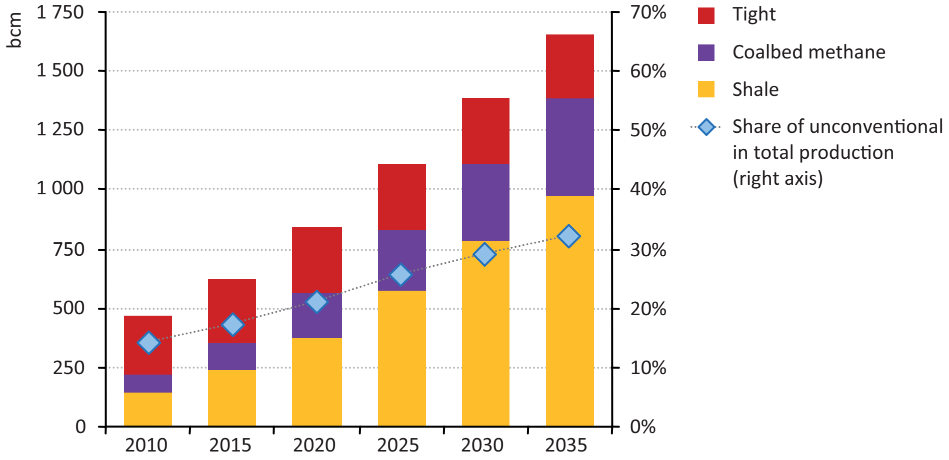
	2010		2020		2035		2010-2035**
	Total	*Share of unconv**	Total	*Share of unconv**	Total	*Share of unconv**	
OECD	**1 183**	**36%**	**1 347**	**49%**	**1 546**	**60%**	**1.1%**
Americas	821	51%	954	62%	1 089	68%	1.1%
Canada	*160*	*39%*	*174*	*57%*	*177*	*67%*	*0.4%*
Mexico	*50*	*3%*	*52*	*12%*	*87*	*43%*	*2.2%*
United States	*609*	*59%*	*726*	*67%*	*821*	*71%*	*1.2%*
Europe	304	0%	272	4%	285	27%	-0.3%
Poland	*6*	*11%*	*9*	*37%*	*34*	*90%*	*7.1%*
Asia Oceania	58	9%	121	49%	172	64%	4.5%
Australia	*49*	*11%*	*115*	*51%*	*170*	*65%*	*5.1%*
Non-OECD	**2 094**	**2%**	**2 635**	**7%**	**3 567**	**20%**	**2.2%**
E. Europe/Eurasia	826	3%	922	3%	1 123	6%	1.2%
Russia	*637*	*3%*	*718*	*4%*	*784*	*6%*	*0.8%*
Asia	431	3%	643	20%	984	56%	3.4%
China	*97*	*12%*	*246*	*45%*	*473*	*83%*	*6.6%*
India	*51*	*2%*	*75*	*21%*	*111*	*80%*	*3.2%*
Indonesia	*88*	-	*106*	*2%*	*153*	*37%*	*2.2%*
Middle East	474	0%	581	1%	776	2%	2.0%
Africa	202	1%	264	1%	397	5%	2.7%
Algeria	*79*	-	*101*	*1%*	*135*	*8%*	*2.2%*
Latin America	159	2%	226	4%	286	22%	2.4%
Argentina	*42*	*9%*	*53*	*9%*	*72*	*48%*	*2.1%*
World	**3 276**	**14%**	**3 982**	**21%**	**5 112**	**32%**	**1.8%**
European Union	*201*	*1%*	*160*	*7%*	*165*	*47%*	*-0.8%*

* Share of unconventional production in total natural gas production.

** Compound average annual growth rate.

The share of unconventional gas in total gas production increases in the Golden Rules Case from 14% in 2010 to 32% in 2035 (Figure 2.4). Of the different sources of unconventional supply, tight gas, at 245 bcm, accounted for just over half of global unconventional production in 2010. However, it is rapidly overtaken in our projections by production of shale gas, which rises from around 145 bcm in 2010 (31% of total unconventional output) to 975 bcm in 2035 (almost 60% of the total). Production of coalbed methane likewise grows rapidly, from 80 bcm in 2010 to nearly 410 bcm in 2035.

Figure 2.4 ▻ Unconventional natural gas production by type in the Golden Rules Case



The continued expansion of unconventional gas production in North America means that the United States moves ahead of Russia as the largest global gas producer, with about 820 bcm of total gas production in 2035, compared with 785 bcm in Russia. North American unconventional output, with substantial contributions also from Canada and Mexico, rises to nearly 740 bcm in 2035 in the Golden Rules Case. But increased unconventional production also occurs widely around the world: whereas unconventional gas production in 2010 is dominated by North America, the share of North America in global unconventional production falls to around 70% in 2020 and only 45% in 2035.[9]

China becomes a major gas producer in the Golden Rules Case and the second-largest global producer of unconventional gas, after the United States (Figure 2.5). Progress with developing unconventional gas resources is bolstered by the twin policy commitments of increasing the share of natural gas in the Chinese energy mix and developing, where possible, the domestic resource base so as to mitigate increased reliance upon energy imports. The large resource base for shale gas and coalbed methane allows very rapid growth in unconventional production from around 2017 onwards and total unconventional

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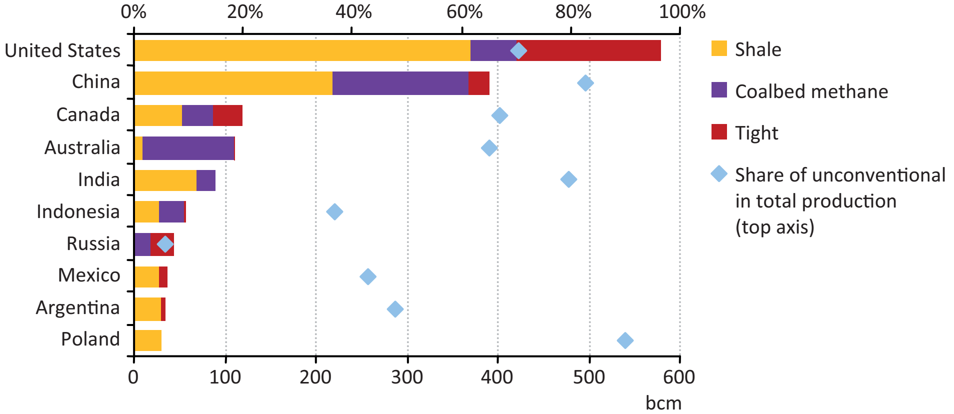
[9] More detailed discussion of the regulatory issues and production outlooks for North America, China, Europe and Australia are included in Chapter 3 of this report.

production reaches just over 110 bcm in 2020 and 390 bcm in 2035, 83% of total Chinese gas production.

Figure 2.5 ▻ **Ten largest unconventional gas producers in the Golden Rules Case, 2035**



Similar policy objectives are assumed to drive an expansion in unconventional gas production elsewhere in Asia, notably in India where unconventional gas supply rises to nearly 90 bcm in 2035 (80% of total gas output). The currently known unconventional gas resource base in India can meet only a part of India's incremental needs, given the prospect of strong growth in gas demand, and production growth starts to tail off towards the end of the projection period. In Indonesia, by contrast, resources of both conventional and unconventional gas are very large; some recent conventional discoveries are offshore and relatively expensive to develop, so the onshore unconventional plays, including rich potential for coalbed methane, are attractive by comparison. Unconventional gas production in Indonesia rises to around 55 bcm in 2035 (almost 40% of total output). Australia is another country that has the opportunity to develop both conventional and unconventional resources with a mix of coalbed methane, tight and shale gas. In the Golden Rules Case, unconventional gas makes up about 65% of Australia's 170 bcm of total gas output by 2035.

The expansion of unconventional gas production in China and the United States (and, to a lesser extent, also in Europe) creates strategic challenges for existing gas exporters. This is evident in the projections for Russia, which remains by far the largest producer of conventional gas.[10] Developments in the Golden Rules Case call into question the speed at which Russia will need to develop relatively expensive new fields in the Yamal peninsula, in the Arctic offshore and in Eastern Siberia. In our projections, Russia's total gas production rises to about 785 bcm in 2035, more than 20% above 2010, but below the levels foreseen in

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[10] A part of Russia's production is classified as tight gas although this is very similar to conventional production in practice; hydraulic fracturing to enhance flow rates is rarely used in gas wells. Russia is, though, projected to expand its output of coalbed methane by 2035.

Russian policy or company outlooks and in our baseline. In the Middle East, an increasingly important challenge for gas producers – with the exception of an export-oriented producer like Qatar – is to meet increasing demand for gas on domestic markets. In our Golden Rules Case projections, this imperative to meet domestic needs leads to small amounts of shale gas being produced, mainly in Saudi Arabia and Oman, but conventional gas continues to predominate. In North Africa, though, unconventional gas plays a slightly more significant role, with Algeria, Tunisia and Morocco starting to produce shale gas in the early 2020s. By the end of the projection period, unconventional gas production reaches around 8% of total output in Algeria; with conventional resources becoming scarcer by this time, unconventional gas helps to maintain consistently high levels of production and export. Overall gas production in Africa is bolstered by expanded conventional output from a traditional producer, Nigeria, but also by output from new conventional producers, such as Mozambique and Angola.

Latin America has large potential for unconventional gas development, with Argentina (primarily shale gas) having the largest resource base, followed by Venezuela (tight gas) and then Brazil (shale gas). Attention in Argentina is focused on the Neuquén Basin in Patagonia, which helps Argentinean unconventional production reach 35 bcm by 2035 in the Golden Rules Case, almost half of the total gas output. Both Venezuela and Brazil have ample conventional resources, which means that there is less need to develop their unconventional potential during the projection period; however, some unconventional gas is produced by 2035 in Bolivia (5 bcm), Peru (5 bcm), Paraguay (3 bcm) and Uruguay (3 bcm).

Implications for other fuels

In the Golden Rules Case, the conditions supportive of unconventional gas production also support increased output of natural gas liquids (NGLs), extracted from liquids-rich shale gas, as well as light tight oil.[11] This oil is analogous in many ways to shale gas, both in terms of its origins – it is oil that has not migrated, or at least not migrated far, from the (shale) source rock – and in terms of the production techniques required to exploit it. Light tight oil is being produced from many of the same basins as unconventional gas in the United States, and, in a price environment combining high oil prices and very low prices for natural gas, there is a strong economic incentive to target plays with higher liquids content. In the Golden Rules Case, we project a strong increase in production of light tight oil in the United States, with the potential for production to spread also to other countries rich in this resource (Box 2.2).

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[11] Almost all shale gas plays produce some liquids and light tight oil production likewise comes with some associated gas. The distinction between liquids-rich unconventional gas plays and gas-rich light tight oil reservoirs is not clear-cut; it normally depends on the relative energy content of the gas versus the liquids produced, but this can vary over time for a single well.

Box 2.2 ▷ The liquid side of the story – light tight oil

The spectacular rise in oil production from North Dakota and Texas in the United States clearly illustrates the growth potential for light tight oil. The Bakken formation under North Dakota has been known about since the 1950s, but production from this formation remained under 100 thousand barrels per day (kb/d) until only a few years ago, since when it has surged to over 500 kb/d and looks set to continue growing. The Eagle Ford shale in south Texas, adjacent to the Mexican border, also shows considerable promise, with production expected to grow from almost nothing three years ago to around 400 kb/d by the end of 2012. Combined production from the Bakken, the Eagle Ford and other emerging light tight oil plays in the United States is expected to reach 2 mb/d by 2020 in the Golden Rules Case.

United States' NGL production from shales such as the Barnett, Eagle Ford and Marcellus is also increasing rapidly and up to 1 mb/d of new capacity is expected to be added by 2020. The growth in NGL production is creating new opportunities for the petrochemical industry, but action will be required to remove pipeline bottlenecks and provide additional fractionation and storage facilities if the benefits are to be fully realised. The growth in global production of NGLs from shale formations and light tight oil in the period to 2020, predominantly in North America, makes up almost half the incremental growth in oil supply over this period.

Production outside North America of NGLs from shale and of light tight oil is unlikely to make a large contribution to global liquids production before 2020 as much evaluation work still needs to be done. However, the Neuquén basin in Argentina shows promise, YPF announcing potential resources of 7 billion barrels (YPF, 2012), while the extension of the Eagle Ford shale into Mexico is also a focus of attention. Our projections for light tight oil production outside North America remain small even beyond 2020, as we have yet to see sufficient progress in confirming resources, so there is some upside potential. It should be noted, however that on the basis of current knowledge, light tight oil resources are expected to be of less consequence than shale gas resources: whereas the estimated shale gas resources in the United States represent at least 35 years of 2010 domestic gas demand, the known light tight oil resources make up no more than four years of domestic oil demand. This is why we currently project light tight oil production in the United States to peak in the 2020s.

The liquids content of shale gas plays is an important consideration in their economic viability as NGLs are easily transported to world markets, while market opportunities for gas are often only local, at prices that may not be aligned to international prices for reasons of policy or infrastructure. However there is always a degree of uncertainty about the extent of liquids content until new shales have been drilled and tested.

International gas trade, markets and security

In the Golden Rules Case, the developments having the most impact on gas markets and security are the increasing levels of unconventional production in China and in the United States, the former because of the way that it slows the growth in Chinese import needs and the latter because it allows for gas exports from North America. The implication of these two developments in tandem is to increase the volume of gas, particularly LNG, looking for markets in the period after 2020.

China's requirement for imported natural gas in the Golden Rules Case grows from around 15 bcm in 2010 to 80 bcm in 2020 and then to 120 bcm in 2035. These volumes are about half the corresponding imports in the baseline case. Chinese gas imports at the levels projected in the Golden Rules Case could be covered by existing contractual arrangements for LNG and pipeline supplies (from Central Asia and Myanmar) until well into the 2020s, pushing back the need for additional projects aimed at the Chinese market.

With the United States developing as an LNG exporter over the period to 2020 and Canada also starting to export LNG from its west coast, exports from North America reach 35 bcm by 2020, after which they stabilise just above these levels as the opportunities for export start to narrow. The influence of these exports on trade flows and pricing is larger than these volumes suggest. LNG from the United States, if priced at the prices prevailing on the domestic gas trading hub, can compete with oil-indexed gas in both the European and Asia-Pacific markets in the Golden Rules Case, and the mere presence of this source of LNG (more so than the actual level of export) plays an important role in creating a more competitive international market for gas supply.

The total volume of gas traded between *WEO* regions[12] in the Golden Rules Case in 2035 is 1 015 bcm. This represents an increase of nearly 50%, compared with the volume of inter-regional trade in 2010 (Figure 2.6), but it is some 15% below the figure for 2035 in our baseline case. The share of inter-regional trade in global supply rises to 22% in 2015, but international market conditions start to ease over the period to 2020 and beyond, as new sources of unconventional gas start to be developed closer to the main areas of consumption. This pick-up in unconventional gas production means that the share of inter-regional trade in global supply plateaus after 2015 before falling to 20% by 2035, reversing the expectation that international trade will play an increasingly important role in meeting global needs.

The European Union's growing requirement for imported gas accounts for 40% of the increase in global inter-regional gas trade in the Golden Rules Case. Here too, the development of indigenous unconventional gas moderates somewhat the growth in imports, so that they reach 480 bcm in 2035, about 135 bcm more than in 2010. Among importing countries in Asia, Japan and Korea (which do not have potential to develop

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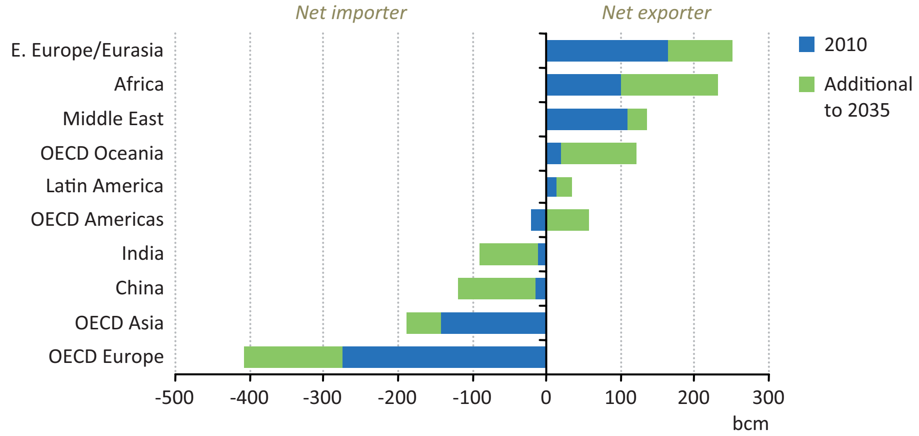
[12] Trade between the 25 regions included in the *WEM*. It does not include trade between countries within a single region.

indigenous production) see imports rise steadily, as does India, whose import requirement rises to nearly 90 bcm from around 10 bcm in 2010.

Figure 2.6 ▻ Natural gas net trade by major region in the Golden Rules Case



Box 2.3 ▻ Implications for prices and pricing mechanisms

In an environment where gas is potentially available from a greater variety of sources, buyers not only in Europe but also in Asia could well insist on greater independence from oil prices in the pricing of gas supplies, particularly when gas is used in the fast-growing power sector in which oil is disappearing as an energy source. The Golden Rules Case is likely to see accelerated movement towards hub-based pricing or a hybrid pricing system in which alternatives to oil-price indexation plays a much larger role in both Europe and across Asia.

The way such a change might play out in practice would depend to a large degree on the reaction of the main traditional exporters, who could confront greater risks in financing expensive upstream developments and transportation projects. Producers such as Russia and Qatar, the largest current exporters of natural gas, have access to ample conventional reserves, with costs that are in most cases substantially lower than those of unconventional gas (and other conventional producers as well). With well-developed export infrastructure, these countries could undercut the prices offered by most other exporters on international markets, retaining or expanding export volumes by offering gas to markets on more attractive terms than others. Alternatively, they could aim to maintain higher prices for their exports, but at the risk of losing market share. In the Golden Rules Case, their strategic choice would have substantial implications for the location of investment and production, including the speed of development of unconventional resources. The net result for gas consumers, however, would be broadly the same: lower prices for imported natural gas.

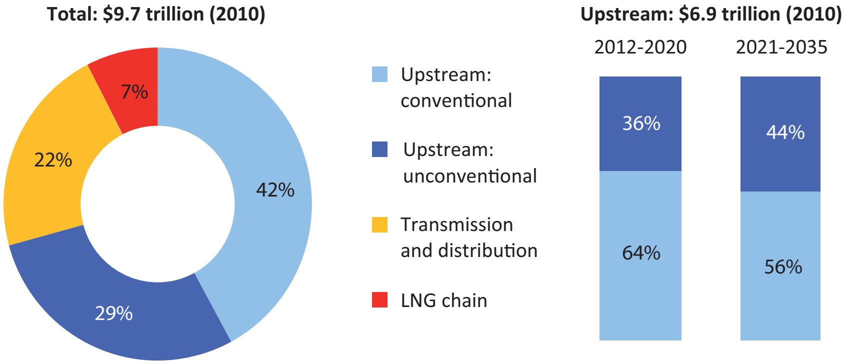
Russia and the Middle East supplied around 45% of inter-regional gas trade in 2010; this declines to 35% in 2035 in the Golden Rules Case, as other players announce or expand their presence in the market, notably Australia, the United States and producers in Africa and Latin America. From around 20 bcm in 2010, Australia's exports rise quickly to 120 bcm in 2035, based on a rapid expansion of LNG capacity, which permits new markets to be captured in the earlier part of the projection period, during which demand for imports remains relatively strong. By around 2020, African exports – based on new conventional projects and LNG, thanks to the large recent discoveries offshore east and west Africa – overtake those from the Middle East.

Overall, the Golden Rules Case presents an improved picture of security of gas supplies. High dependence on imports, in itself, is not necessarily an indicator of insecure supply; but the conditions observed in the Golden Rules Case of a more diverse mix of sources of gas in most markets, including both indigenous output and imports from a range of potential suppliers, suggests an environment of growing confidence in the adequacy, reliability and affordability of natural gas supplies.

Investment and other economic impacts

At the global level, for conventional and unconventional gas together, the Golden Rules Case requires $9.7 trillion in cumulative investment in gas-supply infrastructure in the period 2012 to 2035 (in year-2010 dollars). This represents an increase of $390 billion, compared with the baseline case, reflecting the need to bring on more production to meet higher demand and a slight increase in unit production costs as unconventional resources make up a growing share of production. Spending on gas exploration and development, to find new fields and bring them into production and to maintain output from existing ones, amounts to nearly $6.9 trillion, bolstered by the large number of new wells required (see Spotlight).

Figure 2.7 ▻ **Cumulative investment in natural gas-supply infrastructure by type in the Golden Rules Case, 2012-2035** (in year-2010 dollars)



SPOTLIGHT

How many wells? How many rigs?

Expanded unconventional gas production requires a significant increase in the number of unconventional gas wells over the coming decades, though there is a huge range of uncertainty when calculating the extent of the requirement for unconventional gas wells for a projected level of production. Key variables are the average ultimate recovery per well and the average decline rate of production in the early years, both of which vary significantly between shale gas, tight gas and coalbed methane wells.[13]

We estimate that, to meet the global unconventional gas production requirements of the Golden Rules Case, more than one million unconventional gas wells would need to be drilled globally between 2012 and 2035. For comparison, around 700 000 oil and gas wells have been drilled in the United States over the last 25 years and half a million are currently producing gas. At present, global drilling activity for both conventional and unconventional resources is heavily concentrated in the United States, where more than half of the world's drilling rig fleet (around 2 000 active oil and gas drilling rigs, including those used for unconventional gas) is deployed to sustain production of just 9% of the world's oil and 19% of the world's gas.

In the Golden Rules Case, the United States would still account for around 500 000 of the new unconventional gas wells required by 2035, with the yearly drilling requirement rising from around 7 000 wells per year to 25 000 per year by 2035 (and the unconventional gas rig count increasing by the same order of magnitude, given that the efficiency of rig use probably has potential for only modest increases).

China would have a cumulative requirement of some 300 000 unconventional gas wells over the projection period and an annual requirement increasing from around 2 000 in the early years to 20 000 wells nearer 2035. Assuming that drilling becomes more efficient with time, this might correspond to an increase in the number of unconventional gas drilling rigs from around 400 to 2 000, a demanding increase in the rig count. There are an estimated 1 000 rigs in China at present, but only a fraction of these are capable of horizontal drilling.

In the European Union, the cumulative number of wells in the projection period is around 50 000, increasing to around 3 000 per year by the 2030s. The number of drilling rigs required is between 500 and 600; there are currently around 50 land rigs in Europe, of which only around half may be capable of horizontal drilling.

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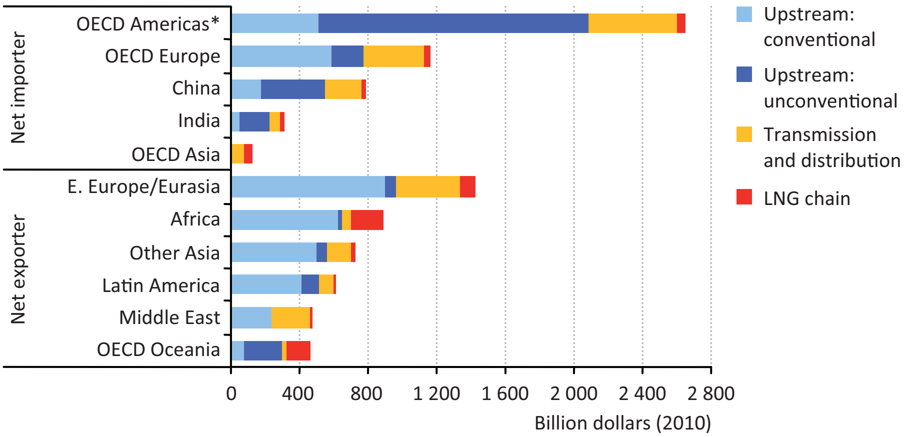
[13] For the purpose of these calculations, we have used an average EUR of around 1 bcf, assumed that about 50% of EUR is recovered in the first three years of production, and a 15% average decline rate of current unconventional gas production (in the United States). Varying these assumptions within a reasonable range produces very different outcomes in terms of the number of wells.

Unconventional resources attract an increasing share of this upstream investment – about 36% before 2020 and 44% in the subsequent period to 2035 – as prospective areas mature (Figure 2.7). Being geographically well-dispersed and closer to demand centres, unconventional gas diminishes the need for long-distance gas transport infrastructure to some degree. Nevertheless, growing trade in the Golden Rules Case requires additional LNG facilities and new long-haul pipelines. Cumulative investment in the LNG chain is $0.7 trillion and investment in gas transmission and distribution infrastructure, including smaller scale networks to connect end-users, absorbs $2.1 trillion.

The proportion of upstream investment made in countries that hold unconventional resources increases. Spending on exploration and development for unconventional gas in the United States alone is more than double total upstream spending in any other country or region.[14] China also becomes one of the world's leading locations for upstream gas investment, thanks to its huge resource base. Countries that were net importers of gas in 2010 make some of the most significant investments in unconventional gas, accounting for more than three-quarters of total unconventional upstream investment (Figure 2.8). This investment can generate the wider economic benefits associated with improved energy trade balances, lower energy prices and employment, all of which add economic value for unconventional resource holders.

Figure 2.8 ▹ Cumulative investment in natural gas-supply infrastructure by major region and type in the Golden Rules Case, 2012-2035



* OECD Americas become a net exporter of natural gas by 2020 in the Golden Rules Case.

The outlook for energy trade balances improves for unconventional resource holders in the Golden Rules Case. China and the European Union remain large net importers of gas,

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[14] Because of the rapid decline in production in shale gas wells, maintaining production requires continuous investment in drilling new wells. This explains why the United States needs the lion's share of the investment in unconventional gas: although it does not grow supply as much as China for example, it needs investment just to sustain its already substantial level of unconventional gas production.

but indigenous unconventional gas production tempers their import bills, which stabilise at about 0.2% and 0.7% of GDP, respectively, after 2020. Australia, where production far outstrips domestic gas demand, sees export revenues reach nearly 2% of GDP in 2035. Net exports of gas bring revenues to the United States after it ceases to be a net gas importer; the more substantial impact on energy trade balances in the United States results from light tight oil production and increased NGLs from higher unconventional gas production, which contribute to a considerable reduction in its oil import bill – to 0.8% of GDP in 2035, compared with a peak of 2.8% of GDP in 2008.

Climate change and the environment

Energy-related CO_2 emissions in the Golden Rules Case reach 36.8 gigatonnes (Gt) in 2035, an increase of over 20% compared with 2010 (Table 2.7) but lower than the 2035 baseline projection by 0.5%. At the global level, there are two major effects of the Golden Rules Case on CO_2 emissions, which counteract one another. Lower natural gas prices mean that, in some instances, gas displaces the use of more carbon-intensive fuels, oil and coal, pushing down emissions. At the same time, lower natural gas prices lead to slightly higher overall consumption of energy and, in some instances, to displacement of lower-carbon fuels, such as renewable energy sources and nuclear power. Overall, the projections in the Golden Rules Case involve only a small net shift in anticipated levels of greenhouse-gas emissions.

Table 2.7 ▻ World energy-related CO_2 emissions in the Golden Rules Case (million tonnes)

	2010	2020	2035	2010-2035*
OECD	12 363	12 157	10 716	-0.6%
of which from natural gas	3 034	3 336	3 758	0.9%
Non-OECD	16 960	21 327	24 674	1.5%
of which from natural gas	3 082	4 118	5 781	2.5%
World	**30 336**	**34 648**	**36 795**	**0.8%**

* Compound average annual growth rate.

The Golden Rules Case puts CO_2 emissions on a long-term trajectory consistent with stabilising the atmospheric concentration of greenhouse-gas emissions at around 650 parts per million, a trajectory consistent with a probable temperature rise of more than 3.5 degrees Celsius (°C) in the long term, well above the widely accepted 2°C target. This finding reinforces a central conclusion from the *WEO* special report on a Golden Age of Gas (IEA, 2011b), that, while a greater role for natural gas in the global energy mix does bring environmental benefits where it substitutes for other fossil fuels, natural gas cannot on its own provide the answer to the challenge of climate change. This conclusion could be changed by widespread application of technologies such as carbon capture and storage, which could reduce considerably the emissions from the consumption of gas (and other fossil fuels); but this is not assumed in the period to 2035.[15]

At country level, the impact of the Golden Rules Case on greenhouse-gas emissions from gas depends to a large degree on the structure of domestic fuel use, in particular for power generation. In countries where the average greenhouse-gas intensity of power generation is already close to that of natural gas, as for example in Europe, the addition of extra natural gas to the fuel mix has relatively little impact on the overall emissions trajectory. By contrast, in countries heavily reliant upon coal for electricity generation, such as China, the increased availability of natural gas has a more substantial impact on CO_2 emissions. Such increased use of gas also reduces emissions of other pollutants; compared with burning coal, combustion of natural gas results in lower emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_X) and gas also emits almost no particulate matter. Local emissions of particulate matter and NO_X are the main causes of low air quality – a particularly important consideration for emerging economies seeking to provide energy for fast-growing urban areas.

Unconventional gas production itself inevitably results in some changes to the land, to surface water and to groundwater systems, particularly given the scale of the production envisaged in the Golden Rules Case. As indicated in the Spotlight, we estimate that production at these levels would require the drilling of over one million new wells in the course of the projection period, over half of which would be in the United States and China. These operations have to be managed strictly in accordance with the Golden Rules, or the associated social and environmental damage will cut short attainment of the Golden Rules Case.

The Low Unconventional Case

Demand

In the Low Unconventional Case, where the Golden Rules are not applied and environmental and other constraints on unconventional gas development provide too difficult to overcome, the competitive position of gas in the global fuel mix deteriorates, compared with the Golden Rules Case, as a result of lower availability and higher prices. Global demand for gas grows more slowly, reaching 4.6 tcm in 2035. The difference in primary gas demand in 2035 between the Low Unconventional Case and the Golden Rules Case is about 535 bcm, an amount close to total gas demand in the European Union in 2010. In the global energy mix, whereas in the Golden Rules Case gas overtakes coal by 2035, in the Low Unconventional Case the share of gas in the global energy mix increases only slightly, from 21% in 2010 to 22% in 2035, remaining well behind that of coal (whose share decreases from 28% to 26%) and of oil.

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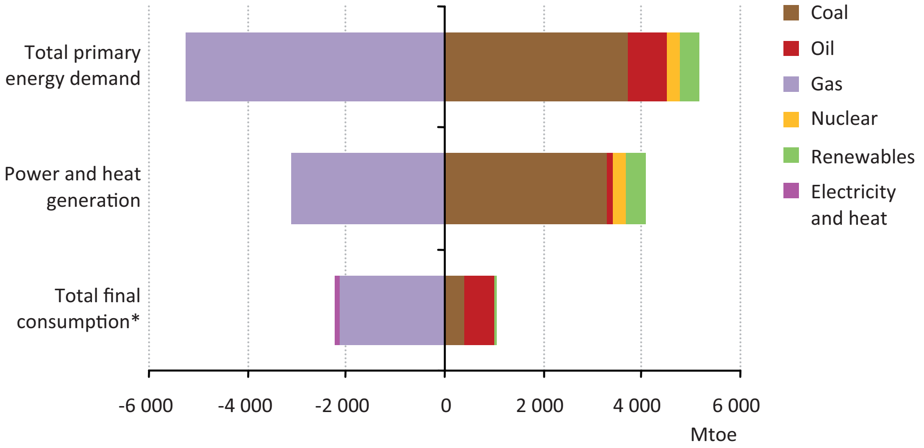
[15] There is the possibility that the capacities for CO_2 storage might be affected by hydraulic fracturing. A recent study (Elliot and Celia, 2012) estimated that 80% of the potential area to store CO_2 underground in the United States could be prejudiced by shale and tight gas development, although others have argued that, even if the rock seal in one place were to be broken by hydraulic fracturing, other layers of impermeable rock underneath the fractured area would block migration of the CO_2.

The fall in gas demand in the Low Unconventional Case, relative to the Golden Rules Case, is mostly compensated for by increased consumption of coal (Figure 2.9). The cumulative difference in total primary gas demand over the projection period is around 5 200 Mtoe (6.3 tcm); coal accounts for almost three-quarters of the increase in the demand for other fuels, the largest coming in China (accounting for about 40% of the additional coal demand). The total primary energy used for power and heat generation is higher in the Low Unconventional Case because of the substitution of gas-fired generation by coal-fired generation; being less efficient, coal plants require more energy to produce the same amount of electricity. In power generation, around 75% of the fall in gas-fired power is taken up by coal. In total final consumption, the effect is felt primarily through the increase in demand for oil, because gas fails to make the same inroads in the transportation sector.

Figure 2.9 ▷ Cumulative change in energy demand by fuel and sector in the Low Unconventional Case relative to Golden Rules Case, 2010-2035



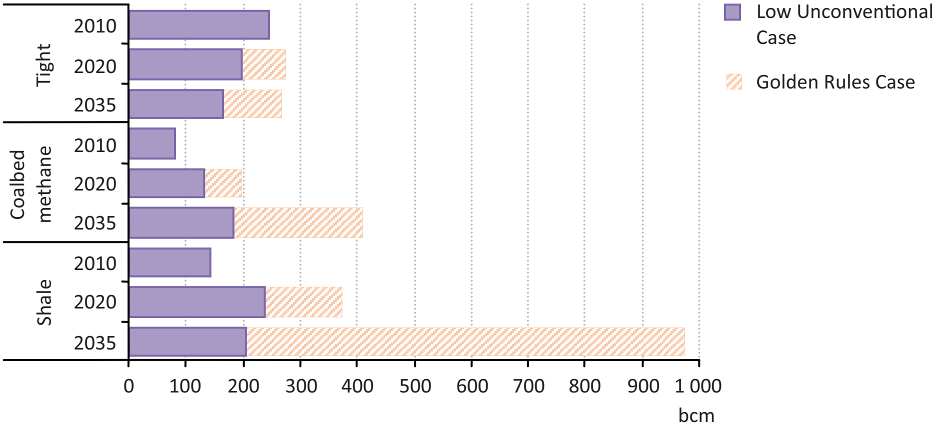
* Total final consumption is the sum of consumption by the end-use sectors industry, transport, buildings (including residential and services) and other (including agriculture and non-energy use).

Supply

In the Low Unconventional Case, total gas supply is lower, at 4.6 tcm, and unconventional production is much lower than in the Golden Rules Case. Unconventional gas production in aggregate rises above 2010 levels of 470 bcm but reaches only 570 bcm in 2020 and falls back to 550 bcm by 2035. Unconventional gas contributes only 6% to global gas production growth over the projection period, meaning that the share of unconventional gas in total gas output falls slightly over time, from 14% in 2010 to 12% in 2035. This is a long way below the 32% share reached by unconventional gas in 2035 in the Golden Rules Case. The difference in unconventional gas production in 2035 between the cases is over 1 tcm, equivalent to 5% of total primary energy supply.

In the Low Unconventional Case, the largest impact is on production of shale gas (Figure 2.10). At a global level, shale gas production increases by 40% over the projection period, reaching just above 200 bcm in 2035, about one-fifth of the level reached in the Golden Rules Case. Tight gas production falls to 165 bcm. Output of coalbed methane is slightly more resilient, rising by two-and-a-half times to around 185 bcm, 45% of the level reached in the Golden Rules Case. This is accounted for by the fact that coalbed methane resources are typically in areas that have existing coal mining operations, in which there is often less resistance to coalbed methane operations than to other types of unconventional gas development – and that the case can be made on environmental grounds that producing the gas is preferable to mining the coal.[16]

Figure 2.10 ▷ Unconventional gas production by type and case



The reduction in unconventional gas output in the Low Unconventional Case has most impact on China and the United States; their total gas production is lower in 2035 by 280 bcm and 240 bcm, respectively. This represents a 30% reduction in US output, but a much larger fall, 60%, in Chinese production relative to the Golden Rules Case (Figure 2.11 and Box 2.4). There are also major declines in output in the European Union (particularly Poland), India, Canada, Argentina, Mexico, and Indonesia. By contrast, the Low Unconventional Case shores up the preeminent position of the main conventional gas resource-holders. Even though total gas supply is lower than in the Golden Rules Case, Russia (around +115 bcm), Iran (nearly +30 bcm) and Qatar (just over +15 bcm) all post significant increases in their 2035 production, compared to the Golden Rules Case. In the Low Unconventional Case, increased demand from Europe and China for Russian gas means that Russia accounts for 20% of global supply, compared with 15% in the Golden Rules Case.

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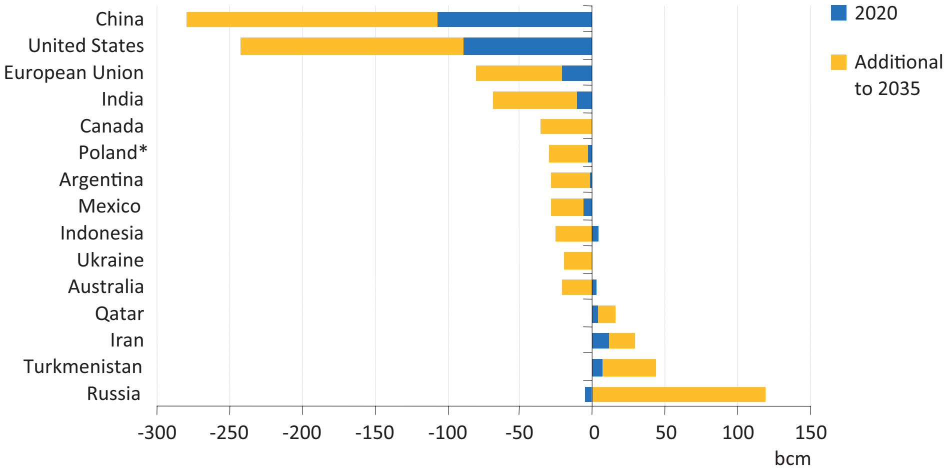
[16] Coalbed methane production can actually reduce methane emissions if the gas would have been released by subsequent coal mining activities (this is sometimes referred to as coal mine methane production).

Figure 2.11 ▷ Change in natural gas production by selected region in the Low Unconventional Case relative to the Golden Rules Case



* The change in Polish output is included also in the figures for the European Union.

Box 2.4 ▷ What could lead to a Low Unconventional Case in China?

The Chinese government has announced ambitious targets for future production of coalbed methane and shale gas: 6.5 bcm of shale gas and 30 bcm of coalbed methane in 2015, and 60 to 100 bcm of shale gas in 2020. These targets are supported by large producer subsidies for both types of resources. Our projections for the Golden Rules Case show a somewhat slower rate of increase before 2020, but are generally in line with official targets. Public opposition to unconventional gas developments is not currently manifest in China; if it were to develop over the projection period without gaining a commensurate regulatory and industry response, including application of the Golden Rules, the result could be production restrictions leading to an output plateau near the level of the 2020 targets, instead of the continuing growth projected in the Golden Rules Case. There are other hurdles which could also hold back the development of unconventional gas in China:

- The resource base could turn out to be much smaller than currently estimated. The current resource estimates are largely extrapolations from a small number of wells.
- Recovery factors or production rates could be lower than thought. In the United States, different gas shale deposits and different coalbed methane deposits yield very different levels of production. Not enough is known yet about the Chinese reservoirs to confirm that the range of productivity will be similar to that observed

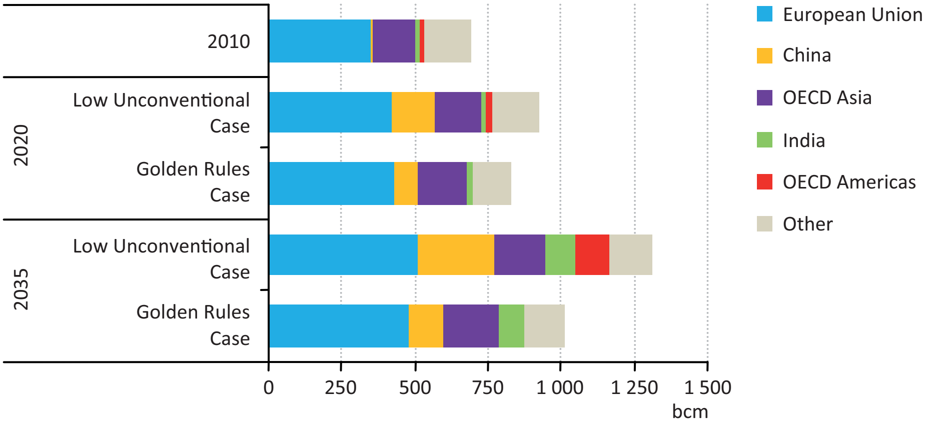
in the United States. On the assumption of similar productivity, the Golden Rules Case will require drilling something like 300 000 new unconventional gas wells in China during the projection period, already a very demanding level of activity. Even modest reductions in productivity would test the limits of the drilling capacity of the country.

- The economics could turn out to be disappointing. Many of the shale gas reservoirs in China are known to be deeper and more complex that those currently exploited in the United States. Both of these factors have a strong influence on the economics. The costs of well construction scale up rapidly with depth. Moreover, most of the coalbed methane resources are located far from large consumption centres: transportation costs make such resources not much more attractive than imports.
- Water availability: a significant part of the shale gas resources is located in regions where either water availability is limited or where competition with agricultural users of the water resources is likely to be a serious issue. This could limit the number of wells and hydraulic fracturing treatments that can be performed in those regions.
- Wavering government support: shale gas and coalbed methane production currently benefit from large subsidies in order to promote their development. When the volumes get large, such subsidies may not be sustainable. Or subsidies to fossil fuels in general may become unacceptable in the later part of the projection period. Loss of subsidies and worsening economics could curb the growth of unconventional gas production from the mid-2020s.

International gas trade, markets and security

The picture of inter-regional trade in the Low Unconventional Case is radically different from that described in the Golden Rules Case. The volume of trade is almost 300 bcm higher in the Low Unconventional Case in 2035, up about 30%, and some patterns of trade are also reversed, with North America requiring large quantities of imported gas to meet its net requirements (Figure 2.12). The United States, a strategically significant gas exporter in the Golden Rules Case, imports nearly 100 bcm by the end of the projection period in the Low Unconventional Case. Despite lower overall gas demand, China's demand for pipeline and LNG imports in 2035 reaches 260 bcm in the Low Unconventional Case, nearly 145 bcm higher than in the Golden Rules Case.

Figure 2.12 ▻ Major natural gas net importers by case



Among the exporters, the share of Russia and the Middle East in global inter-regional trade increases slightly to 46% in 2035 in the Low Unconventional Case, compared with a drop to 35% in the Golden Rules Case. Against a backdrop of rising import dependence in some key gas-consuming regions and a more limited number of potential suppliers, the outlook for customers for gas in the Low Unconventional Case looks less bright. Competition among importers becomes more intense, contributing to tighter markets in Europe and Asia. In North America, with the marginal supply coming from international markets, relatively expensive LNG imports pull up domestic prices in the United States – the opposite effect from the Golden Rules Case, where competitively priced exports have a mitigating effect on prices in export markets.

Box 2.5 ▻ A hybrid case

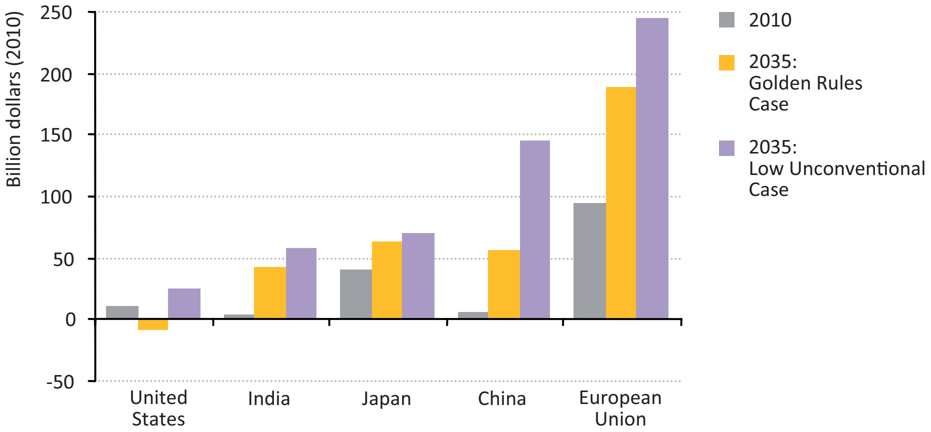
The two cases examined here apply favourable and unfavourable assumptions, respectively and uniformly, to all countries' prospects for unconventional gas development. But it is also possible that some countries follow a path of rapid growth in unconventional resource development along the lines of the Golden Rules Case, while others make slow progress or opt not to develop these resources, as in the Low Unconventional Case. Perhaps the most plausible of these hybrid cases is one in which enhanced attention to environmental issues sustains growth in unconventional output in North America and Australia, while elsewhere – with the partial exception of China – countries fail to realise the regulatory mix that would allow unconventional gas output to grow fast, at least until well into the 2020s. This case is not modelled here, but bears a resemblance to the central scenario of the *WEO-2011* that will be updated in full in this year's *Outlook*, to be published in November 2012.

Investment and other economic impacts

Various constraints in the Low Unconventional Case – moratoria on the use of hydraulic fracturing, overly strict regulation, unreasonably high compliance costs, arbitrary restrictions on drilling locations, less attractive fiscal terms, limitations on water availability and emerging resource limitations – serve to deter upstream investment in unconventional resources. Global cumulative investment in unconventional gas falls by half, to some $1.4 trillion, compared with the investment in the Golden Rules Case, and 60% of investment in unconventional gas is made in the United States. Even so, the share of the United States in global cumulative upstream gas investment declines from 24% to 21%. Limited prospects for unconventional gas prompt $0.7 trillion more cumulative investment in conventional resources. This underscores the relative shift in market power from unconventional resource holders to the major conventional producers, notably in Russia, the Middle East and North Africa.

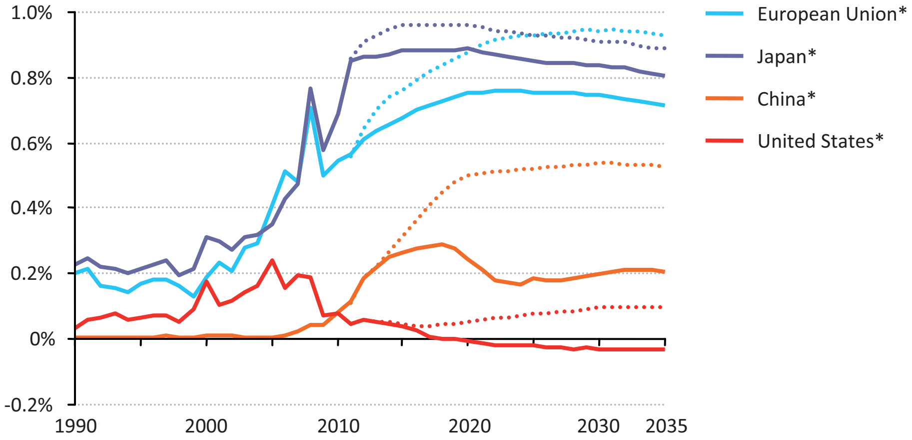
The import bills attached to inter-regional trade rise to $630 billion in 2035 (in year-2010 dollars) in the Low Unconventional Case, nearly 60% higher than in the Golden Rules Case. The proportionate impact on import bills is highest in China and the European Union, but the effect in other countries is also marked (Figure 2.13). China's spending on gas imports in 2035 in the Low Unconventional Case reaches almost $150 billion, or almost three times the level reached in the Golden Rules Case. Gas-import bills in the European Union rise to $245 billion in 2035, 30% above the $190 billion reached in the Golden Rules Case. Spending by the United States on gas imports in 2035 in the Low Unconventional Case totals $25 billion, around double the level of 2010, whereas the United States is a net exporter from 2020 in the Golden Rules Case, with export earnings increasing steadily to around $10 billion in 2035.

Figure 2.13 ▷ **Natural gas-import bills by selected region and case**



It follows that gas import bills expressed as a share of GDP are also sharply higher in the Low Unconventional Case than in the Golden Rules Case (Figure 2.14). For example, China's import bills stabilise at 0.5% of GDP towards the end of the projection period compared with a plateau of just 0.2% in the Golden Rules Case.

Figure 2.14 ▷ **Spending on net-imports of natural gas as a share of real GDP at market exchange rates by case**



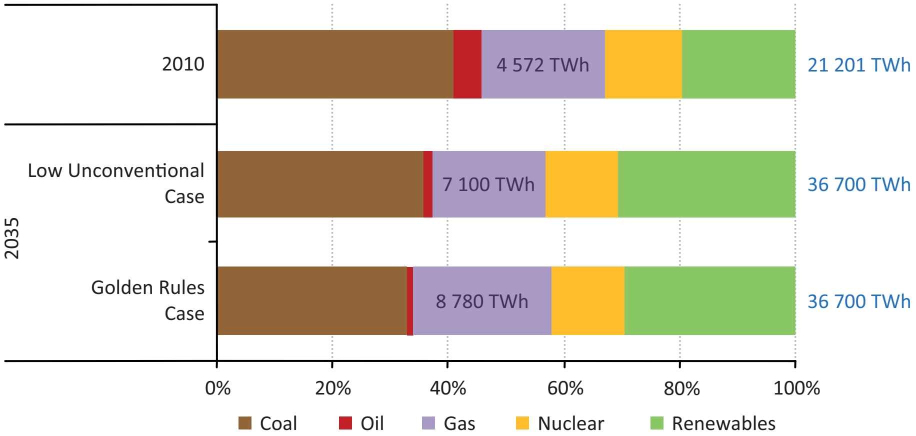
* Solid lines represent the Golden Rules Case; dotted lines represent the Low Unconventional Case.

Climate change and the environment

Although the forces driving the Low Unconventional Case derive in part from environmental concerns, it is difficult to make the case that a reduction in unconventional gas output brings net environmental gains. The effect of replacing gas with coal in the Low Unconventional Case is to push up energy-related CO_2 emissions, which are 1.3% higher than in the Golden Rules Case. The global power generation mix (Figure 2.15) involves a higher share of coal-fired power in the Low Unconventional Case, stemming from the more limited role for natural gas. Additional investment in coal-fired generation locks in additional future emissions, since any new coal-fired power plant has an anticipated operating lifetime in excess of 40 years.

Though many of those concerned with environmental degradation may find it difficult to accept that unconventional gas resources have a place in a sustainable energy policy, a conclusion from this analysis is that, from the perspective of limiting global greenhouse-gas emissions, a Golden Rules Case has some advantages compared with the Low Unconventional Case, while also bringing with it other benefits in terms of the reliability and security of energy supply.

Figure 2.15 ▷ World power generation mix by case



Note: TWh = terawatt-hours.

Nonetheless, reaching the international goal of limiting the long-term increase in the global mean temperature to 2°C above pre-industrial levels cannot be accomplished through greater reliance on natural gas alone. Achieving this climate target will require a much more substantial shift in global energy use, including much greater improvements in energy efficiency, more concerted efforts to deploy low-carbon energy sources and broad application of new low-carbon technologies, including power plants and industrial facilities equipped for carbon capture and storage. Anchoring unconventional gas development in a broader energy policy framework that embraces these elements would help to allay the fear that investment in unconventional gas comes at the expense of investment in lower-carbon alternatives or energy efficiency.

Country and regional outlooks

Are we moving towards a world of Golden Rules?

Highlights

- The United States is the birthplace of the unconventional gas revolution and regulatory developments at both federal and state levels will do much to define the scope and direction of similar debates in other countries. Moves are underway to build on existing regulation and practice, for example by tightening the rules on air emissions, ensuring disclosure of the composition of fracturing fluids and improving public information and co-operation among regulators.
- In North America, both Mexico and Canada also have significant unconventional gas resources and Canada is one of only a handful of countries outside the United States where commercial production is underway. Which way the regulatory debate turns could have a substantial effect on future unconventional supply: in the Golden Rules Case, total production from North America reaches 1 085 bcm in 2035, of which almost 70% is unconventional supply, whereas the equivalent figure in the Low Unconventional Case is only 780 bcm; this makes the difference between the region exporting to, or importing from, global gas markets.
- The prospects for unconventional gas in China are intertwined with the much broader process of gas market and pricing reform, and with open questions about the extent and quality of the resource. Over the longer term, environmental policies and constraints, notably water availability, are also set to play a role. Our projections for the Golden Rules Case are for unconventional output to reach just over 110 bcm in 2020, a very rapid increase but still somewhat lower than ambitious official targets, and 390 bcm in 2035. Unconventional production is some 280 bcm lower in 2035 in the Low Unconventional Case.
- In advance of any substantial unconventional output, the regulatory framework in Europe is under examination at both national and EU levels, with a variety of outcomes ranging from enthusiastic support for unconventional development from Poland to the bans on hydraulic fracturing in place in France and Bulgaria. In our projections in the Golden Rules Case, growth in unconventional supply in the European Union reaches almost 80 bcm in 2035, which is sufficient post-2020 to offset the decline in conventional output.
- New unconventional gas projects in Australia are coming under increased environmental scrutiny, in particular related to the risk of water contamination from coalbed methane projects. This could constrain future unconventional gas output, although Australia has ample conventional resources with which to achieve growth in supply and export; exports of 120 bcm by 2035 in the Golden Rules Case come mainly from unconventional gas developments, whereas a comparable level of export in the Low Unconventional Case is driven by mainly by conventional output.

United States

Resources and production

Until recently, unconventional natural gas production was almost exclusively a US phenomenon. Tight gas production has the longest history, having been expanding steadily for several decades. Commercial production of coalbed methane began in the 1980s, but only took off in the 1990s; it has levelled off in recent years. Shale gas has also been in production for several decades, but started to expand rapidly only in the mid-2000s, growing at more than 45% per year between 2005 and 2010. Unconventional gas production was nearly 60% of total gas production in the United States in 2010. While tight gas and shale gas account for the overwhelming bulk of this, shale gas is expected to remain the main source of growth in overall gas supply in the United States in the coming decades. The United States and Canada still account for virtually all the shale gas produced commercially in the world, though – as discussed in Chapter 2 of this report – many countries are now trying to replicate this experience.

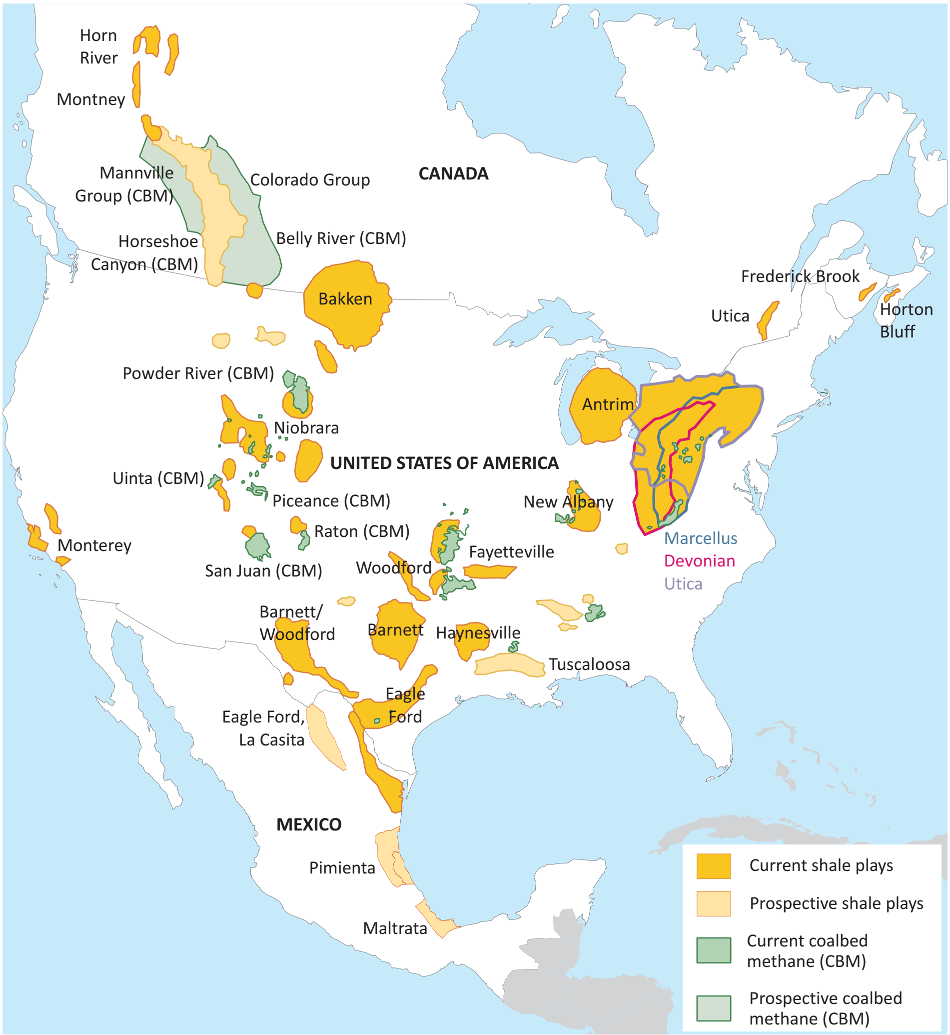
There are large resources of all three types of unconventional gas across the United States. Of the 74 trillion cubic metres (tcm) of remaining recoverable resources of natural gas at end-2011, half are unconventional (Table 3.1); in total, gas resources represent around 110 years of production at 2011 rates. Major unconventional gas deposits in the United States are distributed across much of the country (Figure 3.1). Coalbed methane resources are found principally in the Rocky Mountain states of Wyoming, Utah, New Mexico, Colorado and Montana. Tight gas and shale gas are located in a number of different basins stretching across large parts of the United States, some of which are shared with Canada and Mexico. Two of the largest shale plays that have been identified, the Marcellus and Haynesville formations, taken as single reservoirs are among the largest known gas fields of any type in the world.

Table 3.1 ▷ Remaining recoverable natural gas resources and production by type in the United States

	Recoverable resources (tcm)		Production (bcm)		
	End-2011	Share of total	2005	2010	Share of total (2010)
Unconventional gas	37	50%	224	358	59%
Shale gas	24	32%	21	141	23%
Tight gas	10	13%	154	161	26%
Coalbed methane	3	4%	49	56	9%
Conventional gas	37	50%	288	251	41%
Total	**74**	**100%**	**511**	**609**	**100%**

Sources: IEA analysis and databases.

Figure 3.1 ▷ Major unconventional natural gas resources in North America



Regulatory framework

As pioneers of large-scale unconventional gas development, policy-makers, regulators, producers and the general public in the United States have been the first to face the question of how to evaluate and minimise the associated environmental risks. The emergence of unconventional gas production on a large scale has prompted a broad debate, particularly as production has moved out of traditional oil and gas producing areas. It has also led to changes in the regulatory framework and industry practices. As described in Chapter 1, the principal areas of concern are the impact of drilling on land use and water resources (in particular, the possible contamination of aquifers and surface water) and possible increases in air emissions, particularly of methane and volatile organic compounds.

The legal and regulatory framework for the development of unconventional resources in the United States is a mixture of laws, statutes and regulations at the federal, state, regional and local levels. Most of these rules apply to oil and gas generally and were in place before unconventional resource development took off. They cover virtually all phases of an unconventional resource development, from exploration through to site restoration, and include provisions for environmental protection and management of air, land, waste and water. States carry the primary responsibility for regulation and enforcement on lands outside federal ownership. This approach allows for some regionally specific conditions, such as geology or differing economic or environmental priorities, to be taken into account, with consequential variations in regulatory practices among states. However, on federal lands (extensive in the western United States), the federal government owns the land and mineral resources and directly regulates the extraction process.

Federal laws applicable to unconventional gas resource development are directed mainly at environmental protection. They include the Clean Air Act, Clean Water Act and Safe Drinking Water Act. Certain exemptions from federal rules have been granted; for example, hydraulic fracturing is excluded from the list of regulated activities under the Underground Injection Program authorised by the Safe Drinking Water Act (unless diesel-based fracturing fluids are used). Federal regulations related to community protection and occupational health and safety require that operators make information on certain hazardous chemicals used in drilling operations, including fracturing fluids, available to officials and those responsible for emergency services. Federal rules do not pre-empt additional state-level regulations and public concerns about the risk of pollution have prompted some states to require wider public disclosure about the types and volumes of chemicals used.

State-level regulations relevant to unconventional resources are typically specified in state oil and gas laws; in some cases, these are being updated to respond to public concerns about the environmental impact of unconventional gas development. Typical changes include rules about disclosure of information on fracturing fluids, additional measures to ensure adequate integrity in well casing and cementing, and rules on the treatment and disposal of waste water. Yet regulatory gaps remain in many states, not least because some have limited experience with oil and gas development. The states of New York, New Jersey and Maryland have enacted temporary bans on hydraulic fracturing pending further review of its environmental impacts and the need for changes to regulations; at the time of writing, Vermont also seems set to enact a ban.

Efforts to strengthen the United States' regulatory framework are a public priority, in order to ensure responsible development of unconventional resources and respond to rising public anxiety and pressure. Among the many public organisations focusing on the environmental aspects of unconventional gas development, two are working specifically on improving the quality of regulatory policy: the Ground Water Protection Council and the State Review of Oil and Natural Gas Environmental Regulations (STRONGER). They have both been advising states on regulatory matters to do with unconventional gas. The industry itself has taken steps to promote best practice, both through industry bodies, such as the American Petroleum Institute and through initiatives such as the creation of the FracFocus website, a voluntary online registry to which companies submit data about chemicals used in hydraulic fracturing operations (API, 2011). The site is managed through a partnership with the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.

The United States Environmental Protection Agency has issued federal regulations under the Clean Air Act that aim to reduce emissions of volatile organic compounds from all operations of the oil and gas industry; these will also cut methane emissions. The regulations apply to wells that are hydraulically fractured and will, in essence, enforce the use of "green completions", as already mandated in Colorado and Wyoming. The Bureau of Land Management, responsible for regulation of most energy-related activities on federal land, has proposed new rules that would require companies to disclose the composition of fracturing fluids, seek additional permits and conduct stringent well integrity tests. These initiatives have sparked an intense debate among interested parties as to whether hydraulic fracturing should be regulated at both state and federal level, and whether harmonised regulations on federal lands and on neighbouring leases are required.

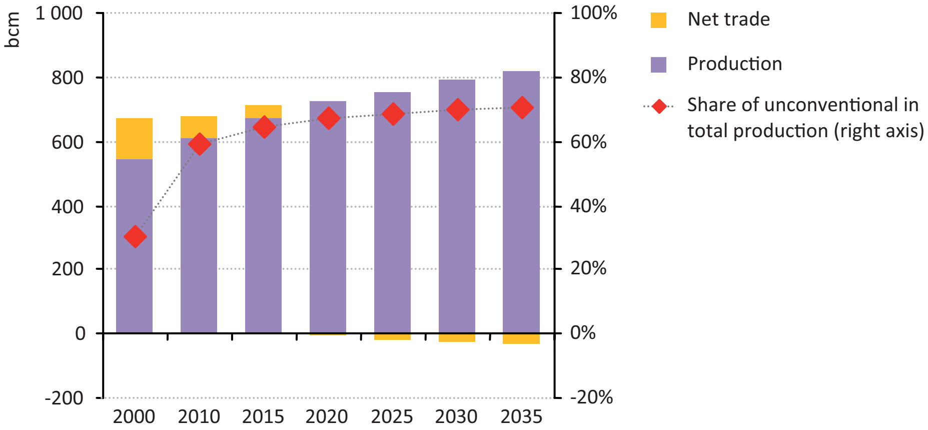
At the end of 2011, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued a set of twenty recommendations for short-term and long-term actions by federal and state agencies to reduce the environmental impact and improve the safety of shale gas production (US DOE, 2011). A major study by the National Petroleum Council on the future of oil and gas resources in the United States has also emphasised the need for "prudent development" and concluded that the benefits of the country's oil and gas resources can be realised by ensuring that they are developed and delivered in a safe, responsible and environmentally acceptable manner in all circumstances (NPC, 2011). These studies and recommendations have been important in defining the scope of regulatory change in the United States and setting its direction; by extension, they could be influential in many countries that are seeking to undertake unconventional gas development.

Within this diverse structure, a major challenge is to maintain reasonable consistency of regulation (for example, among the different states), closing regulatory gaps, where necessary, and doing this in a way that encourages best practice and responds to changes in production technology. Unconventional resource production may be well underway in United States, but shale gas development – and hydraulic fracturing in particular – has become an emotive public issue, with strong and well-organised positions taken by many of the parties involved. This has complicated the prospects for constructive engagement, limiting the common ground on which new regulation (at federal or state level) or new projects (at local level) might be based. Given the scale and pace of development in the United States, there is a likelihood that regulation will be driven by events. For example, an environmental incident linked to unconventional gas development could crystallise public views and prompt new restrictions on unconventional gas production or the use of hydraulic fracturing.

Projections and implications

Assumptions about the regulatory environment have a marked impact on the results of the two cases examined in this report.[1] In the Golden Rules Case, total gas production in the United States grows from around 610 billion cubic metres (bcm) in 2010 to 820 bcm in 2035 (Figure 3.2). Almost all of this increase comes from shale gas production: output of conventional gas, coalbed methane and tight gas remain close to current levels. As a result, the share of shale gas in total gas production rises from 23% in 2010 to 45% in 2035; total unconventional production takes a 71% share of gas output by 2035.

Figure 3.2 ▷ Natural gas balance in the United States in the Golden Rules Case*



* Positive values for net trade denote imports, while negative values represent exports. The sum of production and net trade represents total demand.

In the Low Unconventional Case, total gas production goes into decline after peaking at 660 bcm around 2015, falling to 580 bcm in 2035, 30% less than in the Golden Rules Case (Table 3.2). Production of shale gas in the United States grows until 2017 before limitations on access to resources cause output to fall back to 2010 levels; tight gas and coalbed methane production also decline, to levels seen around 2000 and 1990, respectively. In the Low Unconventional Case, the share of unconventional gas in total supply decreases to only 47% by the end of the *Outlook* period – 23 percentage points less than in the Golden Rules Case. On the other hand, higher gas prices and limited unconventional production in the Low Unconventional Case prompt a mini-renaissance in conventional gas output, with an increase of more than 50 bcm over 2010 production, driven by the investment capital

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[1] See Chapter 2 for details of assumptions in both cases.

and rigs freed up by the shrinking unconventional sector and the possible opening of more offshore and Arctic acreage as the United States struggles to reduce its imports and the associated bills.

These results point in two very different directions for the United States' domestic consumers of gas and its gas industry and its role in international markets. On the domestic market, although gas prices are set to increase in both cases, the rate of the price increase is moderated in the Golden Rules Case by the availability of domestic unconventional gas. United States gas consumption grows by 0.6% per year in this case, a modest rate of increase by global standards (reflecting the maturity of the gas market), but much more impressive considering that overall energy demand growth in the United States averages 0.1% per year (so gas consumption grows six times faster than overall energy demand[2]). In the United States, IHS Global Insight estimates that the lower gas prices attributable to shale gas production will save households $926 per year between 2012 and 2015 (IHS, 2011). Cheaper gas also stimulates industries – chemicals and fertilisers, in particular – that rely on gas as a key feedstock or source of energy. Several chemical companies have announced expansion plans in the United States (PWC, 2011). In the Low Unconventional Case, gas consumption in the United States grows until 2020 and then declines thereafter, ending almost 15% lower by 2035 than in the Golden Rules Case.

Table 3.2 ▷ Natural gas indicators in the United States by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	609	726	821	637	578	242
Unconventional	358	489	580	383	274	306
Share of unconventional	59%	67%	71%	60%	47%	23%
Cumulative investment in upstream gas, 2012-2035**		1 648		1 293		355
Unconventional		1 308		854		454
Net trade (bcm): net imports (+) / net exports (-)	71	-9	-33	57	97	-131
Imports as a share of demand	10%	n.a.	n.a.	8%	14%	n.a.
Share of gas in the energy mix	25%	26%	28%	25%	24%	4%
Total energy-related CO_2 emissions (million tonnes)	5 343	5 218	4 618	5 173	4 511	108

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

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[2] This figure for the United States is higher, for example, than the comparable figure for China, where gas demand grows by an average of 7% per year in the Golden Rules Scenario, "only" about four times faster than total energy growth averaging 1.9% per year.

The boom in shale gas thus far has already transformed prospects for gas trade. The future of this unconventional "revolution" will determine whether the United States becomes an influential gas exporter over the coming decades or, alternatively, sees its imports rise from current levels. As recently as 2008, the United States was projected to require increasing imports of liquefied natural gas (LNG) to meet incremental gas demand (US DOE/EIA, 2008). In the Low Unconventional Case, this again becomes a prospect as domestic production declines.

In the expectation of a more favourable outlook for unconventional gas supply, a number of projects have been proposed to convert idle regasification terminals into liquefaction facilities to enable LNG exports (see Chapter 2). The most advanced of these, Sabine Pass on the United States Gulf Coast, cleared the last of its regulatory hurdles in April 2012 and could be exporting as soon as late 2015, with a target throughput of 22 bcm per year. A further seven projects await Department of Energy export approval, totalling in excess of 120 bcm of capacity. While not all these projects will proceed by 2020, even an additional two projects could see United States LNG export capacity exceed 60 bcm by 2020.

The prospect of LNG export has ignited a debate in the United States about the possible impact on price levels, with domestic gas-intensive industrial users expressing concern that they might lose an element of their current competitive advantage. We assume that other LNG export projects besides Sabine Pass are approved to begin operation but, in the Golden Rules Case, because of limited opportunities for export, the additional capacity may not be needed: LNG exports out of North America reach 40 bcm in 2035 but this is split between the United States and Canada. As discussed in Chapter 2, such exports and capacity would nonetheless have significant implications for the structure of international gas markets and for gas security, especially since a part of these exports would be based on a gas-priced formula, derived from the Henry Hub price.

Successfully meeting public concerns by putting in place the regulatory conditions that deal convincingly with environmental risks could be expected to have a significant impact on the pace of development of unconventional gas resources in other parts of the world. The United States has been the testing ground for unconventional gas technology and the place where this technology has been most widely and most productively applied. Just as experience from the United States has prompted both global interest in developing unconventional resources and reservations about their environmental impact, so too will other countries look to the United States for evidence that social and environmental risks can be managed successfully, in part with appropriate regulation.

Canada

Resources and production

Canada is endowed with large unconventional gas resources of all three types and is one of only a handful of countries outside the United States where commercial production is underway. Production of tight gas was around 50 bcm in 2010 and production of coalbed methane (concentrated in the province of Alberta) close to 8 bcm. Shale gas is believed to have the greatest production potential in the longer term, although commercial production is only 3 bcm. The main Canadian shale gas plays currently being explored and appraised are the Horn River Basin and Montney shales in northeast British Columbia, the Colorado Group in Alberta and Saskatchewan, the Utica Shale in Quebec and the Horton Bluff Shale in New Brunswick and Nova Scotia (Figure 3.1). Remaining recoverable unconventional resources in Canada at end-2011 are estimated to be 18 tcm (11 tcm shale gas, 5 tcm coalbed methane and 2 tcm tight gas), representing around 6% of world unconventional resources. 80% of Canada's total remaining recoverable gas resources are unconventional.

Regulatory framework

Unconventional gas in Canada is subject to a set of federal, provincial and local laws and regulations governing upstream activities, including those relating to environmental impacts. Most oil and gas regulations are provincial, as the resources belong to the provinces (with the exception of those on native lands). The National Energy Board is the federal regulatory body for international and inter-provincial energy issues, while Environment Canada is the federal agency responsible for environmental protection, including the administration and enforcement of federal laws.

The regulatory picture in Canada varies by province, but in response to public pressure and the heightened commercial interest in Canadian unconventional gas opportunities, regulators across the country are paying increasing attention to the potential pollution risks from hydraulic fracturing and to the disposal of waste water from unconventional wells. While each province has its own particular regulations, all jurisdictions have laws to protect fresh water aquifers and to ensure responsible development. In western Canada, gas producers are required by regulation to re-inject produced water into deep saline zones located far below the base of the groundwater, using water disposal wells. In other regions, where no such disposal wells are available, provincial regulations set requirements for treating and disposing of produced water.

Approvals for water use are required from the responsible regulatory agency or government department. Regulators and governments have a variety of control mechanisms available to manage water use and mitigate potential impacts, including the ability to limit the rate at which water is used from any source and to specify aggregate water use limits. There are also regulations aimed at minimising the environmental footprint of drilling and production operations, for example by requiring centralised drilling pads and requiring land restoration after production has ceased.

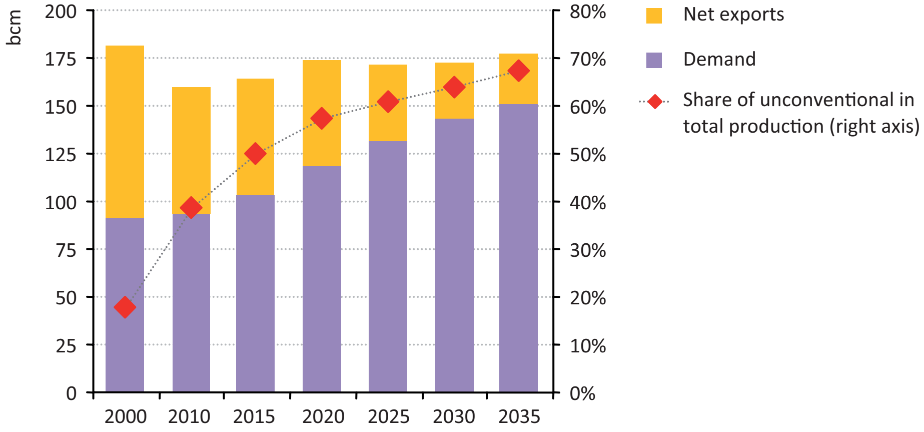
As in the United States, industry bodies are promulgating and promoting best practices. The Canadian Association of Petroleum Producers has recently issued new guidelines for its members, covering many of the issues in the Golden Rules (CAPP, 2012). The Energy Resources Conservation Board, the regulator for the Province of Alberta, a province with a long history of oil and gas production, has initiated a review of its regulatory framework as it applies to unconventional gas (ERCB, 2011). Five of Canada's provinces and one territory are associate members of the United States Interstate Oil and Gas Compact Commission.

The prospect of expanded drilling for shale gas has generated some public and political concern; the clearest incidence of this led the provincial government in Quebec to call a halt in 2011 to the use of hydraulic fracturing, pending an environmental review of the impacts of this practice on water supplies. This followed commercial interest in developing the Utica shale which, running near population centres along the St Lawrence River, generated substantial local opposition. The review is expected to report in 2013.

Projections and implications

Unconventional gas in Canada is expected to play an increasingly important role in offsetting a projected decline in conventional gas production and meeting rising domestic demand. In the Golden Rules Case, unconventional gas production rises from 62 bcm in 2010 to about 120 bcm in 2035, its share of total gas output increasing from just under 40% to two-thirds (Figure 3.3). Shale gas and, to a slightly lesser extent, coalbed methane drive this growth. Total gas production increases from 160 bcm to nearly 180 bcm between 2010 and 2035. Canadian gas demand grows even faster, so net exports drop sharply – from around 65 bcm in 2010 to 25 bcm in 2035. The United States has less need – possibly none at all – to import gas from Canada as its own production of unconventional gas is projected to outpace its domestic gas needs. While Canadian LNG exports to Pacific markets commence before 2020, further growth in exports to Asia is limited in the Golden Rules Case by the large increase in domestic production in China, as well as the rise in unconventional production in Indonesia and Australia.

Figure 3.3 ▷ Natural gas balance in Canada in the Golden Rules Case*



* The sum of demand and net exports represents total production.

In the Low Unconventional Case, shale gas production remains relatively robust, even with the assumed limitations on access to resources. It is about the only unconventional gas resource type with room to grow to offset otherwise rising North American demand for imports. However, overall gas production peaks before 2025 and falls back below current levels by the end of the projection period (Table 3.3). The higher prices that result from slower development constrain demand, which reaches around 130 bcm in 2035, 15% lower than in the Golden Rules Case. Although production is lower in the Low Unconventional Case, it is noteworthy that the required upstream investment is at a level similar to that in the Golden Rules Case; this is because of the relative resilience of shale gas production in the Low Unconventional Case and to the assumption (built into the model) that production tends to become more costly as a given resource starts to become more difficult to access. Since access to shale gas resources is limited in this case, the cost of production rises in a way that balances the effect of lower output on the overall investment requirement.

Table 3.3 ▷ Natural gas indicators in Canada by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	160	174	177	173	141	37
Unconventional	62	100	119	82	84	35
Share of unconventional	39%	57%	67%	48%	60%	7%
Cumulative investment in upstream gas, 2012-2035**		292		296		-4
Unconventional		218		207		11
Net exports (bcm)	66	55	26	63	12	14
Share of gas in the energy mix	30%	34%	40%	32%	35%	5%
Total energy-related CO_2 emissions (million tonnes)	523	547	540	533	521	19

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

Mexico

Resources and production

Mexico's large resources make it one of the most promising countries for shale gas development. Its 19 tcm of shale gas is the fourth-largest shale gas resource base in the world after China, the United States and Argentina; this figure represents some 85% of Mexico's remaining recoverable gas resources. While known about for more than two decades, as elsewhere, shale gas was not considered economically viable to produce until recently.

The government is keen to exploit shale gas resources to boost the country's flagging output of conventional oil and gas. In its National Energy Strategy 2012-2026, for the first time, the Mexican Ministry of Energy has included two scenarios for the development of shale gas: the baseline scenario foresees production of 2 bcm (200 million cubic feet per day [mcf/d]) starting in the Eagle Ford shale play in 2016 and reaching 14 bcm (1 343 mcf/d) in 2026 (Secretaria de Energia, 2012). The "strategy scenario" assumes the additional development of the La Casita shale play, which leads to total shale gas production of 34 bcm (3 279 mcf/d) in 2026.

In line with this strategy, Pemex, the national oil company, is looking in particular at the areas in the north that are extensions of the Eagle Ford shale play (Figure 3.1). Pemex sunk its first shale gas well, Emergente 1, in the Burgos basin in February 2011 and this has been producing at a rate of almost 30 million cubic metres (3 mcf/d). Pemex plans to drill around 175 wells during the period 2011 to 2015 to evaluate reserves and delineate priority areas for development. Pemex also plans to acquire about 10 000 square kilometres of three-dimensional seismic data, which it will use to carry out detailed geological and geochemical modelling studies.

If this exploration effort demonstrates the commercial viability of shale gas production, the large-scale development of these resources would require a huge increase in drilling. Pemex estimates that the development of 8.4 tcm (297 trillion cubic feet) of shale gas – its central estimate of recoverable resources – would call for drilling a total of more than 60 000 wells[3] over the next 50 years, requiring a very large-scale capital investment.

In addition to the need for adequate investment, a number of technical challenges would need to be overcome for this to happen, notably adequate access to water for hydraulic fracturing. Coahuila, where much of the Eagle Ford play is located, is one of Mexico's driest states, with rainfall less than half the national average and all of the surface water rights have already been allocated. Three-quarters of the state's water is used in agriculture for the production of grains and other crops that can survive the desert climate, while the rest is for industrial consumption. Hydraulic fracturing on a large scale would require very careful treatment and recycling of waste water to reduce the need for fresh water. Other hurdles to shale gas development, such as the lack of pipeline infrastructure to deliver gas to market, could complicate operations and make the cost of drilling shale gas wells in Mexico significantly higher than in the United States. A plan to increase the transport and distribution capacity for natural gas is being implemented, including a pipeline that will run close to the main gas-rich areas in the northern parts of the country.

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[3] Information provided in a presentation by Carlos Morales, Director General, PEMEX Exploration & Production, to the IEA Workshop on Unconventional Gas in Warsaw, 7 March 2012. This appears to be based on an Estimated Ultimate Recovery (EUR) of 5 bcf per well; this is representative of good wells in the United States but could overestimate a likely average EUR per well; if so, the number of wells required to produce this volume of shale gas could be higher.

Regulatory framework

The environmental impact of gas development in Mexico is covered by existing environmental, health and safety laws and regulations. There are no specific national regulations in place yet for shale gas; however, the new National Energy Strategy 2012-2026 recognises that the new targets for shale gas production might require specific regulatory provisions and calls for the future development of an "integrated strategy" for shale gas, addressing environmental, social and financial challenges. This will require not only attention to the regulatory framework, but also the allocation of sufficient resources to regulatory bodies to ensure adequate supervision and enforcement.

Pemex holds monopoly rights over all upstream activities in Mexico and no other company is allowed to own hydrocarbons reserves or undertake exploration or production for its own benefit. A law adopted in 2008 allows Pemex to sign incentive-based development contracts with other companies, though the price paid for services cannot be linked to production: three such contracts for the development of small, mature onshore fields were awarded in August 2011. Larger contracts, which could have a more substantial impact on the country's production, are expected to be offered in future.

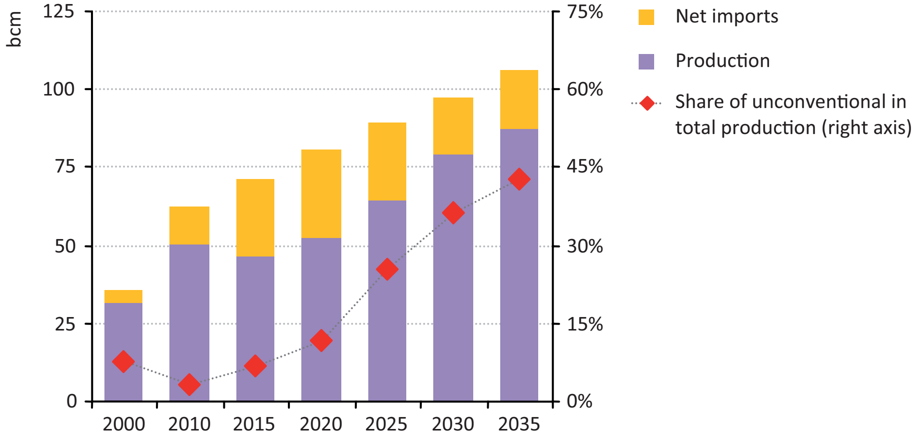
The strategy to be developed for shale gas could follow one of a range of possibilities: it could rest heavily on assistance from companies under service contracts, either basic in terms of remuneration or more strongly incentive-based, although it is also possible that Pemex could decide to handle all shale development on its own. The pace of shale gas development will depend in part on the approach chosen; a greater involvement of private firms, beyond the arrangements already provided for in current legislation, could accelerate the process, but may be politically challenging.

Projections and implications

Shale gas could make a significant contribution to meeting Mexico's gas needs in the longer term, but much will depend on the regulatory regime governing participation by private companies and whether the environmental challenges – notably related to the use and recycling of water for hydraulic fracturing – can be overcome. Development costs will have to be low enough to allow domestic resources to compete with imports from the United States, the price of which recently hit new lows. The alternative – to try and protect the domestic market from cheaper gas imports – is difficult in the context of Mexico's participation in the North American Free Trade Agreement.

In the Golden Rules Case, Mexican gas production grows from 50 bcm in 2010 to almost 90 bcm in 2035, with nearly all of the increase coming from unconventional gas (mostly shale gas, plus some tight gas); conventional gas production grows slightly to around 50 bcm by the end of the projection period, as new fields struggle to compensate for the continuing decline in output from the Cantarell field and other mature fields.[4] Shale and tight gas production reach about 37 bcm combined in 2035, accounting for close to 45% of total Mexican gas production (Figure 3.4). In the Low Unconventional Case, unconventional gas production remains negligible through to 2035.

Figure 3.4 ▷ Natural gas balance in Mexico in the Golden Rules Case*



* The sum of production and net imports represents total demand.

Rapid growth in unconventional gas would have a major impact on Mexico's overall energy mix, with the lower gas prices encouraging gas use and leading to an increase in gas demand. In the Golden Rules Case, demand rises from around 60 bcm in 2010 to 105 bcm in 2035, the share of gas in total primary energy use increasing from 29% to 35% (Table 3.4). The country's need to import gas varies over time. It currently imports about 20% of its gas needs, by pipeline from the United States and in the form of LNG; these imports rise to nearly 30 bcm by 2020, but then fall back to about 20 bcm by 2035 as gas production outstrips demand growth. Higher gas demand and lower imports promise energy security and economic benefits to Mexico, with the possibility of net environmental benefits. In the Low Unconventional Case, the share of gas in primary energy demand actually drops, to 28% by 2035, leading to higher energy-related carbon-dioxide (CO_2) emissions relative to the Golden Rules Case.

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[4] In the strategy scenario, or high case, included in Mexico's National Energy Strategy 2012-2026, conventional gas production increases from around 60 bcm in 2011 to almost 85 bcm in 2026. Shale gas production, on its own, contributes around 34 bcm to total natural gas production in 2026.

Table 3.4 ▷ Natural gas indicators in Mexico by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	50	52	87	46	59	28
Unconventional	2	6	37	0	0	37
Share of unconventional	3%	12%	43%	0%	0%	43%
Cumulative investment in upstream gas, 2012-2035**		140		111		29
Unconventional		47		-		47
Net imports (bcm)	12	28	19	25	28	-9
Imports as a share of demand	19%	35%	18%	35%	32%	-14%
Share of gas in the energy mix	29%	32%	35%	29%	28%	7%
Total energy-related CO_2 emissions (million tonnes)	402	449	492	455	511	-19

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

China

Resources and production

The size of unconventional gas resources in China is at an early stage of assessment, but it is undoubtedly large. At end-2011, China's remaining recoverable resources of unconventional gas totalled almost 50 tcm, comprised of 36 tcm of shale gas, 9 tcm of coalbed methane and 3 tcm of tight gas.[5] This is around thirteen times China's remaining recoverable conventional gas resources. China's shale gas resources lie in several large basins spread across the country, with plays in the Sichuan and Tarim Basins believed to have the greatest potential. The main coalbed methane deposits are found in the Ordos, Sichuan and Junggar Basins (Figure 3.5).

Coalbed methane is currently the primary source of unconventional gas produced commercially in China, with output of around 10 bcm in 2010. Most of this output comes from coal producers PetroChina and China United Coal Bed Methane Company. Shale gas exploration activities have increased in recent years under a government-driven programme to evaluate the resource base. Results from several pilot projects, to be completed in 2012, are expected to inform the selection of high potential areas for further exploration. As of early 2012, an estimated 20 shale gas wells had been drilled by Chinese companies. Based on what is known about China's geology at this early stage, shale gas resources may prove more difficult and more expensive to develop than those in North America. Early

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5. We use the ARI estimate for shale gas to be consistent with our methodology for other countries. This is higher than the 25 tcm estimated by China's Ministry of Land and Resources for recoverable shale gas resources; however the MLR number does not yet include all provinces (MLR, 2012).

indications are that kerogen quality in the shale plays is relatively poor, resulting in low organic content. This suggests that, for China to achieve a similar output to that of the United States, it would need to drill more wells, with longer reach.

Figure 3.5 ▷ Major unconventional natural gas resources in China

This document and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

The Chinese government has outlined ambitious plans for boosting unconventional gas exploration and production. These call for coalbed methane production of more than 30 bcm and for shale gas production of 6.5 bcm in 2015; the targets for shale gas output in 2020 are between 60 and 100 bcm. They are accompanied by the goal to add 1 tcm of coalbed methane and 600 bcm of shale gas to proven reserves of unconventional gas by 2015. In support of this effort, China plans to complete a nationwide assessment of shale gas resources and build nineteen exploration and development bases in the Sichuan Basin in the next four years. Efforts are also supported by the international partnerships that Chinese companies have formed in North America to develop shale gas acreage, which will provide valuable development experience.

An initial tender for four blocks of shale gas exploration acreage in the Sichuan Basin was held in June 2011, with participation limited to six eligible state-controlled companies. Of those, Sinopec and Henan Provincial Coal Seam Gas Development and Utilization Company obtained licences. An expanded group of bidders, including privately-owned Chinese companies (qualified based on sufficient capital, technology and expertise), are expected to participate in a second round of licensing in mid-2012. Foreign firms will not be allowed to participate directly, but may enter into partnerships with eligible companies that submit successful bids. Various major international oil companies have already entered into some form of partnership with state-controlled companies, reflecting their strong interest in pursuing unconventional gas development opportunities in China.

Regulatory framework

China's huge unconventional gas potential and strong policy commitment suggest that these resources will provide an increasingly important share of gas in the longer term, though the pace of development through to 2020 – the key period of learning – remains uncertain. Because of China's highly centralised regulatory and policy-making framework and the high priority placed on industrial and economic development, unconventional gas projects may face fewer hurdles stemming from environmental concerns than those in Europe or the United States. Nonetheless, the regulatory framework is evolving, and different features of it could affect the pace of development in different ways, for example the terms of access, the pace of diffusion of advanced technology, financial incentives, the pricing regime, environmental constraints and infrastructure development.

Strategic policy decisions in China relating to resource management and environmental protection are made nationally, with implementation and enforcement responsibilities often delegated to local authorities. Many aspects of China's legal and regulatory framework for oil and gas development are broadly defined, giving local regulators latitude to consider project-specific circumstances in their decisions (although this can also lead to unpredictable outcomes). Challenges arise from the fragmentation and overlap of responsibilities among various regulating entities, uncertainty about effective co-ordination between them and potentially inconsistent enforcement of regulations.

Domestic petroleum exploration and development has traditionally been the domain of China's state-owned enterprises. Under the Law on Mineral Resources, only state-controlled entities may acquire mineral rights, foreign companies being confined to minority partnerships with state-controlled entities and, in some cases, production-sharing agreements. Although the strategic importance of unconventional gas means that China's national oil companies are likely to be the primary drivers of production growth, there are some changes underway in response to China's ambitious plans for shale gas exploration and development, and the need for the advanced technology and investment that foreign companies can bring. The legal classification of shale gas as a separate "mineral resource" in late 2011 means that the current regulations that give CNPC and SINOPEC exclusive rights for exploration of onshore oil and gas resources do not apply to shale gas, and this step may presage an intention to grant greater access to others. Foreign companies have already been allowed to take a majority stake in coalbed methane projects.

All project promoters must conduct an environmental impact assessment, which must be filed with national and local regulators and approved in advance of submission of a field-development plan. Drilling permits are issued on the basis of the development plan, rather than well-by-well; and any significant changes to the plan, for example related to the density of drilling, require submission of a new environmental impact assessment. Project delays during the early phases of development may occur because of the limited experience of producing unconventional gas in China.

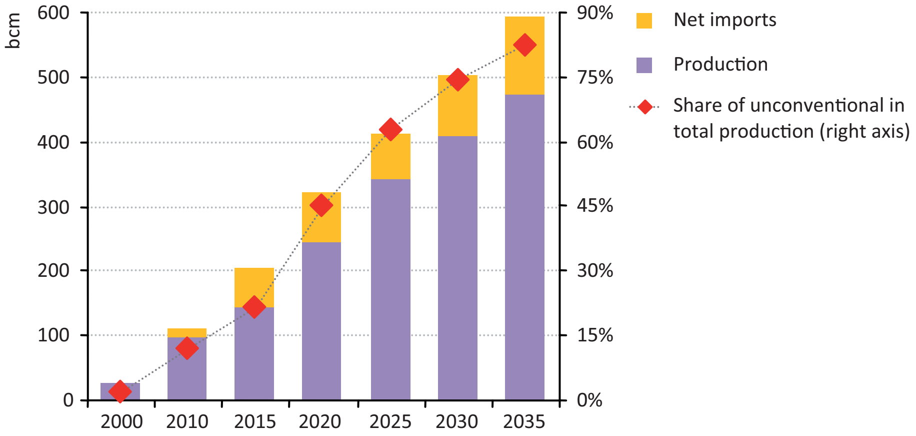
Water availability may prove to be one of the biggest obstacles to unconventional gas development in China, particularly in the north and west, where water is scarce and may be already strained by agricultural or urban needs. Water policies, regulations and plans are determined nationally, though responsibilities for management and enforcement are delegated locally. Many different entities are involved at the national, regional and local levels, which risks limited co-ordination of water resources at the river basin level. National standards establish maximum discharge concentrations for pollutants into water sources and the Circular Water Law promotes reuse and recycling of waste and produced water.

The fiscal regime, gas pricing policies and pipeline access are other regulatory variables that will critically influence the pace of unconventional gas development in China. The 12th Five-Year Plan promises favourable fiscal incentives to producers, namely direct subsidies, preferential tax treatment and priority land use. The domestic coalbed methane industry receives price subsidies of RMB 0.2 ($0.03) per cubic metre for extracted gas and RMB 0.25/m^3 ($0.04) for gas produced for some specific end-users. Shale gas might be expected to attain a similar or higher level of subsidy. According to the 12th Five-Year Plan, the pricing regime for shale gas will be market-based, an important signal that the government is willing to allow higher end-user prices (relative to current controlled prices for natural gas) to encourage development. China's gas pipeline network will necessarily have to expand to reach into unconventional gas production areas in order to avoid becoming a bottleneck as output increases. As major gas pipelines are currently run by national oil companies, making access more available to other producers will be vital.

Projections and implications

Gas is set to play an increasingly important role in meeting China's burgeoning energy needs and the successful development of the country's unconventional resources could accelerate that trend, given effective resource and environmental management. In the Golden Rules Case, unconventional gas production is projected to jump from 12 bcm in 2010 to just over 110 bcm in 2020 and 390 bcm in 2035. Total gas production rises from just under 100 bcm in 2010 to nearly 475 bcm in 2035 (Figure 3.6). Unconventional gas accounts for 83% of total gas production by the end of the projection period. Unconventional gas production in 2035 is predominately from shale gas (56%) and coalbed methane (38%); tight gas (6%) takes a smaller share.

Figure 3.6 ▷ Natural gas balance in China in the Golden Rules Case*



* The sum of production and net imports represents total demand.

Table 3.5 ▷ Natural gas indicators in China by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	97	246	473	139	194	279
Unconventional	12	112	391	37	112	279
Share of unconventional	12%	45%	83%	27%	58%	25%
Cumulative investment in upstream gas, 2012-2035**		554		311		243
Unconventional		374		170		204
Net imports (bcm)	14	77	119	143	262	-143
Imports as a share of demand	12%	24%	20%	51%	57%	-37%
Share of gas in the energy mix	4%	8%	13%	7%	10%	3%
Total energy-related CO_2 emissions (million tonnes)	7 503	9 792	10 449	9 877	10 695	-246

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

In the Low Unconventional Case, output of shale gas and coalbed methane grows much less rapidly, reaching a combined level of less than 115 bcm in 2035 (Table 3.5). The reduced availability of local gas supplies increases the country's dependence on imports at higher average prices. Less ambitious policies to boost demand, coupled with higher prices, lead to slower growth in Chinese gas demand, as the Chinese authorities seek to limit the country's reliance on imports. Demand reaches only 455 bcm by 2035, almost one-quarter lower than in the Golden Rules Case. The share of gas in total primary energy is correspondingly markedly lower: 10% versus 13% in 2035. This results in increased dependence on coal and, to a lesser extent, on nuclear and renewables.

Rapid growth in unconventional gas would greatly strengthen China's energy security and have major implications for international gas trade. In the Golden Rules Case, imports amount to nearly 120 bcm in 2035, about 20% of the country's gas demand, compared with just over 260 bcm or nearly 60% of demand in the Low Unconventional Case. The overall cost of gas imports is correspondingly much lower, by 60%, in the Golden Rules Case. Lower import volumes would improve China's negotiating position *vis-à-vis* its suppliers, including producers of LNG, existing suppliers by pipeline from Central Asia and Myanmar, and Russia, which has the potential to become a major supplier of gas to China but whose opportunities to do so would be much more limited in the Golden Rules Case. The uncertainty surrounding the prospects for China's unconventional gas industry may favour investment in LNG over pipeline projects (and, in both cases, lessen the attractiveness of large long-duration supply contracts) as China may seek more flexibility to allow for gas-import needs turning out to be smaller than expected.

Europe

Resources and production

Europe's unconventional gas resources have attracted considerable interest in the last few years, although in practice the push to develop this resource varies considerably by country, depending on the mix of domestic fuels and imports and perceptions of the risks to energy security and the environment. Attention to unconventional gas focused initially on coalbed methane and tight gas, but has now switched to shale gas. Recoverable resources of shale gas are believed to be large, though how much can be recovered economically remains uncertain.

Europe's shale gas resources are found in three major areas that contain multiple basins, sub-basins and different plays: from eastern Denmark and southern Sweden to northern and eastern Poland (including Alum shales in Sweden and Denmark, and Silurian shales in Poland); from northwest England, through the Netherlands and northwest Germany to southwest Poland; and from southern England through the Paris Basin in France, the Netherlands, northern Germany and Switzerland (Figure 3.7). Poland and France are thought to have the largest shale-gas resources, followed by Norway, Ukraine, Sweden, Denmark and the United Kingdom. Potential coalbed methane resources in Europe are reasonably well established and are significant in some countries, notably in Ukraine, the United Kingdom, Germany, Poland and Turkey.

Figure 3.7 ▷ Major unconventional natural gas resources in Europe

This document and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

As yet, there is no large-scale production of unconventional gas in Europe. How soon it will begin and how quickly it will grow remain to be seen, though there are several factors favouring development. The European Union is the second-largest regional gas market in the world, with demand amounting to around 550 bcm in 2010, and it is set to become increasingly dependent on imports as indigenous production of conventional gas continues to decline and demand continues to expand. The region has a well-established pipeline and storage network (albeit not as densely developed as in the United States). And, crucially, natural gas prices are high compared with North America, adding to the attractiveness of developing new indigenous gas resources.

But there are above-ground factors that are likely to impede rapid growth in unconventional gas production, the most significant of which is the high population density in many of the prospective areas. This increases the likelihood of opposition from local communities, especially in areas with no tradition of oil and gas drilling. State ownership of oil and gas rights can also reduce the incentives for communities to accept development of local unconventional gas resources, compared with parts of the United States where these rights are held by private land-owners.

The European regulatory framework

Most regulations applicable to upstream oil and gas in the European Union are determined at the national level: member states define their own energy mix and make decisions concerning domestic resource development. At the EU level, there is a common set of rules (under the Hydrocarbons Licensing Directive) to secure transparent and non-discriminatory access to the opportunities for exploration, development and production of hydrocarbons, but the main area in which Europe-wide regulation applies is environmental protection, including:

- Water protection (Water Framework Directive, Groundwater Directive and Mining Waste Directive).
- The use of chemicals (under REACH regulation, administered by the European Chemicals Agency).
- The protection of natural habitats and wildlife.
- Requirements to carry out an environmental impact assessment, under general environmental legislation.
- Liability for upstream operators to incur penalties for environmental damage (under the Environmental Liability Directive and the Mining Waste Directive).

Public concerns about the environmental risks associated with hydraulic fracturing have prompted calls for new regulation on aspects of this practice, often based on the "precautionary principle" that is a statutory requirement in European Union law. A 2011 report commissioned by the Directorate General for Energy of the European Commission found that European environmental legislation applies to all stages of unconventional gas developments. It also concluded that, both on the European level and at the national level (in the countries studied), there are no significant gaps in the legislative framework when it comes to regulating shale gas activities at the present level of intensity (Philippe & Partners, 2011). However, it did suggest that the situation might change if activities were to expand significantly and did suggest some improvements to national legislation, including procedures to include local citizens at earlier stages in the impact assessment process.

Additional assessments of various aspects of unconventional gas are currently being carried out within the European Commission. These include: a study on the economics of shale gas, by the Joint Research Centre in collaboration with the Directorate General for Energy; a study on methane emissions, by the Directorate General for Climate Action; and an assessment of the adequacy of the current regulatory framework to ensure an appropriate level of protection to the environment and to human health, by the Directorate General for the Environment. On the basis of the results of these assessments, the Commission will decide whether to put forward regulatory proposals specifically related to unconventional gas.

The European Parliament has also taken up the debate about various aspects of shale gas development. An assessment presented to the Committee on Environment, Public Health and Food Safety (European Parliament, 2011a) found that the current regulatory framework concerning hydraulic fracturing has a number of deficiencies, most importantly, the high threshold before an environmental impact assessment is required[6]; it also called for the coverage of the Water Framework Directive to be re-assessed focusing on the possible impacts of hydraulic fracturing on surface water and urged consideration of a ban on the use of toxic chemicals. A draft report to the same committee, prepared by a Polish parliamentarian, is more supportive of unconventional gas development (European Parliament, 2011b), while recognising the need to address concerns about the environmental effects of extraction. A separate draft report, focusing on the energy and industrial implications of shale gas development, is also under consideration by the Parliament's Committee on Industry, Research and Energy (European Parliament, 2012).

Poland

Medium-term prospects for unconventional gas production in Europe appear brightest in Poland, where exploratory drilling for shale gas is most advanced and where above-ground factors are generally less of an obstacle to development than elsewhere. Optimism about Poland's shale gas potential stems from the size of its resources, although these are still subject to considerable uncertainty. The US EIA put technically recoverable resources in Poland at 5.3 tcm (US DOE/EIA, 2011), while an assessment by the Polish Geological Institute (with the support of the United States Geological Survey), studying archive data on the Baltic, Podlasie and Lublin Basins, estimated recoverable resources at 346 bcm to

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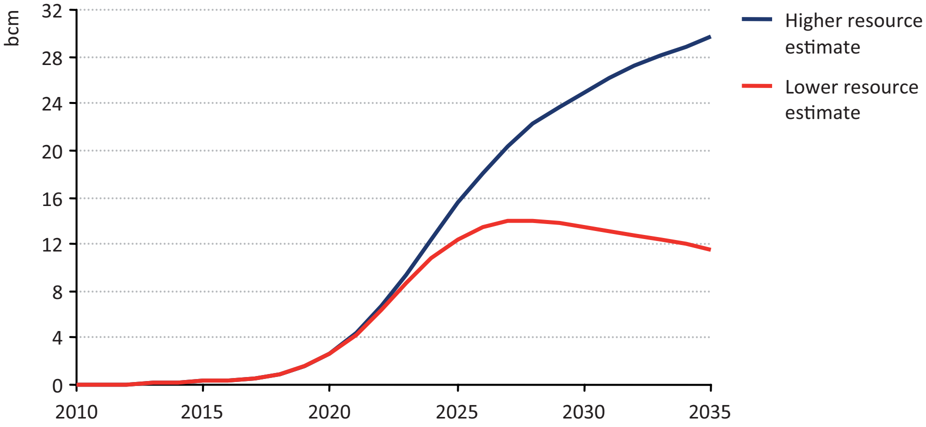
[6] The Environmental Impact Assessment Directive does though include an obligation to screen for possible adverse environmental effects in projects which fall below any relevant thresholds.

768 bcm (PGI, 2012). The large difference is explained primarily by differences in methodologies between the two studies; the range of resource assessments should narrow as more data become available from exploratory drilling.

As described in Chapter 2, the model used for the projections in this report relies on the Rogner and ARI estimates for shale gas resources, which are so far the only assessments that apply a consistent methodology across a large enough number of countries. If actual resources in Poland are significantly lower than assumed, inevitably this would have a considerable impact on our projections, all else being equal. This is illustrated in Figure 3.8, which shows projections for shale gas production in Poland for a higher and lower recoverable resource estimate, respectively, based on the ARI estimate of 5.3 tcm and using a mid-range figure of 0.55 tcm from the Polish Geological Institute estimate.

Figure 3.8 ▷ **Impact of different resource assessments on projected shale gas production in Poland**



Poland has one of the oldest petroleum industries in the world and has been producing oil and gas from conventional reservoirs since the 1850s, though production has fallen to low levels over recent decades. Interest in shale and tight gas began towards the end of the last decade. A series of exploration licensing rounds has led to a large influx of international companies, with a number of firms that are already active in the United States – including ExxonMobil, Chevron, Eni, Talisman and Marathon – buying up drilling rights, either directly or through joint ventures (although the national oil and gas company, PGNiG, holds the most licences). Over 100 exploration licences, most of which have a duration of five years, have so far been issued, covering most of the prospective shale gas areas.

Early results from exploration drilling have put something of a damper on the initial hopes for a rapid take-off in production. Since PGNiG completed Poland's first shale well in 2009, 18 exploration wells have been drilled, with a further 14 underway and 39 planned (as of March 2012). Flow rates were low in the few wells for which data have been made public, with some reportedly proving unresponsive to normal drilling and well-completion techniques. ExxonMobil has announced that two wells that it drilled and completed in 2011 are not commercially viable, though it is looking into whether different fluids, proppants or pumping techniques might produce better results. ExxonMobil and other companies continue to drill new wells.

The Polish government has been very supportive of drilling for shale and tight gas, reflecting the potentially large economic and energy security benefits that could be gained from supplementing the country's dwindling resources of conventional gas and reducing its heavy dependence on gas imports from Russia. Gas demand is expected to grow in the coming years, particularly for power generation, as older, low-efficiency coal-fired stations close. Although shale gas production costs are likely to be above those in the United States, high oil-indexed prices for imported gas should make shale developments profitable. Relatively low population density in the main basins as well as a history of oil and gas activities may favour public acceptance.

The regulatory framework applicable to unconventional gas development is changing with the prospect of commercial production. Until the recent arrival of foreign firms, the upstream sector was dominated by PGNiG, which ensured that the government captured a large part of any rent on hydrocarbons production and reduced the need for explicit regulation for that purpose. The legislative system for the upstream is now being adjusted to the reality of many new market entrants and participants, including changes to the licensing system and the fiscal framework for upstream activity.

A new Geological and Mining Law came into force in Poland at the start of 2012, which clarifies some administrative and legal questions regarding the development of Poland's unconventional gas potential. The most significant change was that licences for exploration of hydrocarbons in Poland can now be granted only through tenders (exploration licences issued over the last five years were on a first-come, first-served basis). Since most prospective gas exploration acreage in Poland has already been awarded, the new regulations will become more significant when the first production licences are sought. The new law also modifies the system of mineral rights ownership, more clearly defining the division between state rights and those of landowners, but shale gas, as a strategic mineral, remains the exclusive property of the state.

France

With resources almost as large as those in Poland, France was expected to be one of the first European countries to produce unconventional gas commercially. Shale gas potential is primarily in two major shale basins: the Paris Basin and the Southeast Basin. The Southeast Basin is considered to be the more prospective, in view of the low depth of parts of the basin, possible liquids content and low levels of clay. The government had issued three licences for shale gas exploration drilling in the Southeast Basin but, in May 2011, in the face of a strong public opposition over the potential environmental impacts of hydraulic fracturing, the government announced a moratorium on its use and later prohibited it by law. Two firms that held licences – France's Total and the US-based Schuepbach Energy – subsequently had their licences cancelled. Schupebach Energy had maintained their intention to use hydraulic fracturing, whereas Total had submitted a report where they committed not to use it. A third company that committed not to use hydraulic fracturing has had its permit maintained.

Public opposition was linked to the fact that part of the prospective basin underlay scenic regions that are heavily dependent on the tourism industry. Resentment was exacerbated by a lack of public consultation: under French mining laws, public consultation is required only at the production stage and not at the exploration stage. Revision of the mining code is under consideration to include earlier public consultation.

A report was commissioned jointly by the Ministry of Ecology and Sustainable Development and the Ministry of Industry, Energy and Economy to provide information on shale gas and light tight oil, the environmental concerns surrounding their development and the applicability of existing hydrocarbon regulation in France to this new potential energy source. A preliminary report recommended some drilling in France, under strict controls, while more information was gathered about the impact of hydraulic fracturing elsewhere in Europe and the United States (Leteurtrois, 2011). However, the final report was not issued because the ban on hydraulic fracturing was voted in the meantime.

In France, as in some other countries, the debate around shale gas developments became a proxy for a much broader question about the approach to sustainable energy policy. In a separate report prepared for the National Assembly, the co-authors did not share a common vision of France's future energy mix, writing two separate conclusions (Gonnot, 2011). One concluded that more study was required to understand the extent of the country's resource and the technologies to safely develop it, with a view to then taking a decision on whether to proceed developing the resources. The second asserted that the development of new hydrocarbon resources has no place in a national energy policy striving to meet agreed climate change objectives.

The Paris Basin has a long history of conventional oil production. In the early 1980s, high hopes were held that significant volumes might be found, but exploration turned out to be disappointing and production has not exceeded a few thousand barrels per day. Production is mostly from the rural Seine et Marne Région, southeast of Paris, where several hundred wells have been drilled. Some geologists have argued recently that the reason large oil fields have not been discovered is that the hydrocarbons have not been expelled from the source rocks. Indeed, there are indications from wells that have intercepted some of the shales that they may be hydrocarbon bearing, probably mostly light tight oil, with some shale gas. Estimates of oil-in-place vary from 1 to 100 billion barrels, though the fraction which might be technically and economically recoverable is not known.

In the Golden Rules Case, we assume a reversal of the ban on hydraulic fracturing. Shale gas production rises after 2020 to reach 8 bcm in 2035, which would allow France to exceed its peak gas production from the end of the 1970s. At the same time, light tight oil production could reach several tens of thousands of barrels per day. Some of the resources, located in sensitive areas, are likely to remain barred from development but, if productivity can be established, there should be enough resources in other areas to sustain such production.

Other EU member countries

There has been a good deal of discussion about unconventional gas prospects in several other EU member countries, but little exploration activity as yet. Most of the wells that have been drilled are for coalbed methane. There appears to be significant potential for shale gas development in several other EU member countries, notably in Sweden, the United Kingdom and Germany.

Sweden's shale gas resources are located in the Scandinavian Alum shale, which extends from Norway to Estonia and south to Germany and Poland. The Alum shale has been mined for oil shale for many decades in central and southern Sweden (and in Estonia), where it is close to the surface. It has the advantages of high organic content and thermal maturity and is relatively shallow, with depths averaging less than 1 200 metres. But it lacks overpressure and contains a high concentration of uranium, which poses problems for water treatment and recycling. Shell has been most active in assessing the shale, having drilled three exploration wells in the Skåne region of southern Sweden, but it ceased operations when they proved to be dry. Opposition to hydraulic fracturing had delayed the programme and threatens to deter renewed exploration activity.

In the *United Kingdom*, a main shale play is the Bowland shale formation (in the Northern Petroleum System), which is relatively shallow, with an average depth of only 1 600 metres, and with certain areas rich in liquids. Cuadrilla Resources has drilled two exploration wells, one of which encountered gas. It subsequently announced that the formation could hold as much as 5.7 tcm (200 trillion cubic feet) of technically recoverable gas. However, operations have been suspended as a result of two small earthquakes that occurred after hydraulic fracturing was carried out. A report commissioned by Cuadrilla concluded that it is "highly probable" that the fracturing and subsequent earthquakes were linked, although future occurrences should be rare given the unique local geology at the well site (de Pater and Baisch, 2011). The UK Department of Energy and Climate Change commissioned an independent report on the causes of the earthquakes and appropriate means of mitigating seismic risks (Green, Styles and Baptie, 2012). It recommended cautious continuation of Cuadrilla's hydraulic fracturing operations and several safety provisions, including greater use of micro-seismic monitoring and new safeguards that would lead to a suspension of operations in case of seismic activity. At the time of writing, the government was awaiting comments on this report before making any decision regarding additional hydraulic fracturing.

The UK government appears to be supportive of continuing shale gas exploration and development. A parliamentary inquiry in 2011 found no evidence that hydraulic fracturing poses a direct risk to underground water aquifers, provided the drilling well is constructed properly, and concluded that, on balance, a moratorium on shale gas activity in the United Kingdom is not justified or necessary at present (UK Parliament, 2011). Nonetheless, the inquiry urged the UK Department of Energy and Climate Change to monitor drilling activity extremely closely in its early stages in order to assess its impact on air and water quality.

Germany has shale resources, estimated at 230 bcm, in the large North Sea-German basin, which extends from Belgium to Germany's eastern border along the North Sea coast. Several companies have acquired exploration licences and ExxonMobil has drilled at least three exploratory shale gas wells in Lower Saxony as part of a ten-well programme. Germany has a history of tight gas production with relatively large hydraulic fracturing treatments having been common practice for the last 20 years. As in France, there has been strong opposition to shale gas drilling on environmental grounds, but attention to the need for indigenous energy sources, including unconventional gas, has been intensified by a decision to phase out nuclear power.

Shale gas exploration efforts are advancing elsewhere in the European Union: there are plans by OMV to drill several test wells in *Austria* in the next two years; in *Lithuania*, exploration licences were being tendered at the time of writing. *Bulgaria* and *Romania* have awarded shale gas exploration licences, but these countries have experienced strong public opposition over fears about the environmental impact of hydraulic fracturing and, in Bulgaria, this has led to parliament voting in early 2012 to ban the use of the technique, making it the second country in the European Union to do so.

EU projections and implications

Against a backdrop of declining indigenous production and a policy priority to diversity sources of gas supply, the European Union has reasons to be interested in exploiting its domestic unconventional gas potential. At the same time, environmental concerns could easily delay or derail development. In our projections in the Golden Rules Case, unconventional gas production is slow to take off but accelerates in the longer term, as confidence grows in the effective application of the Golden Rules in the most prospective countries. In our projections, unconventional production in the European Union climbs to just over 10 bcm by 2020, but it grows more rapidly thereafter, reaching almost 80 bcm by 2035 (Table 3.6). Shale gas accounts for the bulk of this output. Unconventional gas contributes almost half of the European Union's total gas production and meets just over 10% of its demand by 2035. As a result, even though there are not dramatic shifts in the trade balance, as seen in the United States, growth in unconventional production offsets continued decline in conventional output from 2020 (Figure 3.9).

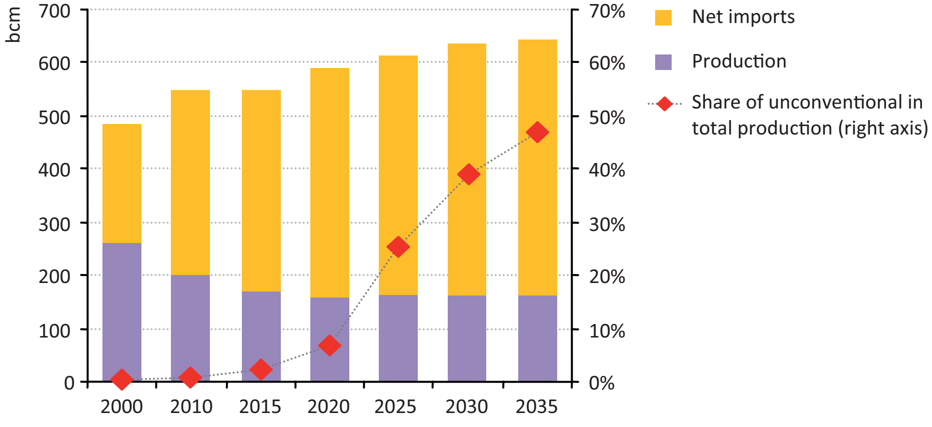
Rising unconventional gas production (both in Europe and worldwide) helps to restrain the rise in gas prices in Europe, which – together with additional policies to encourage gas use – drives up gas demand. As a result, the upward trend in net gas imports into the European Union continues throughout the projection period, reaching 480 bcm in 2035, or three-quarters of total demand (compared with 345 bcm, or more than 60%, in 2010). In the Low Unconventional Case, in which there is very little commercial unconventional production before 2035, European Union net gas imports are 30 bcm higher in 2035 than in the Golden Rules Case (and gas import prices are higher). Consequently, the cost of those imports reaches about $250 billion in 2035 (in year-2010 dollars) – an additional import bill of almost $60 billion relative to Golden Rules Case.

Table 3.6 ▷ Natural gas indicators in the European Union by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	201	160	165	139	84	81
Unconventional	1	11	77	0	0	77
Share of unconventional	1%	7%	47%	0%	0%	47%
Cumulative investment in upstream gas, 2012-2035**		434		235		199
Unconventional		181		-		181
Net imports (bcm)	346	432	480	423	510	-30
Imports as a share of demand	63%	73%	74%	75%	86%	-11%
Share of gas in the energy mix	26%	28%	30%	26%	28%	2%
Total energy-related CO_2 emissions (million tonnes)	3 633	3 413	2 889	3 414	2 873	16

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

Figure 3.9 ▷ Natural gas balance in the European Union in the Golden Rules Case*



* The sum of production and net imports represents total demand.

Ukraine

Ukraine has considerable unconventional gas potential in the form of coalbed methane in the main coal-mining areas of eastern Ukraine and in two shale gas basins: a portion of the Lublin Basin, which extends across from Poland, and the Dnieper-Donets Basin in the east.

Coalbed methane resources are estimated at close to 3 tcm. Technically recoverable shale gas resources in Ukraine are 1.2 tcm, around one-third less than remaining recoverable resources of conventional gas. The Ukrainian section of the Lublin Basin is large and reportedly has higher average total organic content than the Polish section and lower average depth. The Dnieper-Donets Basin – which currently provides most of the country's conventional oil, gas and coal production – also has high organic content, but is deeper.

The government is keen to develop new sources of gas in order to reduce the country's heavy dependence on imports from Russia – it has set a target of producing 3 to 5 bcm of unconventional gas by 2020. Coalbed methane is the most likely source of unconventional production growth in the short to medium term, but, if the conditions are in place, shale gas also offers considerable promise. A new tender for two large shale gas blocks in both basins is underway, offering foreign companies the opportunity to bid for the right to enter a production-sharing contract. Naftogaz, the state-owned oil and gas company, signed a memorandum of understanding with ExxonMobil in 2011 to co-operate on shale gas exploration; other companies are also interested in Ukraine's potential. An earlier shale gas tender led to some exploration drilling. Hawkley, an independent Australian company, drilled a shale gas well in the Dnieper-Donets basin in 2011. Kulczyk Oil, an international upstream company, announced in November 2011 that it had successfully completed the hydraulic fracturing of a well in a previously non-commercial zone of the Dnieper-Donets basin, yielding 65 thousand cubic metres per day (2.3 mcf/d) of gas and condensates.

In the Golden Rules Case, production of unconventional gas in Ukraine reaches 3 bcm in 2020, before ramping up to around 20 bcm in 2035. The Golden Rules Case assumes, importantly, that supportive measures are adopted to facilitate investment in the gas sector: Ukraine has a poor investment climate and upstream conventional gas output currently stands at around 20 bcm per year.

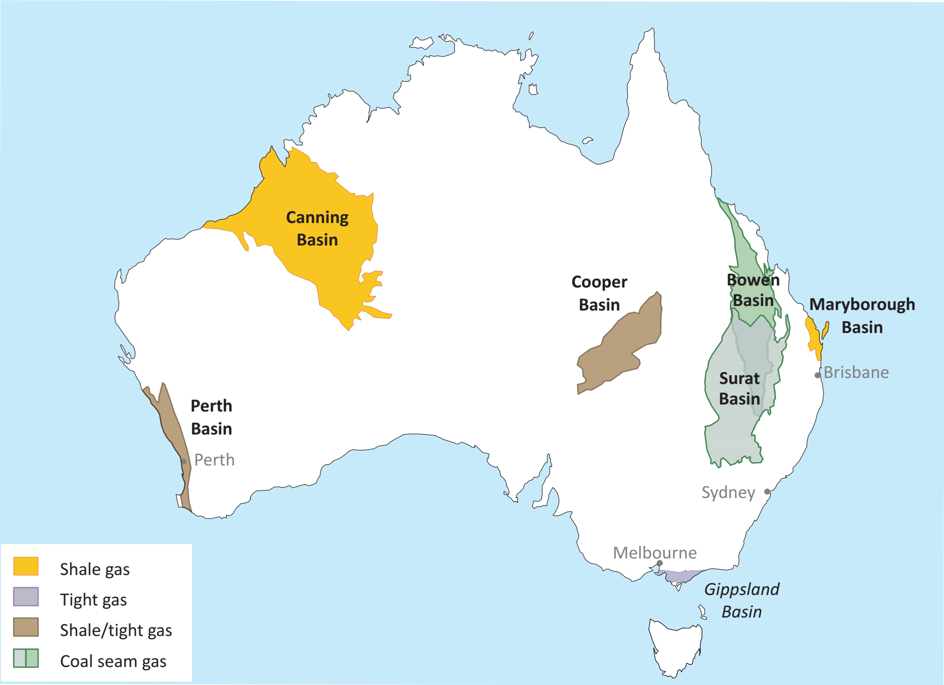
Australia

Resources and production

As a sizeable producer of coalbed methane (known as coal seam gas), Australia is one of only a handful of countries already producing commercial volumes of unconventional gas. Its large resources of shale gas, tight gas and coalbed methane hold the promise of continuing strong growth in unconventional gas output in the long term. The attraction of unconventional gas developments is heightened by the fact that Australia's conventional gas resources, while sizeable, tend to be offshore, expensive to develop and far from national markets.

More is known about the size of the country's coalbed methane resources than about the other two categories of unconventional gas. According to official estimates, demonstrated economically recoverable coalbed methane resources were 930 bcm at the end of 2010 (Geoscience Australia, 2012). The estimates of these resources have grown substantially in recent years, as exploration and development has expanded. Nearly all current reserves are contained in the Surat (69%) and Bowen (23%) basins in central Queensland, with almost all the balance in New South Wales (Figure 3.10).

Figure 3.10 ▷ Major unconventional natural gas resources in Australia



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Commercial production of coalbed methane began in 1996 in eastern Australia and has grown sizeably over the last few years. Output reached 5 bcm in 2010, accounting for about 15% of total Australian gas consumption. Virtually all output comes from the Surat and Bowen basins, with small volumes also now produced from the Sydney Basin. The rapid growth of the unconventional gas industry has been supported by strong demand growth in the eastern Australian market, reflecting in part the Queensland government's energy and climate policies, including a requirement that 13% of power generation in the state be gas-fired by 2005 and 15% by 2010. The abundance of coalbed methane has led to a number of LNG-export projects being proposed in Queensland; and three large plants to be sited at the port of Gladstone are under construction: Queensland Curtis LNG (BG), Gladstone LNG (Santos), and Australia Pacific LNG (Origin and ConocoPhillips), with a fourth – Arrow LNG (Shell/PetroChina) – at an advanced stage of development. Total investment in the three projects underway is projected to be some $40 billion; their capacity of 29 bcm more than doubles current national export capacity. However, policy uncertainty and public reaction to the potential environmental impacts of coalbed methane production has slowed upstream development, particularly in New South Wales.

Remaining recoverable resources of tight gas in Australia are estimated at 8 tcm. The largest resources of these are in low permeability sandstone reservoirs in the Perth, Cooper and Gippsland Basins. Tight gas resources in these established conventional gas-producing basins are located relatively close to existing infrastructure and are currently being considered for commercial exploitation.

Although shale gas exploration is in its infancy in Australia, exploration activity has increased significantly in the last few years. Australia is estimated to contain 11 tcm of remaining recoverable shale gas resources. These are found predominately in the Cooper, Maryborough, Perth and Canning basins. The first vertical wells specifically targeting shale gas were drilled in the Cooper Basin in early 2011 and significant exploration is now underway in this basin and, to a lesser extent, in other promising areas. But a boom in shale gas production is unlikely in the near future because of logistical difficulties and the relatively high cost of labour and hydraulic fracturing.

Regulatory framework

Under the existing regulatory framework governing the upstream hydrocarbons sector in Australia, powers and responsibilities are shared between the federal, state and territory governments and local authorities. The states hold rights over coastal waters from the coast line to the three-mile limit and joint regulatory authority over the federal waters adjacent to each state and the Northern Territory. In addition to various petroleum and pipelines laws, there is an extensive body of legislation governing upstream petroleum activities, covering such aspects as the environment, heritage, development, native title and land rights, and occupational health and safety; most are not specific to the oil and gas sector. A number of bodies across all levels of government have a role in regulating upstream petroleum activities.

Under Australian law, hydrocarbon resources are owned by the state (at federal, state or territory level) on behalf of the community, and governments at all levels have a “stewardship” role in petroleum resource management (AGPC, 2009). Farmers or graziers may hold freehold or leasehold title to land, but generally do not have rights to mineral or petroleum resources – these are subject to petroleum tenure rights granted by the state or territory governments. Underlying native title can coexist with other land title rights. In general, landowners have no right to refuse access to the petroleum tenure holder for petroleum operations; but they do have a claim to compensation for the impact of those operations. Approvals, generally a state or territory responsibility, are required to construct petroleum pipelines and facilities such as LNG trains. Landowners do not have the incentive of ownership of mineral resources to facilitate surface access to unconventional gas projects, but state and territory governments do have an incentive to promote development, as they can benefit from any taxes or royalties levied on production.

Within each jurisdiction, environmental regulation of upstream activities can include hydrocarbon-specific environmental approvals, though there are few rules specific to unconventional gas. The main federal regulations are the Offshore Petroleum and Greenhouse Gas Storage Act 2006 and the Environment Protection and Biodiversity Protection Act 1999 (EPBC Act). Under the EPBC Act, if a project affects matters of national environmental significance, it requires federal approval. LNG projects in Queensland, including their upstream coalbed methane operations, trigger the need for such federal approval. In general, an environmental impact assessment must be carried out in advance of all upstream projects that are likely to have a significant impact on the environment.

The rapid expansion of the coalbed methane industry has led to increased public concern over access issues and the potential environmental risks, particularly the drawdown and contamination of aquifers and groundwater and problems arising from the disposal of produced water. As described in Chapter 1, the techniques used in coalbed methane production differ significantly from those for shale gas; in particular there is a need to remove large amounts of water from the coal formation. This causes concern that those already drawing water from the same formations will be adversely affected and that the disposal of the large water volumes involved in coalbed methane production will not be properly handled. Given the semi-arid conditions in the producing areas, evaporation or discharge of even suitably-treated formation water to existing watercourses may not be appropriate. This has led to delays in issuing approvals for some upstream developments.

The federal government announced in 2011 that all future coalbed methane and other coal projects would come under increased environmental scrutiny. A new, well-resourced and independent scientific committee, established under the EPBC Act, will evaluate most future projects prior to approval to ensure that they do not pose a hazard to underground and surface water sources. Protocols are being developed at federal and state level to determine which projects will be referred to this committee. In Queensland, where most coalbed methane activity is concentrated, new proposals to manage the impact of water extraction on groundwater are being finalised. They provide for cumulative assessment of the impacts on groundwater resources in defined management areas. This work will be based on a major groundwater flow model, designed to predict impacts on aquifers, as well as new monitoring arrangements. A major report, the Surat Underground Water Impact Report, is expected to be published for public consultation by the Queensland Water Commission in mid-2012. A key principle in the regulatory approach is that petroleum operators must make good any impairment of water supply that they cause and that any consequence of underestimating that risk should lie with the operator, not the water source owner or the state government. The upstream industry has argued that the new regulations will hamper the development of the country's nascent unconventional gas sector. In New South Wales, where regulatory activity is less advanced, the state government has introduced a moratorium on hydraulic fracturing while it considers new regulation.

In December 2011, energy and resources ministers at both federal and state levels agreed to develop a nationally harmonised framework for coalbed methane regulation to address the following areas of community concern:

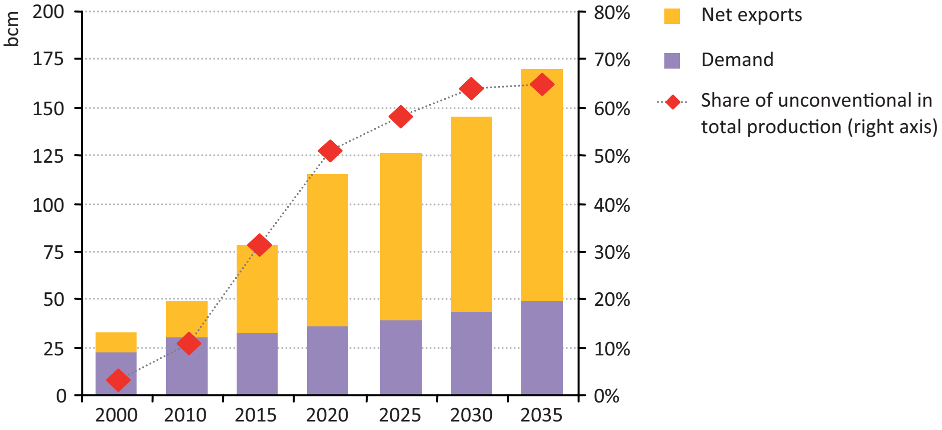
- Water management.
- The need for a multiple land-use framework, meaning measures to reconcile the ability for extraction of coalbed methane with existing and potential agricultural or pastoral uses.
- The application of best practice standards to production activities.
- Minimising environmental and social impacts.

The objective is to achieve measures in these areas which maximise transparency and generate greater public confidence in the effective regulation of the industry while supporting commercial extraction of coalbed methane.

Projections and implications

The prospects for unconventional gas production in Australia hinge to a large degree on whether policy-makers and the industry itself can sustainably manage the associated environmental risks on a basis that retains public confidence in the outcomes. In the Golden Rules Case, this is achieved, with unconventional gas output continuing to expand rapidly, reaching about 60 bcm by 2020 and 110 bcm in 2035. Coalbed methane contributes almost all of this increase, with shale gas production growing more slowly. As a result, total gas production more than triples, with unconventional gas accounting for more than half of gas output after 2020 (Figure 3.11). The projected level of coalbed methane production for 2020 assumes that the four LNG-export projects in Queensland proceed as planned and enter the market before the large increase in unconventional production in other countries, notably China, gains momentum.

Figure 3.11 ▷ Natural gas balance in Australia in the Golden Rules Case*



* The sum of demand and net exports represents total production.

Gas production is driven primarily by exports, based on both conventional and unconventional sources, which rise by 100 bcm in the Golden Rules Case. Exports reach 80 bcm in 2020, based on developments under construction, and continue to grow throughout the projection period. The value of those exports increases seven-fold to just over $55 billion in 2035 (in year-2010 dollars).

In both the Golden Rules and Low Unconventional Cases, east coast Australian domestic prices rise towards the export netback price (the delivered export price less liquefaction and transport costs) from their current very low levels. The high capital costs of Australian LNG plants meaning that these netback levels are likely to be at least $5 to $6/MBtu below the price of LNG delivered to Asian markets. In the Golden Rules Case, Australia's gas consumption nonetheless continues to expand on the back of government policies to encourage switching to gas for environmental reasons (including the recently agreed carbon trading scheme).

In the Low Unconventional Case, coalbed methane production expands at a much slower pace on the assumption of bigger hurdles to development of these resources, while there is no shale gas production at all. In 2035, unconventional gas production falls to around 35 bcm – this is 75 bcm lower than in the Golden Rules Case. The higher international price environment in the Low Unconventional Case means that the upward pull on Australian domestic prices is stronger.

Gas exports still reach more than 110 bcm in the Low Unconventional Case, as investment is shifted to LNG projects based on conventional gas. In this case, the needs of importing countries are much increased and so any gas exporter with the capacity to export has an incentive to do so; this is certainly the case for Australia, with its conventional resources and existing export infrastructure, even if these conventional resources are more costly to develop. Export earnings are even higher in this case, as international gas prices are higher. Unsurprisingly, Australia would stand to benefit from restrictions on unconventional gas developments in other parts of the world, especially in Asia-Pacific, as it is able to expand its own production of conventional and unconventional gas.

Units and conversion factors

This annex provides general information on units and general conversion factors.

Units

Emissions	ppm	parts per million (by volume)
	Gt CO_2-eq	gigatonnes of carbon-dioxide equivalent (using 100-year global warming potentials for different greenhouse gases)
	kg CO_2-eq	kilogrammes of carbon-dioxide equivalent
	gCO_2/kWh	grammes of carbon dioxide per kilowatt-hour
Energy	toe	tonne of oil equivalent
	Mtoe	million tonnes of oil equivalent
	Mt LNG	million tonnes of liquefied natural gas
	MBtu	million British thermal units
	MJ	megajoule (1 joule x 10^6)
	GJ	gigajoule (1 joule x 10^9)
	TJ	terajoule (1 joule x 10^{12})
	kWh	kilowatt-hour
	MWh	megawatt-hour
	GWh	gigawatt-hour
	TWh	terawatt-hour
Gas	mcm	million cubic metres
	bcm	billion cubic metres
	tcm	trillion cubic metres
	mcf	million cubic feet
	bcf	billion cubic feet
	tcf	trillion cubic feet
Mass	kg	kilogramme (1 000 kg = 1 tonne)
	kt	kilotonnes (1 tonne x 10^3)
	Mt	million tonnes (1 tonne x 10^6)
	Gt	gigatonnes (1 tonne x 10^9)

Monetary	$ million	1 US dollar x 10^6
	$ billion	1 US dollar x 10^9
	$ trillion	1 US dollar x 10^{12}
Oil	b/d	barrels per day
	kb/d	thousand barrels per day
	mb/d	million barrels per day
Power	W	watt (1 joule per second)
	kW	kilowatt (1 watt x 10^3)
	MW	megawatt (1 watt x 10^6)
	GW	gigawatt (1 watt x 10^9)
	TW	terawatt (1 watt x 10^{12})

General conversion factors for energy

Convert to:	**bcm**	**bcf**	**Mt LNG**	**TJ**	**GWh**	**MBtu**	**Mtoe**
From:	multiply by:						
bcm	1	35.315	0.7350	4.000 x 10^4	11.11 x 10^3	3.79 x 10^7	0.9554
bcf	2.832 x 10^{-2}	1	2.082 x 10^{-2}	1.133 x 10^3	3.146 x 10^2	1.074 x 10^6	2.705 x 10^{-2}
Mt LNG	1.360	48.03	1	54 400	15 110	5.16 x 10^7	1.299
TJ	2.5 x 10^{-5}	8.829 x 10^{-4}	1.838 x 10^{-5}	1	0.2778	947.8	2.388 x 10^{-5}
GWh	9.0 x 10^{-5}	3.178 x 10^{-3}	6.615 x 10^{-5}	3.6	1	3 412	8.6 x 10^{-5}
MBtu	2.638 x 10^{-8}	9.315 x 10^{-7}	1.939 x 10^{-8}	1.0551 x10^{-3}	2.931 x 10^{-4}	1	2.52 x 10^{-8}
Mtoe	1.047	36.97	0.7693	4.1868 x 10^4	11 630	3.968 x 10^7	1

Notes

- Gas volumes are measured at a temperature of 15°C and a pressure of 101.325 kilopascals.
- The Gross Calorific Value (GCV) of gas is defined as 40.0 MJ/cm for conversion purposes in the table above.
- The global average GCV varies with the mix of production over time, in 2009 it was 38.4 MJ/cm.
- 1 Mtoe is equivalent to 10^7 gigacalories.

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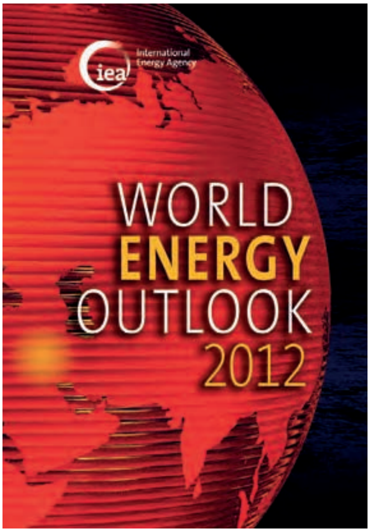

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Foreword

We are very pleased to present this work on natural gas and the transformation of the United States' power sector. The subject is both highly topical and divisive. Very few people saw the dramatic changes coming that are being witnessed in the U.S. natural gas sector. The critical role of unconventional gas—and specifically, shale gas—has been dramatic. The changes taking place in the U.S. natural gas sector go well beyond the boundaries of traditional energy-sector analysis. They touch on areas as diverse as foreign policy and industrial competitiveness.

This makes the topic ripe for robust analytical work, which is the role of the Joint Institute for Strategic Energy Analysis (JISEA).

To help inform both the national and international dialogue on this subject, we have focused on a few key areas critical to decision makers. These issues include greenhouse gas emissions, regulatory interventions, water management, and the portfolio of generation in the power sector.

As part of our series of studies on the U.S. energy system, this body of work continues to elucidate details related to life cycle greenhouse gas emissions of shale gas relative to other options for power generation. It also contributes new analysis related to water and regulatory frameworks that are evolving apace. Additionally, we evaluate various pathways for the evolution of the electric sector given a range of options for natural gas, other technologies, and policy.

Although the four principal areas of focus in this report are closely interrelated, each has its own specific needs in terms of analysis, investment risk, and policy design. We have presented detailed consideration of each area, with further appended supporting material, to contribute to the ongoing and increasing national and international dialogue.

We hope you enjoy the report and find the results and discussion useful for your work.

Doug Arent

Douglas J. Arent
Executive Director, JISEA

Preface

This report was developed with guidance from a cross-section of natural gas and electricity sector stakeholders. In 2011, JISEA convened a workshop with representatives from these organizations, some of whom also provided financial support for this work. That workshop resulted in identifying several key analytical issues for natural gas in the electric power sector that need to be addressed. Research, analysis, and writing were performed independently by the authors, with editorial oversight by JISEA. This study has been extensively peer reviewed. Findings, content, and conclusions of this study are the sole responsibility of the JISEA study team. JISEA provides objective information so that decision makers can make informed choices, but does not make its own policy recommendations.

Although the sponsoring organizations provided invaluable perspective and advice to the study group, individual members may have different views on one or more matters addressed in the report. The sponsoring organizations were not asked individually or collectively to endorse the report findings nor should any implied endorsement by the sponsoring organizations be assumed.

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Acronyms and Abbreviations

AGR	acid gas removal
bbl	barrels
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BLM	Bureau of Land Management
Btu	British thermal unit(s)
CBM	coal-bed methane
CCS	carbon capture and sequestration
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CES	clean energy standard (also known as clean electricity standard)
cf	cubic feet
CH_4	methane, the primary component of natural gas
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
COGCC	Colorado Oil and Gas Conservation Commission
CSP	concentrating solar power
CWTs	centralized waste treatment facilities
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EUR	estimated ultimate recovery
FF	frac flowback (water)
g	gram(s)
GHG	greenhouse gas
GIS	geographic information system
GW	gigawatt(s)
hp	horsepower
hr	hour
kg	kilogram(s)
kWh	kilowatt-hour(s)
lb	pound(s)
LCA	life cycle assessment
LNG	liquefied natural gas
MJ	megajoules
Mcf	thousand cubic feet
MMBtu	million British thermal unit(s)
NG-CC	natural gas combined-cycle
NG-CCS	natural gas generator with carbon capture and sequestration
NG-CT	natural gas combustion turbine
NGLs	natural gas liquids
NO_x	nitrogen oxides
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standards
POTWs	publicly owned treatment works
PW	produced water
PV	photovoltaic

RE	renewable energy (also known as renewable electricity)
RE Futures	Renewable Electricity Futures Study
ReEDS	Regional Energy Deployment System
SCC	Source Classification Code
scf	standard cubic foot
SEAB	Secretary of Energy Advisory Board Shale Gas Production
SolarDS	Solar Deployment System
TCEQ	Texas Commission on Environmental Quality
Tcf	trillion cubic feet
Tg	teragram(s), or million metric ton(s)
VOC	volatile organic compound
yr	year

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Executive Summary

Domestic natural gas production was largely stagnant from the mid-1970s until about 2005. Planning had been under way by the early 2000s to construct about 40 liquefied natural gas import terminals along the U.S. coasts to meet anticipated rising demand. However, beginning in the late 1990s, advances linking horizontal drilling techniques with hydraulic fracturing allowed drilling to proceed in shale and other formations at much lower cost. The result was a slow, steady increase in unconventional gas production.

As the technology improved and spread, domestic shale gas output began to increase rapidly, such that by 2008 commentators began to routinely speak of a shale gas “boom.” Today, shale gas accounts for about 30% of total U.S. natural gas production—up from only 4% in 2005—helping to make the United States the largest producer of natural gas in the world by 2009. Within a decade, the question of how much more dependent the country would become on natural gas imports had been replaced by how much the U.S. gas supply will affect the economics and geopolitics of energy around the globe.

Although the long-term outcome of the shale gas revolution is far from decided, significant shifts are already apparent in U.S. power markets. In that context, low-price natural gas has had the greatest impact to date on generation by coal power plants. Since 2008, coal’s share of annual generation has declined from 48% to 36% as of August 2012. This switch from coal to natural gas, combined with growth of renewable energy generation, has led to a reduction of carbon dioxide emissions in the U.S. power sector of about 300 million tons—equivalent to 13% of total power sector emissions in 2008.

It remains unclear, however, whether natural gas will continue to exert such a dramatic impact on the power sector and the overall U.S. economy. If natural gas prices continue to stay at, or near, historically low levels, then a self-correction in the shale gas boom may occur. Due to price concerns, some companies have shifted away from drilling for dry gas and instead are focusing on plays that provide natural gas liquids. The ongoing debate is about what price is needed for unconventional natural gas production to be more sustainable over the medium term. As an example, analysis from Range Resources indicates that New York Mercantile Exchange prices of $4–$6/MMBtu are needed at the vast majority of plays to generate adequate returns on investment.[1] Other factors—including “use it or lose it” lease terms, reserve filings with the Securities and Exchange Commission, and the amount of natural gas liquids that can be recovered—all play a role in continuing investment decisions. But, for now, natural gas markets are still widely acknowledged as oversupplied, and storage facilities held record high amounts of gas as of mid-2012.

Hydraulic fracturing has received negative attention in many parts of the country—especially those areas not accustomed to the oil and gas industry—due to real and perceived environmental and social concerns. Water use and contamination, air pollution, greenhouse gas (GHG) emissions, and truck traffic are among the concerns that have strained the social license to operate, and they have been the subject of multiple national and international reports and

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[1] Specifically, a 12% internal rate of return (IRR). The reference to this analysis appears in Ventura, J., 2012. “Uncovering Tomorrow’s Energy Today,” presentation at the Goldman Sachs Global Energy Conference 2012. 10 January 2012. Slide 11. Accessed 9 June 2012.

continued dialogue. Field practices associated with unconventional natural gas production have evolved rapidly in some regions, either from new regulatory requirements or voluntary company practices. These field practices are still evolving, can be uneven across regions, and are sometimes controversial. At the same time, consolidation within the industry is shifting production from smaller to larger companies.

The Joint Institute for Strategic Energy Analysis (JISEA) designed this study to address four related key questions, which are a subset from the wider dialogue on natural gas:

1. What are the life cycle greenhouse gas (GHG) emissions associated with shale gas compared to conventional natural gas and other fuels used to generate electricity?
2. What are the existing legal and regulatory frameworks governing unconventional gas development at federal, state, and local levels, and how are they changing in response to the rapid industry growth and public concerns?
3. How are natural gas production companies changing their water-related practices?
4. How might demand for natural gas in the electric sector respond to a variety of policy and technology developments over the next 20 to 40 years?

Major Findings

Although the questions analyzed in this report are interlinked to a certain extent, they have specific requirements in terms of analysis methodologies and associated stakeholders. The key findings are presented very briefly as follows:

- **Greenhouse gas emissions:** Based on analysis of more than 16,000 sources of air-pollutant emissions reported in a state inventory of upstream and midstream natural gas industry, life cycle greenhouse gas emissions associated with electricity generated from Barnett Shale gas extracted in 2009 were found to be very similar to conventional natural gas and less than half those of coal-fired electricity generation.

- **Regulatory trends:** The legal and regulatory frameworks governing shale gas development are changing in response to public concerns and rapid industry changes, particularly in areas that have limited experience with oil and gas development. All of the states examined in this study have updated their regulatory frameworks to address the opportunities and challenges associated with increasing unconventional natural gas production.

- **Water management:** Many regions evaluated in this study are making greater use of innovative water management practices to limit real and perceived risks. However, a lack of reliable, publicly available water usage and management data—such as total water withdrawals, total wells drilled, water-recycling techniques, and wastewater management practices—currently hinders efforts to develop appropriately flexible and adaptive best management practices. Recent studies have documented a number of management practices related to the chemical makeup of fracking fluids, impacts on local freshwater, and on-site wastewater management that may be appropriate in many locations.

However, to date, no public studies have been published on cost-benefit, risk-mitigation potential, or the transferability of practices from one shale play to another.

- **Electric power futures:** A number of different future electric power scenarios were analyzed to evaluate both the implications of shale gas development and use, and various policy and technology changes. These scenarios include power plant retirements, advances in generation technologies, federal policies to reduce greenhouse gas emissions, and variations in natural gas supply and demand. We find that natural gas use for power generation grows strongly in most scenarios.

Life Cycle Greenhouse Gas Emissions from Barnett Shale Gas Using Air-Quality Inventory Data

A national debate over life cycle GHG emissions[2] from shale natural gas erupted in 2011 after a study was released stating that shale gas had equivalent or even greater GHG emissions than coal.[3] Since then, a number of other published, peer-reviewed studies have included contrary findings,[4] although data limitations and methodological variability make conclusive statements problematic about the "real" GHG emission profile.

For Chapter 1, the study team conducted original research on life cycle GHG emissions associated with natural gas production in the Barnett Shale play in Texas. This estimate leverages high-resolution empirical data to a greater extent than previous assessments. The data sources and approach used in this study differ significantly from previous efforts, providing an estimate valuable for its complementary methodological approach to the literature.

The authors used inventories from 2009 that tracked emissions of regulated air pollutants by the natural gas industry in the Barnett Shale play. The Texas Commission on Environmental Quality (TCEQ) collected and screened these inventories. These data cover the characteristics and volatile organic compound (VOC) emissions of more than 16,000 individual sources in shale gas production and processing. Translating estimated emissions of VOCs into estimates of methane and carbon dioxide emissions was accomplished through the novel compilation of spatially heterogeneous gas composition analyses.

Major findings from this analysis of life cycle GHG emissions include:

- Electricity generated using a modern natural gas combined-cycle turbine combusting Barnett Shale gas produced and processed in 2009 has life cycle GHG emissions ranging between 420 and 510 grams carbon dioxide-equivalent emissions per kilowatt-hour (g

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[2] GHG emissions considered within a life cycle assessment (LCA) include those from the "fuel cycle" of natural gas, which includes activities from well drilling and completion, through production, processing, and transport to the power plant, as well as from the life cycle of the power plant, which includes construction and decommissioning of the power plant and combustion of the fuel. Results are normalized per unit of electricity generated (kWh). See Figure 7 within Chapter 1 and the surrounding text for further description of the scope of this LCA.

[3] Howarth, R. W., R. Santoro, and A. Ingraffea. 2011. "Methane and the greenhouse gas footprint of natural gas from shale formations." *Climatic Change Letters*, DOI: 10.1007/s10584-011-0061-5 (http://www.springerlink.com/content/e384226wr4160653/fulltext.pdf).

[4] These studies include Burnham et al. 2012; Jiang et al. 2011; Skone et al. 2011; Stephenson et al. 2011; Hultman et al. 2011.

CO_2e/kWh) generated, depending on assumed lifetime production of a well, with a central estimate of about 440 g CO_2e/kWh—similar to levels reported in the literature from conventional natural gas and less than half that typical for coal-fired electricity generation (Figure 1).[5] Comparisons to conventional natural gas and coal are achieved through harmonization of 200 published estimates of life cycle GHG emissions for those two technologies.[6] Harmonization is a meta-analytical process that makes consistent the assumptions and methods between LCAs.

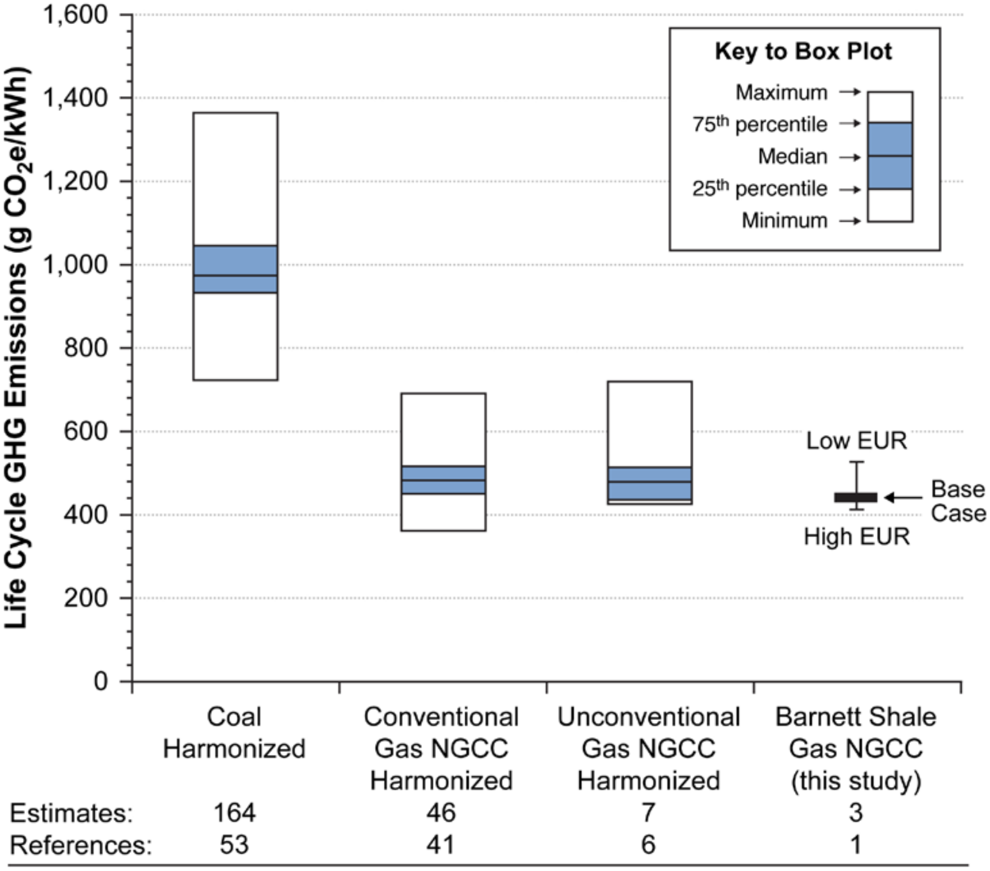

Figure 1. Estimate of life cycle GHG emissions from 2009 Barnett Shale gas combusted to generate electricity in a modern natural gas combined-cycle (NGCC) turbine compared to previously published estimates for unconventional (mostly shale) gas, conventional natural gas, and coal after methodological harmonization.

Notes: EUR = estimated ultimate recovery, or lifetime production; NGCC = natural gas combined-cycle turbine

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[5] The results reported here do not include emissions associated with liquids unloading, a process that the natural gas industry recently reported as applicable to both conventional *and* unconventional wells, but without direct evidence for the Barnett Shale play. (See: Shires and Lev-On (2012).)
However, inclusion of these emissions would not qualitatively change our findings.

[6] See Whitaker et al. 2011 and O'Donoughue et al. 2012 for systematic review and harmonization of published estimates of life cycle GHG emissions from coal-fired and conventional natural gas-fired electricity generation, respectively.

- An estimated 7% to 15% of life cycle GHG emissions from electricity generation (mean = 9%) are from methane emissions throughout the fuel cycle of Barnett Shale gas (well pre-production activities through transmission), mostly from venting during completion and workover, and from the natural gas transmission pipeline network.
- GHG emissions result from many sources throughout the production and use of natural gas. Based on our analysis, more than half can be characterized as sources with potentially controllable leakage—for instance, from tanks or vents**.** Another 20% are combustion sources, which also have some emission control opportunities. Remaining sources, called fugitive emissions, are more challenging to control because of their dispersed nature.
- An estimated 1.5% of Barnett Shale produced gas is emitted to the atmosphere before reaching the power plant, much of which is potentially preventable, with an additional 5.6% of produced gas consumed along the process chain as fuel for different types of engines. Based on the estimated methane content of this produced gas and average assumed lifetime production of a well, this equates to a central estimate of leakage rate across the life cycle of 1.3% methane volume per volume of natural gas processed.
- Chemical composition of produced gas varies considerably within the Barnett Shale area such that at the county level, estimates of GHG emissions differ significantly from those based on composition averaged at a higher spatial resolution (play or nation). Variability in gas composition has implications for the understanding of emission sources and the design of regulatory emission control strategies.

A Changing Regulatory Framework for Unconventional Gas Production

Chapter 2 examines the main federal, state, and local regulatory frameworks that govern unconventional natural gas development. Specifically, it focuses on requirements related to water withdrawals used for hydraulic fracturing, disclosure of chemicals used in hydraulic fracturing fluids, setbacks for wells, baseline water monitoring of surface water resources or water wells, well-construction standards, "green" or "reduced emission" completions, storage of waste in closed-loop systems, and the disposal of produced water. It also examines state compliance monitoring and enforcement capabilities, and the efforts by some local governments in key gas-producing states to limit—and, in some cases, ban—unconventional gas development. Major findings include the following:

- There is a trend toward more regulation at all levels of governance, but there has been a corresponding increase in regulatory fragmentation and differentiation at state and local levels. Better coordination and policy alignment among regulators can help to reduce risks to industry and the public of regulatory fragmentation—including uncertainty, delays, gaps, and redundancies across jurisdictions. Improved communication and sharing of information among regulators at all levels of government and across jurisdictions, as well as increased transparency in the form of publicly available data from industry, would help address regulatory fragmentation and inform regulatory development tailored to specific geographic and geologic characteristics.

- Compliance monitoring and enforcement varies across states, with significant implications for the efficacy of regulations, as well as public confidence. Increased public disclosure of voluntary information—as well as public disclosure of violations, enforcement actions, and company compliance—would increase transparency, offer opportunities to highlight the compliance records of leading companies who have demonstrated a commitment to safe natural gas production, and help address public concerns.

- There is a significant range in the environmental performance of operators in the industry, with some operators performing at a level that goes beyond existing regulations and other operators falling short. There is an evolving portfolio of recommended practices emerging from across the stakeholder community; these practices can complement and supplement regulations.
- The varied state and local approaches to regulation can provide important opportunities for learning and innovation regarding substantive rules, the role of best practices, and compliance and enforcement. Regulators might consider adopting performance-based standards, rather than freezing today's "best management practices" into prescriptive rules that could become outdated.

Management Practices in Shale Gas Production: Focus on Water

Chapter 3 addresses current water usage and water management practices at shale gas development sites and discusses risks to water availability and quality. We evaluated publicly available water usage data from six shale plays throughout the United States. When data were available, we conducted statistical analyses from a randomized sample of wells in each play to gauge current estimates of water usage per well. In addition, data were collected on current wastewater management techniques and volumes associated with managing produced water from wells along with the returned fracking fluids. Lastly, in addition to analyzing current industry practices, we evaluated how water usage, well number, and water management techniques have evolved over time, indicating that water risk and management issues in the future may differ from historical issues. Natural gas exploration and production has significant spatial variability in community and environmental issues, current practices, and regulations. Therefore, JISEA is also publishing the water-related results of this study in a web-based GIS format.

The three primary water impact risks are: regional resource depletion due to use of fresh water during hydraulic fracturing, surface water degradation, and groundwater degradation. Impact risks to water resources vary geographically based on three considerations: 1) where the water comes from, 2) what water use and management practices are followed on site for hydraulic fracturing, and 3) how and where produced water and frac flowback water are treated and/or disposed.

Major findings from this analysis of water impacts include the following:

- Risks to regional freshwater depletion depend on a variety of factors, including water use per well, total number of wells, water recycling rates, and regional water availability. Analysis of use data for four of the six regions from 2007 to 2011 indicated average water use per well ranges from 1.1 to 4.8 million gallons, with a multi-region average of 3.3 million gallons. The total magnitude of water usage depends on the number of wells drilled, which has increased in most regions from 2007 to 2011. In the Eagle Ford play, for example, gas wells increased from 67 in 2009 to 550 in 2011. Total freshwater usage depends on water recycling rates, which may vary greatly depending on location. In

2011, the highest rates of recycling were reported in Pennsylvania, where 37% of produced water and 55% of frac flowback water were recycled, representing nearly 200,000 gallons per well, or 4% of average water use per well in Pennsylvania. Total impacts on regional freshwater resources can be evaluated by comparing total freshwater uses with estimates of regional freshwater availability.

- Wastewater management practices vary regionally and show different trends from 2008 to 2011. In Pennsylvania, 80% of produced water and 54% of frac flowback water was treated through surface water discharge in 2008, whereas in 2011, less than 1% of produced water and frac flowback was treated through surface water discharge. In 2011, centralized disposal facilities and recycling are the primary wastewater management methods, accounting for 80% of produced water volumes and 99% of frac flowback volumes. In Colorado, surface water discharge of both produced water and frac flowback volumes has increased from 2% in 2008 to 11% in 2011. Management of produced water and frac flowback through onsite injection pits and evaporation ponds have remained the dominant practices from 2008 to 2011, representing 72% and 58%, respectively. Treatment at a centralized disposal facility has increased from 26% to 31% from 2008 to 2011. The management and transport of produced water and frac flowback water is considered to be the stage at which spills and leaks are most likely.
- A lack of reliable, publicly available water usage and management data hinders comprehensive analyses of water risks**.** Data are not publicly available for total water withdrawals, total gas wells drilled, flowback volume per well, water recycling techniques, wastewater management, and other management practices for many regions. These data would assist in developing appropriately flexible and adaptive best management practices. Certain resources—such as the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) and FracFocus—have greatly increased public access to information about risks of hydraulic fracturing; however, further efforts would be beneficial.
- A variety of best management practices are currently being employed in different regions, but there is industry uncertainty over transferability, cost-effectiveness, and risk mitigation potential. Recent studies have documented a number of water-related management practices related to the chemical makeup of fracking fluids (disclosure of additives, minimizing or switching to more benign additives, baseline water quality testing), the impacts on local freshwater (measuring and reporting of volumes, water recycling, use of non-potable or non-water sources), and onsite wastewater management techniques (use of closed-loop drilling systems, elimination of flowback and freshwater mixing in open impoundments, use of protective liners at pad sites) that may be appropriate in many locations. However, to date, there are no publicly available studies that have performed cost-benefit analyses, evaluated the risk-mitigation potential of each strategy, or analyzed practices that could be transferred from one shale play to another.

Modeling U.S. Electric Power Futures Given Shale Gas Dynamics

In Chapter 4, the study evaluates different electric power scenarios that are influenced by natural gas availability and price, as well as other key policy, regulatory, and technology factors. Many of the scenarios examine sensitivities for the estimated ultimate recovery (EUR) of gas fields. High-EUR corresponds to more abundant and inexpensive natural gas compared to Low-EUR.

Major findings from the electric sector analysis include the following:

- Natural gas demand by the power sector would grow rapidly—more than doubling from the 2010 level by 2050—in the Reference, or baseline, scenario.[7] Figure 2 illustrates the range of natural gas power generation in all scenarios. The main Reference scenario suggests that natural gas would replace coal as the predominant fuel for electricity generation. Attributes of this baseline scenario include rising power demand, stable greenhouse gas emissions, and slowly rising electricity prices that reflect natural gas availability and prices. By 2050, in the Reference scenario, gas could represent from 28% to 38% of power-sector generation compared to the 2010 portion of 20%.
- In a coal retirement scenario, natural gas, and wind to a lesser extent, replaces coal-based generation. Our modeling results indicate no impact on power sector reliability from 80 GW of coal retirements by 2025 on an aggregate scale, although additional detailed dispatch modeling is needed to evaluate localized impacts. National average retail electricity prices in the retirement scenario increase by less than 2% in 2030 compared to the baseline.
- Under a clean energy standard (CES) scenario, U.S. power sector carbon dioxide emissions would decrease by 90% between 2010 and 2050, with a corresponding 6%–12% increase in average retail electricity prices, including transmission build-out that ranges from 3 to 6 times more than the Reference scenario (measured in million MW-miles). Among the CES sensitivity scenarios, large quantities of variable renewable energy and flexible gas generation work synergistically to maintain system reliability requirements.

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[7] A Reference scenario serves as a point of comparison with other alternative scenarios. The Reference assumes a fairly static view of the future, so it, and all alternative scenarios, should not be considered forecasts or predictions of the future.

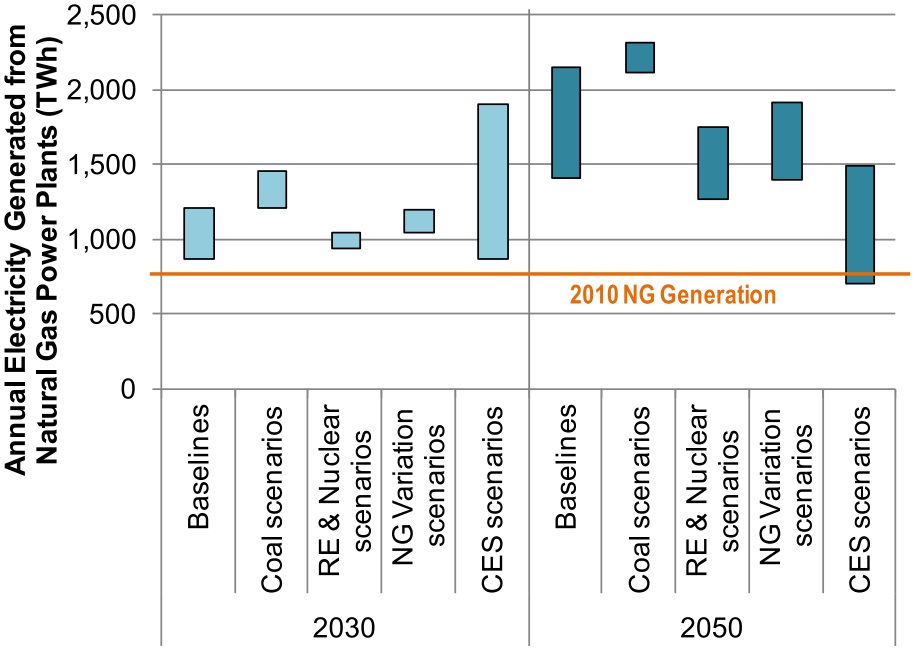

Figure 2. Range of electricity generated from natural gas plants in the scenario analysis

- Advances in generation technologies can have a significant impact on estimated carbon emissions, electricity diversity, and prices. For example, nuclear capital costs would need to decline by half, while gas prices remain relatively high (as simulated in the low-EUR assumption), for the nuclear generating option to compete economically with other options. Wind and solar electricity could more than double by 2050 compared to the Reference scenario with continued improvements in the cost and performance of these technologies. Likewise, continued improvements in production techniques for unconventional natural gas production could enable natural gas to continue to grow market share.
- We consider a range of potential incremental costs associated with operating practices that could better address some of the public concerns in the production of unconventional natural gas. Some of these options include recycling larger amounts of frac flowback water, reducing methane releases to the atmosphere, setting well locations further from potentially sensitive communities, and assuring consistent use of best practices or regulations in well drilling and completions. Sensitivities in incremental costs were evaluated from $0.50/MMBtu to $2/MMBtu. For example, additional costs of $1/MMBtu associated with some or all of these several dozen operating practices would lead to a 17% reduction in gas use for power generation by 2050 compared to the Reference scenario; however, gas-fired generation still more than doubles from the 2010 level.
- A “dash-to-gas” scenario, where other sectors of the economy increase natural gas demand by 12 billion cubic feet per day by 2030, would likely result in higher domestic gas prices and lead to a roughly 20% reduction in power sector natural gas use by 2050 compared to the Reference scenario in that year, but still nearly twice the level used in 2010. Additional research is needed to understand how natural gas prices respond to rising demand in the new natural gas environment.

The rapid expansion of shale gas has created dynamic opportunities and challenges in the U.S. energy sector. How long the ascendancy of natural gas in the electric sector will last will be a function of a wide variety of market and policy factors. The story of unconventional gas is evolving rapidly, and in some cases, unexpectedly. Robust and up-to-date analysis will remain critical to informing the key decisions that must be made by all types of stakeholders in the energy and environmental arenas.

Introduction

This report addresses several aspects of the changing context of natural gas in the U.S. electric power sector. Increasingly plentiful and affordable natural gas has catalyzed major changes in U.S. power generation and has helped to boost U.S. economic recovery. Increased substitution of natural gas for coal in power generation has also cut U.S. GHG emissions. However, processes to produce natural gas—shale gas in particular—have also elevated environmental and safety concerns in certain regions of the country. The rapid rise of natural gas is also beginning to drive more thought on longer-term energy policy issues such as the appropriate level of generation diversity (given the history of volatile prices for natural gas), and trajectories of natural gas use that will still allow GHG mitigation sufficient to address the climate challenge.

This report is intended to help inform those energy policy and investment discussions. This chapter first outlines the current dynamics of natural gas in the power sector and then describes how the remainder of the report addresses selected challenges and opportunities in the use of natural gas to generate electricity.

Natural gas supply and demand are transforming the energy marketplace. Natural gas prices have been relatively volatile over the past 40 years, at least compared to coal (see Figure 3). Today, advances in unconventional gas production, which include a host of technologies and processes beyond horizontal drilling and hydraulic fracturing,[8] have enabled a new market outlook. Shale production grew from less than 3 billion cubic feet per day (bcf/d) in 2006 to about 20 bcf/d by mid-2012.[9] Without this expansion, natural gas prices might be significantly higher because most other sources of domestic natural gas production are in decline.

Given the low-price outlook, many new potential uses for natural gas outside of power generation are being considered and developed—including the export of LNG, the use of compressed natural gas in vehicles, the construction of ethylene plants and other chemical facilities that use natural gas and associated products as a feedstock, and, potentially, investment in gas-to-liquids facilities that convert natural gas into synthetic petroleum products (i.e., diesel) that can be used as a transportation fuel in existing infrastructure. Efforts to further develop the latter may become particularly strong if the price gap shown in Figure 3 remains.

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[8] For a description of this technological progress, see Seto (2011).

[9] In 2011, the U.S. power sector consumed about 22 bcf/d and the entire economy consumed about 67 bcf/d (EIA 2012b).

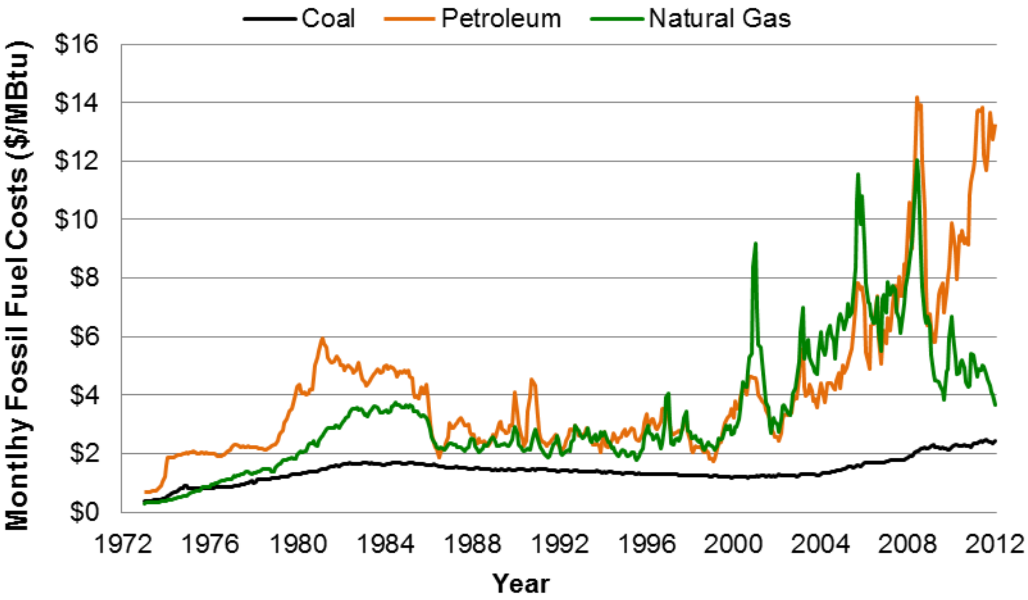

Figure 3. Volatility in fossil fuel costs for power generators

Source: EIA, "Monthly Energy Review," April 27, 2012.

However, given the current low-price environment, many producers have scaled back their plans to drill for dry natural gas, even as they accelerate drilling for wet natural gas (whose natural gas liquids are sold at prices comparable to petroleum products). These cutbacks have contributed to the recent increase in Henry Hub prices, from a low of $1.90/MMBtu in early 2012 to more than $3.60/MMBtu by November 2012. On the other hand, the number of rigs actively developing natural gas has declined sharply since 2009 while production continues to expand, indicating that producers are getting more output with less input (Ebinger et al. 2012). Where prices go next will be influenced by potential new sources of demand noted above, and by supply-side issues, including continued technology improvement, efforts to better protect the environment, and regulatory requirements.

Coal-generated electricity is rapidly declining. Dramatic changes are occurring in the U.S. electric power sector. These changes include a steep reduction in the portion of electric power coming from coal combustion, and a corresponding increase in that provided by natural gas and (to a lesser extent) renewable sources, especially wind power (see Figure 4). Eastern and southern regions are generally experiencing the most rapid shift in generation mix (see Appendix A for more detail). Coal's contribution to total annual U.S. power generation has fallen more rapidly over the past four years than in any time in the history of data collection—from roughly 48% of U.S. generation in 2008 to 36% as of August 2012. Had coal generation remained at the 2008 level, the U.S. power sector would be emitting roughly 300 million tons of additional CO_2 each year.[10]

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[10] This is a "burner tip" analysis only and does not consider the full life cycle GHG emissions of coal or natural gas. Data for 2012 are based on a rolling 12-month sum ending in August. The carbon mitigation calculation is based on a 440 TWh reduction in coal generation and corresponding increase in natural gas combined-cycle generation of 310 TWh. Growth in certain renewable generation sources and a reduction in power demand make up the remaining

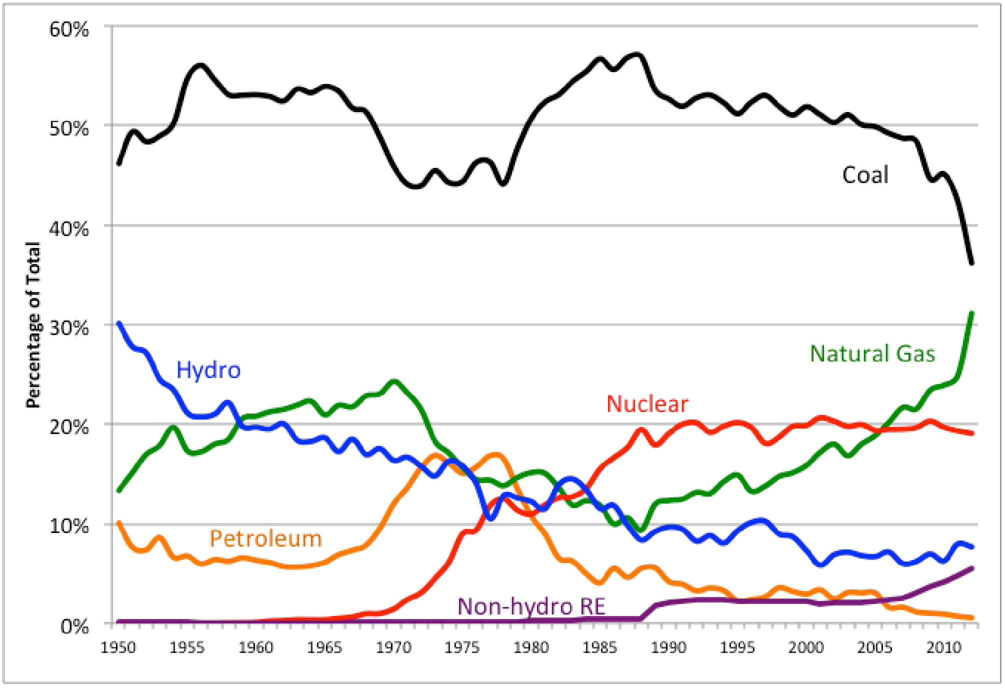

Figure 4. Coal-fired electricity generation is declining rapidly as the use of natural gas and renewable energy expand

Source: EIA, "Annual Energy Review," September 27, 2012; EIA "Electric Power Monthly," October 31, 2012. Data for 2012 includes generation through August only.

The primary drivers of these changes include low-priced natural gas resulting from rapidly growing shale gas production, an unusually warm 2011–2012 winter throughout much of the contiguous United States,[11] and the expectation that EPA will issue new or revised power plant regulations to further protect the environment.[12] It remains to be seen whether this trend of declining coal generation continues, stabilizes, or reverses itself.[13]

Hydraulic fracturing presents opportunities and challenges that are in the headlines daily. These opportunities include additional U.S. jobs, increased economic activity, potentially greater energy diversity (particularly in the transportation sector), and less reliance on imported fossil fuels. Challenges largely center on environmental and social concerns associated with shale gas

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difference. See EIA Electric Power Monthly (October 2012) for more detail. Chapter 1 of this report addresses the issue of life cycle GHG emissions for various electric generating technologies.

[11] The U.S. Department of Energy reported that the number of heating degree days in the first quarter of 2012 were at the lowest level since record keeping began in 1895 (EIA 2012a).

[12] These rules include the Cross-States Air Pollution Rule (recently vacated, but backstopped by somewhat less restrictive requirements), the Mercury and Air Toxics Standard, the Clean Water Act Section 316(b) Water Intake Structures, and the Coal Combustion Residual requirements. Numerous studies attempt to estimate the potential impacts of some or all of these rules after they take effect (see CRS 2011; CERA 2011; and Credit Suisse 2010).

[13] In a May 22, 2012 presentation to investors, for example, ArchCoal stated that half of the coal generation recently lost to low-cost natural gas could be recovered when gas prices rise back above $3/MMBtu (Slone 2012). AEP also noted in an October 24, 2012 news story that it had seen some fuel switching from natural gas back to coal due to rising natural gas prices (Reuters, 2012).

production, especially through hydraulic fracturing.[14] These concerns are acute in some states and increasingly on the docket for federal regulators in several agencies. Current federal regulations to protect surface and underground water resources are less onerous for hydraulically fractured gas production than they are for conventional oil and gas drilling, although many states are passing or updating rules quickly as drilling expands (see Chapter 2, UT 2012, Zoback 2010). Companies are also making greater voluntary efforts to ensure the likelihood that air, water, land, and other resources are protected—at least compared to the early days of hydraulic fracturing—although these efforts are still not practiced universally (see Chapters 2 and 3).

A more general concern for policy makers centers on the role of natural gas versus other sources of electricity in the future: low-priced natural gas could disrupt the development of advanced nuclear or renewable energy technologies, for example, and delay the date when they are cost competitive with traditional energy options. If natural gas prices rose substantially after the power sector had evolved to become more reliant on that fuel, the economy could be vulnerable to an expensive and "locked-in" power sector.

This report focuses on four topics. First, Chapter 1 addresses the full life cycle GHG emissions of shale gas compared to other power generation options. Questions about these "cradle-to-grave" emissions began to appear in 2011 with several reports claiming that shale gas had life cycle GHG emissions as high as, or higher than, coal.[15] Controversy remains over how much methane is released to the atmosphere during the process of producing natural gas, in general, and shale gas, in particular. Chapter 1 uses a new approach to advance the state of knowledge about the life cycle GHG emissions from shale gas based on analysis of highly resolved inventories of air pollutant emissions completely independent of the data sources used in previous research.

Second, Chapter 2 surveys the legal and regulatory trends associated with shale gas production at both the federal and state level. Although federal agencies are taking an active role in ensuring that shale gas is produced safely, Congress has imposed some limitations on what agencies can regulate. The state role in regulating unconventional natural gas production is more pronounced and varied. Chapter 2 summarizes trends in regulatory action at six major unconventional gas plays/basins: Barnett Shale play and Eagle Ford Shale play in Texas, Haynesville Shale play in Texas and Louisiana, Marcellus Shale play in New York and Pennsylvania, North San Juan basin in Colorado, and Upper Green River basin in Wyoming.

Third, Chapter 3 assesses environmental and community risks associated with unconventional natural gas production in the same six regions identified in Chapter 2. It focuses particularly on water issues and company practices that impact water. Public concern over environmental and safety issues has been severe enough in some areas to delay or halt plans to develop unconventional production.

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[14] See, for example, SEAB (2011a and 2011b), MIT (2011), and UT (2012). There is some confusion surrounding hydraulic fracturing and the potential for environmental impact. Those in industry typically use the term in a focused way, referring to the brief period of time that a high-pressure mixture of water, sand, and additives is being injected, and later, partially removed (flowback). The general public often takes a broader view and labels the entire process of producing unconventional gas or oil as hydraulic fracturing. Significant controversy results from the difference in semantics.

[15] See Lustgarten (2011) and Howarth et al. (2011), for example.

A GIS tool was developed to help evaluate:

- Water availability, use, and cost information
- Water flowback and produced water
- Best current practices for management.

Current practices and regulatory oversight need to be evaluated at a deeper level before the overall goal of determining the costs of acceptable practices can be achieved. Chapter 3 describes a comprehensive approach to evaluating risks and following practices so as to support greater public confidence.

In Chapter 4, we report on different U.S. electric power futures based on a variety of potential developments in technology, environmental protection, GHG mitigation, social license to operate, and gas demand outside the power sector. We use the National Renewable Energy Laboratory's (NREL's) Regional Energy Deployment System (ReEDS) to simulate the impact of these different futures, and benchmark information from Chapters 1–3 in the scenario analysis. Chapter 5 synthesizes findings and summarizes potential follow-on research.

1 Life Cycle Greenhouse Gas Emissions from Barnett Shale Gas Used to Generate Electricity

1.1 Introduction

According to the 2010 U.S. Greenhouse Gas Emissions Inventory (EPA 2012a), the natural gas industry[16] represents nearly a third of total methane emissions in the United States in 2010—the largest single category—and is also the fourth largest category of CO_2 emissions.[17] EPA, which produces the U.S. GHG inventory, significantly increased estimates of methane emissions from the natural gas industry for the 2009 inventory year, resulting from a change in its assessment of emissions from four activities, the most important of which were: well venting from liquids unloading (attributed only to conventional[18] wells by EPA); gas well venting during completions; and gas well venting during well workovers[19] (EPA 2011). The sum of these changes more than doubled the estimate of methane emissions from natural gas systems from the 2009 inventory compared to the 2008 inventory. EPA acknowledges what is well understood: the estimates of GHG emissions from the natural gas sector are highly uncertain, with a critical lack of empirical data to support GHG emission assessments (EPA 2011). This is especially acute for production of unconventional gas resources. Data gathering to support re-assessment of the EPA's U.S. GHG inventory and potential regulations is under way.

An emerging literature has attempted to estimate GHG emissions from unconventional natural gas production, based on the limited available information. Measurement of GHGs in the atmosphere, if they could be reliably attributed to specific sources, would be the ideal methodological approach. However, such measurements are expensive, attribution is challenging, and only one pilot study has been published to date based on measurements in one gas field—which, since the time of measurement, has implemented new practices based on changing state regulations (Petron et al. 2012). The state of the practice employs engineering-based modeling, based on as much empirical information as is possible to assemble.

Much of this emerging literature is guided by the methods of life cycle assessment (LCA), which in this context aims to estimate all GHG emissions attributable to natural gas used for a particular function: electricity, transportation, or primary energy content (e.g., heat). Attributable emissions are those from any activity in the process chain of producing the natural gas—from exploration and well pad preparation to drilling and completion—processing it to pipeline quality, transporting it to the location of end use, and combustion. In addition, the construction, operation and maintenance, and end-of-life decommissioning of the end-use technology are also considered.

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[16] For purposes of the GHG Inventory, the natural gas industry includes exploration, production, processing, transmission, storage, and distribution of natural gas to the end user (EPA 2011).

[17] In 2010, total U.S. GHG emissions have been estimated as 6,822 Tg or million metric tons CO_2e (EPA 2012a). Of this total, 84% were from CO_2, with most of the remaining (10%) from methane. Direct emission from the combustion of fuels, including natural gas, for electricity generation contributes 2,258 Tg CO_2, or 33% of total GHG emissions. Natural gas systems contribute 247 Tg of CO_2e, or 3.6% of total emissions, 87% from emissions of methane.

[18] Defined as any non-stimulated well. This report follows EPA (2011) in recognizing "that not all unconventional wells involve hydraulic fracturing, but some conventional wells are hydraulically fractured, which is assumed to balance the over-estimate."

[19] The frequency of which has since been reduced from 10% of wells per year to 1% of wells per year (EPA 2012b).

LCAs are typically performed to compare the results from one system to another.[20] The focus of this chapter is to advance understanding of GHG emissions from the production and use of shale gas in the context of the electric power sector as compared to generation of electricity from conventionally produced natural gas. Natural gas once processed for pipeline transmission to end-use customers is a homogenous product, undifferentiated by source. End-use combustion of the natural gas has, by far, the largest contribution to life cycle GHG emissions (as is true for any fossil-fueled combustion technology); but is not a point of differentiation between conventional and unconventional natural gas. Therefore, this study focuses on the activities associated with production of natural gas because they are the points of potential differentiation between unconventional and conventional natural gas.

We additionally focus on emissions from natural gas processing, given current regulatory and scientific attention to emissions from the natural gas industry and opportunity provided by the unique data sources employed in this study. Furthermore, we rely on the multitude of previously published LCAs of conventionally produced natural gas, updated for recent changes in understanding (EPA 2011; EPA 2012b) and harmonized for methodological inconsistency, as embodied in our publication (O'Donoughue et al. 2012), for comparison to the results of this study. We also compare our results to those for coal-fired electricity generation based on a systematic review and harmonization of that LCA literature, because coal has been the largest source for electricity in the United States over the last 50-plus years (Whitaker et al. 2012).

Prior research comparing life cycle GHG emissions of electricity generated from shale gas to conventional gas has been inconclusive and remains highly uncertain. Both the magnitude and direction of difference reported in these publications vary (Howarth et al. 2011; Burnham et al. 2012; Jiang et al. 2011; Skone et al. 2011; Stephenson et al. 2011; Hultman et al. 2011). This is despite their reliance on very similar data sources (mostly EPA's GHG emission inventory and supporting documentation). Uncertainty in the underlying data sources drives the uncertainty in published results. Furthermore, inconsistent approaches to data use and other assumptions thwart direct comparison of the results of these studies and the development of collective understanding.

Separately, the authors have examined this literature using a meta-analytical technique called harmonization that clarifies the collective results of this emerging literature by adjustment to more consistent methods and assumptions (Heath et al. 2012). In that publication, the authors elucidate differences between previously published estimates of life cycle GHG emissions from combustion of shale gas for power production and key sensitivities identified in this literature. Key sensitivities include EUR and lifetime (years) of wells; emissions and emissions reduction practices from well completion and workover; and emissions and emission reduction practices from well liquids unloading, all of which vary from basin to basin and from operator to operator. A key conclusion from the assessment of previous estimates of unconventional gas life cycle GHG emissions is that given current uncertainties, it is not possible to discern with a high level of confidence whether more GHGs are emitted from the life cycle of shale gas or conventional gas used for electricity generation.

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[20] For interested readers, many texts describe LCA principles and methods, such as Horne et al. (2009) and Vigon et al. (1993).

In this chapter, we present results from a new method of estimating life cycle GHG emissions from shale gas that takes advantage of unusually detailed and rarely produced empirical data specific to a shale gas play and year. Our empirical data sources and approach differ significantly from previous efforts. Broadly, we use the methods of air quality engineering, life cycle assessment, and energy analysis to estimate GHG emissions attributable to the generation of electricity from shale gas produced from the Barnett Shale play in Texas in 2009, the latest year with available data. There are several unique aspects of this research as compared to previous natural gas life cycle assessments:

- Highly resolved estimates of GHG emissions from shale gas production and processing developed at site (facility) and source (equipment and practices) levels.
- Use of industry-supplied and regulator quality-assured data regarding equipment, practices, and emissions developed with very high participation rates.
- Development of a publicly available data set of county-level, extended gas composition analyses of produced (raw) gas demonstrating wide variability of methane and VOC content within the Barnett Shale formation.

It is critical to note that the new results reported here are not necessarily applicable to other plays or years. However, they are discussed in the context of other published literature, where the broad outlines of consistency found within this literature increases confidence in the results, albeit still hampered by many areas of uncertainty remaining to be addressed through further research.

Commercial production of shale gas began in the 1980s, starting in the Barnett Shale play in Texas. The Barnett Shale play continues to be a large source of gas, estimated at more than 6% of total U.S. natural gas production (Skone and James 2010). Data on production and processing activities in this 22-county[21] area (Figure 5) are some of the best available for any unconventional gas formation in the United States. For these reasons, the focus of the analysis of this chapter is shale gas produced from the Barnett Shale formation. As illustrated in Figure 5, the highest production occurred within the Dallas-Ft. Worth metropolitan area, which is in non-attainment for the National Ambient Air Quality Standard for ozone (and other pollutants).

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[21] The Barnett Shale is sometimes referred to as consisting of 23 or 24 counties. However, this analysis focuses on the 22 counties with non-zero gas production for 2009 (TRRC 2012).

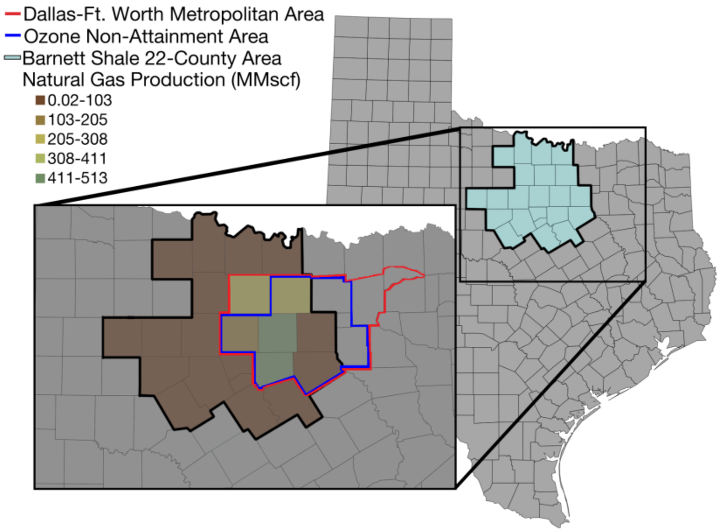

Figure 5. Counties with non-zero gas production from the Barnett Shale formation in 2009, and other demarcations of the Barnett Shale area in Texas (TRRC 2012)

1.2 Methods and Data

There are many different sources of GHG emissions in the natural gas industry (EPA 2011; ENVIRON 2010; API 2009), but the fundamental approach to estimating the magnitude of emission for all of them is:

$$[activity] * [emission\ factor] = [emission]$$

where the emission factor is in units of mass emission per unit activity, and "activities" for the natural gas industry range from counts of drilled wells or pieces of certain equipment to volume of natural gas produced, fuel combusted in an engine, or volume of water produced from a well (e.g., ENVIRON 2010; API 2009; EPA 1995). We call this approach *activity-based emission estimates*.

Different groupings of activity-based emission estimates lead to different types of results. *Inventories* aim to estimate emissions from a given chronological period, representing all activities occurring in that period. Inventories are developed with different foci: geographic, industrial sector, or pollutant. Few GHG emission inventories exist at higher spatial resolution than national, which aggregates industry- and pollutant-specific inventories produced at a national scale.

In contrast, LCAs aim to estimate all emissions attributable to a final product—here, a kilowatt-hour of electricity—scaling all the activities required over time and space to produce that unit of final product. Figure 6 depicts the scope of this LCA of electricity generated with natural gas, which covers all stages in the fuel cycle as well as the power plant's life cycle. As shown, this study combines an original inventory, for stages shown in blue, with best-available literature estimates for the remaining stages. Once co-products are separated from the produced gas, all emissions associated with their storage, processing, transport, and disposal or sale are considered outside of the system boundary for this study (as depicted with dashed lines).

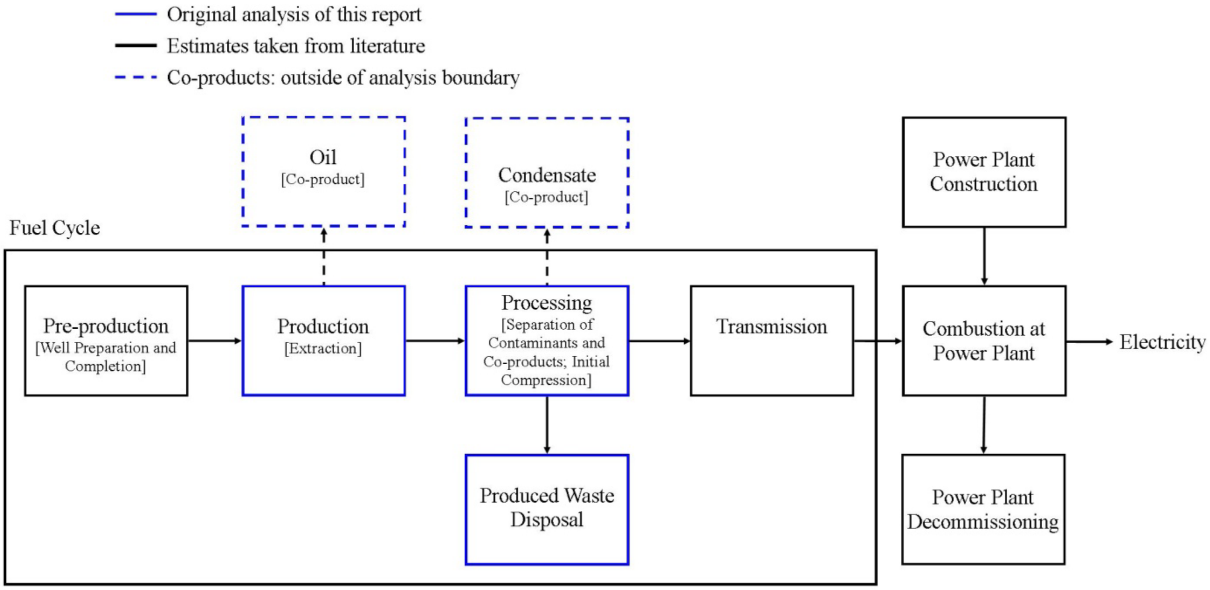

Figure 6. A life cycle assessment of electricity generated from natural gas involves estimating the GHG emissions from each life cycle stage

Because LCAs track the conceptual process chain—rather than the real supply chain—they typically model idealized activities, informed by as much empirical data on real conditions as possible. More than 30 LCAs of conventional natural gas follow this modeling philosophy (O'Donoughue et al. 2012). LCAs on shale gas that follow this approach include one employing a simplified, generic model of the industry (Stephenson et al. 2011); three assessing the U.S. national average or otherwise non-formation-specific conditions (Burnham et al. 2012; Skone et al. 2011; Howarth et al. 2011); and two assessing specific formations—Jiang et al. (2011) on the Marcellus formation and Skone et al. (2011) on the Barnett Shale.

More recently, some LCAs have leveraged EPA's national inventory of the natural gas industry's GHG emissions from a given year to simulate the process chain (Hultman et al. 2011; Venkatesh et al. 2011). These latter assessments benefit from emission estimates meant to be more closely related to actual performance; however, their estimates carry significant uncertainty given the current state of knowledge of activities and emission factors of this industry. In addition, results will change from year to year as the level of activity changes and may not reflect the life cycle of activities for a well (e.g., completions nationally in a given year may contribute a larger fraction of total emissions than what is reflective of their contribution within the life cycle of a single well).

In contrast to such approaches, this study translates estimates of VOC emissions to GHG emissions, capitalizing on a uniquely detailed inventory of VOC emissions and activities collected by the TCEQ. This approach enables a high-resolution GHG inventory for the production and processing of natural gas in the Barnett Shale play, within which individual GHG emissions from all relevant sources are estimated. Then, this annual inventory of the natural gas industry is translated into a longitudinal life cycle assessment for electricity produced from combustion of Barnett Shale gas. A brief summary of the approach is described below, with details provided in Appendix B.

1.2.1 Developing a GHG Emissions Inventory

Inventories of GHG emissions follow a long tradition of inventories for regulated air pollutants such as nitrogen oxides (NO_x) and VOCs that, in combination with sunlight, are precursors of ozone. Because of their role in demonstrating compliance with the National Ambient Air Quality Standard for metropolitan areas, the unit of analysis of these inventories is the county and large, so-called *point sources*. Point-source inventories contain detailed information related to all sources of emissions within specific facilities and are based on activity and characteristics information supplied by those facilities. Smaller, non-mobile sources (called *area sources*) are too numerous for regular, facility-specific information collection efforts and instead are tracked as a class, with emission factors (often simplified) correlating emissions with readily tracked activity data. The natural gas industry has many large point sources (including processing plants, compressor stations, and some production sites); the more numerous, smaller entities (including most production sites and some processing and transmission facilities) are classified as area sources.

Motivated by changing practices in the industry, in 2009, the TCEQ initiated a special inventory to collect detailed information on the activities and characteristics of the smaller entities in the natural gas industry that are normally part of the area-source inventory, similar to what is collected routinely from large point sources (TCEQ 2011). The purpose of the special inventory is to update and improve the TCEQ's estimates of emissions of regulated air pollutants from area sources, focused on the rapidly growing shale gas industry in the Barnett Shale area surrounding the metropolitan area of Dallas-Ft. Worth. The availability of the TCEQ's special inventory, in conjunction with its standard point-source inventory (TCEQ 2010), enables estimates of GHG emissions from activities within this important play at much finer resolution—by geography and entity—than is typically possible.

This study estimates GHG emissions from more than 16,000 individual sources detailed in three different TCEQ emission inventories:[22] the 2009 Point Source Inventory, 2009 Special Inventory, and 2008 Area Source Inventory (Pring et al. 2010). As shown in Figure 7, sources are characterized into profiles, which we further group into three general categories: combustion sources, potentially controllable leakage, and fugitives.[23] We differentiate between *potentially controllable leakage* and *fugitives*, where the former typically involves gas released from an isolatable emission point and therefore is potentially controllable, and the latter comes from more dispersed leaks that are less feasible to control. Many of the individual sources analyzed in this report are potentially controllable, as are many additional emissions in the fuel cycle, which come from completions and workovers, waste disposal, and transmission. For each profile, we estimate emissions with a tiered approach based on the availability of data. In general, primary (most accurate) methods are based on reported volumes, such as fuel combusted or gas emitted, whereas secondary methods are based on reported VOC emissions or average usage conditions. We use primary methods for 83% of sources, secondary for 15%, and profile medians for the remaining 1%.

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[22] Detailed inventory data were received through personal communication (TCEQ 2012).

[23] Skone et al. (2011) state that 25% of compressor engines in the Barnett Shale area are electrically powered, which would require the inclusion of emissions attributed to the generation of that electricity as an additional category. However, no electrically powered compressor engines are listed in the TCEQ data provided, and personal communication with the TCEQ (TCEQ 2012) stated that few, if any, such engines exist in the area.

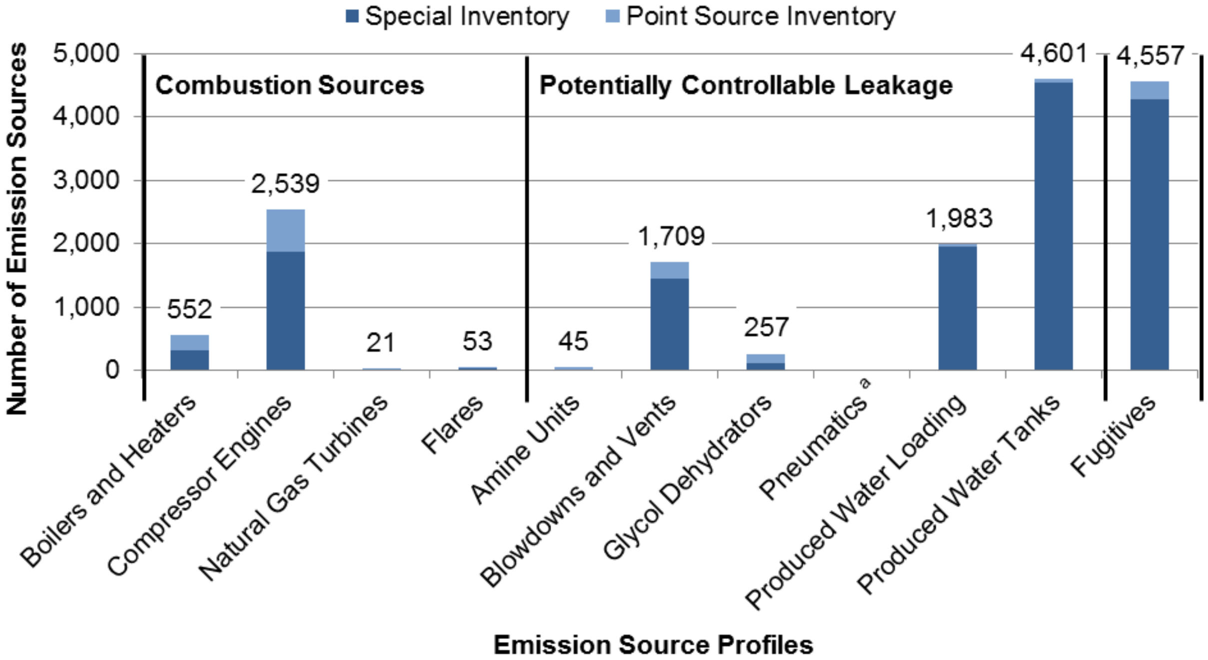

Figure 7. Greenhouse gas sources belonging to the natural gas industry in the 22-county Barnett Shale area; many are potentially controllable

[a]Pneumatics, from the area source inventory, have no count of individual sources

The central principle for translating a VOC emission inventory to one that estimates GHG emissions is the recognition that methane is a VOC,[24] albeit the slowest-acting one (Seinfeld and Pandis 2006). The key to translating VOC emission estimates to methane emissions is the availability of gas composition analyses reporting the proportion of methane, VOCs, and other gases (e.g., CO_2) within a sample. For validation purposes, the TCEQ requested many such gas composition analyses from reporting entities, which have been assembled into the largest known play-specific and publicly available set of gas-composition analyses. Organized by county, this database allows for estimation of methane and CO_2 content in gas emitted through venting and fugitive sources by ratio. It is well understood by geologists, petroleum engineers, investors, and others that gas composition varies within a geologic shale gas basin (e.g., Bullin and Krouskop 2008; Bruner and Smosna 2011); however, this is the first LCA or GHG emissions inventory to explore the implications of this variability.

In addition, other valued hydrocarbon products, such as condensate and oil, are created during the production and processing of natural gas. A principle of LCA research called co-product allocation dictates that the burdens of a system should be shared among all valued products from that system (e.g., Horne et al. 2009). In this study, emissions are allocated with respect to their share of the total energy content of all products from the fuel cycle. In addition to weighting the emissions from each source according to associated condensate and oil production, this means

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[24] The VOCs typically tracked in Texas and national (EPA) regulations are non-methane, non-ethane VOCs. Accordingly, this report follows standard convention and refers to the set of non-methane, non-ethane hydrocarbons as VOCs. However, measurements of the composition of a gas sample (a so-called “extended analysis”) include methane.

that the 25% of the sources in the TCEQ inventories that are associated only with the storage and handling of these co-products (e.g., condensate tanks) have been omitted.[25]

1.2.2 From Inventory to LCA

The GHG emissions inventory estimated here draws mainly from the TCEQ Special Inventory and Point Source Inventory for sources within natural gas production and processing life cycle stages (see Figure 7) (TCEQ 2010, 2011). Natural gas *production* relates to ongoing activities for the extraction of gas at wellheads. Natural gas *processing* relates to ongoing activities for the conversion of the produced gas to the required quality, composition, and pressure for pipeline transport.[26] In addition, the TCEQ area-source inventory is leveraged to estimate emissions associated with some activities at produced water *disposal* sites (Pring et al. 2010).[27]

Emissions from all sources within a fuel cycle phase are summed and then divided by the energy content of gas produced in that year to estimate an emissions factor in terms of mass of GHG emissions per unit of energy content of gas. Gas production statistics come from the Texas Railroad Commission for the 22-county play (TRRC 2012). Each GHG is weighted by its Intergovernmental Panel on Climate Change (IPCC) 100-year global warming potential according to standard procedure to normalize to units of CO_2e (Forster et al. 2007).[28] However, these emission factors cover only a portion of the natural gas fuel cycle, which itself is a subset of the life cycle of electricity generation from natural gas (Figure 6). Therefore, although the inventory data provide an important addition to the relatively sparse information about GHG emissions from shale gas development, literature sources are relied on for data on other emissions sources and life cycle stages—including sources such as completions, workovers, and liquids unloading—where there is considerable controversy currently about activity factors, emission reduction measures, and the magnitude of emissions.

Additional fuel-cycle stages include pre-production and transmission. *Pre-production* consists of one-time or episodic activities related to the preparation of wells, including the drilling and construction of well pads and wells, hydraulic fracturing to stimulate production, and well-completion activities. Emissions factors for these one-time activities, gathered from open literature (Santoro et al. 2011; EPA 2011; EPA 2012b; Skone et al. 2011), must be amortized over the lifetime production (EUR) of a well. *Transmission*, also estimated from literature data (Skone et al. 2011), involves the transport of processed gas to the power plant.[29]

This study combines fuel cycle emission factors into a full LCA by assuming a standard efficiency of conversion to electricity and adjusting for natural gas losses throughout the fuel cycle due to both leakage to the atmosphere and the use of production gas as fuel. This study

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[25] Sources contained within the TCEQ inventories that are considered outside of the system boundary collectively represent 60% of total reported VOC emissions but a much smaller fraction of GHG emissions.

[26] Processing can occur either at wellheads or at separate processing facilities.

[27] Emissions from produced water tanks at produced water disposal sites are tracked by TCEQ; transport of the produced water to the disposal site and operation of engines at these sites are not considered in this analysis.

[28] Global warming potentials (GWP) are also reported by the IPCC for a 20 year horizon and 500 year. The 100-year GWP is used in this study to ensure consistency with the standard practice in LCA and GHG emission inventories. Results based on alternative GWPs or other metrics of climate impact could be developed based on the results reported here.

[29] Following Skone et al. (2011), we consider the final step of processing as initial compression to pipeline pressure.

assumes combustion in a modern natural gas combined-cycle facility with thermal conversion efficiency of 51% (higher heating value) to make the results comparable to the meta-analysis of electricity generated from combustion of conventionally produced natural gas (O'Donoughue et al. 2012). Many natural gas-fired power plants do not operate at this efficiency, and the results reported here can be easily adjusted to apply to alternative conditions. GHG emissions from power plant construction and decommissioning are also considered, amortized over the lifetime generation from the facility (O'Donoughue et al. 2012). Data on emissions from *combustion at power plant*, *power-plant construction*, and *power-plant decommissioning* come from open literature (Skone et al. 2011; Skone and James 2010).

The final estimate of life cycle GHG emissions is calculated as the sum of the estimated emissions from each life cycle stage, adjusted by the thermal efficiency and relevant production losses, as appropriate for each stage and detailed in the appendix. These full life cycle emissions are expressed in units of mass CO_2e per kilowatt-hour generated.

1.3 Results

In this section, we present and discuss key findings. Because of their relevance to the current debate about GHG emissions from natural gas, the full LCA results are presented first, followed by a comparison of these results to other published estimates. Then, the primary research contribution of this chapter is detailed: a high-resolution inventory analysis of the production and processing stages of the natural gas fuel cycle for Barnett Shale gas produced in 2009. Appendix B provides further results, including county-level analysis of production gas composition, allocation of emissions to co-products, and details supporting the presented results.

1.3.1 Life Cycle Emissions

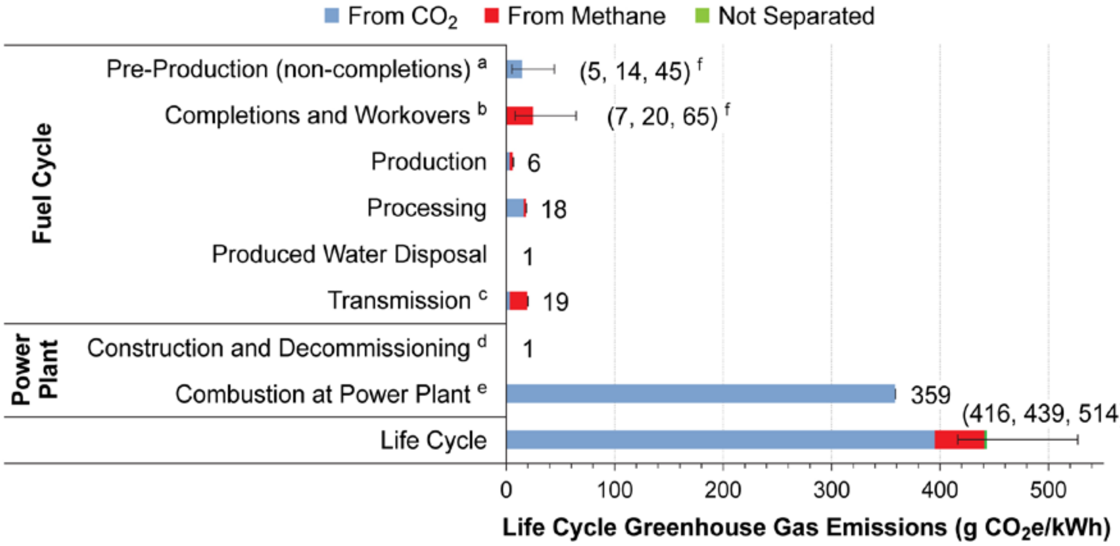
GHG emissions from the natural gas fuel cycle are a focus in the public sphere and of the novel analysis of this study. However, the functional unit of the fuel cycle—a unit of energy content of processed natural gas delivered to the end user—is not easily comparable to that for other fuels for end-uses other than direct heating. Use of natural gas in the electric sector is the focus of this report and is the market for about 30% of natural gas production in 2011 (EIA 2012). Some have argued that future production of unconventional natural gas will only displace dwindling production of conventional natural gas (e.g., Howarth et al. 2012). However, others believe that natural gas could displace existing and new coal as fuel for electricity generation (e.g., Venkatesh et al. 2011; Hultman et al. 2011). Comparisons of the results to both alternatives are provided in the next section.

First, it is critical to emphasize the importance of GHG emissions from combustion at the power plant in the life cycle of natural gas electricity generation. The GHG emissions from combustion are primarily determined by the carbon content of the fuel and the efficiency of converting fuel (chemical) energy to electrical energy. Regardless of whether natural gas comes from conventional or unconventional sources, its chemical and thermal properties once processed are indistinguishable. With regard to carbon content of the fuel, coal has about 75% more carbon per unit fuel energy than gas. Regarding efficiency, when considering new power plants, most new natural gas generation assets will likely be natural gas combined-cycle, which has a characteristic higher heating value efficiency of 51% (O'Donoughue et al. 2012). This efficiency, chosen to maintain consistency with other studies for comparison purposes, does not reflect the existing fleet of natural gas plants, but rather, it is characteristic of a modern, state-of-the-art facility. The existing fleet of coal power plants has an efficiency of close to 34% (Hultman et al. 2011), whereas new plants of either supercritical or integrated gasification combined-cycle designs will reach near 40% (MIT 2007). The efficiency improvement for natural gas combined-cycle plants over old or new coal plants is substantial, especially considering the inherent difference in carbon content of the two fuels (absent any coal decarbonization).

Assuming 51% efficiency for natural gas combined-cycle and 50 g CO_2/MJ carbon intensity of natural gas yields an estimate of nearly 360 g CO_2/kWh from combustion at the power plant. Other stages in the life cycle of the power plant (e.g., construction and decommissioning) add very little (~1 g CO_2e/kWh) to life cycle GHG emissions of electricity generation for fossil-fuel facilities because those emissions are amortized over lifetime generation.

Including the 2009 Barnett Shale fuel cycle emissions compiled in this study, total life cycle GHG emissions from natural gas combined-cycle electricity are estimated to be about 440 g CO_2e/kWh (Figure 8). Of this total, about 18% of life cycle GHG emissions (or 78 g CO_2e/kWh) are embodied in the fuel cycle of Barnett Shale gas, as defined in Figure 7. These fuel cycle emissions from unconventional gas are comparable to those estimated from the fuel cycle of conventional gas, which O'Donoughue et al. (2012) find have a median estimate of about 480 g CO_2e/kWh in the existing literature after methodological harmonization. (See the next section for further discussion and comparisons.) About 10% (or 42 g CO_2e/kWh) of life cycle emissions result from emissions of methane, mostly through venting during completion and workover and from the natural gas transmission pipeline network. These results are calculated assuming a base-case EUR of 1.42 bcf produced over the lifetime of a well, which is the play-average EUR used by the U.S. Energy Information Administration in their National Energy Modeling Systems (NEMS) model (INTEK 2011).

The results are fairly sensitive to alternative estimates of Barnett Shale well EUR, which other studies have found to be one of the most influential parameters on life cycle GHG emissions (Burnham et al. 2012; Stephenson et al. 2011; Skone et al. 2011; Jiang et al. 2011). Adjusting all one-time and episodic emissions by lower- and upper-bound estimates of well-level EUR (INTEK, 2011) yields estimates of life cycle GHG emissions that vary by nearly 100 g CO_2e/kWh. Figure 8 displays the use of reported lower- and upper-bounds of well-level EUR for the Barnett Shale play (INTEK 2011) of 0.45 and 4.26 bcf/well, respectively. Life cycle GHG emissions then range between about 420 and 510 g CO_2e/kWh owing to the tested variability in assumed EUR.



[a] Although lower estimates for this stage have been published, reported emissions increase as the comprehensiveness of processes considered increase. So we use the highest published estimate for this stage that provided results in a form that could be adjusted by EUR (Santoro et al. 2011).

[b] Based on EPA (2011) estimate of 9,175 Mcf natural gas emission/completion, 1% of wells/year workover rate (EPA 2012b), 30-year assumed lifetime (Skone et al. 2011), and 22-county, Barnett Shale average natural gas molecular weight of 20.1 lb/lb-mol and methane mass fraction of 66.2%.

[c] Based on Skone et al. (2011)

[d] Based on Skone and James (2010)

[e] Based on Skone et al. (2011)

[f] Multiple estimates, in parentheses, pertain to high EUR, base-case EUR, and low EUR, respectively. Single estimates pertain to stages without sensitivity to EUR. The error bar is plus or minus the total bar length (life cycle GHG emissions).

Figure 8. Combustion at the power plant contributes the majority of GHG emissions from the life cycle of electricity generated from Barnett Shale gas

1.3.2 Comparisons to Other Studies

There are three important points of comparison for the life cycle GHG emission results presented here:

1. Previous estimates for electricity generated from shale or other unconventional gas
2. Previous estimates for electricity generated from conventional gas
3. Previous estimates for electricity generated from coal.

Direct comparison of the results of LCAs is hindered by the sensitivity of results to alternative assumptions of key parameters and other methodological considerations. Harmonization, which is a meta-analytical approach to enable more direct comparison, has been demonstrated for a wide range of electricity generation technologies (e.g., Burkhardt et al. 2012; Warner and Heath 2012). For coal-fired electricity generation, Whitaker et al. (2012) harmonized 164 estimates from 53 LCAs on four coal generation technologies (i.e., subcritical, supercritical, integrated gasification combined cycle, and fluidized bed). More recently, this approach has been applied to the LCA literature on natural gas-fired electricity generation, where estimates from 42 LCAs on conventionally produced natural gas (O'Donoughue et al. 2012) and 6 shale gas LCAs (Heath et al. 2012) have been harmonized. Results from these studies are used for comparing results of this report to those in the literature because they ensure fair and consistent comparisons and enable insight useful for broad decision-making.[30] It is important to note that the results of this study were developed using the same key assumptions and system boundaries as in the harmonization of the literature estimates for conventional and shale gas—and, more broadly, with those for coal.

Figure 9 displays the results of this chapter's analysis (base case and EUR sensitivity)—which estimates life cycle GHG emissions from Barnett Shale gas produced in 2009 and combusted to generate electricity in a modern natural gas combined-cycle turbine—compared to other estimates, which are based on a systematic review and harmonization of existing literature. Compared to other estimates for shale gas electricity generation, the base case results of this methodologically independent assessment are near the 25th percentile of harmonized estimates, which is similar for the comparison to harmonized conventional natural gas estimates. High and low EUR scenarios are also within the range of previous estimates for shale and conventional gas life cycle GHG emissions. The results are also found to be considerably lower than those for coal—nearly half of the median estimate of 980 g CO_2e/kWh (Whitaker et al. 2012), even under low EUR conditions.

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[30] Estimates of life cycle GHG emissions for specific facilities can legitimately differ from those produced through harmonization. See Heath and Mann (2012) and other harmonization articles in the Special Issue on Meta-Analysis of LCA in the *Journal of Industrial Ecology* (http://jie.yale.edu/LCA-meta-analysis) for further discussion.

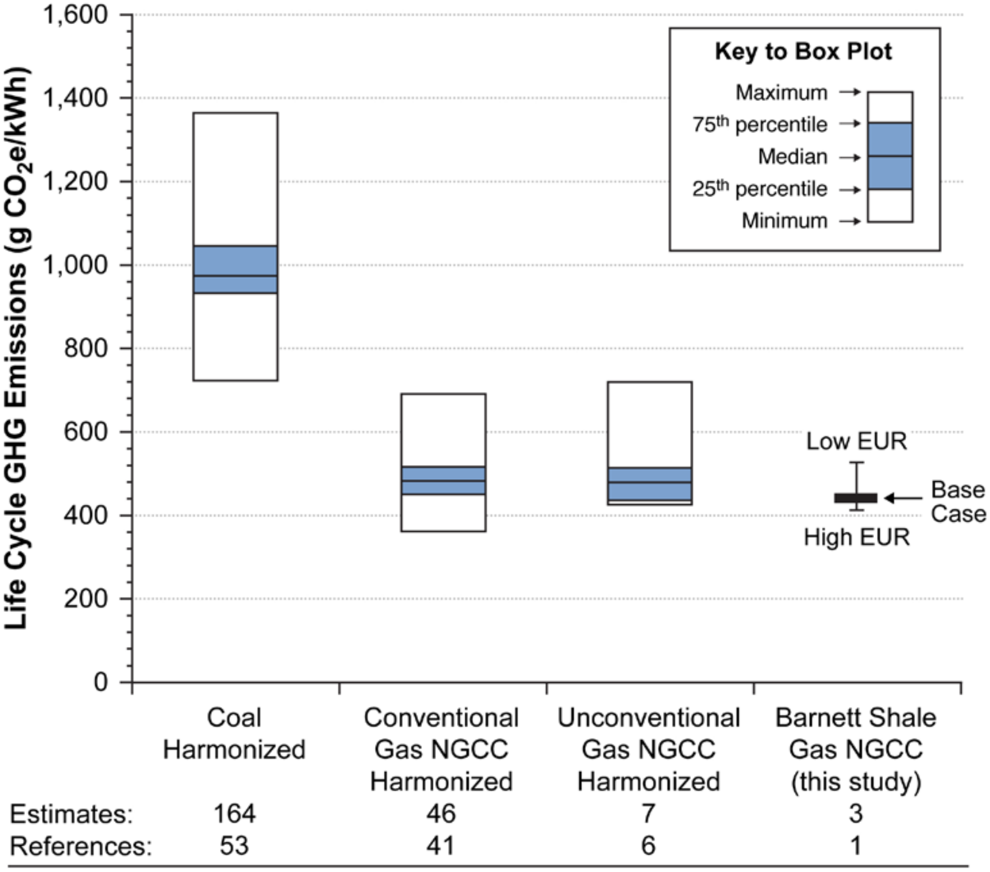

Figure 9. Estimate of life cycle GHG emissions from 2009 Barnett Shale gas combusted to generate electricity in a modern natural gas combined-cycle (NGCC) turbine compared to previously published estimates for unconventional (mostly shale) gas, conventional natural gas, and coal after methodological harmonization. [31]

Notes: EUR = estimated ultimate recovery, or lifetime production; NGCC = natural gas combined-cycle turbine

The rest of this section briefly reviews the key differences that could explain the relationship between the results from this study and those from other shale gas LCA literature. More detailed discussion of each of the existing shale gas life cycle GHG emission estimates can be found in Heath et al. (2012). Differentiating factors that tend to reduce estimates of life cycle GHG emissions for our study compared to some others include: equitably sharing the burdens of natural gas production with valuable co-products; not considering nitrous oxide emissions throughout the life cycle or non-CO_2 emissions from power-plant combustion; not considering embodied GHG emissions of purchased fuels; and not considering transport of produced water to disposal wells. None of the following factors are considered significant points of

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[31] See O'Donoughue et al. (2012), Heath et al. (2012) and Whitaker et al (2012) for further description of the review and harmonization of estimates of life cycle GHG emissions from electricity generated from conventional natural gas, unconventional (mostly shale) gas and coal, respectively. The studies reviewed and harmonized in Heath et al. (2012) for unconventional (mostly shale) gas are: Howarth et al. (2011); Burnham et al. (2012); Jiang et al. (2011); Skone et al. (2011); Stephenson et al. (2011); Hultman et al. (2011).

underestimation: negligible impacts found in previous analyses,[32] contributions only to the fuel cycle (which represents 18% of total life cycle emissions), and negligible quantities of relevant sources.[33] Differentiating factors that tend to increase life cycle GHG emission estimates for particular literature estimates compared to ours include: higher natural gas leakage estimates (Howarth et al. 2011; Burnham et al. 2012; Skone et al. 2011; Hultman et al. 2011; Jiang et al. 2011); higher estimate of methane content of produced gas (Jiang et al. 2011; Burnham et al. 2012; Skone et al. 2011; Hultman et al. 2011); and inclusion of natural gas distribution for transport of gas to the power plant[34] (Jiang et al. 2011; Howarth et al. 2011; Hultman et al. 2011). On the other hand, EURs considered in this chapter are considerably lower than for other studies. This is especially true for the sensitivity analyses conducted by this and other studies, where the low-bound case for all other studies is at least twice the lower-bound estimate reported by EIA for the Barnett Shale play (INTEK 2011).[35]

A key distinguishing feature of the practices typically assumed for conventional as compared to unconventional wells is liquids unloading (i.e., periodic removal of liquids and other debris from a well). EPA has found that this practice occurs frequently—31 times per year on average (EPA 2011)—every year in the life of a well. And emissions from this practice, even when amortized over lifetime production of a well as in LCAs, are significant (e.g., Burnham et al. 2012). A recent survey of 91,000 wells by two industry associations suggests that at least for this sample, emissions from liquids unloading are nearly 80% lower than EPA's estimate (Shires and Lev-On 2012). Not only is the magnitude of emissions from liquids unloading controversial, but the same industry survey suggests that liquids unloading is also practiced on unconventional wells, reversing previous assumptions (Shires and Lev-On 2012). If liquids unloading were practiced on Barnett Shale wells,[36] then life cycle GHG emissions under average-EUR conditions would increase between 6 and 28 g CO_2e/kWh depending on the emission rate assumed[37] and potentially as high as 100 g CO_2e/kWh under low EUR conditions.

1.3.3 Fuel Cycle Methane Losses

Throughout each stage of the fuel cycle, a portion of the produced gas is used or lost: gas is used as a fuel for combustion activities, and it is lost when it leaks to the atmosphere either through potentially controllable leakage or fugitive emissions. As a potent GHG, methane emitted to the atmosphere is especially important to understand.

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[32] For example, Skone et al. (2011) find that nitrous oxide contributes 0.04% to the total life-cycle GHG emissions for a natural gas combined-cycle plant. They also found that nitrous oxide and methane contribute 0.001% and 0.004%, respectively, to the GHG emissions from the energy-conversion facility (which primarily consist of fuel combustion emissions) for a natural gas combined-cycle plant.

[33] Fewer than ten engines in the inventory are identified as using purchased fuels (i.e., gasoline or diesel).

[34] To approximate an upper bound for such an omission, consider that even doubling the estimated emissions from transmission adds only 19 g CO_2e/kWh, or about 4%, to the total life-cycle GHG emissions.

[35] Base-case EURs were 3, 3.5, 3, 2.7, and 2 bcf for Howarth et al. (2011) (average of estimates reported in Table 1), Burnham et al. (2012), Skone et al. (2011), Jiang et al. (2011) and Stephenson et al. (2011), respectively. Lower bounds tested were 1.6, 2.1, 2.7, and 1 bcf for Burnham et al. (2012), Skone et al. (2011), Jiang et al. (2011), and Stephenson et al. (2011), respectively.

[36] Assuming 30-year well lifetime (Skone et al. 2011), 1.42 bcf EUR (INTEK, 2011), and 12% emission reductions (Burnham et al. 2012).

[37] The low estimate assumes an emission rate according to Shires and Lev-On (2012), whereas the high estimate assumes an emission rate according to EPA (2011).

This section reports two related metrics, each important for different purposes. The first metric we refer to as *natural gas losses*, which signifies the percentage of produced natural gas either lost or consumed along the fuel cycle, expressed in units of volume natural gas lost per volume natural gas produced.[38] The second metric we refer to as *methane leakage,* which signifies the volume of methane released to the atmosphere in relation to the amount of gas produced, expressed in units of volume methane emitted per volume natural gas produced. A leakage rate reported in these units enables rapid estimation of methane emissions based on a known amount of produced natural gas.

Based on the analysis of TCEQ inventories for natural gas production and processing emissions, as well as published estimates for other fuel cycle phases, this study estimates that 1.5% of produced gas is emitted to the atmosphere before reaching the power plant (see Table 1). Much of this is potentially preventable, with an additional 5.6% of produced gas consumed along the process chain as fuel for different types of engines. Based on the estimated methane content of this produced gas, this equates to a *leakage rate* across the fuel cycle of 1.3% methane volume per volume of natural gas processed, based on the assumed play-average EUR of 1.42 bcf/well. Because of the contribution of one-time emissions to these results, they are sensitive to EUR; low EUR corresponds to an estimated 2.8% methane leakage rate and the loss of 8.9% of produced gas across the fuel cycle, whereas high EUR corresponds to an estimated 0.8% leakage and 6.5% losses.

Table 1. Loss of Produced Gas along the Fuel Cycle[a]

	Completions and Workovers[b]	Production	Processing	Transmission[c]	Total
Extracted from Ground	100.0%				100.0%
Fugitive Losses	–	0.1%	0.0%	0.5%	0.6%
Potentially Controllable Leakage	0.8%	0.1%	0.0%	0.0%	0.9%
Combusted as Fuel	–	0.9%	3.9%	0.8%	5.6%
Delivered to Power Plant					92.9%

[a] Reported as volume of natural gas consumed or lost per volume of natural gas produced
[b] See footnote to Figure 9
[c] From Skone et al. (2011)

1.3.4 Air Pollutant Emissions Inventory-Based GHG Emissions Estimates

This study develops emissions factors for the production and processing stages of shale gas development based on original estimates of GHG emissions from TCEQ inventories and the Texas Railroad Commission's production statistics. These emission factors are shown in Figure using the functional unit of grams CO_2e per mega-joule of natural gas (i.e., g CO_2e/MJ).

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[38] Although the use of natural gas in production and transportation processes is for beneficial purpose, it nonetheless represents the loss of a potentially marketable product. For instance, increasing the efficiency of engines at pipeline booster stations would increase the amount of product delivered to the end user. From this perspective, we employ the simplified terminology of "loss" of natural gas to include its use prior to sale to an end user.

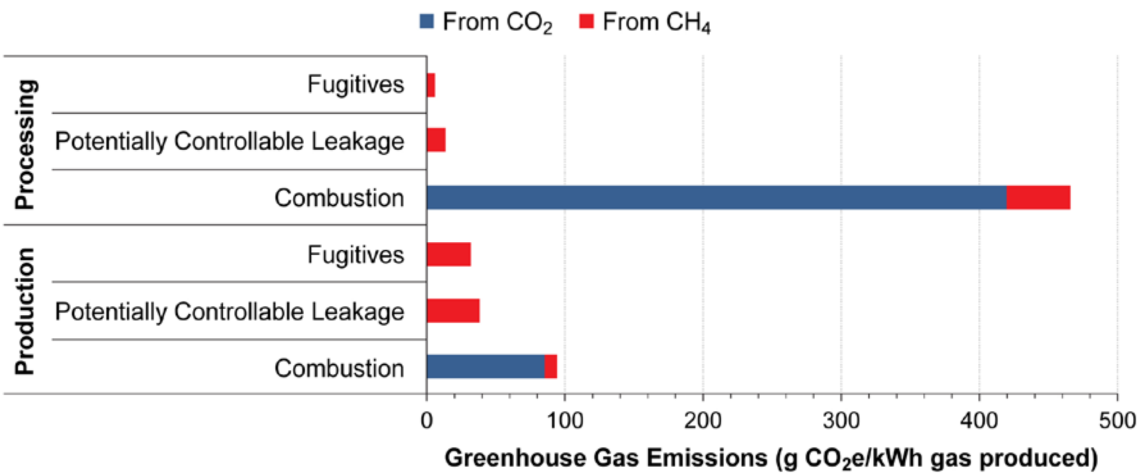

Figure 10. Inventory-based analysis of production and processing fuel cycle stages showing that the majority of GHG emissions are CO_2 resulting from combustion, although the CO_2e from methane emissions is significant

Most noticeably, the majority of GHG (CO_2e) emissions in both of these life cycle stages comes from CO_2 emissions from combustion sources. These emissions represent 53% of the total GHG emissions for the production stage and 87% for the processing stage. In the production stage, 90% of CO_2 emissions come from a large number of four-cycle rich-burn engines, nearly all of which are not normally individually tracked in the point-source inventory. Of the 1,564 compressor engines contributing to CO_2 emissions during natural gas production, only seven are reported to the point-source inventory, with the vast remainder of sources (and 99.9% of the CO_2 emissions) being reported only in the special inventory. Although the point-source inventory is intended to cover major emissions sources, the large number of individually smaller sources that are only captured by the special inventory play an important role in the GHG emissions from natural gas production in the Barnett Shale play. In the processing stage, 49% of CO_2 combustion emissions come from 405 4-cycle, lean-burn engines; 21% from 273 4-cycle, rich burn; 20% from 552 external-combustion boilers and heaters; and the remaining CO_2 emissions come from natural gas turbines, other compression engines, and equipment flares. In contrast to the production stage, 76% of these sources—representing 79% of the CO_2 emissions—are covered by the point-source inventory. Direct emission of CO_2 from fugitives and from processing (to achieve pipeline-quality specifications) is negligible but included for completeness.

Of the remaining GHG emissions, more methane emissions come from potentially controllable gas leakages than from fugitives. Specifically, only 41% of methane released in the production stage comes from fugitives. The 49% of methane coming from potentially controllable leakage in the production stage is dominated by emissions from pneumatic pumps and controls, which are a focus of recent EPA regulations. In the processing stage, fugitives make up an even smaller proportion (10%) of overall methane leakage. Of the 21% of methane emissions in this life cycle stage coming from potentially controllable leakage, more than half comes from emissions from produced water tanks, and almost a third from emissions from glycol dehydrators. Despite only a small proportion of combustion emissions being methane, combustion activities still account for

69% of the total methane emitted in the processing stage as a result of the large numbers of engines.

1.3.5 Sensitivity to Gas Composition Analysis

Because it reflects a key differentiation of this study from previous analyses, this section explores the sensitivity of this study's results to assumptions about the composition of the produced gas. Specifically, this section compares the study's main results—which are based on county-specific gas composition estimates (see Appendix B)—with results based on two alternative assumptions about produced gas composition.

The first alternative calculates emissions using a play-level gas composition estimate, which reflects a production-weighted average of all county estimates with original data. The second alternative uses EPA's reported national average production gas composition (EPA 2011) as the estimated composition for all sources. The national average is used for comparison because most LCAs rely on this gas composition, even for play-specific estimates (e.g., Skone et al. 2011). Table 2 reports the difference in emission estimates for CO_2, methane, and CO_2e using these alternative gas composition analyses compared to this study's spatially explicit approach (main results).

Table 2. Effects of Alternative, Spatially Uniform Estimates of Gas Composition on Inventoried GHG Emissions for the Barnett Shale Play

	Difference from Main Results		
	CO_2	Methane	CO_2e
Production and Processing Combined			
Main Results	–	–	–
Barnett Shale Average	-0.5%	2.6%	0.2%
National Average	-3.5%	5.7%	-1.5%

The overall impact is negligible of using spatially explicit estimates versus the Barnett Shale average, which is a production-weighted average of individual estimates: the effect on the two different GHGs cancel out in terms of CO_2e. The impact of using national average gas composition estimates is larger, but still small. As shown by the difference in Barnett Shale average versus national average results, these impacts come not from shifting to uniform gas compositions, per se, but rather, from using gas composition estimates less reflective of the specific gas analyses obtained from locations within the Barnett Shale region.

However, estimates differ more substantially when looking at a finer scale, as shown in Table 3, which focuses on production-stage emissions estimates for the four top-producing counties in the Barnett Shale. Using Barnett Shale or national average gas composition can lead to estimates one-third lower or higher for Tarrant and Wise counties, respectively, compared to using the county-level average. This variation comes from the substantial difference in estimated gas composition across counties, also shown in the lower portion of Table 3 for the representative gas constituents of VOCs, CO_2, and methane. Note that Tarrant and Wise counties both deviate substantially from the Barnett Shale average, as well as from the national average.

Table 3. Effects of Alternative, Spatially Uniform Estimates of Gas Composition on Estimated Production Emissions at the County-Level

	Denton County[a]	Johnson County[a]	Tarrant County[a]	Wise County[a]	22-County Total
Barnett Shale average vs. main results	12%	-5%	-33%	29%	1%
National average vs. main results	15%	-11%	-36%	29%	-3%

	Denton County[a]	Johnson County[a]	Tarrant County[a]	Wise County[a]	Barnett Shale play average[b]	National average[c]
Volatile organic compounds content[d]	18%	19%	6%	23%	16%	18%
CO_2 content[d]	2%	2%	1%	3%	2%	2%
Methane content[d]	63%	63%	80%	56%	66%	78%

[a] Only the four top-producing counties in the Barnett Shale play are shown.
[b] Production-weighted average across the 22 counties of the Barnett Shale play
[c] As reported in EPA (2011)
[d] Percentage by mass

These results have implications for developing more accurate GHG emission inventories at sub-national levels and any regulatory system that might seek to identify high emitters within plays. Furthermore, when detailed activity data at the site or source level are developed, these data should be matched by detailed gas-composition analyses for the most accurate outcomes.

1.3.6 Areas for Improvement in Understanding

The estimate of life cycle GHG emissions from gas produced from Barnett Shale in 2009 reported here advances our understanding through rigorous analysis of more than 16,000 sources of emissions and accounts for the known spatial heterogeneity in gas composition within the Barnett Shale play. However, future efforts should explore the sensitivity of the estimates herein to the many contributing parameters and several other aspects because further improvement remains.

Chief among the areas for improvement are a greater number of recent measurements of emission factors and statistically representative surveys of current practices characterizing GHG emissions from the natural gas industry. For instance, there is a critical lack of measurements of emissions for completion and re-completion (workover) activities that account for different physical and operational conditions based on use of reduced-emission completion equipment, variations in gas flow during flowback and initial production, and mud degassing (EPA 2011; Shires and Lev-On 2012; CERA 2011; Burnham et al. 2012). Likewise, better and more recent measurements of fugitive emissions from well and processing equipment, as well as pipelines at all stages—gathering, transmission, and distribution lines—are warranted because the existing data are sparse and old. The prevalence of emission-reduction practices (e.g., flaring) during completion, workover, and other activities is another area of considerable lack of empirical information and variability in current assumptions (Heath et al. 2012) that would improve understanding of life cycle GHG emissions.

Furthermore, if other well-specific information—such as annual and lifetime gas, condensate, oil, and produced water production, and lifetime workovers—were available and could be matched to the TCEQ emissions inventories, then fuel cycle and life cycle GHG emissions could be estimated at the well level. These results could allow for consideration of well-level variability, with implications for the design of efficient strategies to control emissions. In particular, given the substantial sensitivity of results to EUR (total life cycle GHG emissions differ from base results by -5% or +17% for upper and lower EUR estimates, respectively), better well-specific information on EUR will improve the precision of emissions estimates. However, EUR is neither geographically nor temporally constant; rather, it relates both to physical characteristics of natural gas deposits and to the (constantly evolving) technical and economic feasibility of recovery of that natural gas. An improved and sophisticated understanding of EUR is therefore necessary. Finally, production activity is often planned for a field based on a set of wells; when initial wells decline in production, they could be restimulated and other wells could be drilled within the same area (through new laterals or new surface sites). Considerable knowledge of these dynamics is currently lacking. Yet, it is important to understanding GHG emissions in the context of deployment strategies used by many large players.

We have assembled the largest publicly available database of gas composition analyses for a shale gas play, and the counties with highest production correspond to those with the greatest number of analyses. However, given the sensitivity of the study's county-level results to the gas composition, it appears to be warranted to devote further effort toward improving the availability of production gas composition analyses specific to a region of interest. A random-sampling campaign conducted by a third party would be an ideal match for the methods used in this chapter if they are deemed useful for future analyses. A nearer-term objective could be to simply increase the pool of gas analyses from any entity willing to make such data available. Results of such further investigation could have implications for developing more accurate GHG emission inventories at sub-national levels and any regulatory system that might seek to identify high emitters within plays.

Further investigation of emissions from liquids unloading from unconventional wells is also warranted given the potentially significant GHG emissions from this activity, as described above. An emissions sampling strategy that accounts for variability across geography, gas type, well type, operator size, and operational practices, among other factors, should lead to an improved understanding of the potential for GHG emissions from liquids unloading for conventional and unconventional wells. Additional activity data regarding frequency of unloading and how this might change over the lifetime of a well, proportion of wells requiring unloading, and prevalence and effectiveness of emission-reduction activities are necessary to develop a more complete understanding of the emissions from this practice. Finally, because emissions from this episodic activity are amortized over lifetime production for use in LCAs, more certainty in the estimate of EUR would improve the accuracy of life cycle emission estimates.

Practices in the natural gas industry change over time, as do resource characteristics. Estimates of GHG emissions should be periodically repeated to reflect those changing practices and characteristics, using the most up-to-date and accurate data on emissions, emission-reduction practices, resource characteristics and activities available. Estimates could also be developed for future conditions based on expected changes in practices due to, for instance, full implementation of promulgated regulations. Such estimates could be compared to goals for GHG emission reduction to highlight whether additional emission reductions are necessary to reach those goals.

Analogously, industry practices and resource characteristics vary by location owing to differences in, for instance, geology, hydrology and state regulations. Estimates of GHG emissions should be developed in other locations using as much geographically specific data and information as possible. Furthermore, GHG emissions will also differ by gas type—not only by broad categories such as conventional and unconventional, but also, by different types of each, e.g., shale, tight, and coal-bed methane for unconventional, and associated, onshore, and offshore for conventional. GHG emissions for each of these types should be characterized so that a more accurate understanding of drivers of variability (if any) by type can inform discussions of opportunities to reduce emissions.

Finally, the bottom-up, engineering-based inventory of emissions should be confirmed through top-down atmospheric measurements. Literature suggests that emissions are typically underestimated through bottom-up approaches compared to concentrations of those same pollutants in the atmosphere (e.g., Townsend-Small et al. 2012; Petron et al. 2012). This effect likely results not only from issues such as non-reported sources, but also from inaccuracies that inherently arise from the use of non-specific methods that depend on average or ideal conditions. Although source attribution is still challenging and these measurements are expensive, they provide a much-needed confirmation of when inventories are accurate and when updates and improvements are necessary to support sound decision-making.

1.4 Conclusions

The aim of this research is to advance the state of knowledge of life cycle GHG emissions from electricity generated from shale gas extracted from a specific play—the Barnett Shale play in north Texas—using data sources independent of those used in previous LCAs of natural gas. We leveraged inventories of regulated air pollutants collected and screened by the Texas Commission on Environmental Quality for a 2009 special inventory of the Barnett Shale gas production, processing, and transportation sectors and their regular point- and area-source inventories in the 22-county Barnett Shale area. We used data supplied by the industry to TCEQ regarding the emissions and characteristics of more than 16,000 individual sources. The TCEQ inventories are used to estimate VOC emissions, a precursor of ozone. VOC emission estimates were translated to methane and CO_2 emissions by using gas composition analyses that report proportions by mass of each constituent. This study compiled a large dataset of such gas composition analyses at the county level, enabling a quantitative accounting of the significant variability that exists within the play of methane, CO_2, and other compounds.

Based on the analysis of TCEQ inventories and the addition of missing life cycle stages not included in those inventories, this study estimates that electricity generated using a modern natural gas combined-cycle turbine combusting Barnett Shale gas produced and processed in 2009 is associated with about 440 g CO_2e/kWh generated, with a sensitivity range based on published high and low EURs of 420 to 510 g CO_2e/kWh. Thus, the life cycle GHG emission result is sensitive to the lifetime production of wells, where additional research would be helpful to more precisely estimate life cycle GHG emissions. Regardless of this uncertainty, however, this chapter's main conclusion is that life cycle GHG emissions from electricity produced from Barnett Shale natural gas lie within the range of previously published estimates for GHG emissions (after methodological harmonization) from electricity produced by either conventional or unconventional natural gas (O'Donoughue et al. 2012; Heath et al. 2012). Furthermore, this report's estimate of life cycle GHG emissions is less than half of the median of published estimates for coal-fired electricity generation (after methodological harmonization) (Whitaker et al. 2012). It should be noted that the estimate of life cycle GHG emissions developed here is not strictly applicable to other locations or years, and that several important aspects of uncertainty in the methods of this research should be improved through additional research. However, the broad agreement between the estimate developed here and those published independently for both unconventional and conventional gas increases confidence in our understanding of life cycle GHG emissions of natural gas used for electricity generation.

This study found that about 19% of base case life cycle GHG emissions results from the fuel cycle of Barnett Shale gas (pre-production through transmission). About 10% of base case life cycle GHG emissions are methane, mostly vented during completion and workover and released from the natural gas transmission pipeline network. Only 11% of life cycle GHG emissions depend on characteristics of shale gas (e.g., extraction techniques, composition); the vast majority of life cycle emissions are not affected by the type or origin of the gas because they occur after processing that has the function of creating a homogenous product.

With regard to the fuel cycle GHG emissions, which were the focus of the analytical effort of this chapter, the vast majority comes from CO_2—80% or more of which is emitted from combustion sources (mostly engines and turbines) in the production and processing stages. The majority of emissions coming from natural gas production activities is from sources not routinely tracked individually (because they do not meet regulatory thresholds) in a classic example of how important the more numerous small sources can be to total emissions and how challenging quantifying and reducing emissions from the natural gas industry will be for regulators. Only through special inventories, such as the one conducted in 2009 for the Barnett Shale area, is it possible to have the kinds of detailed information necessary to estimate source-specific emissions for the vast majority of production sources within this industry. By contrast, processing sources are typically larger, meeting the threshold for annual emissions reporting under the regular point-source inventory.

We find that methane leakage, though playing a smaller role in life cycle GHG emissions from this analysis of 2009 Barnett Shale gas as compared to others, comes mostly from what we have classified as potentially controllable sources, rather than from fugitives—with implications for the potential for GHG emission reductions in the natural gas industry. In gas production, 40% of methane released comes from fugitive sources; methane emitted from potentially controllable leakage in the production stage comes mostly from pneumatic pumps and controls, which are specifically addressed in recent EPA regulations. In the processing stage, fugitives make up an even smaller proportion (10%) of overall methane emissions. As for potentially controllable leakage in processing, half comes from emissions from produced water tanks and a third from glycol dehydrators.

Our method represents an improvement in accuracy by accounting for spatial differences in gas composition as compared to previous LCAs. For instance, methane content of raw gas from the top four producing counties ranges from 56% to 80%, with implications for how much methane is released in venting or fugitive emissions. Previous research has either used play-level average gas composition (e.g., Jiang et al. [2011] for the Marcellus) or the national average. For Barnett Shale total emissions, the difference in results between using county-level gas composition compared to a play-wide average composition is relatively small; however, the improvement is more significant compared to using national average composition.

The overall results for the Barnett Shale play are only marginally sensitive to the variability in gas composition across the play because of offsetting differences. But the variability observed in gas composition has implications for accurate estimation of GHG emissions at finer spatial resolution, monitoring programs, and regulatory strategies. This study found differences in GHG emission estimates at the county level compared to estimates using national average figures; furthermore, inventories of the level of detail of the special inventory provide an important piece of the overall story of emissions. Therefore, accurate usage of such detailed information needs to be matched by more detailed input information, notably gas composition analyses. The database assembled for this study is a first step toward developing more robust databases in the Barnett and other natural gas basins around the country.

Improvements can be made to the estimate produced here of life cycle GHG emissions for 2009 Barnett Shale gas used in a modern combined cycle electricity generator. But this study’s methodologically independent estimate confirms previous research on shale gas electricity generation. In addition, it is similar to previous estimates for generation using conventionally produced natural gas, and it is less than half of that estimated in other studies for coal. Liquids unloading, which is typically assumed to occur only for conventional wells, accounts for most of the difference between this study’s estimate and that developed based on meta-analysis and updating of more than 40 references reporting life cycle GHG emissions for electricity generated from conventionally produced natural gas. However, evidence has emerged suggesting that liquids unloading is also a practice applicable to unconventional wells. If confirmed for Barnett Shale wells in particular, then it means that the estimate reported here should be updated accordingly. The high carbon content and significantly lower thermal efficiencies of coal-fired power plants account for their substantially higher life cycle GHG emissions.

2 Regulatory Framework Governing Unconventional Gas Development

2.1 Introduction

Rapid development of unconventional natural gas in the United States in recent years has raised a number of important environmental concerns, including ground and surface water contamination; disposal practices for frac flowback, produced water, and other associated drilling wastes; impacts on local and regional air quality; methane leakage and venting rates; and increased traffic, noise, and other community impacts. It is clear that regulations have increased at virtually all levels of governance in response to the unconventional gas boom. Various commissions, advocacy groups, and research organizations have weighed in on the pros and cons of additional regulation, including two reports issued by the Secretary of Energy Advisory Board Shale Gas Production Subcommittee ("SEAB Subcommittee").[39] But questions persist regarding the sufficiency of these regulations across differing jurisdictions and the adequacy of compliance monitoring and enforcement in the face of rapid growth.

Because of the "distributed" nature of unconventional gas development and the substantial increase in wells in key basins,[40] local land-use conflicts have erupted in certain areas of the country that have led to restrictions and moratoria on drilling by state, county, and municipal governments, raising questions about the industry's continued social license to operate in specific jurisdictions[41] (Dryden 2012; Middlefield 2012). In response, some states—notably Pennsylvania—have recently enacted legislation to restrict the ability of local governments to

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[39] *See e.g.*, U.S. DOE, *Secretary of Energy Advisory Board Shale Gas Production Subcommittee, Ninety-Day Report,* (Aug. 11, 2011) and *Second Ninety-Day Report* (Nov. 18, 2011), http://www.shalegas.energy.gov/resources/081111_90_day_report.pdf; National Petroleum Council, *Prudent Development Realizing the Potential of North America's Abundant Natural Gas and Oil Resources* (2011), http://www.npc.org/NARD-ExecSummVol.pdf; Cardi Reports, *The Economic Consequences of Marcellus Shale Gas Extraction: Key Issue*s, prepared on behalf of Cornell University (Sept. 2011), http://www.greenchoices.cornell.edu/downloads/development/marcellus/Marcellus_CaRDI.pdf; Thomas Kurth, et al., "American Law and Jurisprudence on Fracing," Haynes and Boone, LLP (2010), http://www.haynesboone.com/files/Publication/3477accb-8147-4dfc-b0b4-380441178123/Presentation/PublicationAttachment/195a3398-5f02-4905-b76d-3858a6959343/American_Law_Jurisprudence_Fracing.pdf ; Bipartisan Policy Center, Energy Project, *Shale Gas: New Opportunities, New Challenges* (Jan. 2012), http://www.scribd.com/doc/95194795/Shale-Gas-New-Opportunities-New-Challenges; Charles G. Groat and Thomas W. Grimshaw, *Fact-Based Regulation for Environmental Protection in Shale Gas*, report prepared for the Energy Institute, University of Texas at Austin (Feb. 2012), http://energy.utexas.edu/images/ei_shale_gas_regulation120215.pdf; Rebecca Hammer, et al, *In Fracking's Wake: New Rules are Needed to Protect Our Health and Environment from Contaminated Wastewat*er, Natural Resources Defense Council (May 2012) http://www.nrdc.org/energy/files/Fracking-Wastewater-FullReport.pdf; International Energy Agency, Golden Rules for a Golden Age of Gas, 9-10 (May 29, 2012), http://www.worldenergyoutlook.org/media/weowebsite/2012/goldenrules/WEO2012_GoldenRulesReport.pdf (discussing the importance of public acceptance for continued expansion of unconventional gas development in the U.S. and abroad).

[40] For a graphic depiction of the rapid increase in shale gas wells in Pennsylvania, see U.S. Energy Information Administration, "Horizontal drilling boosts Pennsylvania's natural gas production," available at http://www.eia.gov/todayinenergy/detail.cfm?id=6390.

[41] Some national governments, including France and Bulgaria, have also banned hydraulic fracturing (BBC News 2012). For a list of current moratoria and bans, see Sierra Club, FRAC Tracker, http://www.sierraclub.org/naturalgas/rulemaking/.

regulate unconventional gas development.[42] Other states, such as Colorado, have engaged in multi-stakeholder processes to strengthen and continue to revise new rules for oil and gas development that have been embraced by multiple constituencies and paved the way for innovative legislation that is re-shaping the electric power sector in the state (COGCC 2008; Xcel 2012). See Textbox 1 for more on Colorado's recent experience. But even in those states, such as Colorado, where oil and gas development has been a feature of the landscape for decades, a number of communities have expressed concerns about the proximity and pace of unconventional gas development and are seeking to impose new restrictions on development.[43]

Text Box 1: Colorado's Clean Air-Clean Jobs Act

In 2010, then Governor of Colorado Bill Ritter introduced landmark legislation that fundamentally altered the energy make-up of the state's electric power sector. The legislation, HB 1365, also known as the "Clean Air-Clean Jobs Act," required regulated utilities to reduce emissions of nitrogen oxides by 70% to 80% or greater from 900 megawatts of coal-fired generation by 2018 and meet certain "reasonably foreseeable" environmental requirements, such as lower ozone standards. To meet these targets, the state's regulated utilities proposed a plan that included retiring aging coal-fired power units, retrofitting others with state-of-the-art clean technology, and expanding capacity for units powered by natural gas and renewable energy sources. The Act had broad support from a number of constituencies including local Front Range governments, local and national non-governmental organizations, Xcel Energy and the natural gas industry (CCC 2010; Xcel 2012). Importantly, much of this support can be tied to the state's decision to first put in place strong rules for the development of its oil and gas resources before introducing legislation that would very likely lead to increased production. Many believe there is still work to be done to ensure that production is done properly statewide, especially in the Front Range, where new production is taking hold that did not exist to the same extent in 2008. However, many point to the Colorado model as an example of collaboration, innovation, and leadership that can be replicated elsewhere.

In short, the regulatory landscape affecting unconventional gas development is complex, dynamic, and multi-layered. Going forward, there is a risk of increased regulatory fragmentation within and among gas-producing basins, as well as a lack of coordination among the different government entities responsible for regulating and ensuring compliance with various aspects of unconventional gas development, leading to additional uncertainty, gaps, redundancies, potential delay for producers, and under-enforcement.[44] At the same time, leading companies continue to

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[42] 58 Pa. Cons. Stat. § 3218; see also CO SB 088, introduced unsuccessfully Feb. 16, 2012.

[43] For example, Boulder County, Resolution No. 2012-16 (Feb. 2, 2012); Colorado Springs, Steve Bach, Mayer of Colorado Springs, "Memorandum on Administration of the Use of Regulations Set Forth in Chapter 7, City Code," (Nov. 28, 2011); the City of Erie, Ord. No. 09-2012 (Mar. 7, 2012); and the city of Longmont, Ord. No. O-2012-18 (Dec. 20, 2011)—all enacted temporary moratoria on applications for oil and gas development.

[44] For a recent report that surveys state shale gas regulation and similarly finds significant variations among them, see Resources for the Future, "A Review of Shale Gas Regulations by State," http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale_Maps.aspx.

develop and elaborate best practices[45] to control and/or mitigate some of the environmental impacts associated with unconventional gas development. Some of these corporate practices go beyond existing regulation and some have served as the basis for new regulations.[46] Although it is impossible to predict the precise mix of future regulation, it is likely that additional regulations will be adopted and implemented as unconventional gas development proceeds. These could affect the costs of producing unconventional gas, but without basin- and company-specific data, it is not possible to determine the amount of additional compliance costs associated with any particular regulatory scenario. This is an important area for future research.

This chapter examines the main federal, state, and local regulatory frameworks that govern unconventional natural gas development.[47] Specifically, this chapter focuses on requirements related to water withdrawals used for hydraulic fracturing, disclosure of chemicals used in hydraulic fracturing fluids, setbacks for wells, baseline water monitoring of surface water resources or water wells, well construction standards, "green" or "reduced emission" completions, storage of waste in closed-loop systems, and the disposal of produced water. It also examines state compliance monitoring and enforcement capabilities. The goal of the research was to identify changes and trends in the governing legal frameworks across the different basins, as well as key challenges going forward. Specific attention is given to regulatory uncertainty, fragmentation, gaps, and redundancies associated with the proliferation of new rules and regulations at multiple levels, as well as the implications of shifting public perception and support for gas development across various jurisdictions.

Due to time constraints, it was not possible to examine all impacts associated with gas development and corresponding regulatory responses. Key areas for future research include, for example, regulations aimed at reducing the risk of surface spills of acids and chemicals used in hydraulic fracturing, storm-water controls, open-pit requirements, and mitigation measures for truck traffic. Beyond the scope of this report is a complete discussion of the environmental and public health risks posed by unconventional gas development and an analysis of the extent to which the current regulatory and statutory regimes reduce such risks, or the extent to which voluntary implementation of best practices fill any gaps remaining.

The chapter focuses on six unconventional U.S. basins: Barnett Shale play and Eagle Ford Shale play in Texas, Haynesville Shale play in Texas and Louisiana, Marcellus Shale play in New York and Pennsylvania, North San Juan basin in Colorado, and Upper Green River basin in Wyoming. As Table 4 illustrates, each of these basins is marked by distinct resource, geologic, and hydro-geologic characteristics, and each has had different historical and contemporary

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[45] The term *best practices* used here has the same meaning as that used by the SEAB in that it refers to "improvements in techniques and methods that rely on measurement and field experience" (SEAB 2011a). Best practices are not static, but rather, continuously evolving, as evidenced by the rapid changes in technologies related to stimulation techniques, methane capture, and water recycling.

[46] See, for example, green completions, voluntary disclosure of chemicals used in hydraulic fracturing fluids, and reuse of produced and flowback waters. EPA specifically cited industry's voluntary use of green completions in promulgating recent federal standards to limit air pollution from new and modified stationary sources in the Crude Oil and Natural Gas Production Category (EPA 2012c).

[47] Statutes applying uniquely to federal lands or actions, such as the Federal Lands Policy and Management Act, National Environmental Protection Act, and Endangered Species Act, are not discussed. For a more complete description of the federal framework that applies to unconventional gas development, see EPA 2000 and Kurth 2010.

experiences with oil and gas development. Accordingly, unconventional gas development in each of these basins and jurisdictions poses a distinct set of environmental issues, and it is the subject of a different mix of state and local regulation.

Table 4. Description of Shale Plays and Basins Studied

Primary Designation	Secondary Designation	Hydrocarbon Resources	Interest for Study	Production Characteristics
Barnett Shale Play	District 5, North Texas	Mostly dry gas, shale	Original shale gas basin, history, water stressed, near urban areas	6,000–8,500 feet deep
Eagle Ford Shale Play	Oil Producing Counties, South Texas	Oil, NGLs and gas, shale	High activity, resource diversity, water stressed	Oil 4,000–8,000 feet, NGLs/gas 8,000–12,000 feet deep, average thickness 450 feet
Haynesville Shale Play	DeSoto Parish, Louisiana	Mostly dry gas, shale	Second-largest shale gas reserves in U.S., active production	10,500–13,000 feet deep, high temperature and pressure
Marcellus Shale Play	Susquehanna River Basin, Ohio River Basin, Pennsylvania	Mostly dry gas, shale	Rapidly growing, diverse, area of significant public attention	5,000–7,000 feet deep, 100–500 feet thick, largest shale gas reserves in U.S.
North San Juan Basin	La Plata County, Colorado	Coal-bed methane	Colorado regulations, distinct risks due to CBM production	Fruitland formation, 550–4,000 feet deep
Upper Green River Basin	Jonah Field, Pinedale Anticline Wyoming	Mostly dry gas, tight sands	Active production, ozone nonattainment	Vertical wells, 8,000–11,000 feet deep in tight sands

This chapter also examines recent actions by local governments to ban, delay, or regulate hydraulic fracturing or gas development; responses to such actions by state courts and legislatures; and the implications of these developments for the industry's social license to operate in specific parts of the country.

Lastly, this chapter identifies several important examples where companies have adopted measures that go beyond compliance—namely, "green" completions, voluntary disclosure of chemicals used in hydraulic fracturing fluids, and reuse of produced and flowback waters. In some cases, these best practices have become the basis for new regulations (e.g., "green" completions). In others, they continue as voluntary actions that fill gaps or go beyond existing regulatory frameworks (e.g., reuse of produced and flowback waters).

The major conclusions that emerge from this analysis are as follows:

- Although there is a trend toward more regulation at all levels of governance, there has been a corresponding increase in regulatory fragmentation and differentiation at state and local levels. Better coordination and policy alignment among regulators can help to reduce risks of regulatory fragmentation including uncertainty, delays, gaps, and redundancies across jurisdictions. Improved communication and sharing of information between regulators at all levels of government and across jurisdictions—as well as increased transparency in the form of publicly reported and publicly available data from industry—will help ensure that regulations are coordinated and tailored to specific geographic and geologic characteristics. Appropriately designed regulations that reflect local conditions such as gas composition and geology reduce environmental risks and ensure more efficient resource recovery.
- Compliance monitoring and enforcement actions vary significantly across states, with significant implications for the efficacy of regulations, as well as public confidence in the ability of state regulators to ensure that development proceeds safely. Public disclosure of violations, enforcement actions, and company compliance would bring greater transparency and accountability to an industry that, by its nature, poses unique compliance and enforcement challenges due to the disparate and often remote location of facilities and its rapid development in recent years. It would also provide an opportunity to highlight the compliance records of leading companies that have demonstrated a commitment to safe natural gas production.
- There is a significant range in the environmental performance of operators in the industry, with some operators performing at a level that goes beyond existing regulations and other operators falling short. Ongoing consolidation in the industry could lead to more widespread adoption of best practices across the industry. However, additional implementation of beyond-compliance measures is unlikely to lead to less regulation given limited public acceptance of the concept of self-regulation in the industry. In some instances, the implementation of best practices may serve as the foundation for future regulation (Efstathiou 2012), which, in turn, could serve to level the playing field among producers and may help restore public trust in areas of the country where unconventional gas development has been controversial.
- There is a need for basin- and company-specific data to analyze the extent to which implementing beyond-compliance measures or additional regulation will affect the cost of producing natural gas and, by extension, the supply of gas to the electric power sector.[48] This study was not able to collect such data (see Chapter 4), but this will be a focus of a potential follow-up study.
- Notwithstanding the challenges of regulatory fragmentation, different state and local approaches to regulating unconventional natural gas development provide important opportunities for learning and innovation regarding substantive rules, the role of best practices, and process. Colorado, for example, recently implemented landmark legislation

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[48] A recent report estimates that the application of 22 "Golden Rules" for shale gas development could add about 7% to the overall drilling and completion costs on a per well basis (IEA 2012). Assuming today's costs and prices are roughly equivalent, 7% added costs in the U.S. would amount to roughly an additional $0.25/MMBtu produced.

with the support of multiple constituencies, including the natural gas industry and environmental groups, that resulted in a dramatic shift in the state's electric power sector away from coal toward greater use of natural gas and renewable energy (see Chapter 1 for a discussion of the potential climate benefits associated with using natural gas as opposed to coal as a feedstock for electricity generation). This could not have happened absent an initial effort to revise the state's oil and gas laws. New York's decision to undertake a detailed and extensive study of the impacts associated with high-volume hydraulic fracturing has led to development of some of the most comprehensive rules in the country. It remains to be seen whether, if adopted, they alleviate public concerns regarding the risks associated with unconventional gas development .

2.2 Federal Legal Framework

The major federal environmental laws provide the overarching framework for regulating many of the environmental impacts associated with unconventional natural gas development. Some of these laws, however, contain explicit exemptions or definitional exclusions for natural gas development, resulting in a significant role for state regulation in key areas such as waste management, disclosure of chemicals used in hydraulic fracturing and releases, and well construction standards other than for underground-injection disposal wells. This section analyzes the federal regulatory framework governing air, water, and waste issues associated with unconventional gas development. It focuses on the scope of federal regulation, the extent to which state law fills any gaps left open by the federal regulatory scheme, recent legislative proposals and rule-makings, key trends, and the implications of a changing federal regulatory framework for future development.

2.2.1 Overview and Key Trends

Federal laws governing the air, water, and waste impacts associated with the production of unconventional natural gas vary in terms of scope. EPA has broad authority to regulate emissions of air pollutants, including GHGs, direct and indirect discharges of wastewater from point sources, and the injection of produced water into underground injection wells for disposal.[49] The federal government, primarily through the U.S. Department of the Interior, also has authority over the development of natural gas on federal and tribal lands. Federal oversight over the management of hazardous and solid wastes, reporting and disclosure requirements of toxic or hazardous releases, and the process of hydraulic fracturing itself is much more limited—and, in some cases, it is entirely absent given specific exemptions and definitional exclusions under certain federal laws such as the Resource Recovery and Conservation Act; the Comprehensive Environmental Response, Compensation and Liability Act; and the Safe Drinking Water Act.

Some federal exemptions have been the focus of proposed legislation in past and current Congresses,[50] and efforts to repeal or narrow these exemptions are likely to continue. Congress also recently requested that EPA conduct a study evaluating the potential impacts of hydraulic fracturing on drinking water (EPA 2011e). Depending on the results of this study, the first of

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[49] An exception to this is section 112(n)(4) of the Clean Air Act, which contains prohibitions on the aggregation of hazardous air pollutant emissions from certain gas wells and other equipment that constrain regulation of such sources (42 U.S.C. § 7412(n)(4)).

[50] See, for example, The Fracturing Responsibility and Awareness Act of 2011, H.R. 1084.

which are due out sometime in 2012 with additional results in 2014, EPA may assume a more active role in regulating hydraulic fracturing—including reconsidering its determination that certain natural gas wastes are not hazardous, and recommending changes to the statutory framework that applies to the process of hydraulic fracturing. In the meantime, the states continue to play an important role in regulating various aspects of hydraulic fracturing. The extent to which states have filled gaps left open by federal regulation is discussed in Section 2.3.

The trend at the federal level is toward more regulation. As discussed in more detail below, a number of federal rules related to gas development have been finalized, proposed, or announced recently in response to increased development, and there have been repeated calls for new legislation. Taken together, these efforts indicate a growing interest in hydraulic fracturing and unconventional gas development at the federal level and the likelihood of additional federal regulation, and possibly legislation regarding the removal of certain exemptions in existing statutes, as has been proposed in the past.

2.2.2 Hydraulic Fracturing

The process of hydraulic fracturing, other than when diesel fuel is used, is expressly excluded from federal regulation under the Safe Drinking Water Act's Underground Injection Control program.[51] Were hydraulic fracturing not specifically excluded from the definition of *underground injection*, the natural gas industry would be required to comply with certain federal well construction, operation, and closure requirements, as well as disclosure requirements. This has been, and likely will continue to be, a source of controversy because numerous bills were introduced in 2009, 2010, and 2011 to bring the process of hydraulic fracturing within EPA's control (Martin et al. 2010).[52] Although prior attempts have all been unsuccessful, it is likely that similar legislation will be introduced in the future (Hammer and VanBriesen 2012). Additional pressure for greater federal regulation could also come as a result of EPA's hydraulic fracturing study if it concludes that the process of injecting fluids underground during hydraulic fracturing increases the risk of groundwater contamination.[53]

EPA recently published draft guidance governing the use of diesel in hydraulic fracturing fluids that includes requirements for diesel fuels used for hydraulic fracturing wells, technical recommendations for permitting, and a description of diesel fuels for EPA underground injection control permitting (EPA 2012b). As proposed, this guidance only applies where the EPA is the permitting authority. States with primacy over the Underground Injection Control program, which include Texas, Louisiana, and Wyoming, are not required to follow the guidance (Figure 11).

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[51] 42 U.S.C. § 300h(d)(1)(B)(ii) (2005).

[52] The most recent efforts being The Fracturing Responsibility and Awareness Act of 2011, H.R. 1084.

[53] An area of ongoing controversy and debate is whether or not the process of hydraulic fracturing poses a greater risk of subsurface water contamination than other aspects of development that are common to all types of oil and gas production such as surface spills, impoundment failures, and faulty well construction (Groat and Grimshaw 2012; Hammer and VanBriesen 2012; Jones 2011).

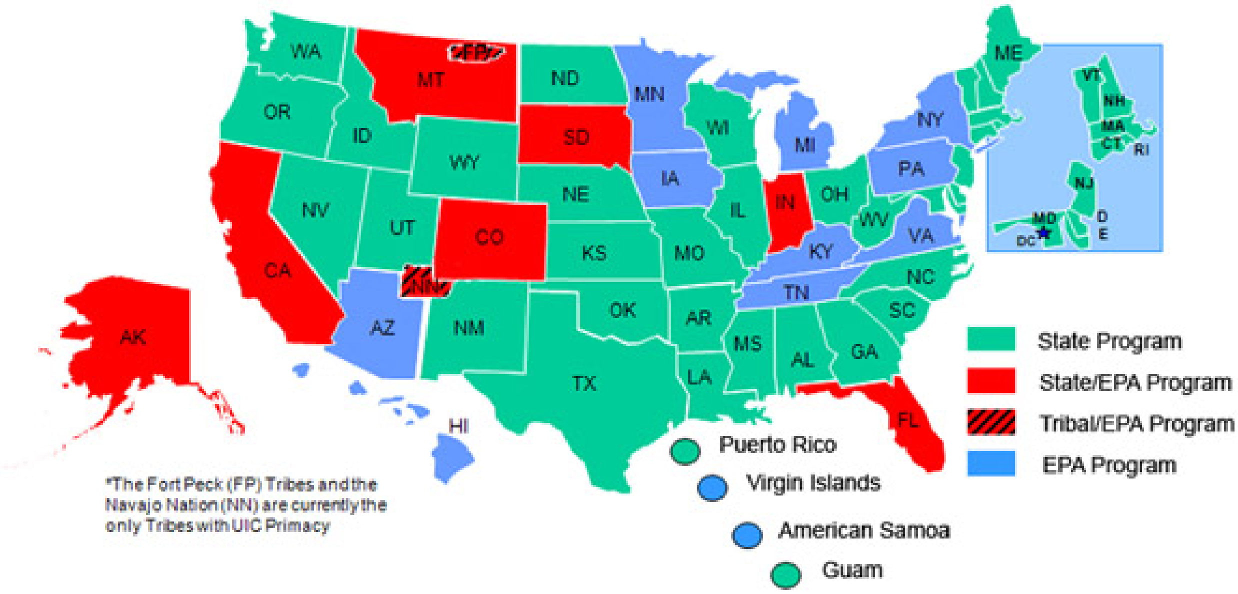

Figure 11. EPA map of Underground Injection Control Program Primacy[54]

Given the limited federal role in this area, states are the primary regulators of well construction standards that apply to the process of hydraulic fracturing (see Section 2.3.3 below).[55] However, with respect to natural gas development on federal lands, the Bureau of Land Management (BLM) recently proposed a rule that would require the use of cement bond logs on surface casing and mechanical integrity testing prior to hydraulic fracturing to improve well integrity (BLM 2012). Both EPA's proposed diesel fuel guidance and BLM's proposed well construction standards help to provide greater regulatory certainty to the production of natural gas. However, state regulations remain central given the limited applicability of the EPA guidance and BLM standards.

2.2.3 Water Quality

As reported in various news media, for the public, some of the most prominent environmental concerns associated with unconventional gas development that have emerged are adverse impacts to groundwater and surface water resources. The major federal statutes protecting water quality—the Clean Water Act and the Safe Drinking Water Act—apply to various aspects of unconventional gas development, with different approaches and experiences in different parts of the country.

The Clean Water Act prohibits the unauthorized discharge of wastewater into the surface waters of the United States from point sources. Discharges may be authorized by permits issued under the National Pollutant Discharge Elimination System, whose permits require industry-specific, technology-based limits and water-quality-based effluent limitations. The latter vary depending

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[54] EPA, "UIC Program Primacy," http://water.epa.gov/type/groundwater/uic/Primacy.cfm.

[55] Well integrity is essential not only to reduce risks associated with hydraulic fracturing, but also, with the entire universe of down-hole activities (i.e., wells that are not hydraulically fractured also pose a risk to surface and subsurface water sources if not properly cased, cemented, and monitored).

on local conditions because they are tailored to protect specific designated uses of surface waters.

EPA has established two national effluent limitation guidelines that apply to unconventional gas wells. The first completely prohibits the discharge into navigable waters of natural gas wastewater pollutants, such as produced water, drilling muds, or drill cuttings from any source associated with oil and gas production, field exploration, drilling, well completion, or well treatment, located east of the 98th meridian. [56] The second guideline applies to operators west of the 98th meridian and allows the discharge of produced water only if it may be used beneficially for agricultural or wildlife propagation.[57]

Indirect discharges to publicly owned treatment works (POTWs) and discharges from centralized waste treatment facilities (CWTs) are also subject to the Clean Water Act framework. However, EPA has not promulgated pretreatment standards that apply to the discharge of shale and coal-bed methane (CBM) wastewater to POTWs, leaving a gap in the federal framework that has been the source of considerable controversy. Discharges from CWTs are subject to federal technology-based standards, although these standards do not contain limits for all of the pollutants contained in natural gas wastewater—in particular, bromide or total dissolved solids. [58]

EPA's decision under the CWA to prohibit direct discharges of drilling wastewater to surface waters in states east of the 98th meridian, combined with limited injection well capacity in that part of the country (see Chapter 4, discussing the fact that Pennsylvania has only eight Class II underground disposal wells), has resulted in increased use of indirect discharges to POTWs and CWTs. Many POTWs, however, are not designed or permitted to handle the volumes and types of wastewater produced from the booming shale gas industry (Urbina 2011). In Pennsylvania, insufficient treatment capacity for shale gas wastewater resulted in contamination of state waters—in particular, elevated levels of total dissolved solids, organic chemicals, and metals (EPA 2011c)—prompting the state to request operators to voluntarily cease sending shale gas wastewater to older POTWs and also resulting in new state limits for total dissolved solids and chlorides[59] (EPA 2011b).

EPA has announced its intent to develop pretreatment standards for discharges of CBM and shale wastewater in 2013 and 2014, respectively (EPA 2011a). These standards should bring certainty to this area, reduce the likelihood that treated wastewater discharges from POTWs will contaminate surface waters, and improve public confidence in the ability of natural gas development to be done safely. Depending on how these standards are set, they may also drive the development of technologies to recycle and reuse wastewater. If, for example, EPA adopted a "no discharge" or otherwise stringent limit, operators would need to rely more heavily on other

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[56] Onshore Subcategory Guidelines, 40 C.F.R. § 435.30 (2012). The 98th meridian runs through North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, and Texas. Direct discharges of produced water west of the 98th meridian are permitted provided the water does not exceed specified parameters for oil or grease and can be used for agricultural or wildlife propagation. *Id*. § 435.50.

[57] *Id*. § 435.50. Produced water has an effluent limitation of 35 mg/L of oil and grease. *Id.* § 435.52.

[58] See 33 U.S.C. § 1317 (2012); EPA, "National Recommended Water Quality Criteria," available at http://water.epa.gov/scitech/swguidance/standards/criteria/current/index.cfm.

[59] 25 Pa. Code § 95.10(b)(3)(iv)-(vi).

forms of wastewater disposal such as underground injection or recycling. In parts of the country, such as Pennsylvania, where underground injection wells are limited, a "no discharge" standard could result in significantly more recycling and reuse—especially if doing so is less costly than transporting wastewater out of state for injection.

As noted above, in addition to complying with national effluent limitation guidelines, POTWs and CWTs discharging wastewater must comply with numeric limits on certain pollutants designed to ensure that discharges do not impair the designated uses of surface water bodies. Although EPA has established guidance for water-quality criteria for some natural gas wastewater, it does not cover all pollutants contained in wastewater (Hammer and VanBriesen 2012).[60] Additional guidance from EPA would provide a certain degree of certainty and more uniform protection because states rely on EPA guidance when adopting water-quality criteria, and EPA retains authority to promulgate its own criteria if it determines a state has failed to adopt adequate standards of its own. Notably, EPA recently signaled its intent to update water-quality criteria for chloride, which is arguably outdated because it was established well before the recent shale gas boom (EPA 2011b).

2.2.4 Hazardous and Solid Wastes

2.2.4.1 Management of Waste

Subtitle C of the Resource Conservation and Recovery Act imposes stringent "cradle-to-grave" requirements that apply to the generation, transportation, treatment, storage, and disposal of hazardous waste.[61] Most of the wastes associated with natural gas drilling, however, are exempt from the Resource Conservation and Recovery Act's program for hazardous wastes. Specifically, drilling fluids, produced water, and other wastes "intrinsically related" to the production and development of natural gas are exempt from Subtitle C hazardous waste requirements.[62] As a result, management of these wastes is primarily a matter of state law. Non-exempt wastes, such as unused fracturing fluids, waste solvents, and used hydraulic fluids, are subject to the Resource Conservation and Recovery Act and may be covered under Subtitle C if they exhibit hazardous characteristics or are specifically listed as hazardous wastes. Exempt wastes not regulated as hazardous are subject to state rules because EPA has not promulgated regulations governing the management of oil and gas solid waste (NRLC 2012). Although this allows for regulation to be tailored to local geologic or hydrologic conditions, it also creates greater horizontal fragmentation, uncertainty, and the potential for inadequate state rules. See the discussion in Section 2.3.5.2 and Table 28 in Appendix C comparing state rules for produced water.

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[60] The current guideline only applies to certain pollutants such as chloride, oil and grease, suspended solids, turbidity, and nitrates. See EPA, "National Recommended Water Quality Criteria," available at http://water.epa.gov/scitech/swguidance/standards/criteria/current/index.cfm.

[61] 40 C.F.R. pt. 260 et seq. Specifically, generators must ensure and fully document that their hazardous waste is properly identified, managed, and treated prior to recycling and disposal. They must comply with requirements for training and emergency arrangements (including having an emergency coordinator and testing and maintaining emergency equipment) and must track the shipment and receipt of their waste. Additionally, a hazardous waste generator is limited in the amount of waste it can accumulate. A large-quantity hazardous waste generator (one that generates 1,000 kg or more of hazardous waste per month) must move all the waste it generates off site within 90 days; a small-quantity generator must move all its waste off site within 180 days. See EPA, Regulations Governing Hazardous Waste Generators, at III-41-47, http://www.epa.gov/osw/inforesources/pubs/orientat/rom33.pdf.

[62] In addition, EPA has determined that produced water injected for enhanced recovery is not waste subject to the Resource Conservation and Recovery Act and is therefore exempt from regulation under the statute. However, produced water stored in above-ground impoundments is subject to state law (EPA 2000).

Some observers have called for the federal regulation of natural gas waste as hazardous under Subtitle C of the Resource Conservation and Recovery Act (Hammer and VanBriesen 2012). EPA has not signaled its intent to reverse its decision regarding the management of natural gas waste; however, it remains a possibility, and may turn, in part, on the outcome of EPA's study on hydraulic fracturing.

2.2.4.2 Liability for Releases of Hazardous Substances

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), also known as "Superfund," imposes strict liability for releases of hazardous substances on owners and operators of "facilities" (which include natural gas production sites), as well as arrangers and transporters of hazardous substances. The definition of *hazardous substance* under CERCLA, however, is limited in its application to crude oil, petroleum, and natural gas.[63] Specifically, petroleum and crude oil—as well as hazardous substances that are normally mixed with or added to crude oil or crude oil fractions during the refining process—are not considered hazardous substances under the so-called "petroleum exclusion."[64] Also excluded from the definition of hazardous substances are natural gas, natural gas liquids, liquefied natural gas, and synthetic gas usable for fuel.[65] Releases of other hazardous substances from natural gas drilling operations, such as hydraulic fracturing fluids containing hazardous chemicals, are subject to standard CERCLA liability. Thus, federal law provides for some potential CERCLA liability for natural gas operators, but the scope of such liability is narrow. Moreover, even though some states, such as Colorado, Texas, and Pennsylvania, have adopted their own environmental cleanup legislation, these states have all retained the federal definition of hazardous substances.[66]

2.2.4.3 Reporting of Hazardous or Toxic Chemical Releases

Federal law imposes few reporting requirements on operators of natural gas production facilities for the release of hazardous or toxic chemicals. Under CERCLA, operators must report releases of hazardous substances above reportable quantities, although the same definition of hazardous

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[63] 42 U.S.C. § 9601(14).

[64] *Id*. Discharges of oil from certain production facilities may be subject to the Clean Water Act's Oil Pollution Prevention Program, which requires covered facilities to prepare and implement Spill Prevention Control and Countermeasures to prevent oil discharges (EPA 2000).

[65] *Id*. at § 9601(14).

[66] New York has a state law mirroring CERCLA, including a state Superfund to pay for site cleanup when no responsible party can be identified or the responsible party has inadequate funds for the cleanup. The state requires reporting and cleanup of petroleum spills within the state through its spill response program and its Brownfield and Superfund laws. New York's Brownfield regulations still exclude "natural gas, natural gas liquids, liquefied natural gas, synthetic gas usable for fuel, or mixtures of natural gas and such synthetic gas" from the definition of "hazardous waste" and "contaminant," thereby removing natural gas from the law's application. New York Department of Environmental Conservation, *Chemical and Petroleum Spills*, http://www.dec.ny.gov/chemical/8428.html; see also New York General Remedial Program Requirements, N .Y. Comp. Codes R. & Regs. title 6, § 375-1.2(w)(1). Pennsylvania operates within the CERCLA framework, but also has separate state legislation to fill in gaps in CERCLA. Pennsylvania Department of Environmental Protection, *Superfund*, http://www.portal.state.pa.us/portal/server.pt?open=514&objID=589587&mode=2. This state legislation retains the exclusion for natural gas and petroleum from the definition of "hazardous substance" and "hazardous waste." Pennsylvania Hazardous Sites Cleanup Act, 756 Act 1988–108, sec. 103 (definitions of "hazardous substance" and "hazardous waste"). Colorado has a statute on hazardous waste cleanup that essentially authorizes the State to cooperate with the federal government in the implementation of CERCLA. Colorado Hazardous Waste Cleanup Act, C.R.S. § 25-16-101. The Colorado statute adopts the CERCLA definition of hazardous substance, thereby excluding petroleum and natural gas. *Id*.

substance applies here as it does to the statute's liability scheme.[67] Oil and gas operators are not required to report annual releases of toxic chemicals under rules promulgated pursuant to the Emergency Planning and Community Right-to-Know Act's Toxics Release Inventory or to disclose the chemicals used in hydraulic fracturing to members of the public or regulators due to the exemption of hydraulic fracturing under the Safe Drinking Water Act.[68]

Natural gas operators are subject to requirements to report or disclose chemicals stored on-site, although these are limited. Owners and operators of storage facilities holding in excess of 10,000 pounds of any hazardous chemical must submit chemical inventory information to state and local emergency response and fire officials.[69] In addition, under the Emergency Planning and Community Right-to-Know Act and regulations promulgated pursuant to the Occupational Safety and Health Act, natural gas operators using products containing hazardous chemicals must maintain material safety data sheets on site, and must make them available to state and local emergency response and fire officials, subject to trade secret protection.[70]

States are increasingly filling the gap related to public disclosure of the chemicals used in hydraulic fracturing fluids. As discussed in more detail below, there is a clear trend toward public disclosure of all chemicals, not just those listed on material safety data sheets (Table 23 in Appendix C). This trend is evident at the state level and in the recently proposed BLM rule, which would require disclosure for production on federal and tribal lands (BLM 2012).

In terms of other reporting requirements, EPA has announced an intention to gather data on the aggregate amounts of exploration and production chemical substances and mixtures used in hydraulic fracturing. It is unclear to what extent these regulations will fill any of the gaps that remain in federal reporting requirements. But EPA has signaled an intent to avoid vertical fragmentation by framing its proposal as one that "would not duplicate, but instead complement, the well-by-well disclosure programs of states"(EPA 2011d).[71] In addition, states may adopt their own reporting requirements for releases.[72]

2.2.4.4 *Disposal of Produced Water*

As noted above, states primarily regulate waste disposal. One exception is the disposal of produced water into Class II underground injection wells, which is regulated by EPA's Underground Injection Control program, although states with primacy issue the actual permits.[73] Some states have recently raised concerns regarding the disposal of produced water into Class II wells, in response to evidence linking such disposal to earthquakes (Niquette 2011; Hammer and VanBriesen 2012). For example, nine earthquakes were recorded recently in Youngstown, Ohio,

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[67] 42 U.S.C. § 11004 (2012). EPA also requires operators to disclose "the source and analysis of the physical and chemical characteristics" of chemicals used in underground well stimulation permit applications (EPA 2008b).

[68] 42 U.S.C. § 11023(b) (2012) (EPA 2000; Wiseman 2010).

[69] 42 U.S.C. § 11022 (2012).

[70] *Id.*; 29 C.F.R. §1960.34(b)(6) (2012). Disclosure to the public of material safety data sheets is available upon written request.

[71] Letter from Stephen A. Owens, Assistant Administrator to Ms. Deborah Goldberg, Earthjustice re: TSCA Section 21 Petition Concerning Chemical Substances and Mixtures Used in Oil and Gas Exploration or Production, (Nov. 23, 2011), http://www.epa.gov/oppt/chemtest/pubs/EPA_Letter_to_Earthjustice_on_TSCA_Petition.pdf.

[72] See, for example, COGCC R. 906(b)(3) (requiring oil and gas producers to report spills that threaten to impact waters of the state).

[73] 40 C.F.R. § 144.6 (2010).

all of which were located within a half mile of an injection well, and all of which occurred within the first 11 months of injection of produced water into the well (Niquette 2011). Although scientists have yet to determine the cause of recent earthquakes, there have been instances in the past where injection wells used by other industries have been linked to earthquakes. (Holland 2011). This indicates that any causal relationship between underground injection of waste and seismic activity is not an impact unique to the natural gas industry. However, the volume of produced water associated with the significant increase in unconventional gas development across the country may place an increased strain on underground injection well capacity, especially in those areas where other disposal methods are less available. In addition to potentially causing earthquakes, underground injection of large amounts of produced water can increase the risk of subsurface contamination due to leaky wells.[74] Some suggest EPA should require the disposal of produced water into Class I, rather than Class II, wells because the former are subject to more rigorous standards on well construction, operation, and closure (Hammer and VanBriesen 2012). This will likely be an area of continuing public scrutiny and could be subject to additional state or federal regulation in the future.[75]

2.2.5 Air Quality

EPA has broad authority under the Clean Air Act to promulgate rules to reduce air pollution from natural gas sources. The most prominent air-quality issues associated with unconventional gas development include emissions of ozone precursors, VOCs and oxides of nitrogen, various hazardous air pollutants, and methane, all of which are subject to the basic Clean Air Act framework. Concentrated natural gas development has led to elevated ozone levels in rural parts of Wyoming and Utah where little other industrial activity occurs (Fruedenthal 2009; Streater 2010), and has also contributed to ozone pollution in more urban and industrial areas such as the Dallas Fort-Worth metropolitan area (Armendariz 2009). In 2012, the EPA responded to exceedances of the national health-based ambient air quality standards (i.e., National Ambient Air Quality Standards) for ozone in the Upper Green River basin by classifying the basin—for the first time—as in nonattainment with the 2008 8-hour National Ambient Air Quality Standard for ozone. [76] This listing could result in the state adopting more stringent rules to reduce emissions of VOCs and/or NO_x from natural gas sources in the basin to meet its Clean Air Act obligations.

Until recently, EPA has exercised its Clean Air Act authority with respect to natural gas production by focusing on a select number of natural gas production sources such as new and modified gas-processing plants, glycol dehydrators, crude oil and condensate storage vessels, and select engines used in the natural gas supply chain (e.g., engines used to power compressors). Most of these rules were implemented long before the unconventional natural gas boom occurred.

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[74] Personal conversation with Mark Williams, Professor of Geography and Fellow, INSTAAR, University of Colorado-Boulder, April 25, 2012.

[75] Notably, the Ohio Dept. of Natural Resources has enhanced Class II well permitting requirements, requiring seismic tests prior to construction of the well and ongoing monitoring, among other protections. Ohio Dept. of Natural Resources, Class II Disposal Well Reforms/Youngstown Seismic Activity Questions and Answers, http://ohiodnr.com/downloads/northstar/YoungstownFAQ.pdf.

[76] See EPA State Final Designations, April 2012 and May 2012, http://www.epa.gov/ozonedesignations/2008standards/state.htm.

In April 2012, however, EPA issued revised New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) (EPA 2012c)[77] that update existing standards and apply new requirements to previously unregulated sources. Specifically, EPA's new rules add requirements limiting VOCs and hazardous air pollutants emitted from completions and recompletions of hydraulically fractured natural gas wells (known as the "reduced emission completion" or "green completion" requirement), pneumatic devices, storage vessels, compressors, and "small" glycol dehydrators located at major sources of hazardous air pollution (EPA 2012c). Certain of these requirements result in the co-benefit of reducing methane because, in many cases, controlling VOCs also results in methane reductions (EPA 2012c). In addition, EPA updated standards and limits that apply to gas processing plants and large glycol dehydrators located at major sources of air pollution (EPA 2012c).

The revised NSPS and NESHAPS regulations provide a national floor that addresses unevenness in state air requirements. For example, EPA's new green completion requirements impose a level of uniformity across states with respect to control of ozone precursors and methane from unconventional natural gas development, as illustrated in Table 29, Appendix C, which compares green completion requirements. These new requirements implement one of the key recommendations of the SEAB, that EPA "adopt rigorous standards for new and existing sources of methane, air toxics, ozone precursors and other air pollutants from shale gas operations[.]" (SEAB 2011a, 2011b). Prior to EPA's adoption of the reduced emission completion requirement, many operators voluntarily used green completion practices to maximize resource recovery, illustrating how certain best management practices can serve as the foundation for future regulation (Efstathiou 2012, EPA 2012c).

In August 2012, EPA released a rule that requires capture or high-efficiency combustion of associated gas produced from crude oil wells in the Fort Berthold Indian Reservation in North Dakota.[78] The rule applies during well completions and re-completions, the separation phase of oil production, and during production. Specifically, the rule requires that operators control emissions of VOCs by 90% during well completions or re-completions or perform a reduced-emission completion, route all produced gas and gas emissions to a control device capable of at least a 90% control efficiency upon production, and, within 90 days of production, capture all associated gas or route it to a control device capable of 98% control efficiency.

In September 2012, natural gas producers will also begin reporting GHG emissions from facilities subject to EPA's Mandatory Greenhouse Gas Reporting rule. As required by that rule, natural gas facilities that emit 25,000 metric tons of CO_2e or more of GHGs will be required to report GHG emissions (EPA 2010). Operators have been granted a grace period to use less rigorous measurement practices initially, but the data collected will provide much greater certainty regarding actual methane leakage rates. Precise information regarding methane emissions from natural gas systems is essential to resolving discrepancies among life cycle assessments, such as those discussed in Chapter 1.

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[77] U.S. E.P.A, Final Rule, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," http://www.epa.gov/airquality/oilandgas/pdfs/20120417finalrule.pdf.

[78] EPA, "Approval and Promulgation of Federal Implementation Plan for Oil and Natural Gas Well Production Facilities; Fort Berthold Indian Reservation (Mandan, Hidatsa, and Arikara Nations), ND" 77 Federal Register 48878 (August 15, 2012).

Despite EPA's broad authority to implement clean air measures, states retain significant room to regulate. States with delegated programs may implement standards more stringent than federal law, unless prohibited by state law from doing so. States retain authority to regulate sources and air pollutants not covered by existing federal rules, and states may also impose more stringent rules than federal to meet National Ambient Air Quality Standards for criteria pollutants.

2.3 State Statutory and Regulatory Frameworks

Against this backdrop of federal environmental regulation, state and local governments have adopted numerous laws and regulations governing unconventional gas development, with considerable variation across different states, especially regarding the handling of waste and wastewater, construction of wells other than underground injection disposal wells, and baseline water-monitoring requirements. States also have exclusive jurisdiction over water withdrawals, other than those occurring on federal lands,[79] and over various land-use controls such as setback requirements and zoning, some of which have been delegated to local governments. As discussed above, although a number of federal rules apply to protecting water and air resources, states also retain authority to develop more stringent standards and to regulate impacts or sources not covered by federal law. Prior to EPA's recent revisions of the NSPS and NESHAPS, some states—notably Colorado and Wyoming—adopted air regulations that went beyond then-existing federal standards [80] (WY DEQ 2010), whereas New York has proposed a number of regulations to protect water sources and ensure safer waste management that go beyond federal and other state rules. Some states have increased inspection capacity to respond to the rapid increase in unconventional gas development; however, there is considerable variation in state inspection capacities and enforcement approaches.

This section analyzes the state regulatory frameworks governing air, water, waste, and compliance and enforcement issues associated with unconventional gas development in Colorado, Wyoming, New York, Texas, Louisiana, and Pennsylvania. It focuses on the extent to which state law fills any gaps left open by the federal regulatory scheme, as well as on key trends, differences in the regulatory frameworks across the different basins, compliance monitoring, and enforcement capabilities and actions.

2.3.1 Overview and Key Trends

The wide variation in state approaches to the regulation of unconventional natural gas development reflects differences in resource characteristics (e.g., dry versus wet gas, deep shale versus shallow CBM), geology, and hydrology, as well as different experiences with oil and gas development and different approaches to and preferences for environmental protection. Across the country, states have responded to hydraulic fracturing in very different ways. Vermont, for example, recently enacted legislation banning hydraulic fracturing in the state.[81] New York, as noted, has imposed a temporary moratorium on drilling as it develops regulations.[82] Recently, the Cuomo administration announced that it will undertake a public health study of the potential impacts of hydraulic fracturing and re-start the rule-making process prior to issuing any new

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[79] See, for example, the proposed BLM rule, which requires operators to identify the source of water to be used in fracturing in order for the BLM to determine impacts and mitigation measures, if needed (BLM 2012).

[80] COGCC R. 805(b).

[81] H 464 (enacted May 16, 2012).

[82] 9 N.Y. Comp. Codes R. & Regs. tit. 9, § 7.41.

regulations.[83] A number of states (specifically Colorado, Wyoming, and Pennsylvania) have revised their oil and gas rules extensively—at least once, and in some cases, continue to do so—to respond to the uptick in unconventional resource development; Louisiana and Texas have engaged in much more limited revisions. New York, as noted above, is in the process of revising its regulations. Louisiana, Pennsylvania, and Colorado have all recently submitted their hydraulic fracturing rules to the State Review of Oil and Natural Gas Environmental Regulations for review, whereas Wyoming and Texas have not (and New York has not yet finalized its high-volume hydraulic fracturing regulations) (STRONGER, 2010; STRONGER 2011a; STRONGER 2011b). Pennsylvania and Louisiana significantly increased the number of oil and gas inspectors in response to increased development, whereas resources in other states appear quite limited. Data are limited and more research is needed, but there appears to be very little consistency in the ways that states record, respond to, and enforce against violations—including substantial ranges in penalties and the number of violations that result in enforcement actions. Areas highlighted as meriting additional attention from state regulators are improved transparency regarding compliance monitoring, company compliance histories, and enforcement actions.

Different regulatory approaches by states can lead to uncertainty, gaps, and/or redundancies in mitigating some of the more significant environmental risks associated with unconventional gas development and ensuring overall compliance. But they can also provide a source of policy innovation because different jurisdictions experiment with new approaches to regulating various aspects of shale gas development. An example is New York's proposal to require operators to document that, compared to available alternatives, chemical additives used in hydraulic fracturing fluids exhibit reduced aquatic toxicity and pose a lower potential risk to water resources and the environment.[84] For this reason, it is important that state regulators and policy makers share information and lessons learned with other states. National standards provide a baseline or floor in some areas, such as national effluent limitation guidelines for wastewater discharges and EPA's recent NSPS and National Emission Standards for Hazardous Air Pollutants. However, a permanent feature of the regulatory landscape appears to be the uneven and varied nature of state and local regulation and enforcement regarding most other aspects of shale gas development.

Despite the variety in specific state and local regulations and enforcement, some important trends are evident. All states reviewed here recently revised their oil and gas rules and/or laws to respond specifically to the increase in unconventional resource development. Colorado, New York, Wyoming, and Pennsylvania recently undertook extensive reviews and revisions of their laws and regulations that , in some cases, resulted in considerably more comprehensive—and in many instances, protective—rules than those in Louisiana and Texas. For example, Colorado and Wyoming have been leaders in rules to reduce emissions of ozone precursors, and New York and Pennsylvania are leaders in laws regarding measurement and public disclosure of water sources and waste. See Table 22, Appendix C, for a general description of revisions to state oil and gas laws.

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[83] Danny Hakim, "Shift by Cuomo on Gas Drilling Prompts Both Anger and Praise," *New York Times,* Sept. 30, 2012.

[84] N.Y. Comp. Codes R. & Regs. tit. 6, §560. 3.

There is a clear trend in all of the states studied toward greater transparency—such as mandatory public disclosure of chemicals used in hydraulic fracturing and the composition of wastewater, reporting of the amounts and sources of water used in hydraulic fracturing, and more rigorous well-construction standards, including notifications of hydraulic fracturing and well completions. A key recommendation of the SEAB Subcommittee (SEAB 2011a) was greater transparency, in the form of public disclosure of the chemicals, amounts, and sources of water used or produced during hydraulic fracturing, baseline water monitoring measurements, and reduction and measurement of air emissions. These activities have the potential to lead to better public understanding and acceptance of natural gas development.

All states covered in this study have added requirements that providers of fluids used in hydraulic fracturing and/or operators disclose the contents of most chemicals to the public. These requirements are in addition to, and go beyond, federal requirements that require operators to maintain material safety data sheets for certain hazardous chemicals stored on-site in threshold quantities, and to report releases of hazardous chemicals in threshold quantities.[85] In addition, all of the states covered in this study require operators to report the amount and, in most cases, the source of water used in hydraulic fracturing either to the public or state regulators.

Other areas of state regulation or interest include: baseline water-monitoring requirements; use of closed-loop drilling systems to contain waste, rather than open, earthen pits; reporting or reduction of emissions of air pollutants; standards to ensure well integrity; and more active involvement on the parts of local government over drilling activities.

State compliance monitoring and enforcement capacity varies considerably, although significant data limitations across the different states mean that any comparisons should be considered provisional. Based on available data, some states—notably Pennsylvania and Louisiana—recently increased state inspection capabilities to respond to increased development, whereas resources in other states appear quite limited. The methods that states use to track and report violations and enforcement actions also differ substantially—with some states, notably Pennsylvania, making violations and enforcement actions publicly available via online databases; other states, notably Colorado and Wyoming, have been criticized for a lack of transparency and limited public access to such information.[86]

Variation across states in substantive regulations, as well as compliance monitoring and enforcement capacity, can be explained by a number of factors. Some are legal, such as federal effluent limitation guidelines that differ across regions and state statutes limiting the amount of penalties that can be assessed for violations. Others reflect differences in local environmental conditions (e.g., elevated ozone levels in the Upper Green River basin and Denver metropolitan area, respectively, led Wyoming and Colorado to adopt air rules that went beyond then-existing federal requirements, forming the basis for some of EPA's new NSPS rules); geologic and hydro-geologic conditions (e.g., developing shallow CBM resources poses unique risks that deep shale does not)[87]; proximity of drilling to densely populated areas or sensitive environmental

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[85] 42 U.S.C. § 11021-11022 (2006); 55 Fed. Reg. 30,632 (July 26, 1990).

[86] See, for example, Earthworks (2012b) and Soraghan (2011).

[87] See, for example, COGCC R. 608(b)(4).

areas (e.g., setback requirements and buffer zones)[88]; historical and contemporary experiences with oil and gas development; and preferences for environmental protection.

2.3.2 Water Acquisition

The regulation of water withdrawals is primarily a matter of state and local, rather than federal, law. The legal framework governing water rights differs from state to state, although there is some consistency along regional lines.[89] There is a clear trend toward requiring operators to identify the sources of water used, report the amount of water used in hydraulic fracturing, and provide for incentives to promote reuse of water used in hydraulic fracturing such as by recycling flowback waters or production fluids. All states require operators to report on the amount of water used for hydraulic fracturing, as does BLM's new proposed rule.[90] In addition, both New York and Pennsylvania require operators to provide for the reuse and recycling of flowback water or production fluids in water management plans or wastewater source reduction strategies. States also have begun to require minimum in-stream flow below points of water withdrawal and other measures to ensure that aquatic wildlife, water quality, and other water users will not be adversely affected.[91]

A handful of local governments also regulate some aspects of water acquisition. For example, Archuleta County, Colorado, requires operators in the North San Juan basin to submit a water management plan that includes a plan for disposal or reuse, projected water use, identification of the water source, and water availability (Archuleta 2010). The City of Fort Worth, Texas, requires operators to describe the water source proposed to be used for drilling in application for permits to drill.[92] As unconventional gas development expands in various parts of the country, it seems likely that more local governments will seek to get involved in regulating aspects of water acquisition.

For more information related to state and local regulation of water withdrawals, see Table 24, Appendix C, Water Acquisition Requirements.

2.3.3 Hydraulic Fracturing and Well Construction Standards

State well-construction standards vary considerably, which to a certain extent can be explained by differences in local geology. However, certain safeguards do not depend on differences in local conditions. Standards that have been recommended to increase well integrity include the use of state-of-the-art cement bond logs, pressure testing of casing, monitoring and recording bradenhead annulus pressure, and assurances that surface casing is run below all known underground aquifers to reduce the risk of drinking water contamination from fluid or gas

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[88] See, for example, setback requirements in the Barnett Shale and New York's proposed buffer zones to protect sources of drinking water, Appendix C.

[89] The two most common doctrines governing water rights are the prior appropriation and riparian doctrines. The prior appropriation doctrine provides rights to continued use of water to those who first put water to beneficial use and is the predominant regime in most of the West (CDWR 2012; Groat and Grimshaw 2012). In a riparian water rights system, water rights are tied to the ownership of land adjacent to water resources.

[90] DOI, Bureau of Land Management, Proposed Rule "Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands", May 4, 2012, http://www.doi.gov/news/pressreleases/loader.cfm?csModule=security/getfile&pageid=293916.

[91] See, e.g., 58 Penn. Stat. § 3211(m)(2).

[92] Fort Worth, Tex., Ord. No. 18449-02-2009.

migration (SEAB 2011b). Of the states reviewed, only Colorado and Louisiana require the use of cement bond logs.[93] New York has proposed to require the use of cement bond logs. All states except Wyoming require some kind of pressure testing of casing, although the specifics vary regarding the testing and circumstances requiring testing. Colorado is the only state that requires monitoring of annulus pressure with bradenhead (Texas requires all wells to be equipped with bradenhead, but only requires a pressure test in certain instances). All states require surface casing to be set below known aquifers, although the specific requirements vary. For specific requirements, see Table 25 in Appendix C.

2.3.4 Baseline Water-Quality Monitoring

Requiring operators to conduct baseline monitoring of wells or water resources near gas operations is an important objective for all stakeholders because it results in science-based measurement data that can be used to identify whether or not well activities cause contamination. For example, in Pennsylvania, operators who conduct pre- and post-baseline water monitoring of nearby water sources can overcome a rebuttable presumption that a well operator is responsible for pollution of nearby water resources if the monitoring demonstrates that constituents found in the sampled water sources did not come from the well operator's activities.[94] In Colorado, the Colorado Oil and Gas Association instituted a voluntary baseline monitoring program, with results being submitted to the Colorado Oil and Gas Conservation Commission (COGCC), provided landowner consent.[95] Colorado requires baseline water testing in the North San Juan basin (as well as other parts of the state), in limited circumstances to protect sources of drinking water, resources located near CBM wells, and in the Greater Wattenberg Area.[96] New York has proposed to require operators to make reasonable attempts to sample and test all residential water wells within 1,000 feet of a well pad prior to commencing drilling. If no well is located within 1,000 feet, or the surface owner denies permission, then the operator must sample all wells within a 2,000-foot radius. Monitoring continues at specified intervals as determined by the U.S. Department of Environmental Conservation.[97] For more information related to state baseline monitoring requirements, see Table 26, Appendix C, Baseline Monitoring Requirements.

2.3.5 Storage and Management of Wastes

2.3.5.1 Waste Storage

As noted above, waste storage is largely a matter of state and local law. The onsite storage of waste—such as produced and flowback water, drill cuttings, and fluids—is usually restricted to either storage tanks or open lined or unlined pits. Open pits pose a number of risks, including

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[93] We do not include where state regulations refer to logs generally, as opposed to using the specific terminology "cement bond logs."

[94] 58 Pa. Cons. Stat. § 3218. In those instances where an operator is deemed responsible for contaminating or diminishing a private or public water source, he or she must restore or replace the water with an alternate source.

[95] Colorado Oil & Gas Association, "Colorado Oil & Gas Association Voluntary Baseline Groundwater Quality Sampling Program," http://www.coga.org/index.php/BaselineWaterSampling.

[96] Colorado requires baseline sampling of surface waters located downstream of drilling operations conducted near surface waters intended for drinking water and baseline sampling of water wells located near CBM wells. COGCC R. 317.b (2012). The state also recently added a statewide requirement that operators provide notice to surface and adjacent landowners, which must include instructions for the collection baseline water samples. COGCC R. 305.e.1.A (2012). Operators drilling in the Greater Wattenberg Area must also conduct limited baseline water sampling prior to drilling. COGCC R. 318A.

[97] Proposed N.Y. Comp. Codes R. & Regs. tit 6, § 560.5(d).

threats of drowning to migratory birds and wildlife, air pollution caused by the volatilization of hazardous or organic compounds, and soil and water contamination posed by overflowing pits or liner failures (Earthworks 2012, NM OCD 2008). According to the Ground Water Protection Council, "The containment of fluids within a pit is the most critical element in the prevention of shallow ground water contamination" (GWPC 2009). This study did not perform a comprehensive analysis of state pit requirements; however, a preliminary review revealed significant variation among state pit rules in terms of liner, monitoring, fencing, and other construction and operation requirements, which is complicated somewhat by the use of inconsistent nomenclature for pit types.

An alternative to the use of pits is the use of closed-loop or "pitless" drilling systems that require the storage of fluids in tanks, preferably closed tanks, rather than open pits. Closed-loop drilling reduces many of the risks associated with open pits (Earthworks 2012). Closed-loop drilling also "allows for enhanced monitoring of fluid levels and characteristics which allows for more efficient use of drilling fluids, reduces waste, encourages recycling, and reduces potential liability associated with waste management and reduces site closure costs"[98] (TRRC 2012). New York has proposed to require closed-loop drilling for drilling fluids and cuttings associated with high-volume hydraulic fracturing operations. Colorado, Pennsylvania, Wyoming, and Fort Worth (Texas), require the practice in certain situations, such as where drilling occurs in sensitive areas where there is a heightened risk of water contamination from pit failure or the implications of contamination are more severe if contamination does occur. A recent bill introduced in Colorado would have required enhanced use of this practice statewide.[99] BLM's proposed rule for development on public and tribal lands provides for the use of either closed-loop systems or pits (BLM 2012). For a comparison of state and local closed-loop drilling requirements, see Table 27, Appendix C, Closed-Loop or Pitless Drilling Requirements.

2.3.5.2 Produced Water Disposal

State requirements regarding the disposal of produced water also vary considerably. Some of this variation can be explained by local conditions, such as the scarcity of underground injection wells in Pennsylvania, as noted above. However, disparate regulatory requirements also contribute to state-by-state variation.

In general, natural gas operators have a variety of options for disposing of wastewater. These include discharging wastewater directly to surface waters, sending the waste to treatment facilities such as POTWs or CWTs authorized to discharge, disposal via underground injection well, reuse for further hydraulic fracturing, disposal into evaporation ponds or impoundments, or disposal via land application. However, legal and practical constraints can limit some of these options.

Of the states reviewed, Colorado, Wyoming, and Texas allow for direct discharges only in specified circumstances (e.g., if produced water meets national effluent limitation guidelines for agricultural or wildlife propagation). State requirements vary considerably with respect to indirect discharges to POTWs or CWT facilities. All of the states studied except New York allow for disposal or storage of produced water in evaporation or open pits, subject to specific

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[98] NY SGEIS, § 7.1.7.4.

[99] SB 12-107 (introduced January 31, 2012).

circumstances where closed-loop systems are required. Similarly, all states except New York and Texas allow for produced water to be disposed of via land application, such as road-spreading or land farming, but the specific requirements and limits for doing so vary considerably. New York has proposed to require operators to demonstrate that all flowback water and production brine will be treated, recycled, or otherwise properly disposed of over the projected life of the well,[100] and also, that operators prepare a waste tracking form for flowback and production brine similar to what is required for medical waste.[101] Operators in Pennsylvania must prepare a wastewater source reduction strategy identifying the methods and procedures operators will use to maximize recycling and reuse of flowback or production fluids, and most states are increasingly encouraging reuse and recycling. Additional requirements to incent or require recycling and reuse of produced and flowback are likely given the heightened interest in reducing the risk of contamination posed by other disposal methods, and reducing impacts to freshwater resources associated with withdrawals. See Table 28, Appendix C, Produced Water Disposal, for specific state disposal requirements for produced water.

2.3.6 Air Quality

As discussed above, EPA and the states exercise joint authority over standards to limit or report amounts of air pollution from unconventional gas activities.

State regulation of air contaminants varies significantly, with Colorado and Wyoming containing some of the most comprehensive and rigorous requirements to reduce emissions statewide and in areas home to significant drilling activity. Some of Colorado's and Wyoming's air rules have been driven by exceedances of the national ambient air-quality standards for ozone. For example, Wyoming adopted more stringent requirements to reduce VOCs from natural gas operations in the Upper Green River basin in response to elevated levels of ozone in the winter, as did Colorado in response to violations of national ambient air-quality standards for ozone in parts of the Denver-Julesburg Basin in the Denver Metropolitan Area. Attainment of national ambient air-quality standards (i.e., National Ambient Air Quality Standards) is determined at regional and local levels (so-called "air quality management regions"); also, states have flexibility under the Clean Air Act in developing state implementation plans under the National Ambient Air Quality Standards program. Therefore, state air pollution requirements and controls vary considerably.

In addition to meeting baseline federal requirements, areas that fail to meet—or are at risk of failing to meet—national ambient air-quality standards may adopt additional measures beyond those that apply statewide in order to improve air quality. Indeed, many of the standards recently adopted by EPA in its recent NSPS—such as those that apply to completions and re-completions of hydraulically fractured wells, storage vessels, and pneumatic devices—are similar to those already required in the Upper Green River basin in Wyoming and in Colorado (WY DEQ 2010, CDPHE 2012, COGCC 2008).[102] A different situation exists for the Barnett Shale, also in an area that fails to meet national ambient air-quality standards for ozone, where the state imposes few limits on the emissions of VOCs and hazardous air pollutants; here, EPA's new rules will add a number of requirements. See Table 29, Appendix C, for a comparison of how EPA's new

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[100] Proposed N.Y. Comp. Codes R. & Regs. tit 6, § 750-3.12.

[101] NY SGEIS, § 7.1.7.1.

[102] See also COGCC R. 805.

reduced-emission completion requirement (or "green completion") compares with existing requirements in the basins reviewed.[103]

Despite EPA's enhanced role in regulating air pollution, states retain substantial discretion to regulate uncovered sources or pollutants, or, where permitted under state law, adopt more stringent rules and/or require additional reporting. For example, Pennsylvania recently added a requirement that natural gas operators report annually amounts of air pollutants.[104] New York has also proposed additional clean-air measures, including a requirement that natural gas operators submit plans to reduce GHG emissions.[105] State requirements vary considerably related to the amount of associated natural gas that operators may flare or vent during production. As production increasingly shifts toward liquids and oil-rich formations, this issue is likely to be an area of continuing policy focus because EPA's reduced-emission completion requirement does not apply to associated gas emitted during the production phase of oil wells.[106] EPA's recent Fort Berthold Indian Reservation rule provides one example of how regulators, going forward, may address the problem of associated gas emissions.

A number of recent air studies and reports have raised questions related to the sufficiency of current air regulations to protect the health of local communities from hazardous air pollutants and reduce fugitive and vented methane emissions (McKenzie et al. 2012; Petron 2012). As the industry expands, especially into more densely populated areas, concerns regarding air quality and GHG emissions will likely persist and receive ongoing regulatory attention.

2.3.7 Compliance Monitoring and Enforcement

Compliance is essential if regulations are to serve their purpose of mitigating environmental risks. Significant challenges for compliance monitoring occur due to the unique nature of the unconventional natural gas industry, characterized by dispersed and often remotely located facilities controlled by numerous operators whose practices can vary significantly. On top of this, regulators face a rapidly changing industry as development, technologies, and practices continue to expand in scale and scope.

A number of reports that have addressed the adequacy of state compliance monitoring and enforcement capabilities conclude that state inspection and enforcement capacity varies significantly, as do state processes for recording and disseminating compliance histories to the public (Groat and Grimshaw 2012; Earthworks 2012b; Soraghan 2011). For example, as Table 5 illustrates, Colorado and Wyoming have 15 and 12 inspectors, respectively, dedicated to oil and gas facilities (Earthworks 2012b; Groat and Grimshaw 2012). Pennsylvania, by comparison, quadrupled its enforcement staff in 2010, resulting in 193 enforcement personnel, 65 of whom are inspectors (Earthworks 2012b). Similarly, Texas has 125 inspectors while Louisiana has 38 (Groat and Grimshaw 2012, LDNR 2011). Data for New York were not identified.

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[103] Texas air rules are not comparable to EPA's recent rules in overall scope or rigor, with the exception of Fort Worth's "green completion" requirement. See Appendix C for green completion requirements.

[104] Act 13.

[105] NY SGEIS, § 7.6.8.

[106] For a discussion of this issue, see Clifford Kraus, *New York Times*, "In North Dakota, Flames of Wasted Gas Light the Prairie" (September 28, 2011).

As illustrated in Table 5, the number of inspections performed in each state varied considerably as well, although the data demonstrate a correlation between the number of inspectors and number of onsite inspections. Adequate inspection capability is critical to carry out the SEAB recommendation that "regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing" (SEAB 2011a).

Table 5. Compliance Monitoring and Enforcement Capabilities[107]

State	Inspectors (2010–2011)	Field Inspections (2010–2011)	Total Violations (2009–2011)	Percent of total Violations that are Procedural	Percent of Violations that Result in Enforcement[108]
CO	15[109]	16,228[110]	N/A	N/A	N/A
LA	38[111]	363	158	60	70
PA	65[112]	298	2,280	22.4	N/A
TX	125	N/A	35[113]	72[114]	20
WY	12	2	N/A	N/A	N/A

Research conducted by the University of Texas identified significant variation among states in terms of the types of violations found (e.g., pit and tank construction and maintenance are the most common violations in Louisiana, whereas permitting violations are most common in Texas). Despite the variation in violations, it appears that most violations identified are minor or procedural violations. Note, however, that this does not necessarily mean that most environmental impacts associated with gas development are minor, nor that companies comply with more "serious" requirements at higher rates. A number of factors affect the types of violations that inspectors identify, such as the visibility of violations (e.g., special equipment is needed to detect and measure natural gas leaks from equipment), state inspector capacity to respond to complaints or conduct investigations, and types of complaints reported (Groat and Grimshaw 2012).

Enforcement varies considerably among states, as well. Table 5 illustrates that the percent of violations leading to enforcement actions differed significantly among states where data are available (e.g., 70% of violations noted resulted in enforcement actions in Louisiana compared to only 20% in Texas) (Groat and Grimshaw 2012; Soraghan 2011). Penalties also vary significantly across jurisdictions, due in part to statutory constraints limiting the amount of penalties a state may assess for a given violation (e.g., the maximum fine for a violation in Colorado is $1,000 per day, whereas enforcement authorities in Pennsylvania and Texas can issue fines of $5,000 and $10,000 per day, respectively) (Earthworks 2012b). Some have questioned whether monetary penalties are sufficient to deter non-compliance given the

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[107] Data taken from Groat and Grimshaw (2012), unless otherwise noted.
[108] Soraghan 2011.
[109] Earthworks 2012b.
[110] *Id.*
[111] LDNR 2011.
[112] Earthworks, 2012b.
[113] See Chapter 4.
[114] These are for 2008–2011, rather than 2009–2011.

resources of some companies (Earthworks 2012; Soraghan 2011). Others posit that orders to cease production may be more likely to lead to compliance (Soraghan 2011).

Lastly, public dissemination regarding violations, enforcement actions, and company compliance histories also varies across states. Of the states reviewed, only Pennsylvania maintains a publicly searchable database of violations and enforcement actions. More complete and publicly available data on the compliance histories of companies are needed to understand the effectiveness of compliance and rules, as is more transparency and consistency in the ways that states record and report violations and impose penalties (SEAB 2011a). As with regulations themselves, unevenness in state compliance monitoring and enforcement capacity can lead to additional uncertainty and gaps as well as delay, because public mistrust of industry and regulators can undermine the industry's social license to operate, resulting in bans or moratoria on drilling.

2.3.8 Summary of State Statutory and Regulatory Framework

States are the primary regulators, inspectors, and enforcers of most impacts associated with unconventional natural gas development. Regulatory requirements, compliance monitoring, and enforcement capabilities vary across states. Some of this variation is reduced by the recent trend toward consistency in requirements related to the public disclosure of fluids and the amount and sources of water used in hydraulic fracturing. Additional regulation is likely in the area of well integrity standards—specifically, greater adoption of requirements to ensure adequate casing and cement jobs such as cement bond logs and pressure testing of casing. In addition, in light of continued public concern regarding adverse air, water, and waste impacts associated with unconventional gas development, states are likely to adopt regulations requiring baseline water-monitoring requirements, air-quality rules, and provisions that encourage or require greater reuse of produced and flowback waters. Some states may need to increase their inspection and enforcement resources to ensure that rules are being followed. Processes that provide greater transparency regarding state methods for identifying violations and bringing enforcement actions would help to improve public understanding of the extent to which additional resources are needed. Additional accountability and public trust are likely to result from self-reporting mechanisms that are publicly available, such as a joint industry non-governmental organization database on company compliance records (see SEAB 2011a).

2.4 Local Regulation and Social License to Operate

Across the country, communities have responded to the increased development of unconventional natural gas with mixed reactions. In half of the states reviewed for this study (Colorado, New York, and Pennsylvania), legislation has recently been proposed or enacted to limit the power of local governments to regulate unconventional gas development, or to make such local authority explicit (see Figure 12). In these states, 30 local governments have banned hydraulic fracturing or oil and gas development altogether, and an additional 73 have issued temporary moratoria pending review and potential revision of local land-use or other ordinances.[115] This section examines three different approaches to the issue of local authority,

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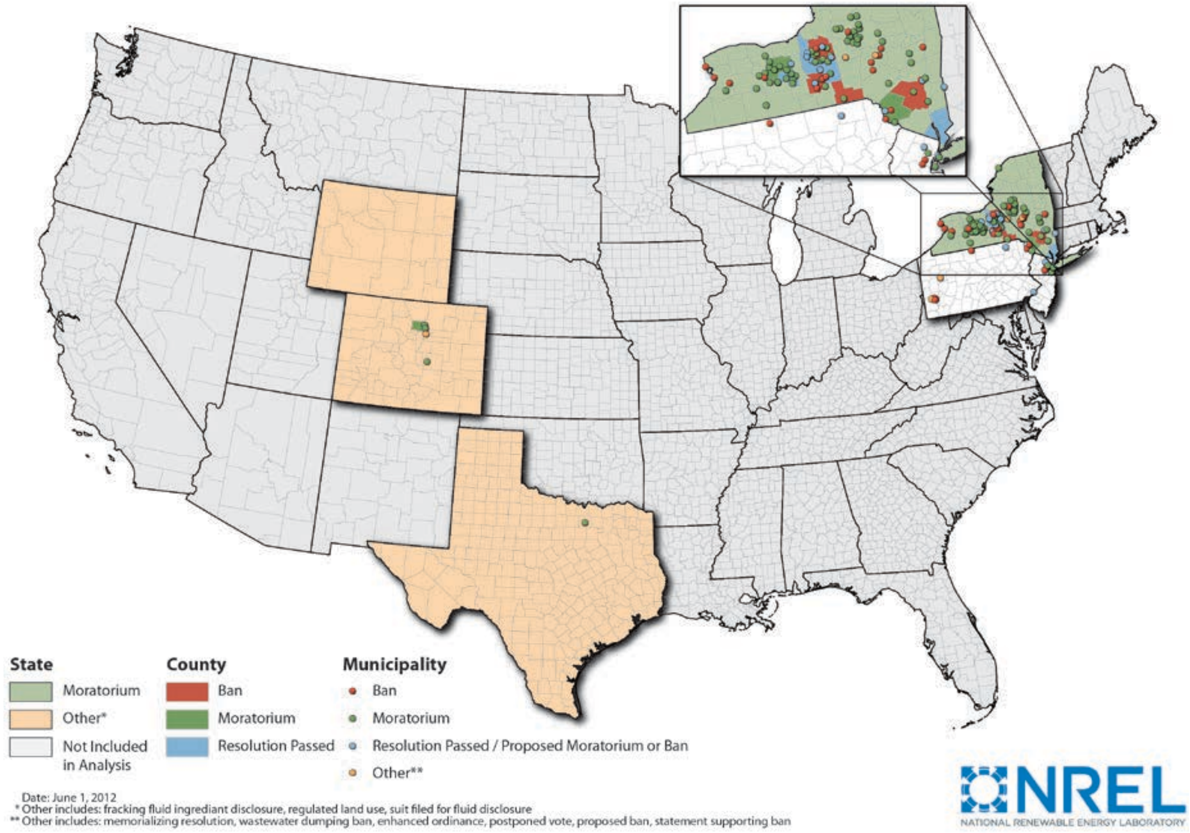
[115] A handful of states have also banned or issued moratoria. In addition to New York, New Jersey (see A 3653 (introduced Jan. 6, 2011, http://www.njleg.state.nj.us/2010/Bills/A4000/3653_R1.HTM), and Maryland (see The Marcellus Shale Safe Drilling Act of 2011 H.B. 852 (effective June 1, 2011, http://mlis.state.md.us/2011rs/fnotes/bil_0002/hb0852.pdf) instituted temporary moratoriums on hydraulic fracturing; Vermont recently banned the practice (see H. 464 [enacted May 16, 2012]).

and provides an example of one set of requirements—setback requirements—intended to protect local communities and sensitive resources from adverse drilling impacts to illustrate differing approaches across and among states.



Date: June 1, 2012
* Other includes: fracking fluid ingrediant disclosure, regulated land use, suit filed for fluid disclosure
** Other includes: memorializing resolution, wastewater dumping ban, enhanced ordinance, postponed vote, proposed ban, statement supporting ban

Figure 12. Variation in the rules for six states of rules covering natural gas fracking

States grappling with the issue of local control have adopted very different postures. At one end of the spectrum, Pennsylvania recently enacted legislation that places virtually all control over natural gas development in the hands of the state government.[116] This law, which went into effect April 16, 2012, elicited significant public opposition (Robinson 2012a; Robinson 2012b). A state court judge recently overturned those portions of the law restricting local governments from regulating oil and gas development on the basis that they unconstitutionally violate the substantive due process rights of local governments to enact zoning ordinances that protect the interests of neighboring property owners and neighborhood characteristics (Pellegrini 2012).

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[116] Act 13 supersedes all local ordinances purporting to regulate oil and gas operations, other than those adopted pursuant to the Pennsylvania municipalities and planning code and Flood Plain Management Act and provides that "all local ordinances regulating oil and gas operations shall allow for the reasonable development of oil and gas resources." Municipalities must allow "oil and gas operations, other than activities at impoundment areas, compressor stations and processing plants as a permitted use in all zoning districts." The Act allows for the location of well pads within 300 feet of existing buildings, unless the wellhead is less than 500 feet from any existing building. Under the Act, counties may require oil and gas operators to pay impact fees ranging from $40,000 to $60,000 for the first year of production adjusted based on natural gas prices and inflation thereafter. 58 Pa. Cons. Stat. § 3218.

The Corbett Administration filed an appeal of that decision which is set to be heard by the Supreme Court of Pennsylvania on October 17, 2012.[117]

New York's approach to local control represents the other end of the spectrum. In that state, 26 localities have banned natural gas development or hydraulic fracturing altogether, two of which have been upheld as valid exercises of local zoning authority (Dryden 2012; Middlefield 2012). In addition, two bills have been proposed in New York that would allow local governments to enact or enforce laws and ordinances relating to oil, gas, and solution mining.[118]

In Colorado, the issue of local control over oil and gas drilling has become an increasingly prominent subject of discussion. Earlier this year, the Governor formed a multi-stakeholder task force to address the issue. The task force ultimately recommended "coordinated regulation through a collaborative approach…" (CDNR 2012), but what this means in practice remains to be seen. Five bills related to the topic of local control were introduced in the most recent legislative session.[119] In addition, four localities in the Front Range have moved to delay drilling pending a review of their oil and gas, land use, and public health laws; a fifth locality is currently considering a moratorium.[120] To date, the result of these reviews has been one set of final regulations issued by the City of Longmont, draft regulations issued by Boulder County,[121] and one set of operator agreements.[122] The City of Longmont finalized its ordinance in July 2012. The ordinance includes riparian and residential setbacks, disclosure requirements, water testing, wildlife protections, and a ban on drilling in residential areas.[123] Boulder County's draft revisions also contain residential and riparian setbacks, water-testing requirements, emergency response, and other measures intended to protect public health such as air-pollution controls.[124] Shortly after Longmont issued its ordinance, the Colorado Oil and Gas Conservation Commission filed a lawsuit against the City of Longmont alleging that state law preempts a

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[117] Scott Detrow, *StateImpact*, "Corbett Administration Filed Act 13 Appeal with State Supreme Court" (July 27, 2012), http://stateimpact.npr.org/pennsylvania/2012/07/27/corbett-administration-files-act-13-appeal-with-state-supreme-court/.

[118] A8557 (Aug. 24, 2011) (authorizes local governments to address natural gas drilling in their zoning or planning ordinances); A3245 (Jan. 24, 2011) (would allow local governments to enact and enforce local laws/ordinances of general applicability).

[119] SB 088, introduced Feb. 16, 2012 (would have granted COGCC exclusive jurisdiction to regulate oil and gas operations); HB 1173, introduced Feb. 6, 2012 (would have required closed-loop systems for hydraulic fracturing fluid storage/containment); HB 1176, introduced Feb. 6, 2012 (would have mandated setbacks of at least 1000 feet from any school or residence in urban areas); HB 1277, introduced Feb. 20, 2012 (would have stated that oil and gas operators would be subject to the same local government control as for other types of mineral extraction, i.e., a shared state and local approach); SB 107, introduced May 5, 2012 (contained specific requirements, such as closed-loop drilling, water reporting requirements, and the prohibition of the use of carcinogens in hydraulic fracturing fluids).

[120] As noted above, these include Boulder County, Erie, Longmont, and Colorado Springs. At the time this chapter went to publication, the town of Lafayette, Colorado, was considering a temporary ban on oil and natural gas drilling. *NGI's Shale Daily*, "Another Colorado City Considering Drilling Restrictions" (September 6, 2012).

[121] At the time this Chapter went to publication, the Boulder County Planning Commission was considering proposed Land Use Code amendments to address drilling in the County. The City of Longmont finalized its oil and gas revisions to its Municipal Code, Ordinance O-2012-25, on July 17, 2012.

[122] Copies of the agreements are available on the Town of Erie's website, http://www.erieco.gov/CivicAlerts.aspx?AID=487 (last visited September 25, 2012).

[123] City of Longmont Ordinance O-2012-25 (July 17, 2012).

[124] Boulder County, Docket DC-12-0003: Amendments to Oil and Gas Development Regulations, http://www.bouldercounty.org/find/library/build/dc120003stafrecregs20120924.pdf.

number of the purported protections including the riparian and wildlife setbacks, residential well-site ban, disclosure rule, water-testing requirements, a requirement that operators use multi-well sites, and visual mitigation measures.[125] The Oil and Gas Conservation Commission has yet to take an official position on Boulder County's regulations. Nevertheless, the Commission's suit against Longmont may indicate that the approach recommended by the Governor's Task force earlier this year will tilt in favor of state rather than local regulation, with the amount of control retained by the local governments unclear.

Local governments across all states covered in this study are also seeking to impose additional setback requirements, but the governing state law on these requirements varies by jurisdiction. Local setback requirements that are more stringent than state law exist in the Barnett Shale play, Eagle Ford play, Marcellus Shale play in Pennsylvania, and North San Juan basin. There is considerable variety in setback requirements, as well as increasing public interest in this issue. Lack of consensus regarding the appropriate distance required to protect against adverse air, noise, visual, or water pollution may, in part, explain the continuing controversy over setback requirements (CU 2012). For a comparison of specific state and local requirements, see Table 30, Appendix C, Setback Requirements.

2.5 Best Management Practices

Various commissions and reports have stressed the need for continuous improvement in industry practices, as well as industry-led organizations dedicated to developing and disseminating information on best practices (SEAB 2011b; NPC 2011; IEA 2012). Technological innovation in the effort to control and mitigate some of the resource and environmental impacts of unconventional gas development can improve efficiency, reduce environmental risk, and bolster public confidence. As in many industries, leading operators in unconventional gas development have often performed at a level over and above existing regulatory requirements, providing important sources of innovation for new practices and regulations. Notably, a handful of important regulatory developments started as best management practices adopted by leading operators.

For example, as noted above, prior to EPA's adoption of its recent NSPS for the oil and gas sector, leading companies implemented reduced-emission completions ("green completions") to increase profits by maximizing sales of natural gas from the recovery of natural gas otherwise lost to the atmosphere; others voluntarily report chemicals used in hydraulic fracturing fluids to the Groundwater Protection Council's public FracFocus website.[126] Today, a number of companies are developing methods to recycle and reuse flowback and produced waters that reduce operator costs, as well as the risks associated with other forms of disposal.[127] As discussed in the following chapter, documenting such beyond-compliance best practices is an area that merits further study.

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[125] Colorado Oil and Gas Conservation Commission v. City of Longmont (filed August 30, 2012 in the Boulder County District Court).

[126] See Ground Water Protection Council Chemical Disclosure Registry, http://fracfocus.org/.

[127] See GIS Mapping Tool in Chapter 4 of this report.

2.6 Conclusion and Key Findings

The combination of hydraulic fracturing and horizontal drilling has been hailed by some as the most important energy innovation of the last century, with dramatic implications for the economics and politics of energy in the United States and throughout the world. This "disruptive" technology has fueled a boom in unconventional gas development in various parts of the United States over the last 10 years. Law and regulation (at multiple levels) have struggled to keep up with the rapid growth of the industry. And the contemporary legal and regulatory landscape that applies to unconventional natural gas development is complex, dynamic, and multi-layered.

The federal government has demonstrated a keen and growing interest in this area, as evident by the prominent role natural gas plays in the current Administration's energy policy (White House 2011), the formation of the SEAB Subcommittee, and the announcement or promulgation of a number of new rules related to air and water quality, data collection regarding the aggregate amounts of chemicals used in fracturing fluids, and development on public lands discussed above. Additional federal regulations and new legislation are also possible. The results of EPA's study on the effects of hydraulic fracturing on drinking water could play a key part in directing any such changes.

States will continue to serve as the major source of regulation, with primary responsibility for well-construction standards, disclosure requirements for hydraulic fracturing fluid chemicals and water used during well stimulation, baseline water-monitoring requirements, waste management, and overall compliance monitoring and enforcement. State and local requirements—other than disclosure requirements regarding chemicals and water usage—vary considerably, and this is likely to continue as more states revise their rules to respond to new development. Greater coordination between regulators at all levels of government could help to reduce uncertainty and fragmentation,[128] as would greater reliance on the expertise contained in organizations such as the State Review of Oil and Natural Gas Environmental Regulation and the Ground Water Protection Council (SEAB 2011a; SEAB 2011b).

State compliance monitoring and enforcement capabilities vary widely. The limited data that have been assembled indicate most violations are minor, but that "enforcement actions are sparse compared to violations noted" (Groat and Grimshaw 2012). Substantially more data and research are needed to understand the extent to which companies are complying with state, local, and federal requirements.

This information gap could begin to be filled by greater reporting, via self-certification requirements that are publicly available, as well as by state databases, searchable by the public, that contain compliance and enforcement records. These activities would also bring greater certainty to this issue.

A number of commissions and industry associations have expressed support for continued development and implementation of beyond-compliance measures (SEAB 2011b; NPC 2011; IEA 2012), and the need for such measures to avoid controversy, delay, and continued

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[128] For example, BLM's recent proposed rule notes the importance of consistency in federal and state disclosure requirements and the intent to provide consistency by lining up its requirements with those adopted in leading states.

opposition in certain parts of the country. As discussed in the following chapter, more work is needed to identify and evaluate such measures. Given the rapid pace of unconventional gas development in various parts of the country, best practices will have to complement regulation—and, in some cases, be folded into it. But as the regulatory landscape evolves, it will be important to establish a framework, where possible, that incentivizes the ongoing development and adoption of new state-of-the-art practices and technologies to minimize the risks associated with developing natural gas resources.

3 Key Issues, Challenges, and Best Management Practices Related to Water Availability and Management

3.1 Introduction and Objectives

Shale gas development has several categories of potential risks including air, water, land, and community (Figure 13). Examples of air risks include emissions of GHGs (largely methane) and hazardous air pollutants (e.g., benzene). Land impact risks include ecosystem degradation and land disturbance. Related to water, the risks are either quantity related (regional water depletion) or concerns of quality (surface or groundwater contamination). Community risks include excessive truck traffic and the noise, road damage, and other associated impacts. Induced seismicity is also considered a community issue and the broadest community risk from it could be the loss of the social license to operate (e.g., Energy Institute 2012; Robinson 2012; Zoback et al. 2010.)

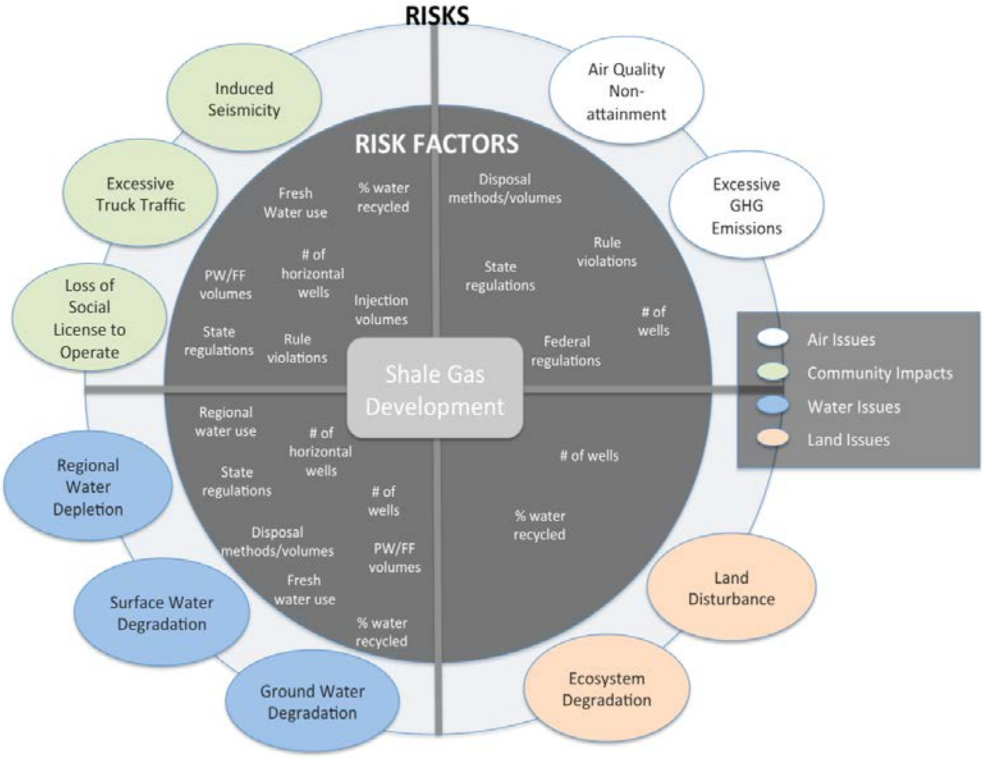

Figure 13. Description of shale gas development risks and characterization metrics

This chapter focuses on the risks and impacts of shale gas development on water resources. Ongoing improvement of the quality and quantity of water resource-related data will inform decisions related to shale gas development. Data collected in this chapter mark the beginning of the risk characterization needed to adequately define best management practices. Specifically, unconventional shale gas development might impact water resources through four major causal routes—one related to water quantity and three related to water quality.

- Water Quantity:
    - Regional water depletion due to large volumes of freshwater use for hydraulic fracturing
- Water Quality:
    - Surface and groundwater degradation resulting from inadequate construction practices and well integrity
    - Surface and groundwater degradation resulting from inadequate onsite management of chemicals used in hydraulic fracturing
    - Surface and groundwater degradation resulting from inadequate wastewater management practices

To better understand the risks to water resources from shale gas production, the variety of risk factors related to water need to be further defined and a thorough spatial and temporal characterization should be completed. The science regarding risks and impacts of the shale gas industry is relatively new and still in a state of flux (EDF 2012; IEA 2012). For this project, we approached the topic by using available literature studies, public databases, and industry interactions.

We established the following objectives to assess the risks to water resources:

- Understand the quantities of water currently being used in six shale plays in the United States as they relate to current estimates of water availability and existing water uses
- Understand the quantities of flowback and produced water for each shale play and the wastewater management techniques employed
- Identify Best Management Practices, including quantity and quality impacts and costs

To accomplish these objectives, we studied six unique natural gas producing regions of the country (as identified in Chapter 2) to capture the spatial variability of water use, water availability, and wastewater management (see Table 8). The six regions include a coalbed methane (CBM) basin (North San Juan); a vertically fractured tight sand basin (Upper Green River); three primarily dry gas shale formations (Barnett, Haynesville, and Marcellus); and one shale formation that is producing condensates and oil along with natural gas (Eagle Ford).

3.2 Importance of Water for Shale Gas Development

The recent expansion of shale gas development is, in part, due to advances in horizontal drilling and hydraulic fracturing. As shale gas development continues to grow rapidly across the U.S., the demand for water used during site operations is also expected to increase (COGCC 2012b). Drilling and fracking operations involved in shale gas development require millions of gallons of water per well that must be acquired and transported to sites to fracture the shale formations (EPA 2011). Hydraulic fracturing is essential for tight formations such as shale because the geological structure does not have the necessary permeability to allow natural gas to flow freely through the formation and into a wellbore (Arthur 2011). The current development of unconventional shale gas would not be economically viable without hydraulic fracturing, making it important to have an adequate, dependable supply of water to support fracking operations. Equally important is preventing fracking operations from negatively affecting a region's water resources, both in terms of quantity and quality.

Water used in hydraulic fracturing comes from several sources including surface water, groundwater, municipal potable water supplies, or reused water from other water sources (Veil 2010). To date, freshwater has been used for most hydraulic fracturing operations in most regions (Nicot 2012). Surface water, such as streams, rivers, creeks, and lakes, are the largest source of fresh water for operators in the Eastern United States. Groundwater can be a feasible source of water, but only when sufficient amounts are available. In Texas, groundwater is more commonly used than surface water. Public water supply might be an alternative in some regions, because permits for surface and groundwater can take more time to secure.

The impact of water usage will depend on the availability of local water resources, which can vary regionally depending on the geographic location of the shale play, ground and/or surface water sources, and competing demands for water from other users. In locations vulnerable to droughts, operational water needs could adversely impact the viability of gas production from tight formations (Vail 2010). Droughts, particularly in water-stressed regions (such as the arid Southwest), can limit the amount of available water, increasing the competition for water between potable water supplies, water for agriculture, and water for fuel.

3.3 Assessment of Risks to Water Quantity and Water Quality

Shale gas development may incur risks to both regional water quantity and quality. Quantity-related risks depend on the number of wells drilled, water use per well, amount of recycling or non-potable water use that occurs to offset freshwater demands, and local water availability. Quality-related risks depend on onsite construction techniques, onsite chemical management practices, and wastewater management practices. Risks may vary for any given shale gas development site. In many cases, risks to water resources extend beyond the location of the well being drilled, depending on the source location of the water and where wastewater is treated. Figure 14 shows the various risks to water resources that can result from hydraulic fracturing operations.

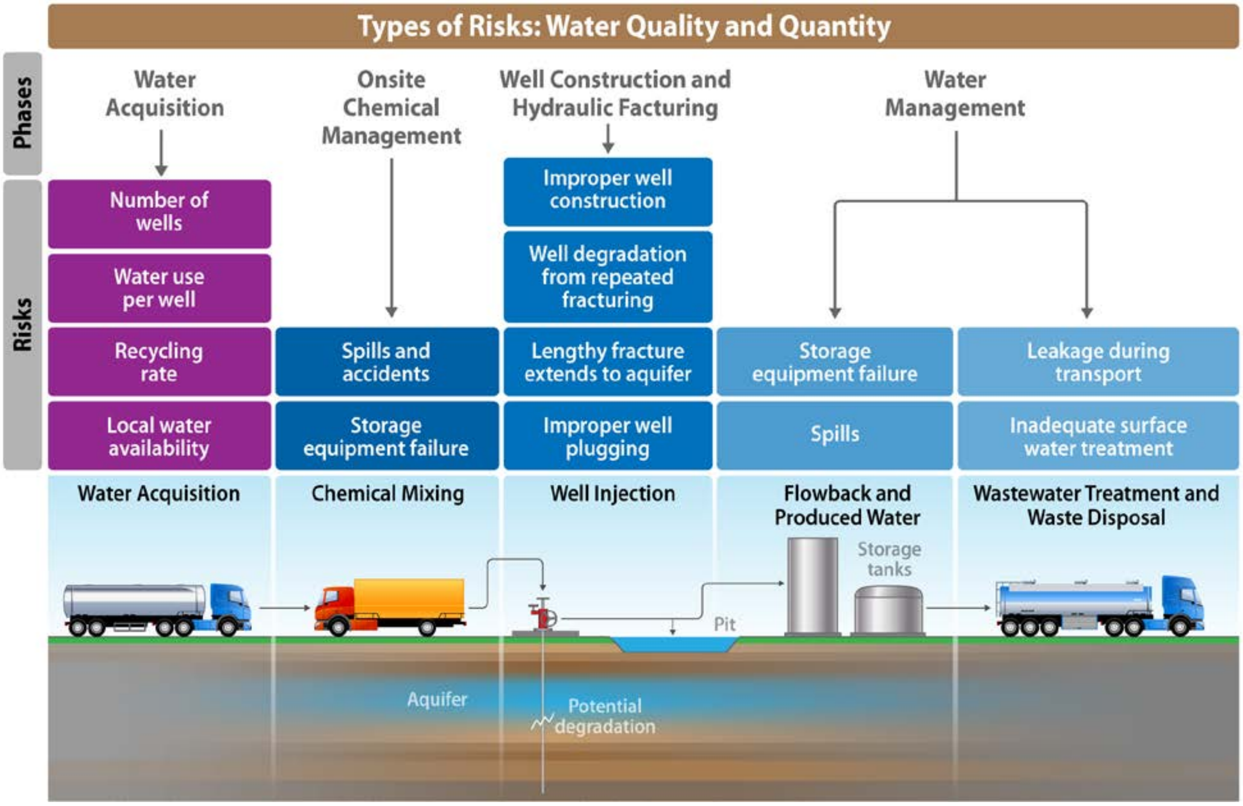

Figure 14. Water quality risks by phase of natural gas production.[129]

3.3.1 Risks to Water Quantity

3.3.1.1 Current Industry Activities Affecting Water Use

A crucial component of hydraulic fracturing is securing a sufficient amount of water for operations. Water may not always be available on the lease site; therefore, developers may have to obtain access to water from a different location and transport water to the site. In such cases, the risks to water resource quantities are assessed with respect to the water's source location, not to where it is eventually used. Where operators source their water depends on several factors, such as location, availability, timing, and cost. The closer a water source is to a well, the lower are the operational costs, whether it be pumping or transporting the water by truck.[130] In many cases, the total amount of water required for multiple operating wells (and the permits required) will be greater than local daily flows. For example, in Pennsylvania, the Susquehanna River Basin Committee (SRBC), which oversees all water source permits in the basin, has approved permits totaling 108 MGD (million gallons per day) at 151 locations (as of September 1, 2011), whereas the estimated peak daily withdrawal of those locations is only around 30 MGD. This means that freshwater impoundments might need to be constructed to collect and store water over a period of time to eventually be used to supply water for drilling and developing multiple wells (SRBC 2012).

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[129] Graphic adapted from (EPA, 2011).

[130] Trucks can often have an impact on rural roads, both in terms of increased traffic and increased wear on roads. Analysis of these impacts is beyond the scope of this paper.

Total water use at a shale gas development site depends on the number of wells drilled, water use per well, and amount of recycling that occurs. The term water "use" is used in this chapter, which, in part, reflects the ambiguity of whether the water usage reported in publicly available sources represents freshwater withdrawals, use of freshwater along with recycled water, water consumption, or a combination of these categories. Future research could clarify the definitions of water usage reported by industry.

Number of wells

In the areas for which data are available, the number of producing wells drilled each year has been increasing since 2009 (Figure 15).

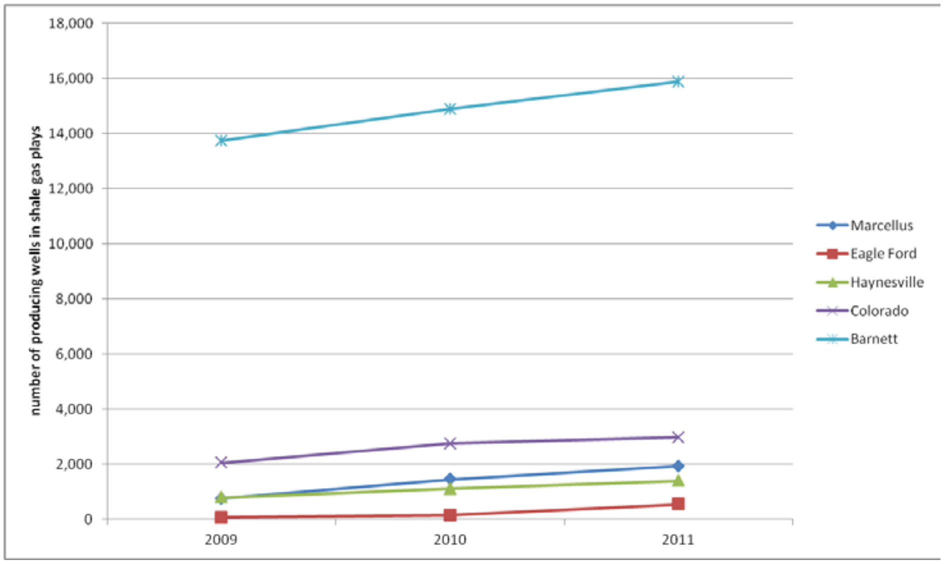

Figure 15. Total number of producing wells in shale gas plays, 2009–2011 (TRRC 2012c; COGCC 2012b; LADNR 2012; PA DEP 2012a; Eagle Ford Shale 2012).

The greatest number of wells is in the Barnett Shale formation, increasing 16% from 2009 to 2011, with nearly 16,000 producing wells (TRRC 2012c). In the other formations considered in this study, the total numbers of wells are smaller, but have been increasing faster. From 2009 to 2011, the total number of wells increased by 45% in Colorado (COGCC 2012b), 76% in the Haynesville formation (LADNR 2012), 154% in the Marcellus formation (PA DEP, 2012a), and 721% in the Eagle Ford formation (Eagle Ford Shale 2012). In all of these formations, well drilling applications have continued to increase each year, indicating a continued trend for the near future.

Water use per well

Data on the water usage per well were available for five of the six regions considered here. Data from about 100 nominal wells were randomly collected for four regions (Marcellus, Barnett, Eagle Ford, and Haynesville) from www.fracfocus.org, a voluntary online chemical disclosure registry of the water used for fracturing. FracFocus provides statewide and county-wide data. Well data are classified according to their API number, county, fracture date, operator name, well name, well type (Oil/Gas), latitude, longitude, datum, and total water use (including fresh water, produced water, and/or recycled water). Water use statistics are compiled and are displayed in Appendix D.

Average water use from the 100-well study in the five regions ranges from 1.1 to 4.8 million gallons per well, with a multi-region average of 3.3 million gallons per well (Figure 16).

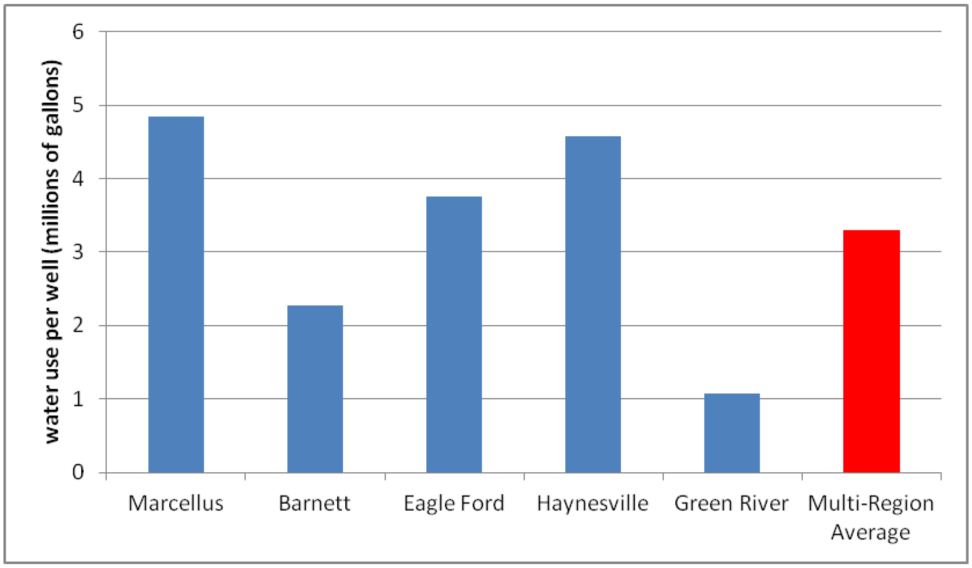

Figure 16. Average water use per well (in millions of gallons) for five regions (2011) (Fracfocus.org).

The Barnett, Eagle Ford, and Green River formations had average water uses of less than 4 million gallons per well, and the Marcellus formation had the highest average water use of 4.8 million gallons per well. Furthermore, considerable variation in water use per well within each formation is shown in Figure 17.

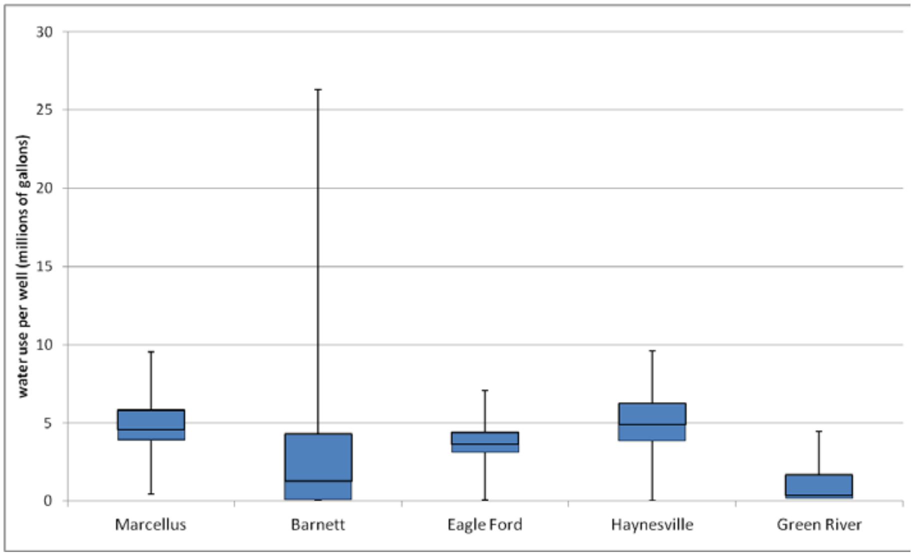

Figure 17. Water use per well for four formations, in millions of gallons. (fracfocus.org)

Note: Low and high error bars represent minimum and maximum reported water usage per wells, respectively. Upper and lower ends of boxes represent 75th and 25th percentile, respectively. Horizontal lines in boxes represent medians.

Results of the 100 well analyses indicate that water usage per well can vary by up to three orders of magnitude (29,000 gallons to 26 million gallons per well in the Barnett formation) depending on geology, type of well and drilling techniques, and industry practices. Median estimates of water usage per well are around five million gallons for the Marcellus, Eagle Ford, and Haynesville formations, yet individual wells can vary greatly. The Barnett formation has the second lowest median value of 2.3 million gallons per well, yet also the highest individual well value of 26 million gallons per well. These statistics do not indicate whether a portion of the water utilized for hydraulic fracturing includes recycled water.

Recycling rates

The impacts on local freshwater resources can be reduced by recycling produced water and frac flowback water. To use wastewater, a series of steps are commonly employed (Mantell, 2011). The water must often be stored in onsite holding tanks before treatment and is filtered or transported to another storage tank to test its remaining constituents. The water is then pumped or otherwise transported to another well location for reuse. Currently, only Pennsylvania tracks the amount of produced water and frac flowback water being recycled for reuse for drilling and hydraulic fracturing operations. Other states considered in this analysis do not have recycling or reuse as a category in their annual reporting forms, yet recycling may be occurring. In Pennsylvania, recycling of produced water has increased from 9% in 2008 to 37% in 2011 (PA DEP 2012b). In general, recycling of frac flowback water has increased from 2% in 2008 to 55% in 2011. In 2011, based on data reported, this recycling led to the reuse of about 65,000 gallons of produced water per well and 120,000 gallons of frac flowback water per well (Figure 18).

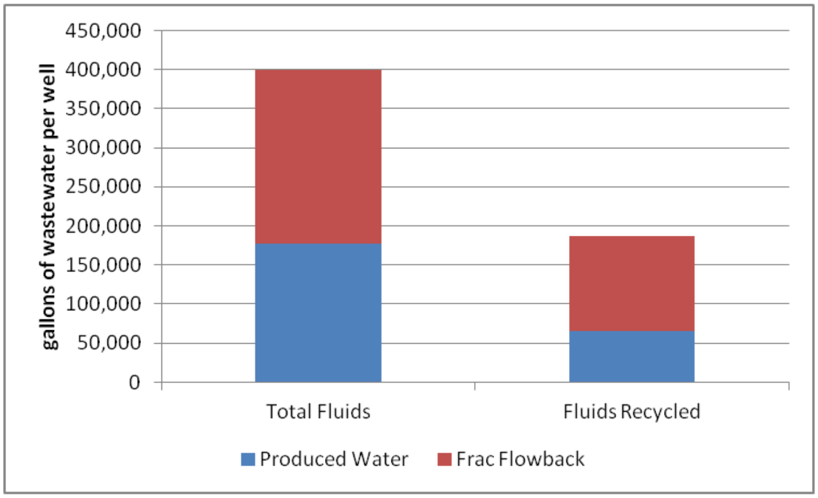

Figure 18. Wastewater production and total recycling at shale gas operations in Pennsylvania in 2011 (PA DEP 2012b)

Although data are not available for recycling rates in other formations, certain state organizations actively encourage recycling practices. The Railroad Commission (RRC) of Texas has provided authorization for seven recycling projects in the Barnett formation, five of which are still active (TRRC 2012d). No recycling authorizations have been given for the Eagle Ford or Haynesville formations to date. The Colorado Oil and Gas Conservation Commission (COGCC) actively encourages reuse and recycling of water used in well construction as well as produced water. Although there are no data of quantities, the COGCC notes that several operators in the Piceance Basin have constructed infrastructure for reusing water for drilling and completing new wells (COGCC, 2012b).

The feasibility of recycling and reusing produced water and frac flowback depends, in part, on how much and how quickly water returns to the surface. In the Marcellus and Barnett shale formations, Chesapeake Energy reports that about 500,000 to 600,000 gallons per well will return to the surface in the first 10 days, compared to about 250,000 gallons per well in the Haynesville formation (Mantell, 2011). How much of the produced water can be recycled depends on the chemical composition of the water, including its total dissolved solids (TDS), total suspended solids (TSS), and its concentration of chlorides, calcium, and magnesium. High TDS can increase unwanted friction in the fracking process. High TSS can plug wells and decrease the effectiveness of biocides. High concentrations of other elements can lead to high risks associated with scaling.

Recycling produced water and frac flowback can partially reduce the demand for freshwater sources for new hydraulic fracturing operations. The reduction in freshwater demand is limited by the amount of water that is returned to the surface. In general, the amount of water returned to the surface—and thus, the amount of water that could be recycled—is on the order of 10% of the freshwater requirements for developing a well with hydraulic fracturing. The volumes of produced water may vary widely from well to well, making it difficult to predict how much water is produced and how much recycling potential there is for each well.

Water availability

Local water availability conditions in the six study regions can vary greatly. Further information of each shale region can be found in Appendix D. An overview of the six regions is shown in Figure 19.

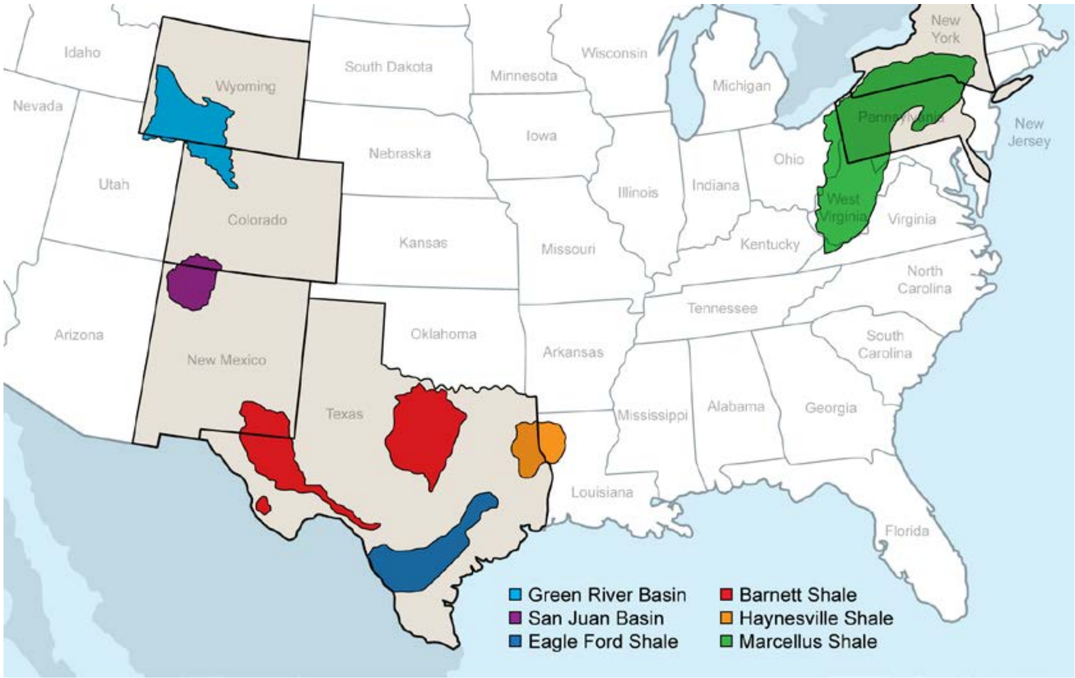

Figure 19. Six shale plays considered in this study.

Marcellus Shale, PA

The Marcellus Shale is located within or nearby highly populated areas of the northeast U.S. occupying the states of New York, Pennsylvania, Maryland, West Virginia, and Ohio. Competition for water might be challenging for shale gas development. However, the area overlying the Marcellus Shale formation has abundant precipitation, making water readily available (Arthur 2010). Three major watershed basins overlie the formation: the Susquehanna, Delaware, and Ohio River Basins are the main suppliers of water for shale gas development. The Marcellus Shale is overlain by about 72% of the Susquehanna River Basin (SRB), 36% of the Delaware River Basin, and about 10% of the Ohio River Basin (Arthur 2010). The SRB drains 27,510 square miles, covering about half the land area of Pennsylvania and portions of Maryland and New York (Arthur 2010). Major streams and rivers in the SRB are potential surface water withdrawals for shale gas development.

Texas water

Texas has dominated shale gas production in the U.S. over the past decade. The Barnett Shale was the sole producer in the early 2000s and accounted for about 66% of the U.S. shale gas production from 2007 to 2009 (Nicot 2012). Texas is subject to drought and wet period cycles that might become extreme with climate change and impact the water available. Water requirements are reported to the RRC of Texas. Surface water is owned and managed by the State and requires a water-right permit for diversions. Groundwater is owned mostly by landowners, but is generally managed by legislatively authorized groundwater conservation districts (Nicot 2012). Groundwater is generally available in each of the shale gas plays, and unlike surface water, groundwater is located close to production wells.

Barnett Shale, TX

The Barnett Shale is located in central Texas around the Dallas-Ft. Worth area. Precipitation is variable across the state of Texas. The mean annual precipitation in the Barnett area is about 790 mm per year (Nicot 2012). About 60% of the water used in hydraulic fracturing operations in the Barnett Shale play comes from groundwater sources, specifically the Trinity and Woodbine aquifers in North Central Texas (Andrew et al. 2009). The Trinity Aquifer extends from south-central Texas to southeastern Oklahoma, and groundwater use varies across the Barnett Shale development area. For example, groundwater provides about 85% of total water supply in Cooke County, but only 1% for Dallas County (Andrew et al. 2009). Extensive development of the Trinity Aquifer in the Dallas-Ft Worth metropolitan area had caused groundwater levels to drop more than 500 feet in some areas (Andrew et al. 2009). For many rural areas, groundwater from the Trinity Aquifer remains the sole water source. Water use can vary widely from county to county depending on the pace of shale gas development. Municipal water use is dominant (greater than 85%) in the footprint of the Barnett Shale play in Denton and Tarrant counties; elsewhere, water use is mixed with some irrigation and manufacturing (Nicot 2012). Surface water is available in the Barnett Shale area, including major rivers and reservoirs; however, population growth is expected to increase demand for water resources and cause increasing competition. It is predicted that the net water use for shale gas production in the Barnet Shale play will increase from 1%–40% at the county level for selected counties (Nicot 2012).

Eagle Ford Shale, TX

The Eagle Ford Shale play is located in South Texas. The mean annual precipitation in the Eagle Ford Shale is about 740 mm per year (Nicot 2012). Surface water in the Eagle Ford Shale region is not as readily available and abundant as the northeast sections of Texas. A small portion of the Rio Grande River at the Mexican border is used, and several streams are ephemeral and recharge underlying aquifers. However, even when surface water is available, it is often not located adjacent to sites; therefore, trucking and piping of water is often required. Operators rely mostly on groundwater from the Carrizo Aquifer, though groundwater has already been partially depleted for irrigation in the Winter Garden region of South Texas (Nicot 2012). Over-extraction of groundwater for irrigation in the past limits water availability for current and future shale gas production (Nicot 2012). Water used in south Texas is variable; municipal water use is dominant (greater than 85%) in the footprint of the Eagle Ford in Web County (Nicot 2012). It is predicted that during the peak years of production, the net water use for shale gas production in the Eagle Ford Shale region will increase from 5% to 89% at the county level for selected counties (Nicot 2012).

Haynesville Shale, LA

The Haynesville Shale is located in East Texas and western Louisiana. The eastern part of Texas has high precipitation, with a mean annual precipitation of 1,320 mm per year, resulting in a widespread and abundant supply of surface water (Nicot 2012). The region also hosts large aquifers, specifically, the Carrizo Wilcox and Queen City/Sparta Aquifers. Shale gas production in Louisiana relies heavily on local groundwater from the Carrizo Aquifer and currently derives about 75% of the water from surface water or lesser-quality shallow groundwater (Nicot 2012). The groundwater is more readily available in East Texas, with the only competition for water use being industrial and municipal demands (Nicot 2012). Furthermore, it is predicted that during the peak years of production, the net water use for shale gas production in the Haynesville Shale region will increase from 7% to 136% at the county level for selected counties (Nicot 2012).

San Juan Basin, CO

The San Juan Basin is located in the arid Southwest U.S., occupying the Four Corners area of Colorado, New Mexico, Arizona, and Utah. The basin is characterized by a wide range of topographic settings that include valleys, canyons, badlands, uplands, mesas, and buttes (Haerer 2009). Precipitation in the San Juan Basin varies regionally. Annual precipitation in the high mountain areas in Colorado can receive as much as 1,020 mm per year, whereas annual precipitation in lower altitudes of the central basin in New Mexico can receive less than 200 mm per year (Levings 1996). Runoff water from snow and precipitation, which flows into rivers such as the San Juan River, makes up a large portion of the surface water. However, because of high evaporation rates and the hot and dry climate of the Southwest, surface water in the basin is limited and has already been fully appropriated.

Thus, groundwater resources tend to be the only source of water in most of the basin, and they are used mainly for municipal, industrial, domestic, and stock purposes (Levings 1996). The San Juan structural basin is a major oil and gas producing area, and groundwater is produced as a byproduct of these operations (Levings 1996). Several major aquifers exist in the basin; most are unconfined and located within the Tertiary formations (Haerer 2009). The amount of available water varies, depending on the underlying geological rock formations. For example, the Fruitland Formation and Pictured Cliffs Sandstone are aquifers that are sources of drinking water along the northern margin of the basin and act as a single hydrologic unit. The Ojo Alamo Sandstone is the primary aquifer for the southern margins and is a possible source of groundwater (EPA 2004). Groundwater levels in the Fruitland Formation have declined significantly due to the development of energy resources in the San Juan Basin (Levings 1996).

Green River Basin, WY

The Green River Basin is located in the southwest corner of Wyoming, northwest Colorado, and northeast Utah. The basin drains to the Green River, a major tributary to the Colorado River. On average, the basin receives about 250–400 mm of precipitation annually and less than 13% of the basin receives more than 500 mm (WWDC 2010). Precipitation is highest during the months of April and May and the least in December and February. There are four regional aquifer systems in the Wyoming side of the Green River Basin. The Cenozoic, Mesozoic, Paleozoic, and Precambrian aquifer systems range from the youngest and most heavily used to the oldest and least used, respectively (WWDC 2010). There has been relatively little development of groundwater resources in the Green River Basin, and the recent increase in shale oil and gas development has relied on groundwater resources as the primary supply to the industry. In Wyoming, irrigated agriculture is the largest water consumer. However, the energy and mineral sectors have historically added volatility in water use and allocation, requiring large amounts of water (WWDC 2010). Groundwater in the basin is used for domestic and pubic supplies, and industrial uses including mining and irrigation. Oil and gas development has increased substantially in the Green River Basin and accounts for a large part of the increase in groundwater use (WWDC 2010).

3.3.1.2 Current Water Quantity Risks Resulting from Industry Activities

Risks to water quantity resulting from industry practices in shale gas development include reductions in both available surface water and groundwater. These risks occur in the areas from which water resources are sourced, not necessarily the hydraulic fracturing site. In areas where the levels of the groundwater table are already affected by multiple sectors' uses (e.g., agriculture, municipal water supply), large increases in use by any sector might affect water availability or the cost of pumping for all other users.

The water quantity risk to any given water basin depends on how much water is used and on the local water availability. Water usage in shale gas development, as described above, depends on the total number of wells, water use per well, and recycling rate. Water availability depends on local geologic and climatic conditions and on competing users of water. In the study regions, the total number of producing wells has been increasing steadily since 2008. With the exception of Pennsylvania, there are no data indicating a substantial increase in the recycling rate of wastewaters, and the total quantities of freshwater used for hydraulic fracturing have been increasing. The impact of recycling on reducing freshwater demands is limited by the amount of flowback and brine produced from each well. The use of non-freshwater sources, such as shallow brackish waters, could alleviate demands on freshwater; but there are no readily available data on availability or current usage of these water sources for shale gas operations.

Values of total water available physically and legally can be difficult to quantify, but our report analyzes the water usage of oil, gas, and mining activities as a percentage of all other existing water uses. On a state level, the amount of water currently withdrawn for hydraulic fracturing is a relatively minor fraction of total water withdrawals. In Colorado for example, total water diversions for hydraulic fracturing represent only 0.1% of all water diversions in the state (COGCC 2012b). In Texas, mining activities, which include hydraulic development, accounted for just 2% of total water withdrawals in 2011 (TDWB 2012).In Texas and Colorado, irrigation accounts for more than 55% and 85%, respectively, of total water withdrawals (COGCC 2012b; TDWB 2012).

Greater insights into risks to water resources can be gained by analysis on a geospatial scale smaller than the states, such as the county level. In many counties where shale gas development sites are located, mining activities already account for a substantial percentage of existing water usage (Figure 20) (Kenny et al. 2009).

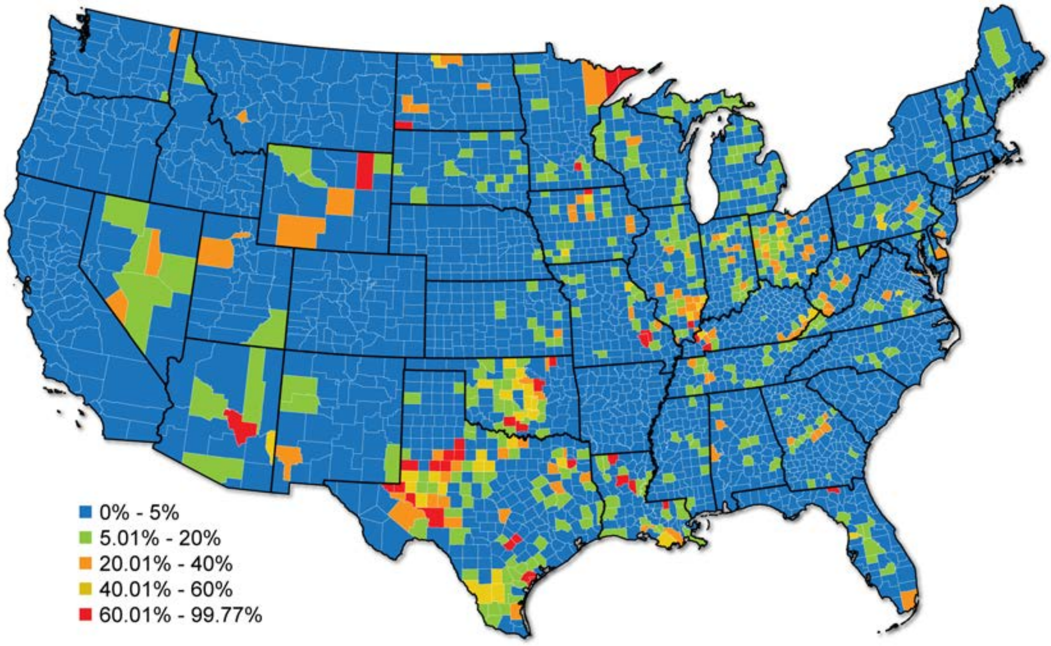

Figure 20. Mining water withdrawals as a percent of total water withdrawals, 2005 (Kenny 2009).

In 2005, mining activities in Texas counties that overlapped with the Barnett, Eagle Ford, and Haynesville formations accounted for a large percentage of total water withdrawals. Similarly, counties in Louisiana overlapping with the Haynesville formation, counties in New Mexico overlapping with the Barnett and San Juan formations, and counties in Wyoming overlapping with the Green River formation show that mining activities account for water withdrawals representing 5% to over 60% of total withdrawals in that county. Thus, water use for mining activities already represents a substantial portion of total water usage in the regions where shale gas development is occurring. Rapid expansion of water required for hydraulic fracturing could impact local water availability, depending on water resources in each region. Further research is needed to evaluate the impact that the current and projected water use for mining activities, including hydraulic fracturing, could have on the water resources and other water demands in these regions.

3.3.2 Risks to Water Quality

3.3.2.1 Current Industry Activities Affecting Water Quality

Risks to water resources depend on well and drilling construction practices, handling of chemicals on site, and wastewater management. Risks to water quality can occur at both the location of hydraulic fracturing and where water is stored or treated.

Onsite well-construction and hydraulic fracturing practices

In terms of risk to water resources, well design and construction phase is a crucial component of the hydraulic fracturing process. Proper well construction can separate the production operations from drinking water resources. Well construction involves drilling, casing, and cementing—all of which are repeated multiple times until a well is completed. Drilling is conducted with a drill bit, drill collars, drill pipe, and drilling fluid such as compressed air or a water- or oil-based liquid (EPA 2011). Water-based liquids typically contain a mixture of water, barite, clay, and chemical additives (OilGasGlossary.com 2010). Once removed from the well, drilling liquids and cuttings must be treated, recycled, and/or disposed of.

Casing is steel pipe that separates the geologic formation from the materials and equipment in the well, and that also provides structural support. The casing is designed to withstand the external and internal pressures during the installation, cementing, fracturing, and operation of the well. Some operators might forego casing, in what is called an open-hole completion, if the geologic formation is considered strong enough structurally to not collapse upon itself. Casing standards vary regionally and are set by state regulations. Once the casing is in place, a cement slurry is pumped down the inside of the casing and forced between the formation and the casing exterior. The cement serves as a barrier to migration of fluids up the wellbore behind the casing, as well as a structural support for the casing. The cement sheath around the casing and the effectiveness of the cement in preventing fluid movement are the major factors in establishing and maintaining the mechanical integrity of the well; however, even a properly constructed well can fail over time due to stresses and corrosion (Bellabarba et al. 2008). For a given well, there may be multiple levels of drilling, casing, and cementing to prevent contamination of local water resources (Figure 21).

Once the well is constructed, the formation is hydraulically fractured. The hydraulic fracturing occurs over selected intervals where the well is designed to permit fluids to enter the formation. Hydraulic fracturing fluids, by volume, are mostly water and propping agents such as sand, designed to facilitate the fracturing and keep the new fractures open.

The chemicals present in hydraulic fracturing fluids can react with naturally occurring substances in the subsurface, causing these substances to be liberated from the formation (Falk et al. 2006; Long and Angino 1982). These naturally occurring substances include formation fluids (brine), gases (natural gas, carbon dioxide, hydrogen sulfide, nitrogen, helium), trace elements (mercury, lead, arsenic), radioactive materials (radium, thorium, uranium), and organic materials (organic acids, hydrocarbons, volatile organic compounds).

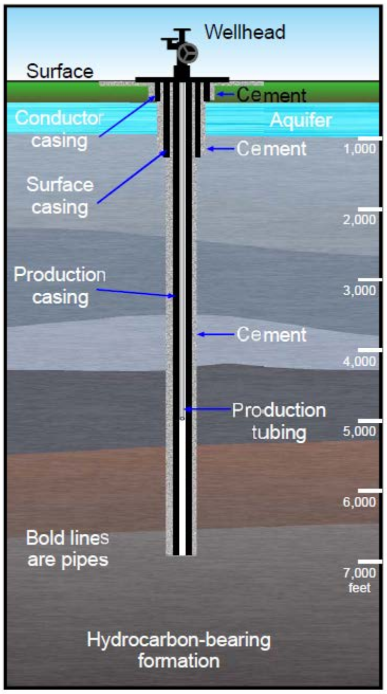

Figure 21. Schematic of well that includes several strings of casing and layers of cement (EPA 2011)

Once a well is no longer producing gas economically, it can either be re-fractured or plugged, to prevent possible fluid migration that could contaminate soils or waters (API 2009). A surface plug is used to prevent surface water from seeping into the wellbore and migrating into groundwater resources.

Onsite handling of chemicals

The chemicals used in fracking fluids are often mixed together on site with the propping agent (usually sand) and water. The types of chemicals and their volumes might vary from site to site and from developer to developer, depending on formation properties and developer common practices. Chemicals are stored on site in tanks before mixing and hydraulic fracturing operations begin. In general, 0.5% to 2% of the total volume of fracking fluid is made up of chemicals (GWPC and ALL Consulting 2009). The composition and relative amounts of chemicals might change from site to site. Table 6 provides an example of the variety and amounts of chemicals that comprise fracking fluid, where chemicals contribute 0.5% of the volume.

Table 6. Example Composition of Hydraulic Fracturing Fluids (GWPC and ALL Consulting 2009; API 2010)

Component	Example Compounds	Purpose	Percent Composition (by Volume)	Volume of Component (Gallons)[131]
Water		Deliver proppant	90	2,970,000
Proppant	Silica, quartz sand	Keep fractures open to allow gas flow out	9.51	313,830

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[131] Based on the average water use per well identified in this study, 3.3 million gallons

Component	Example Compounds	Purpose	Percent Composition (by Volume)	Volume of Component (Gallons)[131]
Acid	Hydrochloric acid	Dissolve minerals, initiate cracks in rock	0.123	4,059
Friction Reducer	Polyacrylamide, mineral oil	Minimize friction between fluid and pipe	0.088	2,904
Surfactant	Isopropanol	Increase viscosity of fluid	0.085	2,805
Potassium Chloride		Create a brine carrier fluid	0.06	1,980
Gelling Agent	Guar gum, hydroxyethyl cellulose	Thicken fluid to suspend proppant	0.056	1,848
Scale Inhibitor	Ethylene glycol	Prevent scale deposits in pipe	0.043	1,419
pH Adjusting Agent	Sodium carbonate, potassium carbonate	Maintain effectiveness of other components	0.011	363
Breaker	Ammonium persulfate	Allow delayed breakdown of gel	0.01	330
Crosslinker	Borate salts	Maintain fluid viscosity as temperature increases	0.007	231
Iron Control	Citric acid	Prevent precipitation of metal oxides	0.004	132
Corrosion Inhibitor	N,N-dimethyl formamide	Prevent pipe corrosion	0.002	66
Biocide	Glutaraldehyde	Eliminate bacteria	0.001	33

In this example, we consider the average water use per well as identified in this study to be 3.3 million gallons. Therefore, the total volume of chemicals used—0.5% of the fracking fluid volume—is about 16,500 gallons per well. The total average volume of chemicals used in hydraulic fracturing fluids ranges from 5,500 to 96,000 gallons per well, given the wide range of water use per well, in addition to the chemical composition (Table 7).

Table 7. Estimates of Total Gallons of Chemicals Used per Well

	4.6 million gallons per well (average estimate)	2.3 million gallons per well (low estimate)	7.3 million gallons per well (high estimate)
Lower bound of chemical composition (0.5% of volume)	16,500 gallons	5,500 gallons	24,000 gallons
Upper bound of chemical composition (2.0% of volume)	66,000 gallons	22,000 gallons	96,000 gallons

Wastewater management practices

After hydraulic fracturing operations, pressure decreases and fluids return to the surface before the well begins formal gas production. Although there are no standardized definitions, the used fracking fluids (frac flowback) and naturally occurring water resources (produced water) both return to the surface. In general, the frac flowback returns first at high rates (e.g., ~100,000 gallons per day) for a few days; then produced water surfaces at lower rates for the remainder of the well's lifetime (e.g., ~50 gallons per day). The rates of production and total volumes of frac flowback and produced water vary greatly within and between shale plays—ranging from 10% of original fracking fluid volume to as high as 75% (EPA 2011). Frac flowback and produced water both contain naturally occurring substances, including oil, gas, radionuclides, volatile organic compounds, and other compounds that could contaminate local water resources.

Frac flowback and produced water are stored on site in storage tanks or impoundment pits prior to treatment, recycling, and/or disposal (GWPC 2009).Onsite impoundments can be designed for short-term use (for storage purposes) or for long-term use (evaporation pits), and impoundment regulations and requirements can vary greatly by location.

Operators have a variety of options for managing wastewaters, including recycling and reusing, onsite evaporation in impoundments, onsite injection into wells, disposal at a centralized facility through evaporation or underground injection, and treatment through surface water treatment plants. Overall, national disposal methods are dominated by underground injection (EPA 2011). Current industry practices might vary from state to state, and have shown different trends from 2008 to 2011. For example, Colorado (Figure 22) and Pennsylvania (Figure 23) show stark differences and trends.

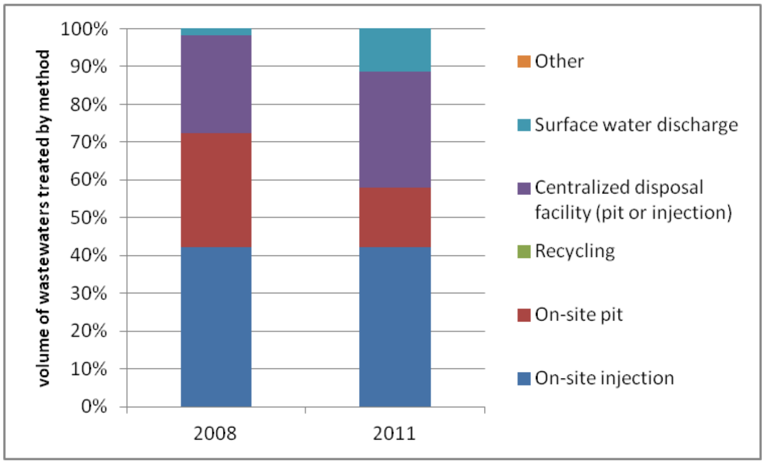

Figure 22. Colorado wastewater treatment methods, 2008–2011 (COGCC 2012a)

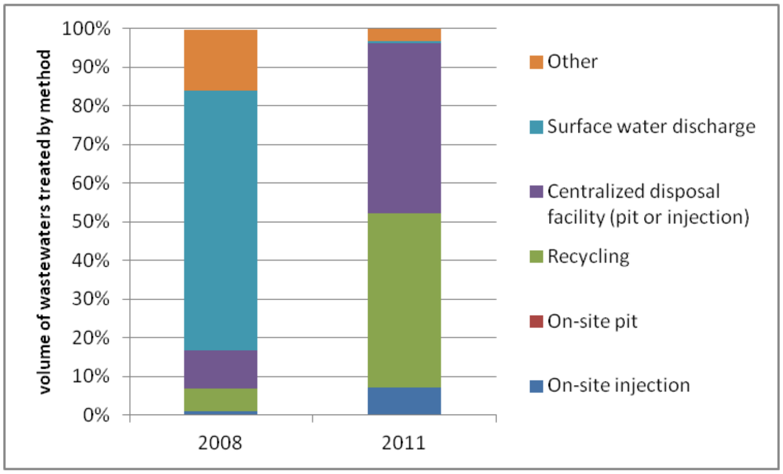

Figure 23. Pennsylvania wastewater treatment methods, 2008–2011 (PA DEP 2012b)

In Pennsylvania, surface water treatment decreased from 67% of total wastewater volumes in 2008 to less than 1% in 2011 (PA DEP 2012b). In contrast, in Colorado, surface water treatment increased from 2% of total wastewater volumes in 2008 to 11% in 2011 (COGCC 2012a). In Pennsylvania, recycling increased from 6% of total wastewater volumes in 2008 to 45% in 2011, whereas there are no data indicating any recycling occurring in Colorado. The dominant disposal method in Colorado remains injecting or evaporating wastewater fluids on site. Onsite disposal methods decreased in Colorado, managing 72% of total wastewater volumes in 2008 to 58% in 2011. In Pennsylvania, onsite well injection increased from 1% of total wastewater volumes in 2008 to 7% in 2011. Both states increased their use of centralized industrial disposal facilities between 2008 and 2011. In Pennsylvania, the use of centralized disposal facilities increased from 10% of total wastewater volumes in 2008 to 44% in 2011. In Colorado, the use of centralized disposal facilities increased from 26% of total wastewater volumes in 2008 to 31% in 2011.

Water disposal methods can change from year to year due to evolving regulations and industry experience. Data from 2008 showed a high percentage of surface water discharge for wastewaters in Pennsylvania; after 2008, there was a sharp decline. This is due to the changes to the Pennsylvania Department of Environmental Protection's (DEP) 25 Pa Code Chapter 95 Wastewater Treatment Requirements. These requirements were changed on April 11, 2009, after total dissolved solids levels were measured far above environmentally healthy levels in 2008 and 2009 (STRONGER, 2010). The high TDS was above drinking water standards in the Monongahela River. The TDS also promoted golden algae growth, resulting in higher toxicity levels in Drunkard Creek, killing over 30 different species of aquatic life. The new regulations required a maximum TDS discharge of 500 mg/L (STRONGER, 2010). This new regulation makes it uneconomical to use municipal water treatment in Pennsylvania because wastewaters can reach up to 360,000 mg/L TDS (USGS 2002b). In addition, injection has remained relatively unfavorable in Pennsylvania because the state has only eight Class II underground injection wells, three of which are commercially owned. The other injection wells are privately owned and only service the companies that own them (Phillips 2011).

Recycling operations can be more expensive than other waste management options. Recycling and reuse of water involves energy for treatment, and costs associated with storing water, transport of water, and transport and disposal of the solid wastes removed from the treated water.

In contrast, injecting wastewater into wells only involves the transport of water to an injection well and fees for the disposal. Recycling options can also be limited by high concentrations of materials that make recycling uneconomic.

3.3.2.2 Current Water-Quality Risks Resulting from Industry Activities

Risks to public water quality resulting from industry practices include risks to both surface water and groundwater sources, and they are not limited to the location of the hydraulic fracturing operation. Risks to surface and groundwater resources exist at each stage of development—well construction and hydraulic fracturing operations, chemical handling, and wastewater management.

Improper well construction or improperly plugged wells are one source of risk by which groundwater contamination can occur (PA DEP 2010b; McMahon et al. 2011). In addition to risks associated with construction integrity, risks are also associated with well durability for wells that are repeatedly hydraulically fractured. The potential exists for fracking fluids, as well as other naturally occurring substances, to reach groundwater sources if well construction or plugging operations are inadequate. The degree of risk will be dependent upon local geology, the composition of the chemicals and naturally occurring substances, and the mobility of the substances within the formation.

Another source of risk during the hydraulic fracturing operation in coalbed methane (CBM) reservoirs is the potential for the fractures to extend into aquifers or into pre-existing faults or fractures (natural or man-made) that might directly extend into aquifers. Currently, it is difficult to predict and control fracture location and lengths, and the overall risk will depend on the local geology and fracking practices used. In shale gas formations, decreasing pressure gradients and natural barriers in the rock strata serve as seals for the gas in the formation and also block the vertical migration of frack fluids (GWPC and ALL Consulting 2009). In contrast, CBM reservoirs, such as the North San Juan considered here, are mostly shallow and may also be co-located with drinking water resources. In CBM areas, hydraulic fracturing operations near a drinking water source might raise the risk of contamination of shallow water resources from hydraulic fracturing fluids (Pashin 2007; EPA 2011).

Another risk to water quality is the handling and mixing of chemicals on site. Risks include spills or leaks that might result from equipment failure, operational error, or accidents. Leaked chemicals could be released into bodies of surface water or could infiltrate groundwater resources. There have been reports of surface spills of hydraulic fracturing fluids; however, little is known about the frequency, severity, and causes of these spills (Lustgarten 2009; Lee 2011; Williams 2011). The risks to local water resources will depend on the proximity to water bodies, the local geology, quantity and toxicity of the chemicals, and how quickly and effectively clean-up operations occur.

Wastewater management practices have risks to water quality that potentially affect water resources both on and off site of the location of the shale gas development operations. Considering risks on site, spills of frac flowback or produced water could contaminate local surface and/or groundwater resources. In addition, there could be equipment failures (e.g., poorly constructed impoundments) during onsite wastewater storage prior to treatment. Potential offsite risks include spills or leakage that might occur during the transport of wastewaters to the location where they will be treated. If surface water treatment is used, there is a risk of the surface water treatment plant not having the capabilities to fully treat the wastewater before it is released back into the hydrologic cycle (Puko 2010; Ward Jr. 2010; Hopey 2011).

From 2009 to 2011, Pennsylvania had 337 reported violations that were classified as “minor effect” or “substantial effect” (NEPA 2012). Violations of these types include the release of wastes or produced water on site in amounts less than 10 barrels (420 gallons). From 2009 to 2011, Texas had 14 reported “minor effect” or “substantial effect” violations, and one reported “major effect” violation. “Major effect” violations include large spills or improperly disposed of wastes greater than 10 barrels (420 gallons), small to large spills that were moved off site and impacted a resource such as a drainage ditch or wetland, and any spill of fracturing fluid greater than 1 barrel (42 gallons). For Colorado, the only publicly accessible statistics related to violations are Notices of Alleged Violations (NOAVs). The number of NOAVs does not represent the number of violations because violations do not necessarily lead to the issuance of NOAVs. Also, when NOAVs are issued, they may cite violations of more than one rule, order, or permit condition. Colorado violations could not be acquired, and data for violations in other states were not available. More detailed information about violations in states where data are available is listed in Appendix D. Further research is needed to fully determine the severity and cause of the reported violations.

3.4 Data Availability and Gaps

Substantial gaps in data availability prevent a full assessment of risks to water resources resulting from shale gas operations. Only certain statistics are publicly available for each region, and in some regions that cross state boundaries, information is only available for the part of a play that is in one state (Table 8.)

Table 8. Overview of Data Availability

		CO	NM	PA	NY	TX	TX	LA	WY
	Risk Factor or Analysis Metric	**North San Juan**	**North San Juan**	**Marcellus**	**Marcellus**	**Barnett**	**Eagle Ford**	**Haynesville**	**Upper Green River**
1	Disposal methods/volumes	◊		◊	◊				^
1a	Fraction of water recycled	◊		◊					
2	Fresh water use	^	^	◊		^	^	◊	^
2a	*Fracturing water*	◊		◊		◊	◊	◊	◊
2b	*Source permitting*	^		◊		^	^	^	^
3	PW/FF volumes	◊		◊		^	^	^	
3a	*Injected volumes*	◊				^	^	◊	◊
4	State regulations					◊			
4a	*Rule violations*			◊					
5	Regional water use			◊					
6	Total wells			◊		^	◊		
6a	*% Horizontal*			◊			◊		
Key									
◊	Data available								
^	Partial data available								

Comprehensive analyses of water risks are hindered by a lack of reliable, publicly available water usage and management data. Data are not publicly available for many regions for total water withdrawals, total wells drilled, water recycling techniques, wastewater management, and other management practices. These data would assist in developing appropriately flexible and adaptive best management practices. Certain resources—such as the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) and FracFocus—have greatly increased public access to information about risks of hydraulic fracturing; but further efforts are desired. Data collection and availability could improve with further collaboration and interaction with industry stakeholders, as well as other stakeholders.

3.5 Best Management Practices (BMP)

Various attempts have been made to define best practices for water management (e.g., IEA 2012; Energy Institute 2012; ASRPG 2012; Chief O&G 2012; SEAB 2011; API 2010). Based on these reports, the following are best practices that are generally accepted to be important for understanding and minimizing risks related to water quantity and quality:

3.5.1 Monitoring and Reporting

- *Measure and publicly report the composition of water stocks and flow throughout the fracturing and cleanup process.* There is little information on the management of fracturing water from acquisition to disposal or recycle, both in terms of quality and quantity.

- *Adopt requirements for baseline water-quality testing.* Background testing is recognized for its value, but is often not standardized. Better guidance is needed for statistically defensible testing.
- *Fully disclose hydraulic fracturing fluid additives.* Disclosure of fracturing fluid chemicals on fracfocus.org is now in place in Colorado, Wyoming, and Texas and is being considered in several other states.

3.5.2 Water Quantity

- *Recycle wastewaters.* Freshwater demand can be minimized by treatment and reuse of produced water and frac flowback. Flowback water produced in the hydraulic fracturing process is returned at relatively high flows and might contain more chemicals of concern than produced water. Optimized handling of this fluid is important for mitigating risks to water quality and quantity because it can lessen the need for transport and wastewater disposal.

3.5.3 Water Quality

- *Use a closed-loop drilling system.* In closed-loop drilling processes, contaminated water is not exposed to air or pits where it could leak, thus eliminating the storage of discarded drilling fluids in open pits at the drilling site.
- *Eliminate flowback water mixing with fresh water in open impoundments.* Disposing of untreated flowback water in reservoirs containing fresh water to be used for hydraulic fracturing increases the risk of harmful spills or leaks.
- *Use protective liners at pad sites.* The use of liners or other protective devices at pad sites can contain minor spills and prevent environmental contamination. Proper collection and disposal equipment is also important to have on site.
- *Minimize use of chemical additives and promote the development and use of more environmentally benign alternatives.* "Green" hydraulic fracturing fluid has been developed—based on fluid mixtures from the food industry—that do not impair groundwater quality in the case of an inadvertent leak or spill.

A next step in developing BMPs for reducing risks to water resources in shale gas development is to evaluate the efficacy of each of the above BMPs (Kemp 2012; Energy Collective 2012). Currently, little or no data exist that analyze the effectiveness or cost-benefit tradeoffs of these BMPs. Further examination of BMPs could assist developers in evaluating important water management questions—such as whether installing protective liners at pad sites or reducing use of chemical additives would have a greater impact on reducing risks to water resources in their regions. A first step in this direction would be to develop a methodology for quantifying and comparing current water-management practices with potential risks.

In many cases, BMPs might be more appropriate or cost-effective for certain geological conditions than others. A further area of needed research is to evaluate the extent to which certain BMPs are applicable or effective across multiple types of formations. To better address this question, researchers could engage a variety of stakeholders—including industry, regulators, researchers, environmental groups, and the public—to understand what practices are currently in use, how effective they are at reducing the risk of water impacts, and where improvements are needed.

A major challenge facing some of these BMPs is that there are no national or state-level disclosure initiatives to track or evaluate the success of their implementation. For example, it is difficult to determine how many operators are currently employing (and with what success) the widely discussed BMP to use closed-loop drilling practices because operators are not required to report this information. Absent such reporting, data collection efforts would likely require close collaboration with multiple industry partners operating in a variety of locations, and this could be time-intensive.

3.6 Summary

We used publicly available datasets to provide an initial evaluation of water risks associated with hydraulic fracturing in six natural gas plays in the United States. Data were limited in every region; continued efforts to catalogue and publish water data will improve future analyses.

Hydraulic fracturing operations have the potential to impact water resources. One of the impact risks associated with water is regional resource depletion due to the use of fresh water during hydraulic fracturing. Water-use data were collected for five of the six regions with average use per well ranging from 1.1 to 5.8 million gallons, with a multi-region average of 3.3 million gallons per well. Total water usage can be estimated by determining the average water use per well, number of wells, and recycling rate; this total freshwater demand value can be compared with estimates of local water availability. Hydraulic fracturing demands are a small fraction of total state water demands, but they can be a substantial portion of water demands in the counties in which the hydraulic fracturing operations are active. If water must be transported from off site to a hydraulic fracturing site, water quantity risks might extend to counties where hydraulic fracturing is not occurring. In all regions considered, the number of wells drilled for hydraulic fracturing has increased each year since 2009. Recycling rates have increased significantly in Pennsylvania since 2009, when the state issued new regulations regarding the treatment of wastewaters.

A second impact risk associated with water is degradation of surface and groundwater quality. Water-quality impacts are a risk during the well construction, hydraulic fracturing, mixing of chemicals, and the wastewater management of shale gas development. As noted above, hundreds of substantial or major violations have been reported that have resulted in spills of produced water, frack fluids, or chemicals. However, it is not clear if water resources have been contaminated—and if so, to what extent—or by which pathway the spills occurred.

A better understanding of the potential contamination pathways (listed here) and their impacts to water resources could assist in identifying and evaluating the phases of operation that have the highest risk of impacting water quality. Potential contamination pathways during well construction and hydraulic fracturing are improper well construction, well degradation from repeated use, lengthy fractures, and improper well plugging. Potential contamination pathways during the mixing of chemicals phase are spills, accidents, and storage equipment failures. Potential contamination pathways at the hydraulic fracturing site during the management of wastewaters are onsite storage equipment failures and spills. Additional contamination pathways and risks occur during the transport of wastewaters to disposal facilities and the potential stress put on surface water treatment plants that might not be capable of treating the types of wastes produced from hydraulic fracturing operations.

Currently, a variety of BMPs are being employed in different regions to minimize risks to water resources. However, there is uncertainty in the industry concerning BMP transferability, cost-effectiveness, and risk mitigation potential. In addition, it is unclear to what extent these BMPs are being employed by different operators. Recycling of frac flowback and produced water is an accepted recommended practice, but limited information exists regarding prevalence, methods, and costs. Except for Pennsylvania, recycling data are not available from public databases, so it is difficult to estimate how much water is being reused in these regions.

3.7 Conclusions and Next Steps

Prior efforts, in addition to with this study, have identified the variety of water-related risks and potential contamination pathways resulting from shale gas development. However, existing publicly available data are not sufficient to perform a full risk assessment on a national or regional scale. A comprehensive and actionable risk assessment would require additional analyses, including the following:

- Quantitatively assess the magnitude of the impacts of the contamination pathways discussed in this report.
- Quantitatively assess the probability that the risks discussed will occur, based on existing industry practices.
- Identify the contamination pathways and risks that, at present, are adequately or inadequately addressed by current industry practices.
- Evaluate BMPs in terms of risk mitigation potential, cost-effectiveness, regional transferability, and industry prevalence.
- Evaluate in detail the wastewater recycling practices, including estimates of current recycling rates, estimates of total potential freshwater savings resulting from recycling, and a life cycle assessment (in terms of energy inputs, emissions, and costs) to identify thresholds for deciding whether to dispose of or recycle wastewaters.

The application of systematically developed BMPs could increase the transparency and consistency by which shale gas development occurs, providing benefits to industry and interested stakeholders. Effective BMPs follow from a defined prioritization of risks in the context of other risks. Risk prioritization would be facilitated by greater availability of industry data and current practices. Further collaboration and interaction with industry, and other stakeholders could improve data collection efforts and are a first step in achieving the analysis objectives above. Lastly, water resources are just one category of risk resulting from shale gas development. Future efforts could evaluate water-related risks and BMPs alongside other risks to air, land, and community.

4 Natural Gas Scenarios in the U.S. Power Sector

4.1 Overview of Power Sector Futures

This chapter summarizes results from modeling different U.S. power sector futures. These futures assess key questions affecting today's natural gas and electric power markets, including the impacts of:

- Forthcoming EPA rules on power plants
- Decarbonization options such as a clean energy standard (CES)
- Potential improvements in key generation technologies
- Higher costs for natural gas production assumed to arise from more robust environmental and safety practices in the field
- Expanded use of natural gas outside of the power generation sector.

The simulations were done using NREL's ReEDS model, incorporating findings from Chapters 1, 2, and 3, as applicable, and looking out to the year 2050.

ReEDS is a capacity expansion model that determines the least-cost combination of generation options that fulfill a variety of user-defined constraints such as projected load, capacity reserve margins, emissions limitations, and operating lifetimes. The model has a relatively rich representation of geographic and temporal detail so that it more accurately captures the unique nature of many generation options, as well as overall transmission and grid requirements. It is a power-sector-only model, so special steps were taken to consider the feedback effects of natural gas demand in other sectors of the economy. These steps, along with additional details about the model, are more fully described in Appendix E of this report.[132]

The scenario analysis presented here is not a prediction of how the U.S. electricity sector will evolve in the future—rather, it is an exercise to compare the relative impacts of different scenarios. Three Reference scenario cases are used as points of comparison for other scenarios based on policy, business, or technology change:

1. Baseline – Mid-EUR
2. Baseline – Low-EUR, and
3. Baseline – Low-Demand.

The modeling team explored four potential policy scenarios in addition to the Reference scenario:

1. A *Coal scenario*, driven by a combination of forthcoming EPA rules, low-cost natural gas, and the age of existing coal generators. Specifically, this scenario addresses the

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[132] A full description of the model is also available at: http://www.nrel.gov/analysis/reeds/pdfs/reeds_documentation.pdf.

question of what new capacity will need to be built if and when coal plants retire, and what impacts would result from proposed NSPS.

4. A *CES scenario* with carbon mitigation sufficient for the U.S. power sector to contribute its share in lowering emissions to a level that many scientists report is necessary to address the climate challenge (IPCC 2007; C2ES 2011). This simulates a CES similar to that proposed by Senator Jeff Bingaman, but analyzes impacts through 2050 (EIA 2012a).
5. An *Advanced Technology scenario* where several different generation options—nuclear, solar, and wind—achieve cheaper and thus more widespread deployment; and
6. A *Natural Gas Supply-Demand Variation scenario* for natural gas, aimed to simulate the impact of (1) steps taken to incrementally address environmental and safety concerns associated with unconventional gas production, and (2) significant growth in natural gas demand outside the power sector (Dash-to-Gas). In both cases, the incremental cost of securing natural gas for power generation results in different power sector futures over the long term.

The family of scenarios is summarized in Figure 24.

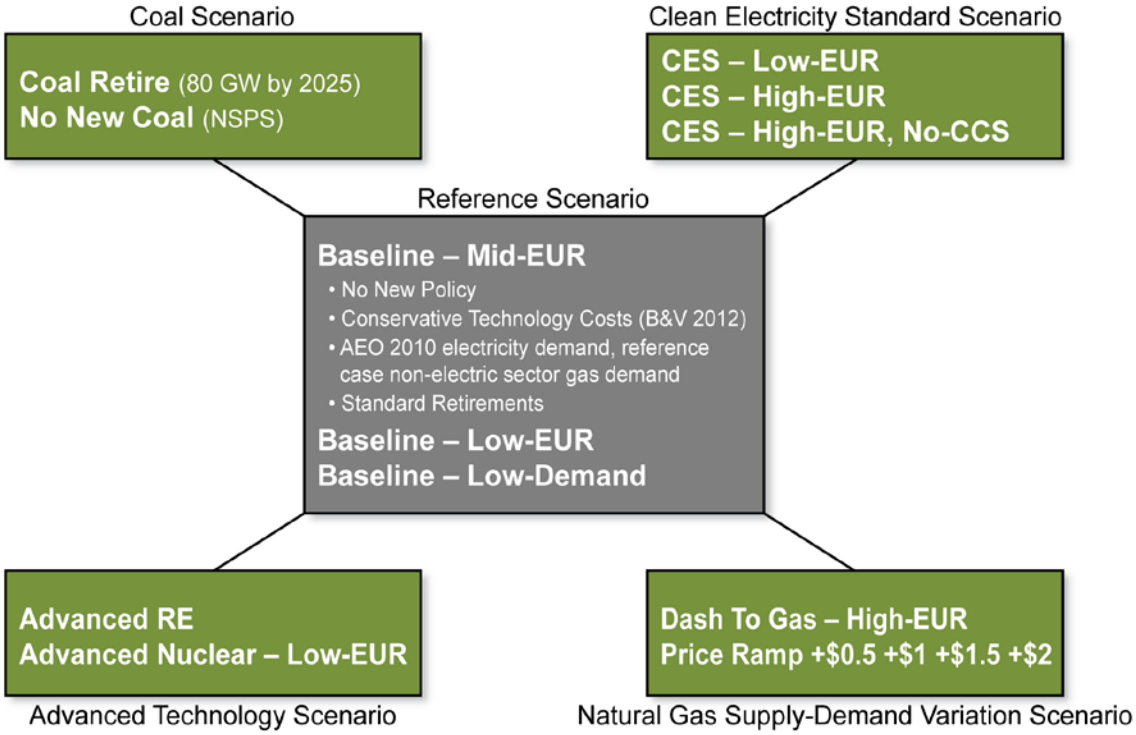

Figure 24. Scenarios evaluated in the power sector futures

4.2 Assumptions and Limitations

Technology cost and performance metrics used in ReEDS are presented in Appendix E. All costs in this study are listed in 2010 dollars unless otherwise noted.

Supply curves were developed to represent natural gas cost to the power sector and the response of this cost to increased power sector demand. The supply curves were developed based on linear regression analyses from multiple scenarios developed by the Energy Information Administration in the Annual Energy Outlook 2011 (EIA 2011).[133] The supply curves represent the price of fossil fuel to the power generators as a function of overall electric sector consumption of the fuel. In particular, as electric sector consumption increases, the marginal fossil fuel price to power generators (and all consumers of the fossil fuel) would increase. Within each year of the ReEDS optimization, the model sees this price response to demand through the linear supply curves. Three sets of supply curves were developed, representing different levels EUR[134] of natural gas. Additional detail on these supply curves is also outlined in Appendix E.

Current renewable tax incentives and state renewable portfolio standards are represented in the ReEDS model. Tax incentives include the modified accelerated cost recovery system for tax depreciation, the production tax credit for utility-scale wind technologies, and the investment tax credit for solar and geothermal technologies.[135] The tax credits are assumed to expire at their legislative end date and not be renewed. In particular, the wind production tax credit expires at the end of 2012, and the solar ITC declines from 30% to 10% in 2016. Although the solar and geothermal investment tax credits have no legislative end date, they are assumed to expire in 2030 as to not influence the long-term expansion decision of the model.

All scenarios evaluated here assume that 30 GW of coal-fired capacity will retire by 2025. The Coal scenario in Section 4.4 considers a higher level of coal retirement and has more detail on the assumed distribution of coal retirements.

ReEDS determines when new high-voltage electricity transmission infrastructure is required and tracks the costs associated with its deployment. It does not track the need to build new natural gas pipeline infrastructure, so those costs are not included in this analysis.

ReEDS is not designed to account for distributed generation; therefore, the penetration of distributed (residential and commercial) rooftop PV capacity was input exogenously into ReEDS from NREL's Solar Deployment Systems (SolarDS) model (Denholm et al. 2009). SolarDS is a market penetration model for commercial and residential rooftop PV, which takes as inputs rooftop PV technology costs, regional retail electricity rates, regional solar resource quality, and rooftop availability. In all cases, except in the Advanced Technology scenario, 85 GW of rooftop PV was assumed to come on line by 2050. This assumption was based on some of the Renewable Electricity Futures (RE Futures) Report 80%-by-2050 renewable electricity scenarios (NREL 2012).

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[133] (EIA 2011). Annual Energy Outlook 2011 scenarios are projections out to the year 2035, and these results are extrapolated to 2050 for use in the ReEDS model. A separate supply curve was developed for each year to represent changes in projected supply and demand interactions as estimated in the multiple Annual Energy Outlook 2011 scenarios. The modeling team had already commenced work by the time the 2012 edition of the Annual Energy Outlook was released, so it could not take advantage of those newer data.

[134] EUR is the amount of natural gas (or petroleum) that analysts expect to be economically recovered from a reservoir over its full lifetime. Three potential measures of EUR are used throughout this study (High, Mid, and Low) to reflect the ranges of optimism and uncertainty over unconventional natural gas availability and price.

[135] Detailed information on these tax incentives can be found on the Database of State Incentives for Renewables and Efficiency at: http://www.dsireusa.org/.

4.3 Reference Scenario

Three different baseline cases were evaluated in the Reference scenario:

- Baseline – Mid-Estimated Ultimate Recovery (Mid-EUR) case, with average power demand growth and a moderate outlook for natural gas prices
- Baseline – Low-EUR case reflecting the potential for more limited—and hence, more expensive—natural gas
- Baseline – Low-Demand case with Mid-EUR expectations. Low demand for electricity could be the result of continued economic stagnation (low gross domestic product [GDP] growth) or successful efforts to curb energy demand through energy efficiency, demand response, smart grid, and other programs to reduce the need for new electricity supply.

A Baseline – High-EUR case was not considered in this family in order to keep the number of results manageable. As noted previously, the Reference scenario is not a prediction of the future U.S. electricity mix *per se*, but instead, it serves as a point of comparison for the other scenarios. Each baseline case in the Reference scenario is summarized in Table 9.

Table 9. Description of Reference Scenario

Case Name	Assumption for Future Electricity Demand	Assumption for Estimated Ultimate Recovery (EUR)
Baseline – Low-EUR	Standard Growth (EIA 2010)	Low-level
Baseline – Mid-EUR	Standard Growth (EIA 2010)	Mid-level
Baseline – Low-Demand	Low Growth (NREL 2012)	Mid-level

Figure 25 and Figure 26 present the projected growth of electric generating capacity and generation for each of the three baseline cases. In the Baseline – Mid-EUR case, total capacity grows from roughly 1,000 GW in 2010 to just over 1,400 GW in 2050. While nuclear and coal capacity decrease as a result of net aged-based retirements, natural gas combined-cycle and natural gas combustion-turbine capacities nearly double, with especially strong growth expected after 2030 when nuclear and coal retirements accelerate. On-shore wind capacity grows steadily from roughly 40 GW in 2010 to nearly 160 GW in 2050, representing about 3 GW of new additions each year on average over the period—a significant reduction from deployment in recent years. In all three baseline cases, oil and gas steam-turbine capacity is fully retired by roughly 2035 due to their low efficiency. Nuclear capacity also declines in all three baseline cases beginning around 2030 as plants reach the end of their operational lifetime and licensing arrangements, and no new plants are built due to uncompetitive economics. As noted above, rooftop PV is not endogenously calculated by ReEDS, but was exogenously assumed for each of the scenarios and baseline cases. Under the technology cost assumptions used, utility-scale PV showed more limited growth compared to natural gas and wind, reaching roughly 10 GW by 2030 and 20 GW by 2050.

The Baseline – Low-EUR case considers a future in which natural gas is less abundant, and thus more expensive, than the Baseline – Mid-EUR case. The primary impact in such a future is less natural gas capacity and more coal and wind. For example, in this baseline case, the cumulative installed wind capacity reaches about 200 GW by 2050.

In the final Baseline – Low-Demand case, growth in natural gas capacity is affected the most, although wind and coal also see little to no growth.

Considering the associated generation futures in these three baseline cases may be more instructive because capacity alone does not indicate how power plants are operated. Generation from natural gas combined-cycle plants doubles over the 40-year period, growing especially rapidly starting around 2030 because it is used to make up for the retired nuclear and coal generation (see Figure 26). Generation from natural gas combustion-turbine is almost too small to see in these charts, but plays an important role in meeting peak load needs. In the Baseline – Low-EUR case, new coal capacity is added and its generation plays a growing role in meeting power demand after 2030. This new coal is not needed in a low-demand future, and little new wind or other renewable energy generation is needed either.

Figure 27 presents four key metrics for the baseline family of cases. First, natural gas consumption rises 2.5-fold from 2010 to 2050 in the Baseline – Mid-EUR case, but still nearly doubles in the other two cases. Second, average real natural gas prices that generators pay are expected to nearly double by 2050 in the Baseline – Mid-EUR case,[136] while the Baseline – Low-EUR case would see higher prices throughout the period. A Baseline – Low-Demand future will put far less pressure on natural gas prices because they peak at just over $8/MMBtu in 2050. Third, CO_2 emissions from the power sector are expected to remain relatively flat throughout the period. In the Baseline – Low-Demand case, emissions decline significantly as existing coal is replaced with natural gas. Finally, average real prices paid for retail electricity grow steadily through 2050 to roughly $130/MWh in the Baseline – Mid-EUR and Baseline – Low-EUR cases, but are about $15/MWh cheaper in the Baseline – Low-Demand case.

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[136] Prices to power generators are higher than well head prices by approximately $1/MMBtu, but vary by region.

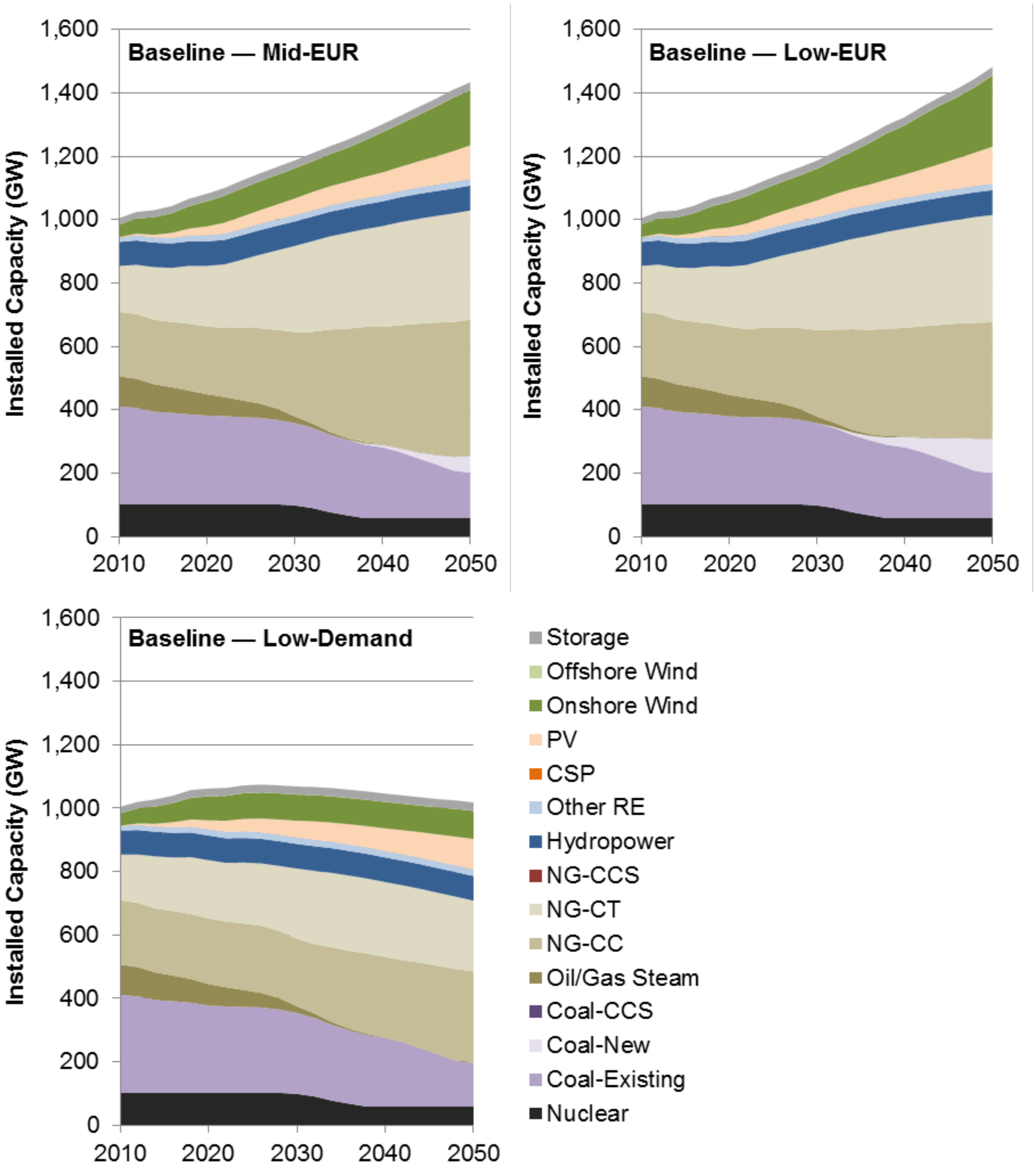

Figure 25. Projected capacity in the Reference scenario, 2010–2050, for Baseline – Mid-EUR, Baseline – Low-EUR, and Baseline – Low-Demand cases

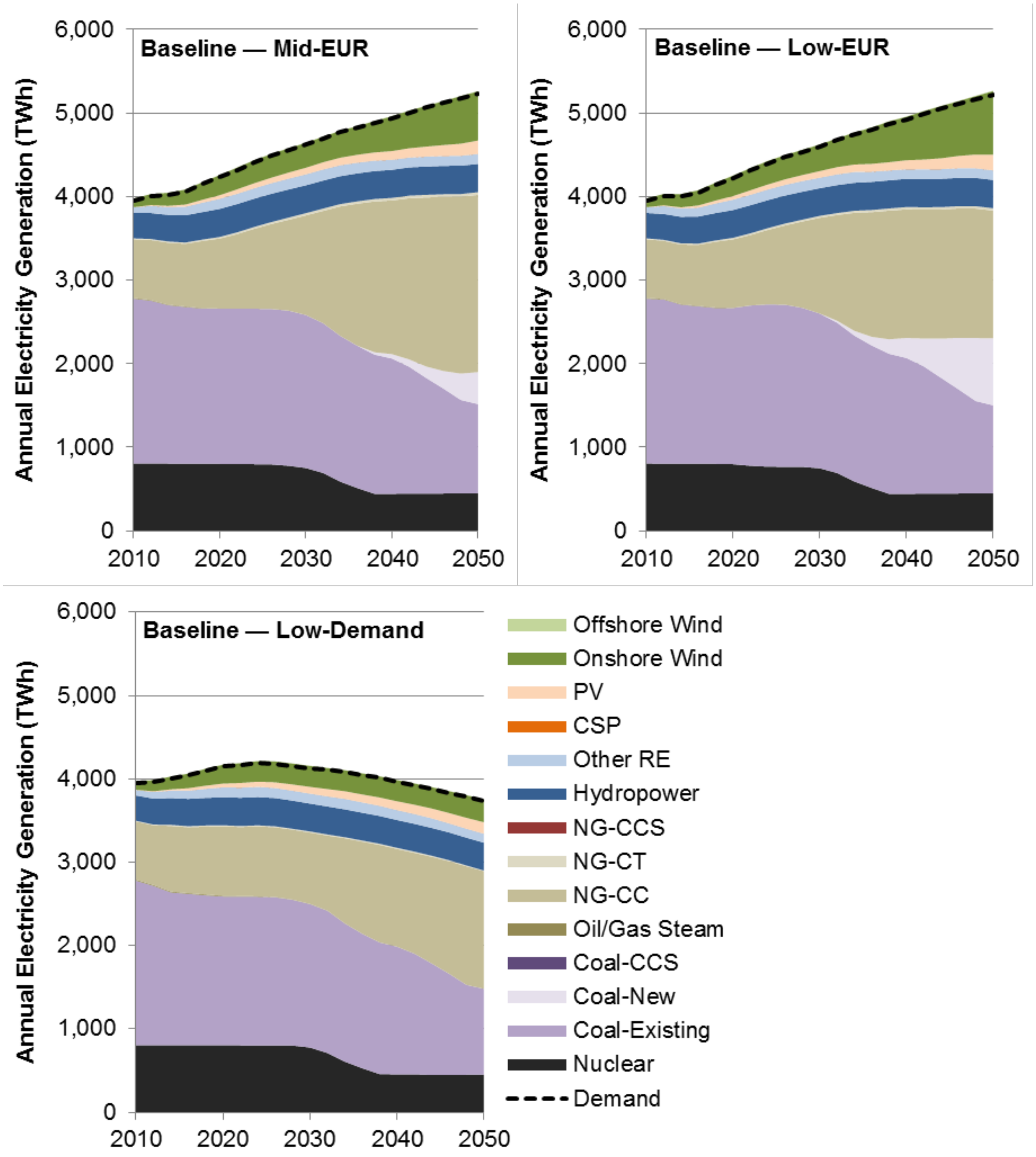

Figure 26. Projected generation in Reference scenario, 2010–2050, for Baseline – Mid-EUR, Baseline – Low-EUR, and Baseline – Low-Demand cases

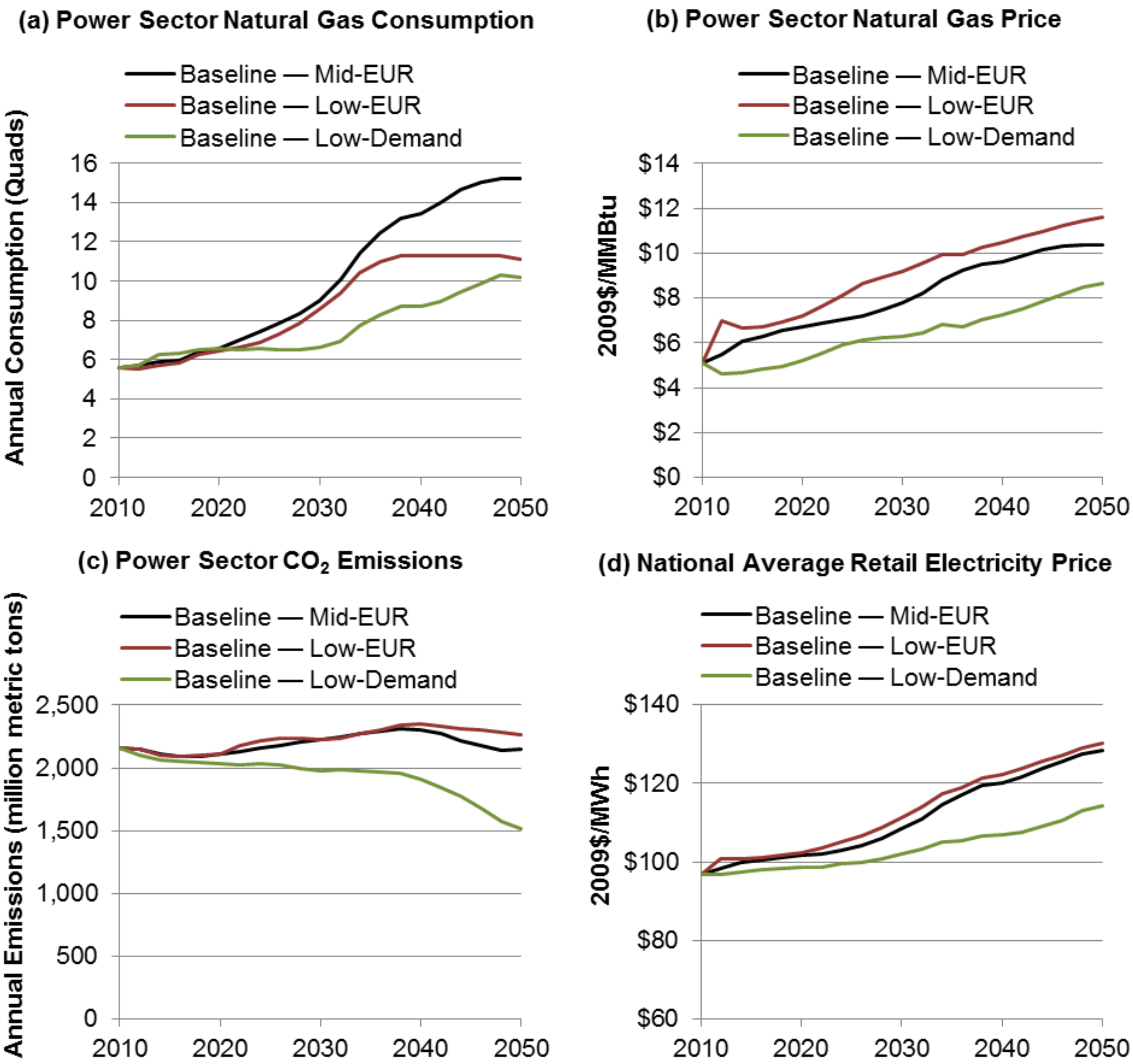

Figure 27. Selected metrics for the Reference scenario, 2010–2050

4.3.1 Implications of Reference Scenario

An electric power future as envisioned in the Baseline – Mid-EUR case would include rapid growth in natural gas generation and less reliance on coal and nuclear power. In effect, natural gas and coal swap positions compared to their historical levels. One concern in such a future is that if volatility returns to natural gas prices after additional new capacity is built—and coal plants are already retired—the economy will be more directly exposed to fluctuating electricity prices. Careful consideration of the benefits and costs of such a shift in generation diversity is warranted.

Although CO_2 emissions do not grow signficantly in such a future, they also do not begin to transition to a trajectory that many scientists believe is necessary to avoid dangerous impacts from climate change. GHG emission reductions of up to 80% by 2050 (compared to 2000 levels) are considered necessary by most climate scientists to stabilize atmospheric concentrations of GHG and prevent the most serious impacts from a changing climate (IPCC 2007). The Reference scenario results do not put the U.S. power sector on a trajectory to meet this target.

A low power demand future, consistent with recently observed trends,[137] may provide greater generator diversity and prevent a potential over-reliance on natural gas. This Baseline – Low-Demand case also has lower emissions and price impacts, although growth in low-carbon energy deployment slows significantly.

4.4 Coal Scenario

This scenario considers two cases:

- *Coal Plant Retirements case:* The impact of retiring an aggregate 80 GW of coal-fired generation by 2025
- *No New Coal without CCS case:* The impact of not allowing any new coal-fired generating capacity to be built unless it is equipped with CCS technology, which is similar to the proposed EPA New Source Performance Standard rule[138]

As noted previously, the baseline in all scenarios assumes that 30 GW of coal will retire by 2025 due to endogenous age-based rules, plus additional retirements of other aging non-coal-fired plants. Many studies have been published that estimate the potential impact of the forthcoming EPA rules—and increasingly, low-priced natural gas—that are assumed to drive the decision to retire existing plants (Macedonia et al. 2011). A more fundamental reason for retirement may be that about two-thirds of the U.S. coal fleet was built in the 1970s or before (SNL 2011). The two cases evaluated in the Coal scenario are summarized in Table 10. Text Box 2 provides additional information on the EPA rules.

Table 10. Description of Coal Scenario

Case Name	Coal Capacity Retired by 2025 (GW)	Assumption for natural gas Estimated Ultimate Recovery (EUR)
Coal Plant Retirements	80	Mid-level
No New Coal without CCS	30 (same as Reference)	Mid-level

As noted previously, there are two forthcoming EPA rules that are likely to cause many older coal-fired plants to consider either costly retrofits to control pollution or retirement as a more economic solution: the Cross-States Air Pollution Rule and the Mercury and Air Toxics Standard. Two other EPA rules are under development that would attempt to address concerns about (1) water intake structures for cooling purposes at most power plants (the 316(b) rule) and (2) disposal of coal combustion residuals, also known as the coal ash rule.

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[137] Total net power generation in the U.S. peaked in 2007, according to EIA statistics, and has not yet returned to pre-recession levels (EIA 2012c).

[138] For additional background on the proposed NSPS ruling, see http://epa.gov/carbonpollutionstandard/.

Text Box 2: Coal Plant Retirements, EPA Rules, and Low-Price Natural Gas

Over the past few years, power sector analysts have debated the impact of new and forthcoming EPA rules on coal plant retirements. These rules include, but are not limited to, the following:

- Cross-States Air Pollution Rule
- Mercury and Air Toxics Standard
- Clean Water Act Section 316(b) cooling water intake structure ruling
- Coal Combustion Residual Rule.

Selected highlights of the rules include:

Cross-States Air Pollution Rule: Limits fine particulate emissions and ozone *transport* in many eastern state power plants by reducing SO_x and NO_x emissions. Compliance options include the installation of low-NO_x burners, catalytic reduction, and scrubbers. The U.S. Court of Appeals struck down this rule in August 2012, and an earlier version known as the Clean Air Interstate Rule will be enforced in its place until EPA redesigns it.

Mercury and Air Toxics Standard: Reduces mercury, acid gases, trace metals and organics emissions at power plants by requiring maximum achievable control technology. Compliance options include scrubbers, filters, and activated carbon injection. Final rule released, and a 3-year compliance period is under way, although legal challenges are also mounting.

316(b): Protects fish and aquatic life from entrapment or entrainment in cooling-water intake structures at power plants. Compliance options include screens, barriers, nets, or cooling towers. The date for issuing the final rule was recently pushed back from July 2012 to June 2013.

Coal Combustion Residual Rule: Establishes standards to manage risk of post-combustion coal waste from power plants. There are two regulatory options under consideration by EPA with different ramifications on power generation cost and impact.

Dozens of studies have been conducted to estimate the impact of these rules on power generators, although most were conducted before the rules were finalized and natural gas prices plummeted in early 2012. Relatively straight-forward financial analysis can be used to determine if it is better to retrofit a power plant so that it can comply with the new rule or retire it. However, real-world decision-making depends on a host of other factors—including future market outlook and plans, portfolio risk management, potential carbon regulations, and reliability assessments.

Some studies anticipated relatively minor impacts from plant retirements (5–20 GW by 2020) (EIA 2011; BPC 2011), whereas others forecast major potential impact and reliability concerns (30–75 GW by 2020) (EEI 2011; CERA 2011; NERA 2011). As of early 2012, about 35 GW of coal-fired generators had already announced that they would retire before 2020. At the same time, as natural gas prices plummeted through 2011 and 2012, generators ramped up operation of natural gas combined-cycle units and scaled back on use of coal generation.

The fuel switching that has already occurred primarily due to low gas prices is equivalent to about 60 GW of coal-fired capacity, although this calculation assumes the coal plants are operated infrequently (32% capacity factor). Most of the oldest coal generators in the U.S. fleet are operated infrequently and have fewer pollution controls. Although fuel switching is a voluntary decision by power generators—and hence, optimized to maximize profits in most cases—the impact of the forthcoming EPA rules will apply different decision-making criteria on top of the inexpensive natural gas driver. Thus, many of the studies conducted to assess the impact of coal plant retirements may need to be redone to account for both drivers of changing generation.

Although most existing studies have anticipated anywhere from 20 to 70 GW of coal retirements by 2020 due to these rules, natural gas price forecasts have fallen below levels that many of the studies used to evaluate the retrofit-retirement decision. The level chosen for this study, 80 GW, is based on these lower natural gas prices and a longer time horizon (2025). *Where* the retirements occur is another important assumption because it will impact whether or not new plants or transmission lines need to be built to replace the lost generation, or if existing natural gas combined-cycle plants can be operated more frequently to meet the load. The retirement distribution chosen was based mainly on the age of existing coal plants and the degree to which they had already installed pollution control devices such as activated-carbon injection and flue-gas desulfurization. Figure 28 displays where existing coal plants were retired, and shows the percentage of coal capacity that is assumed to shut down in each balancing area.

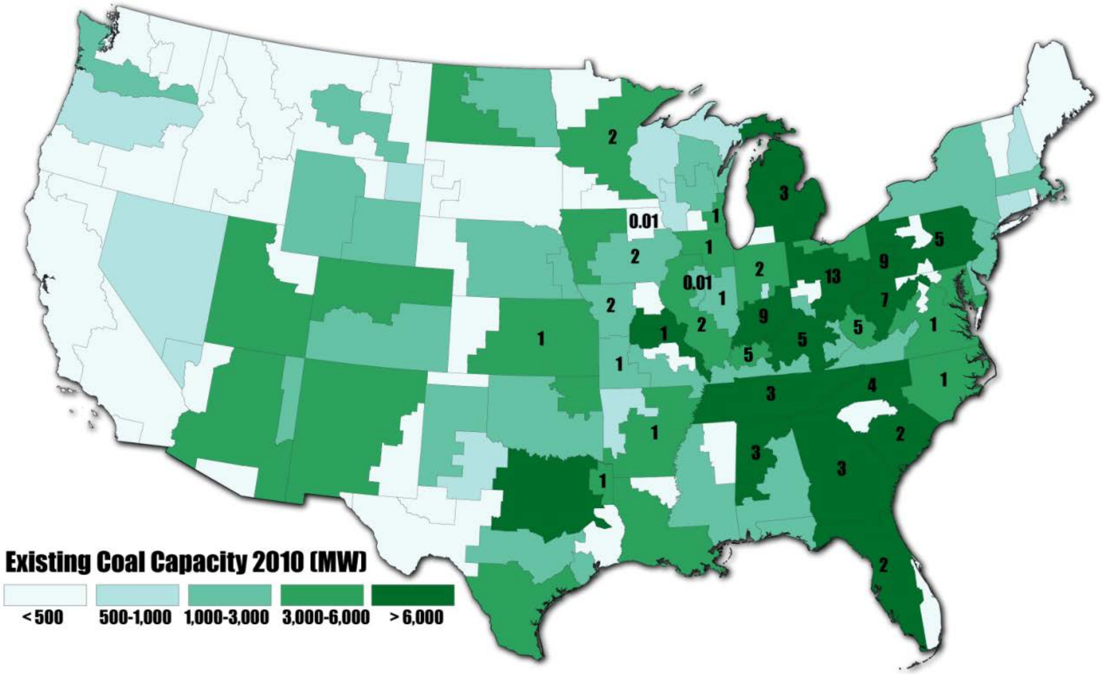

Figure 28. Assumed distribution of retirements in the Coal scenario by percentage of total coal capacity retired in 2025 in each balancing area of ReEDS

The impacts of the two coal cases are summarized in Figure 29 for the years 2030 and 2050. In the Coal Plant Retirements case (where a net 50 GW of additional retirements are seen, compared to the baseline in 2025), most of the retired coal in 2030 is replaced with natural gas combined-cycle, although some additional new wind generation is also added. In the No New Coal without CCS case, there is no difference from the Baseline – Mid-EUR through 2030 because no new coal plants were built by then in the baseline. Cumulative CO_2 emission savings are significant in the Coal Plant Retirements case: 3,300 million tons of CO_2 between 2011 and 2050, even if annual reductions are more modest (see Figure 30). The impact of retirements on average real electricity prices is also modest.

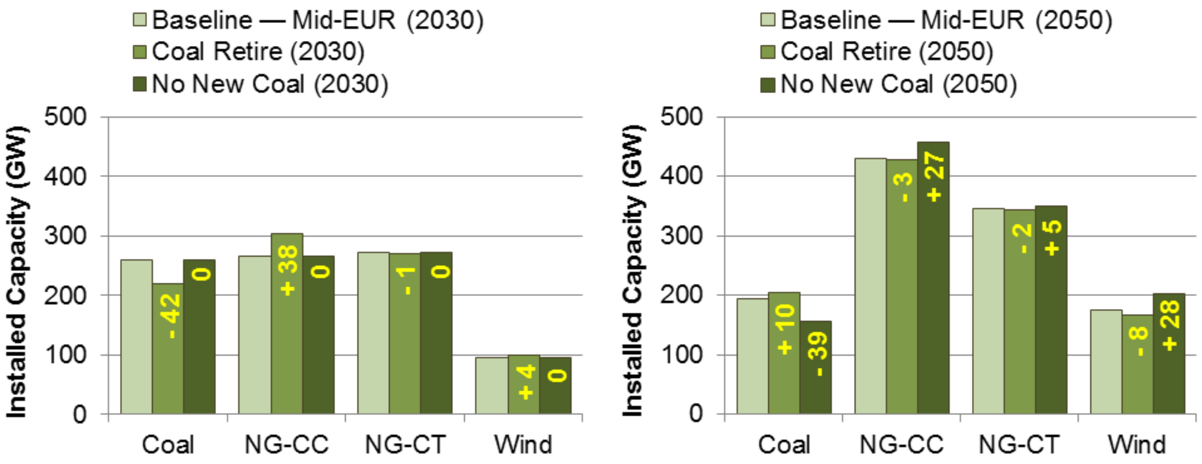

Figure 29. Impacts of coal plant retirements and no new coal without CCS compared to the baseline for 2030 and 2050

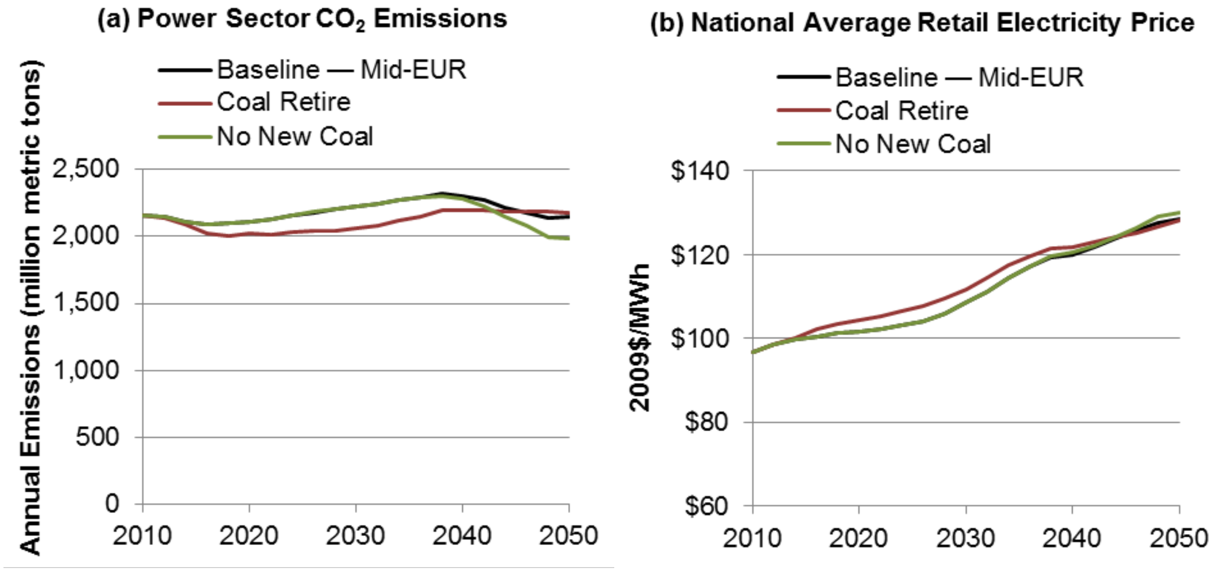

Figure 30. Selected metrics for the Coal cases, 2010–2050

4.4.1 Implications of Coal Scenario Findings

Coal retirements are replaced on a nearly one-to-one basis with natural gas, although wind plays a small role in the early years. In later years, more new coal is built, compared to the baseline, and less wind. In aggregate, however, coal retirements lead to a notable reduction in cumulative CO_2 emissions at relatively modest cost. Initial statistically based analysis does not indicate any difficulty in maintaining adequate reserve margins needed for reliability purposes, although this evaluation is done at a relatively coarse level. A more detailed dispatch model would be required for realistic evaluation of grid reliability issues in such a coal retirement case.

The No New Coal without CCS case, intended to simulate the NSPS, has little impact in early years, but does prevent the construction of new coal after 2030. Compared to the Reference scenario, where new coal does come on line after 2030, the No New Coal without CCS case does not have any new coal coming on line through 2050 because CCS is not an economic option. In this case, natural gas combined-cycle and wind contribute equally to replace what coal would have been built in the baseline.

4.5 Clean Energy Standard Scenario

After cap-and-trade legislation failed to pass the U.S. Senate in 2010, CES became the preferred vehicle for those decision makers seeking to mitigate GHG emissions in the U.S. power sector.[139] A CES sets targets for the sale of qualifying clean energy generation over time, similar to a renewable portfolio standard,[140] but awards credits roughly based on the relative carbon weighting of emissions compared to standard coal-fired generation (EIA 2012a). In this analysis, new nuclear and renewable generators receive 100% crediting because they have no burner-tip emissions; natural gas combined-cycle generation receives 50% crediting when used without CCS and 95% crediting with CCS; and coal receives 90% crediting, but only with CCS. This analysis follows the current CES legislation under discussion in Congress[141] calling for an 80% clean energy target in 2035, but extends the target to reach 95% by 2050.

Full life cycle GHG emission values could be used in the CES crediting, rather than the current burner-tip estimates, to provide a more representative picture of climate impacts. As discussed in Chapter 1, the current understanding of the full life cycle emissions of unconventional gas is not significantly different from the values noted above; therefore, this analysis does not attempt to use them. As additional information becomes available, however, follow-on research could evaluate the impacts of different crediting values on the long-run evolution of the U.S. power sector.

Three separate CES cases are considered here:

- CES – High-EUR case
- CES – High-EUR case where CCS is not available, either for technical, economic, or social reasons
- CES – Low-EUR case.

Table 11 summarizes the three cases evaluated in the CES scenario.

Table 11. Description of CES Scenario

Case Name	Is Carbon Capture and Sequestration Available/Economic?	Assumption for Estimated Ultimate Recovery (EUR)
CES – High-EUR	Yes	High-level
CES – High-EUR, without CCS	No	Mid-level
CES – Low-EUR	Yes	Mid-level

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[139] Three Senate leaders have put forth CES legislation since then: Senator Lindsay Graham (SC), Senator Dick Lugar (IN), and Senator Jeff Bingaman (NM).

[140] For more background on renewable portfolio standards and clean energy standards, see (C2ES 2012).

[141] On March 1, 2012, Senator Jeff Bingaman introduced the Clean Energy Standard Act of 2012. More information on the bill is available at: http://www.energy.senate.gov/public/index.cfm/democratic-news?ID=67e21415-e501-42c3-a1fb-c0768242a2aa.

Figure 31 presents the impacts of the three CES cases on generation through 2050. In the early years before 2030, natural gas replacing coal is the primary contributor to meeting the rising CES targets. Beginning around 2030, however, natural gas is no longer able to contribute to meeting the target without CCS because it receives only 50% crediting toward the target. Instead, coal with CCS, wind, and natural gas with CCS are the next-cheapest options in the CES – High-EUR case. If CCS is not available (CES – without CCS), wind generation is the next-cheapest alternative to take its place. In such a case, renewable energy sources contribute about 80% of total generation by 2050.[142]

A CES power future with more costly natural gas (CES – Low-EUR) would result in less natural gas generation, more solar and wind, and reliance on coal CCS rather than gas CCS compared to the CES – High-EUR case.

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[142] NREL recently published the RE Futures study that evaluates many of the technical issues and challenges of operating the grid with such high percentages of renewable energy. See NREL (2012) for more detail.

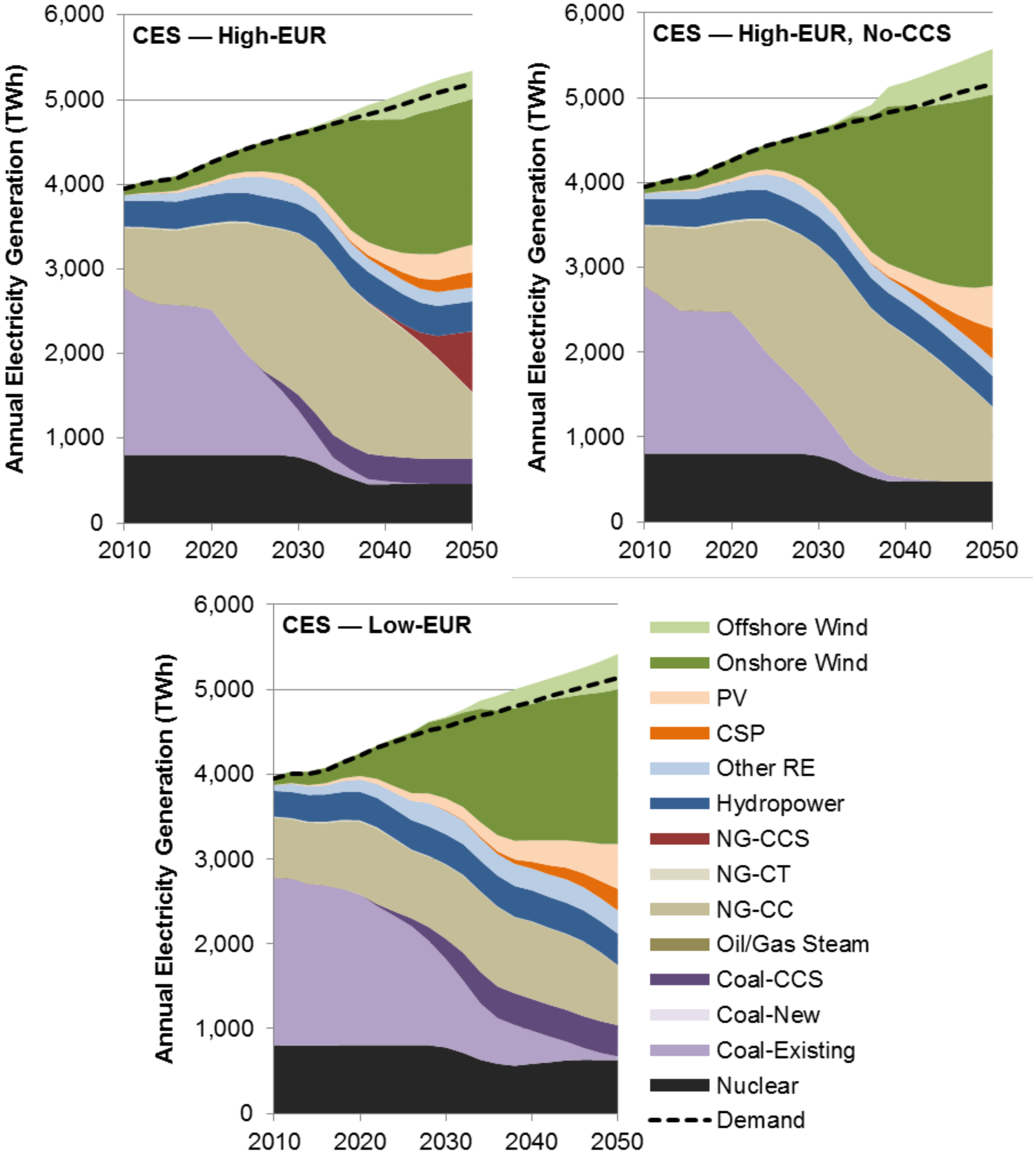

Figure 31. Projected generation in CES scenario, 2010–2050 for CES – High-EUR, CES – High-EUR, without CCS; and CES – Low-EUR cases

The amount of natural gas used in the CES scenario varies significantly by case, as shown in Figure 32. In all cases, however, it peaks around 2030, and prices remain lower than the Baseline – Mid-EUR case through 2050. Power sector gas demand temporarily falls after 2030 in the CES – High-EUR case, but begins to climb again around 2040 as natural gas CCS becomes an economic contributor to the CES target. When CCS is not available, natural gas consumption continues to decline and is back at 2010 levels by 2050. In the CES – Low-EUR case, natural gas usage remains muted throughout the scenario lifetime as other options meet the target more economically. Average real electricity prices would increase compared to the Baseline – Mid-EUR case beginning in roughly 2020 and settle at levels between 6% and 12% higher by 2050.

By 2050, CO_2 emissions from the U.S. power sector decline by more than 80% in all CES cases compared to the baseline. Coal generation without CCS has disappeared by that time in all cases. The power sector would be on a trajectory in all CES cases to achieve that sector's contribution to carbon mitigation commensurate with levels the Intergovernmental Panel on Climate Change deems necessary to stabilize atmospheric concentrations of greenhouse gases (IPCC 2007) at a level that could avoid the most dangerous aspects of climate change.

Because the CES cases project a very large build-out of wind power, ReEDS tracks the amount of new transmission lines needed to deliver power from where it is generated to where it is used. The estimated costs of building this new transmission infrastructure are included in the capacity analysis. Figure 33 presents a geospatial map of where new transmission lines would be required through 2050. The vast majority of this new wind generation would be constructed in the Midwestern states for use throughout the Eastern Interconnect. Smaller quantities would be built in the Western and Electric Reliability Council of Texas (ERCOT) Interconnects. The greatest amount of transmission is needed when CCS is not available, and wind must play an even larger role. In this case, more than twice the amount of transmission, as measured in million megawatt-miles of capacity, would be needed compared to the CES – High-EUR case in 2050 (or six-times the amount as the Baseline – Mid-EUR case).

4.5.1 Implications of CES Scenario

The CES options analyzed here indicate that the U.S. power sector could achieve significant decarbonization by 2050 at relatively modest economic costs, although barriers to building sufficient transmission may be formidable (NREL 2012). About six times more transmission is needed in the CES – without CCS case than in the Baseline – Mid-EUR case by 2050, and three times as much in the CES – High-EUR case. A greater diversity of power generation is achieved when CCS is available and economic for use on coal or gas plants. Heavy reliance on the need for transmission is also lessened when CCS is available. Additional research should be considered to evaluate potential natural gas infrastructure barriers in such a scenario of high variable renewable energy generation.

In all CES cases, large quantities of variable renewable energy are supported and firmed by flexible natural gas generators. Natural gas generators help enable a power generation mix that relies heavily on variable renewable technologies such as wind and solar.

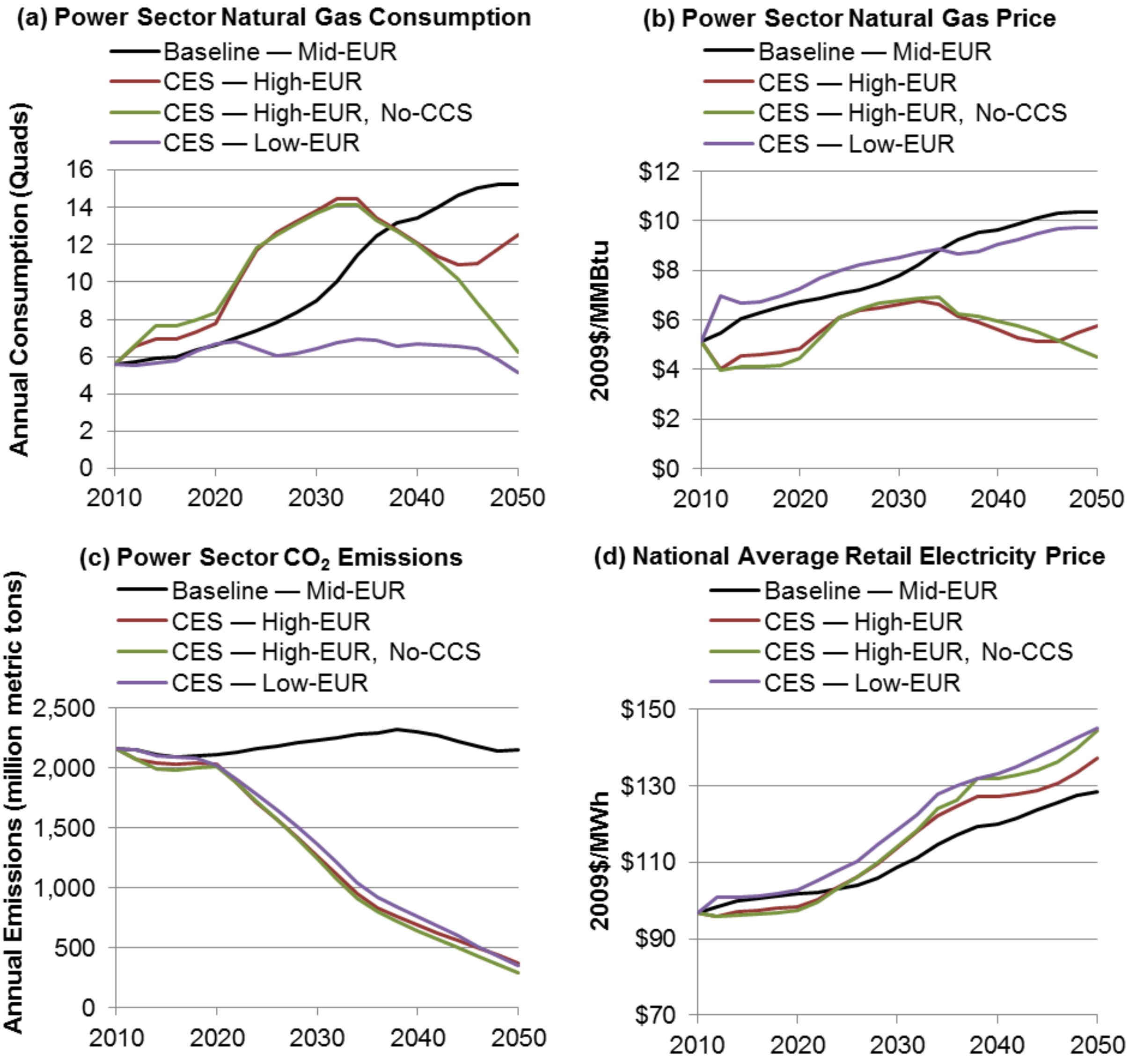

Figure 32. Selected metrics for the CES scenario, 2010–2050

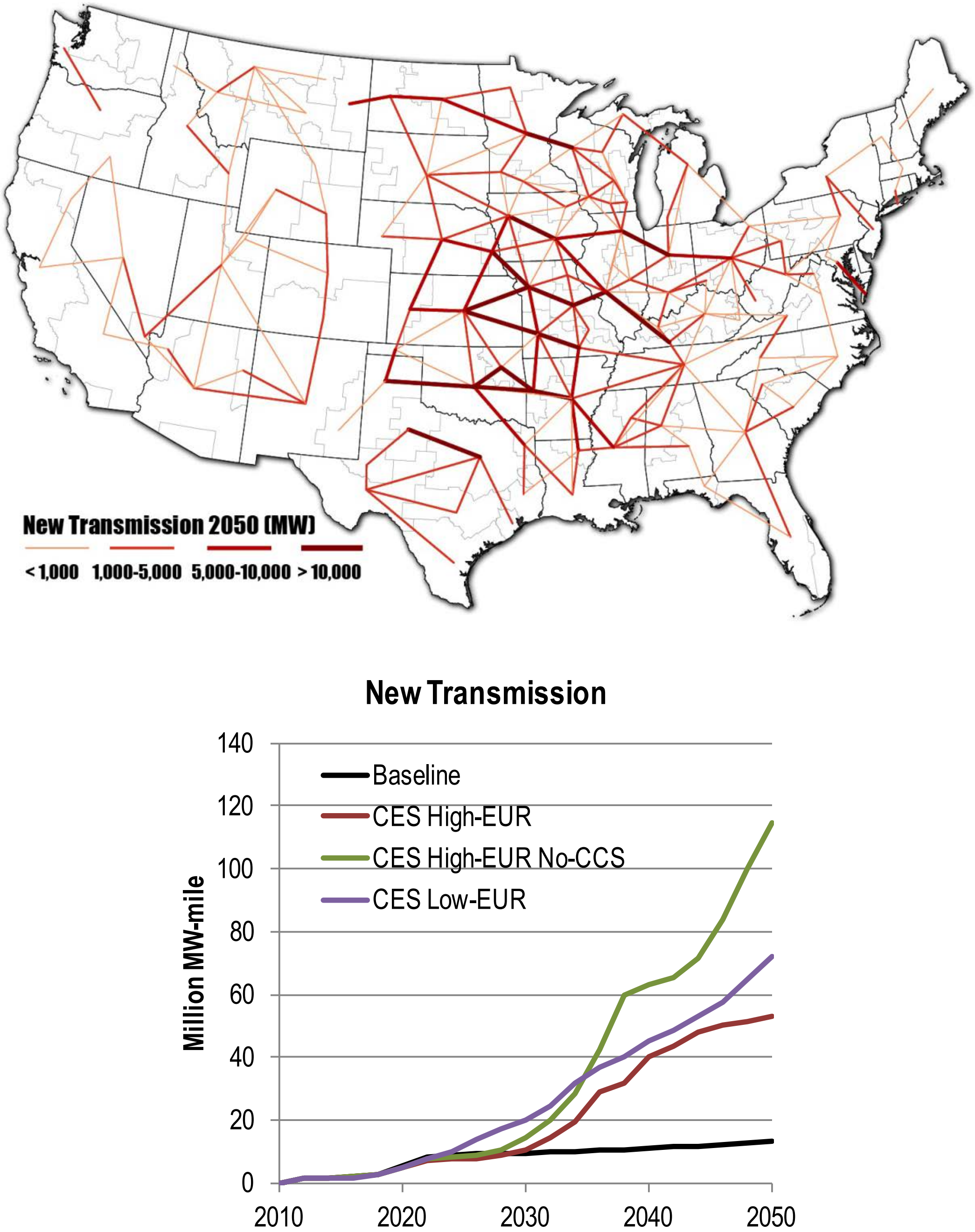

Figure 33. Map of new transmission required by 2050 in the CES – High-EUR case, and measures of new transmission needed in all cases, 2010–2050

4.6 Advanced Technology Scenario

The Advanced Technology scenario considers additional progress in the evolution of cost and performance metrics of certain generation options compared to the Baseline – Mid-EUR case. Two cases are considered here:

- *Advanced Nuclear:* A 50% reduction in the capital costs of nuclear generation by 2020. This scenario also uses a Low-EUR assumption for natural gas.
- *Advanced Renewable Electricity (RE):*[143] Capital costs for utility-scale solar PV, concentrating solar power (CSP) with thermal storage, and wind are assumed to decline, as shown in Table 12. In addition, improvements in performance of advanced RE technologies are assumed to be more significant, as shown in Table 13 (e.g., in 2050, Class 5 wind is assumed to have an annual capacity factor of 46% compared with 43% in the baseline). CSP is assumed to have the same performance as in the baseline, but with towers available at an earlier time (2015 instead of 2025), resulting in higher performance earlier. Furthermore, distributed PV was exogenously input and assumed to reach 240 GW of capacity by 2050,[144] compared to 85 GW in the baseline. This case uses a Mid-EUR natural gas assumption.

Table 12. Assumed Reductions in Capital Costs for the Advanced Technology Scenario

	2020 ($/kW)	2050 ($/kW)
Advanced Nuclear	6,200 → 3,100	6,200 → 3,100
Advanced On-shore Wind	2,012 → 1,964	2,012 → 1,805
Advanced PV	2,550 → 2,213	2,058 → 1,854
Advanced CSP	6,638 → 4,077	4,778 → 2,982

Table 13. Assumed On-shore Wind Improvements in Capacity Factors for the Advanced Technology Scenario

	Class 3	Class 4	Class 5	Class 6	Class 7
2020	0.33 → 0.38	0.37 → 0.42	0.42 → 0.45	0.44 → 0.48	0.46 → 0.52
2050	0.35 → 0.38	0.38 → 0.43	0.43 → 0.46	0.45 → 0.49	0.46 → 0.53

Table 14 summarizes the major assumptions used in the Advanced Technology scenario.

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[143] Advanced RE capital costs and performance improvements were taken from the RE Futures report (NREL 2012), evolutionary technology improvement (RE-ITI) cost projection.

[144] This projection is based on the SunShot Vision Report (DOE 2012).

Table 14. Description of Advanced Technology Scenario

Case Name	Cost Assumption	Assumption for Estimated Ultimate Recovery (EUR)
Advanced Nuclear	Nuclear capital costs decline by 50% in 2020 compared to the baseline scenario.	Low-level
Advanced RE	Wind, PV, and CSP capital costs decline as shown in Table 12. Performance improvements as described above and shown in Appendix E.	Mid-level

The impact of potential improvements in these two categories of technology is shown in Figure 34. The primary impact in the Advanced Nuclear case is that enough new nuclear generation is built to offset the decline in age-based retirements by the end of the modeling period.[145] Additionally, because this case assumes a Low-EUR for natural gas (and thus, higher prices), some new coal plants are also built beginning in 2030 to meet load. The new coal plants largely offset the carbon abatement that otherwise would have occurred due to the new nuclear generation. Retail prices are also higher during most of the reporting period because the Low-EUR assumption was made (see Figure 35).

In the Advanced RE case, wind and solar generation expands considerably compared to the Reference scenario. In the case of wind, this illustrates the sensitivity of potential expansion because the assumed cost reductions and performance improvements were relatively modest. Growth in utility-scale PV capacity is substantial in this case, while actual generation increases more modestly due to the relatively low capacity factor that solar achieves. By 2050, CO_2 emissions decline by a little more than one-quarter compared to the baseline, while retail electricity prices are also slightly lower due to the assumed reduction in cost for RE technologies (Figure 35).

4.6.1 Implications of the Advanced Technology Scenario Findings

Under the assumptions used in this analysis, nuclear generation does not become cost competitive with other options until capital costs decline by roughly one-half from today’s level and natural gas prices are assumed to be relatively high (Low-EUR). Even under the cost assumptions used in the Advanced Nuclear case, new coal was still competitive with the cheaper nuclear, offsetting some of the carbon advantages of nuclear. Despite these apparently high hurdles, breakthroughs in advanced nuclear designs are possible (OECD 2011; Martin 2012) and could contribute meaningfully to a more diverse and energy-secure power future in the United States.

Even modest reductions in capital costs for renewable energy technologies can have significant impact on their competitiveness compared to baseline assumptions. Wind power appears particularly sensitive to assumed reductions in capital cost and performance improvements, expanding nearly 100% compared to the baseline with capital cost reductions of about 10%. Similar reductions in utility PV capital costs lead to near-identical impacts in the deployment of that technology, whereas a greater reduction in CSP capital costs would be needed to see a large expansion in the role of that technology.

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[145] This case was also evaluated under High-EUR and Mid-EUR gas futures, but nuclear was not competitive in that environment, so only the Low-EUR results are shown here.

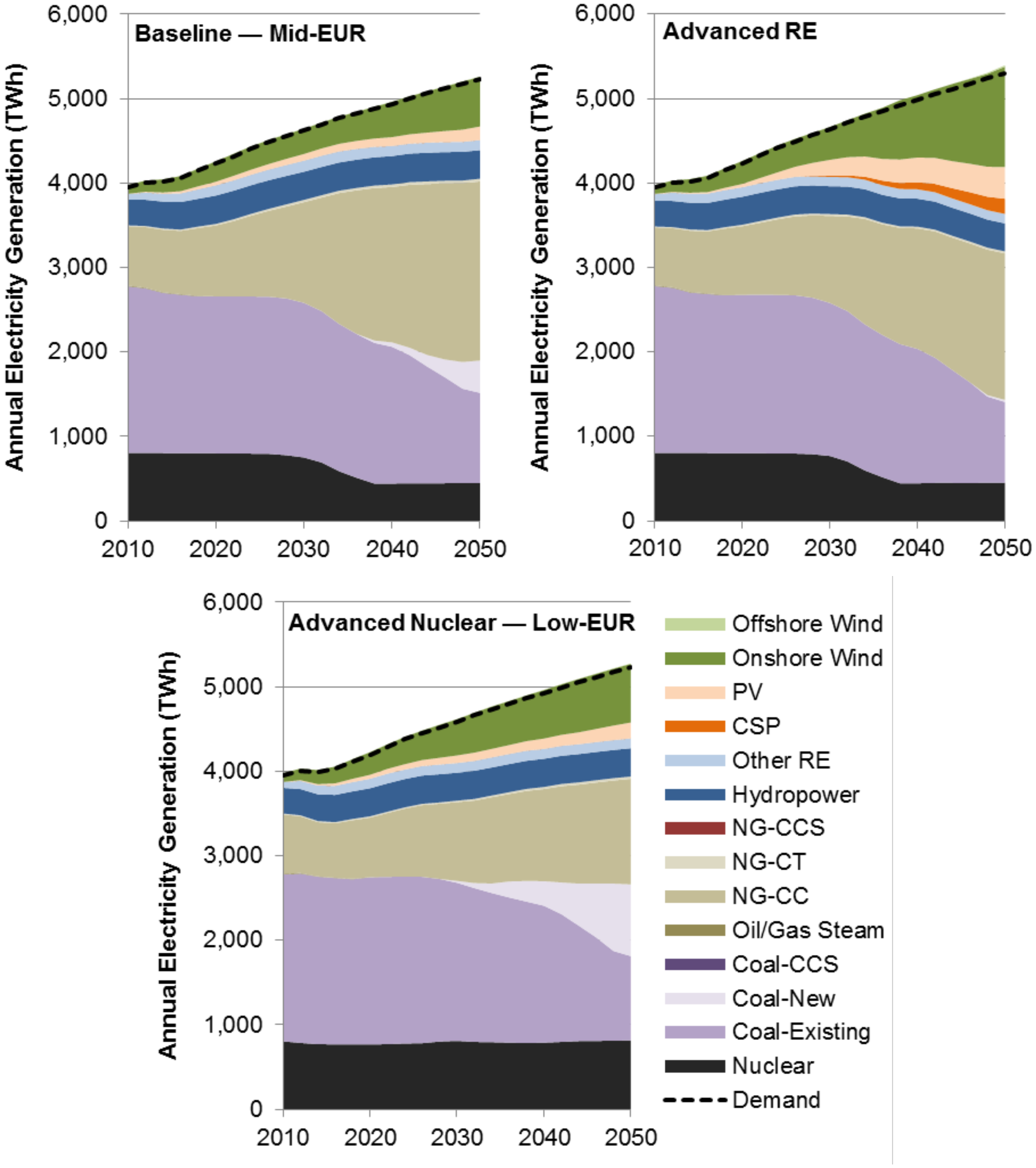

Figure 34. Generation in the Advanced Technology scenario, 2010–2050

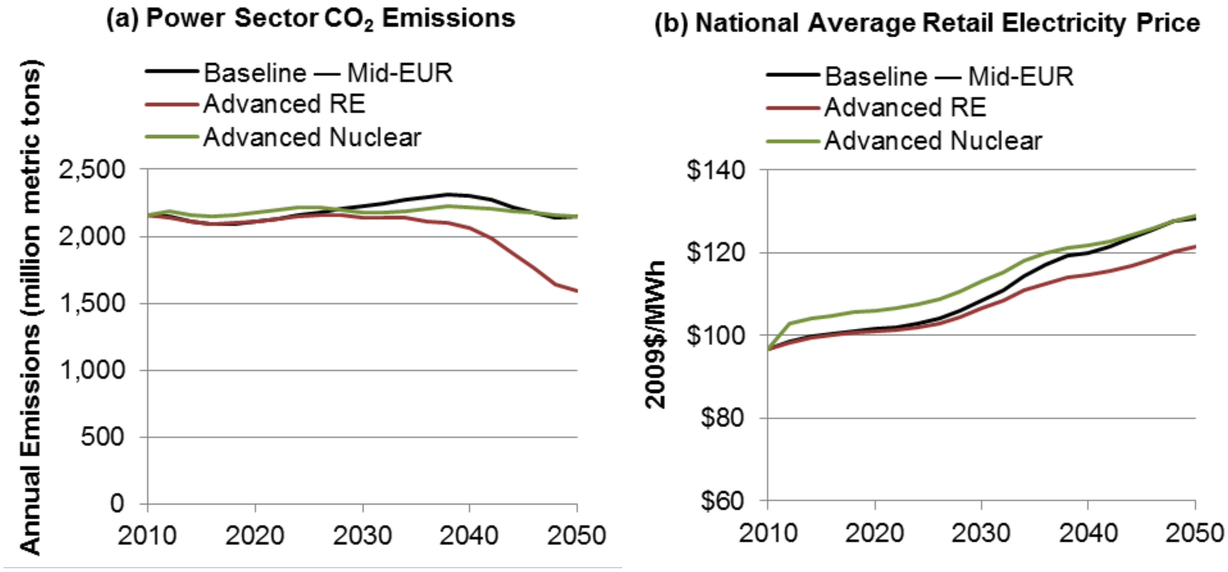

Figure 35. Selected metrics for the Advanced Technology scenario, 2010–2050

4.7 Natural Gas Supply and Demand Variations Scenario

Two separate cases are considered here:

- *Natural Gas Supply Cost Variations:* Variations in natural gas supply costs that could result either from additional state or federal regulations, or from more costly field practices that suppliers follow to better protect the environment. The impact of these incremental natural gas costs on the power sector over the longer-term are simulated using ReEDS. This analysis covers a broad range of potential incremental costs associated with producing natural gas in a way that commands stronger public support yet is still feasible for producers and consumers. Chapters 2 and 3 of this study discuss practices that could result in this more secure outcome on the supply side, but does not arrive at actual estimates of incremental cost impacts in $/MMBtu terms. The values used here could still be helpful to those who know what their incremental costs are, or to a broader audience in the future when cost estimates are available.
- *Natural Gas Demand Variations:* Variations in demand for natural gas outside the power sector that could result from a “dash-to-gas” across the larger economy. This dash-to-gas could occur in the export of LNG, greater use of natural gas in vehicles (either as compressed natural gas throughout the fleet, or as LNG in heavy-duty vehicles). Under a dash-to-gas case, natural gas prices rise due to the greater demand and make it more expensive for power generators to use natural gas generation.

Table 15 summarizes key assumptions used in the Supply and Demand Variations scenario.

Table 15. Description of Natural Gas Supply and Demand Variations Scenario

Case Name	Focus	Assumption for Estimated Ultimate Recovery
Natural Gas Supply Cost Variations	Evaluate impact to power sector as incremental natural gas production costs increase from $0.50/MMBtu to $2/MMBtu	Mid-level
Natural Gas Demand Variations (Dash-to-Gas)	Evaluate impact to power sector as natural gas demand in other sectors increases by 12 bcf/d by 2026	High-level

4.7.1 Natural Gas Supply Cost Variations

Figure 36 illustrates adjustments to the natural gas supply curves that could result when additional measures are taken to protect the environment when producing natural gas. These measures could be the result of new regulations or different practices in the field. Examples of these added costs might include the following:

- Activities such as recycling or treating a greater quantity of water supply used in hydraulic fracturing
- Minimizing the amount of methane that is released to the atmosphere before, during, and after fracturing a well
- Casing wells in a more robust and consistent way
- Practicing more robust techniques of cement bond logging
- Substituting more environmentally benign options for traditional hydraulic fracturing additives
- Engaging local stakeholders in dialogues in advance of drilling to ensure their concerns are heard and addressed
- Enforcing larger setbacks from potentially sensitive communities
- Disposing of or treating flowback water in improved ways.

Few publicly available studies estimate what these specific costs might be and how they vary by region. The International Energy Agency (IEA) recently published Golden Rules for a Golden Age of Natural Gas (IEA 2012), a very general statement of 22 steps that should be considered when producing natural gas. The IEA report stated that, “We estimate that applying the Golden Rules could increase the overall financial cost of development a typical shale-gas well by an estimated 7%.”[sic] (IEA 2012). Therefore, if it normally costs $3.00/MMBtu to develop shale gas, the Golden Rules cost would be $0.21/MMBtu higher at a typical play. This is nominally consistent with, although lower than, recent estimates of the costs of complying with pending federal rules—including the new EPA air regulations for oil and gas producers, which might cost between $0.32 and $0.78/MMBtu, according to one analyst (Book 2012). Informal consultations associated with this study suggest that maximizing water recycling might result in $0.25/MMBtu in added costs. The additional costs that could result from enhanced environmental and safety practices in the field, noted in Chapters 2 and 3, were unable to be quantified. However, it is clear that these costs will vary by region and that many additional safeguards could be practiced at less than an incremental cost of $1/MMBtu. A 2009 study funded by the American Petroleum

Institute anticipated much higher costs if new federal regulations were imposed on natural gas producers (IHS 2009).

To assess the potential impacts of these incremental supply costs, this study considers a range of additional costs—starting from \$0.50/MMBtu and going up to \$2/MMBtu in increments of \$0.50/MMBtu—and evaluates the impacts on the long-range evolution of the power sector when these costs are applied. Figure 36 shows the reduction in natural gas use in the power sector as incremental costs are increasingly applied. At the upper limit, natural gas consumption for power generation declines from roughly 15 quads[146] in the Baseline – Mid-EUR case to 10 quads (incremental \$2/MMBtu added) by 2050. With a \$0.50/MMBtu added cost of gas production, the long-term impacts are far more modest—resulting in a reduction of gas use for power generation in 2050 of less than 2 quads. Coal—and wind, to a lesser extent—replaces the generation lost by the more expensive gas. Other impacts associated with these assumed incremental costs appear relatively modest.

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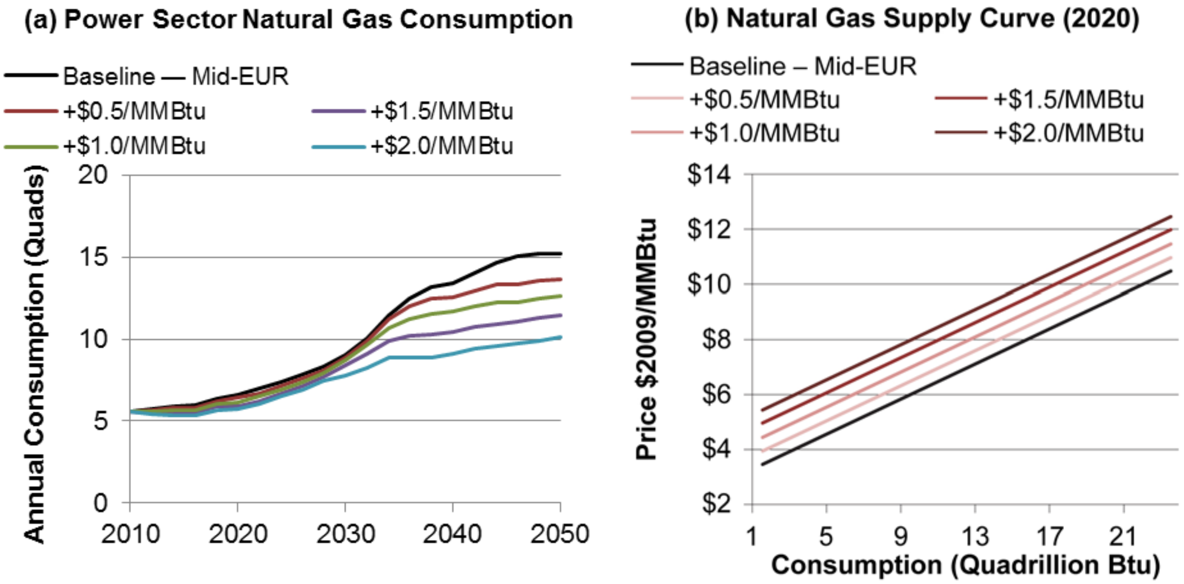
[146] To roughly convert from quads to bcf/d, multiply by 2.6. Thus, 15 quads per year equal about 38.5 bcf/d.



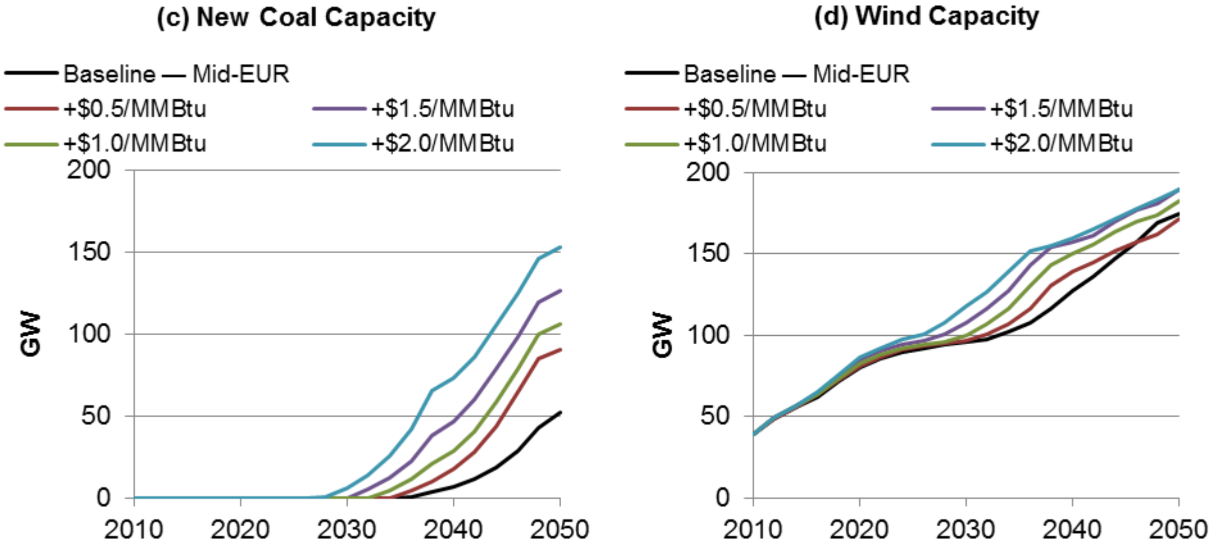
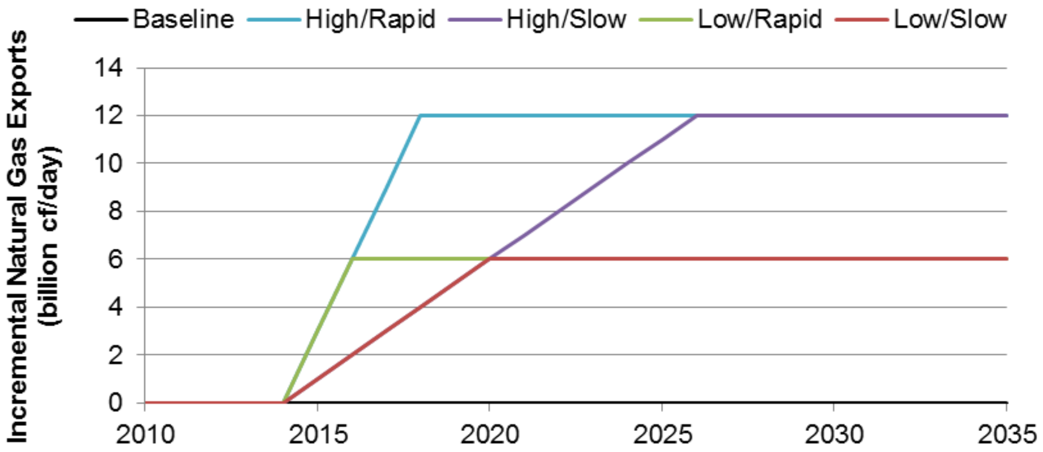


Figure 36. Selected metrics for the Natural Gas Supply Cost Variation case, 2010–2050

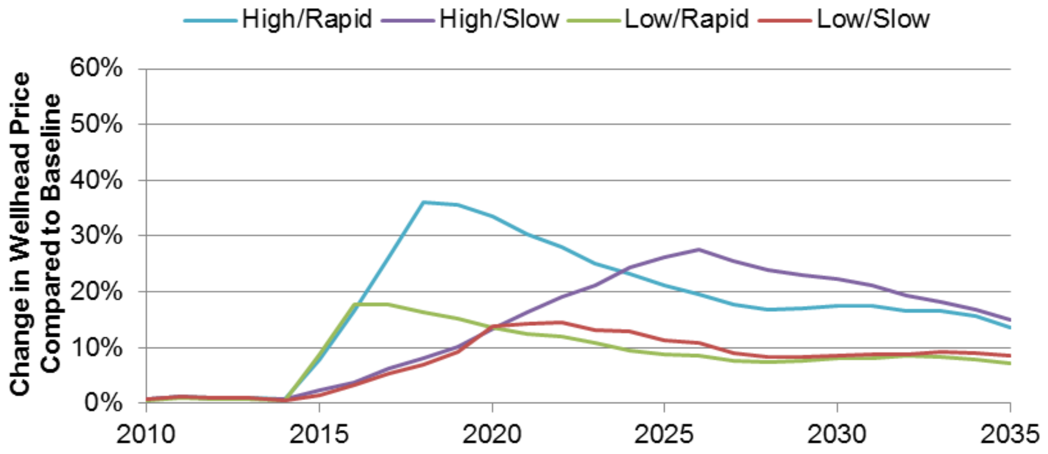
4.7.2 Natural Gas Demand Variations (Dash-to-Gas)

The Natural Gas Demand Variations case considers the impact to potential expansion of natural gas generation if a significant shift to natural gas occurs in other sectors of the economy. Specifically, it looks at the combined potential of new LNG exports, natural gas vehicle deployment (both compressed natural gas and LNG in heavy-duty trucking), and use in industrial and chemical applications and any other sector that in aggregate reaches 12 bcf/d by 2026.

A growing number of studies analyze the impact of LNG exports on domestic natural gas prices (EIA 2012b; Pickering 2010; Deloitte 2011; Ebinger et al. 2012). Estimates vary considerably depending on methodology used, location, and assumptions about overall gas availability. The case examined here uses the methodology in the EIA LNG exports scenario as a basis for the full economy “dash-to-gas.”[147] Thus, it takes the “high and slow” EIA-derived price impact of exporting 12 bcf/d of LNG by 2026 and uses it to represent the impact of a combined 12 bcf/d in the total economy, distributed among LNG exports, vehicle use, industrial use, and any other applications (see Figure 37 and Table 16).



Source: U.S. EIA based on DOE Office of Fossil Energy request letter



Source: U.S. EIA, National Energy Modeling System

Figure 37. EIA LNG export scenarios and their projected impacts on domestic natural gas prices, 2010–2035

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[147] The upper limits (i.e., high/rapid scenario) of the EIA study have been criticized by some (Ebinger et al. 2012) as too extreme and not representative of how LNG exports might really occur. Although the study in this report uses the second-most extreme (high/slow) LNG export scenario considered by the EIA, the scenario is constructed to capture a wider range of potential natural gas end-uses than just LNG exports.

Table 16. Non-Power Sector Natural Gas Demand Assumptions in the Natural Gas Demand Variations Case

	2010	2020	2030	2040	2050
	(billions of cubic feet per day)				
LNG Exports	0	5.0	7.3	5.0	0
Vehicles[148]	0	1.5	2.7	3.0	0
Industry/Other	0	1.5	2.0	1.5	0
Subtotal	0	8.0	12.0	9.5	0

In the Natural Gas Demand Variations (dash-to-gas) case, gas prices rise by a maximum of 29% above the Reference scenario value in 2026 before re-equilibrating. The power sector mix is similar to the Baseline – Low-EUR case (compare Figure 38 with Figure 26), although still slightly more reliant on natural gas generation. A dash-to-gas future, then, would restrict gas generation to less than doubling by 2050 compared to the 2010 level. The larger macroeconomic impacts associated with this future were not evaluated; however, overall gas demand declines by about 3 quads by 2050 (Figure 39) compared to the baseline. The price of natural gas for power generators rises by a maximum of $2/MMBtu above the baseline value in the early 2020s before returning to the baseline level in 2050, when the other sectors are assumed to terminate their extra reliance on natural gas (see Figure 39).

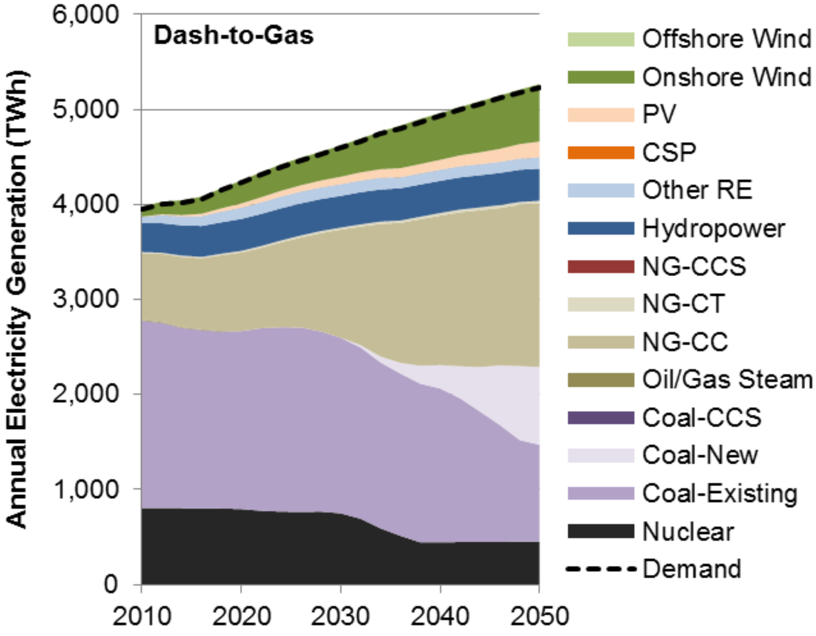

Figure 38. Power generation mix in the Dash-to-Gas case

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[148] These estimates for compressed natural gas use in vehicles are proposed by Wellkamp and Weiss (2010).

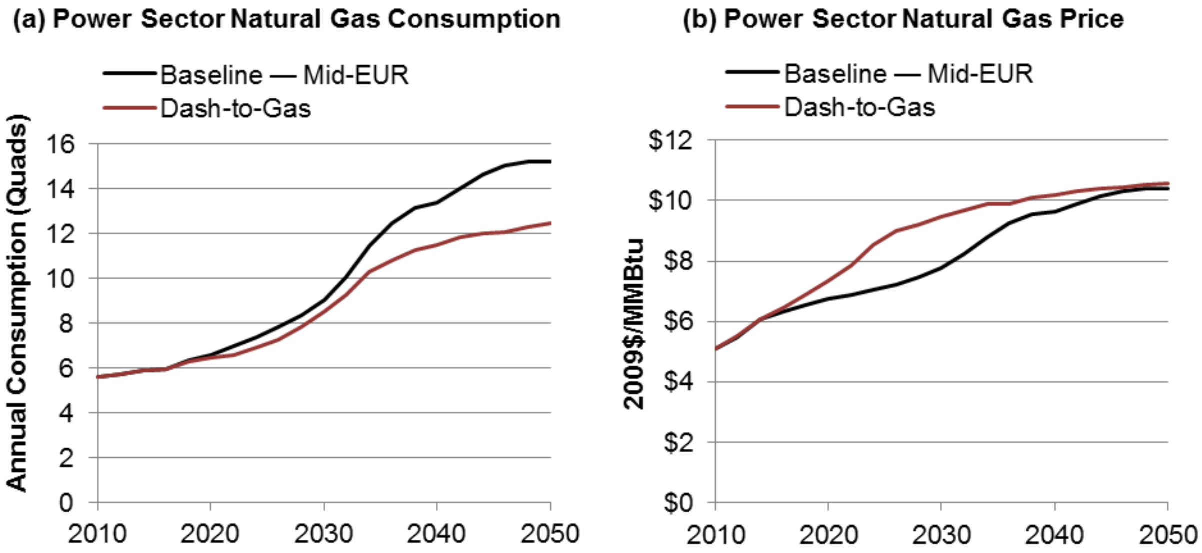


Figure 39. Selected metrics for the Dash-to-Gas case, 2010–2050

4.7.3 Implications of the Natural Gas Supply and Demand Variations Findings

Many additional measures could be taken by producers to address the real and perceived risks associated with unconventional natural gas production at a modest impact to the evolution of the power sector. If total costs from a long list of potential practices reached $1.00/MMBtu, natural gas usage in the 2050 power sector might be expected to decline from 2.5 times the 2010 level in the Baseline to 2 times in the Supply Variation case. Costs associated with ensuring stronger public support of unconventional gas and oil production would vary by region and producer. Technologies associated with unconventional natural gas production are under rapid development, so the cost impacts will be changing dynamically. Follow-on research should attempt to gather additional data from producers to better estimate what the real cost would be of addressing issues of social license to operate on a basin-by-basin level. The question for industry might then be: Are these added costs worth absorbing—and an acceptable price to pay—to ensure both greater public and utility-sector confidence in the production practice over the longer term?

Understanding the price impacts of a Dash-to-Gas case is still poorly characterized due to the newness of the recent change in natural gas supply outlook. Based on currently available estimates, a fairly strong dash-to-gas in other sectors of the economy would have a visible, although still marginal, impact on the evolution of the electric power sector—with natural gas use declining somewhat due to the higher prices and other forms of generation increasing to take its place. As additional experience and estimates of this elasticity become available, follow-on research should re-examine the impacts.

4.8 Conclusions for Power Sector Modeling

The role of natural gas in the U.S. power sector is sensitive to assumptions about EUR. More research is needed to better understand how much gas will ultimately be recovered from unconventional plays.

Coal retirements and fuel switching are already occurring ahead of the rollout of EPA rules. The modeling results indicate that any new plants needed to replace retiring coal would mostly be fired by natural gas and that on an aggregate level, reliability standards are maintained without an unusual level of new construction. This analysis did not attempt to evaluate location-specific reliability impacts associated with coal-plant retirements; more granular dispatch models would be needed to investigate those questions with more certainty.

The CES modeling results indicate that substantial reductions in CO_2 emissions are achievable at modest cost, although transmission barriers could stand in the way. When CCS is not available under a CES, generation options decline, the need for new transmission expands significantly, and the power mix becomes less diverse. Therefore, CCS is an important option for a low-carbon power sector, but may not be essential.

Continued focus on technology research, development, and deployment is needed to bring down costs and ensure a diverse power mix in the future. Even modest reductions in renewable energy capital costs and improvements in performance may have a meaningful impact on their continued deployment in the future. Continued advancements in technologies used to find and produce unconventional gas could also have a strong impact on improving the social license to operate at an acceptable price, and thus, should be pursued at all levels.

Finally, increased costs associated with potential changes in field practices of natural gas producers were evaluated over a fairly broad range. If these costs turn out to be less than an incremental $1/MMBtu, then the long-term impact on natural gas in the power sector is not significantly different from the baseline conclusions: gas demand for power generation declines by about 17% while CO_2 emissions increase marginally. An important outcome of this study—and a potential question for follow-on research and discussion—would be whether these additional costs associated with protecting the environment, improving safety, and commanding public confidence are worthwhile to society and gas producers.

Natural gas appears plentiful and at historically low price levels for the foreseeable future, but going forward, decision makers may want to pay special attention to generation diversity. An undesirable outcome would result if a major shift to natural gas generation occurred before a substantial rise in natural gas prices—due, for example, to mischaracterizations of EUR, a failure to earn the social license to operate, or some other reason that may currently be considered "unlikely." Continuing research, development, and deployment over a wide variety of generation and gas production options can help prevent such an outcome. It would also provide greater flexibility in addressing the threat of climate change.

5 Conclusions and Follow-On Research Priorities

5.1 Conclusions

Major, high-level findings derived from the research conducted in this study include:

- Life cycle greenhouse gas emissions associated with electricity generated from the Barnett Shale play gas in 2009 were found to be very similar to conventional natural gas and less than half of those associated with coal-fired power generation.
- Low-priced natural gas has led to more than 300 terawatt-hours of fuel switching from coal to gas in the U.S. power sector between 2008 and 2012. This switching, in combination with rapid growth in certain renewable energy generation sources, has led to a reduction in power-sector carbon dioxide emissions of about 300 million tons—about 13% of the sector's total. This fuel switching may stop or reverse itself if natural gas prices rise relative to coal. Natural gas can play an important role in greenhouse gas mitigation over the short- to mid-term, but if policymakers pursue an 80% mitigation target by 2050, carbon capture and sequestration may need to be commercially viable by 2030 for natural gas power generation to continue growing.
- The legal and regulatory frameworks governing shale gas development are changing in response to public concerns, particularly in regions that have less experience with oil and gas development. All of the states examined in this study have updated their regulatory frameworks to address the opportunities and challenges associated with greater unconventional natural gas production. Better coordination and information sharing among regulators may help ensure efficient and safe production, while greater availability of transparent and objective data may help address some of the public's concerns.
- States and natural gas producers are developing additional, often voluntary, field practices to ensure that shale gas can be produced with high standards of environmental protection—although these standards are not always uniformly followed. Continued advances in technologies and practices could help address public concern over unconventional gas production. Some data, such as the amount of water used per well in hydraulic fracturing, are readily available and can be analyzed on a regional basis. However, a lack of publicly available information on industry practices limits a full-scale assessment of water risks associated with shale gas operations. Further collaboration and interaction with industry partners could help improve data collection efforts.
- A suite of different future electric power scenarios was evaluated to test the implications of different policy and technology changes. These scenarios include power plant retirements, advances in generation technologies, federal policies to reduce greenhouse gases, and variations in natural gas supply and demand. The study found that natural gas use grows robustly in nearly all scenarios over the next two decades. Over the longer term, natural gas demand for electricity generation faces greater uncertainty, leading to larger ranges of change in gas demand—including the case where demand in 2050 is roughly the same as that in 2010 in the event a clean energy standard is pursued and carbon capture and sequestration is not commercially available (see Figure 32).

Readers should consult corresponding chapters to view more comprehensive findings and ensure that the appropriate context is conveyed with each finding.

5.2 Follow-on Research

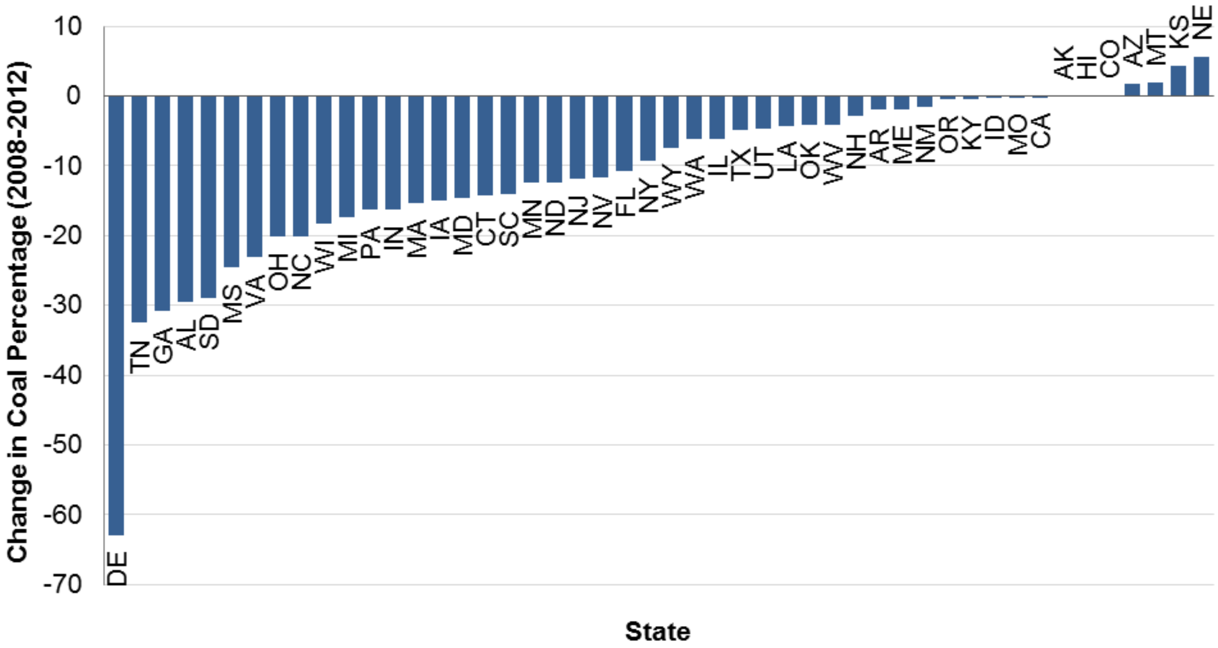
Because of time and budget constraints, the research team could not investigate some issues as fully as warranted. Each chapter identifies areas where additional research would likely lead to improved understanding on certain issues. Selected follow-on research taken from this larger list is presented below. Please refer to the main chapters for a more comprehensive discussion on these follow-on research topics.

- More field-measurement-based research on methane leakage and mitigation options at unconventional gas production facilities (outside of the Barnett Shale play) considering geographic and operational variability at well, play, and national scales.
- More industry- and basin-specific research to estimate the incremental costs associated with various regulatory scenarios, including more robust environmental standards in unconventional gas production. Additional social research to understand how improved standards might impact public perception of gas production and the social license to operate. Additional economic research to understand how higher costs would impact producers, and the degree to which they might be able to pass costs on directly to consumers.
- More comprehensive evaluation of risks in shale gas production and how they can be best addressed using new technologies and field practices. Increased quantitative understanding of the magnitude and probability of risks to water resources that result from current industry practices and proposed best management practices. More comprehensive evaluation of the regional diversity of risks, costs, and effective industry practices inherent in shale gas development.
- Greater understanding of the impact of additional natural gas demand, especially liquefied natural gas exports, on domestic and international prices. In general, greater certainty and understanding of natural gas price volatility and estimated ultimate recovery in the relatively new abundant natural gas environment would also be beneficial.
- Finally, this study did not use a modeling tool that simulated operation and expansion of natural gas pipelines. Follow-on work that included such capabilities might identify additional opportunities and barriers to growth in electric power natural gas use.

Appendix A: Shifting Coal Generation in U.S. States

This appendix summarizes recent data on changes in coal-fired electricity generation published by the Energy Information Administration (EIA) of the U.S. Department of Energy. Many of these changes are due to some combination of low-priced natural gas, aging coal generators, and impending regulations from EPA. However, some changes—especially in small states—could be unrelated. Using data at the state level—rather than the larger boundaries of regional transmission organizations or independent system operators—is somewhat artificial when showing changes in electricity generation. Nevertheless, state-level data are convenient, and important trends can be seen in the grouping of some states.

Figure 41 presents a snapshot of the change in coal-fired generation percentage between 2008 and the first 2 months of 2012 for most states. The charts that follow provide additional information on how changes in generation mix have occurred in the first 15 states shown in Figure 41.



Data: U.S. Energy Information Administration, Electric Power Monthly, data through February 2012.
Note: DC, RI, and VT are not included.

Figure 41. Changes in coal percentage of total net generation at the state level, 2008–2012

Figure 42 through Figure 56 show how generation mix has changed between 2005 and early 2012 for the 15 states with the largest drop in coal percentage as a percent of total net generation. The data for all of these figures come from the U.S. Energy Information Administration, “Electric Power Monthly.” The data are through February 2012, and the 2012 data include only January and February net generation. Some seasonal effect is reflected in the 2012 year-to-date data points.

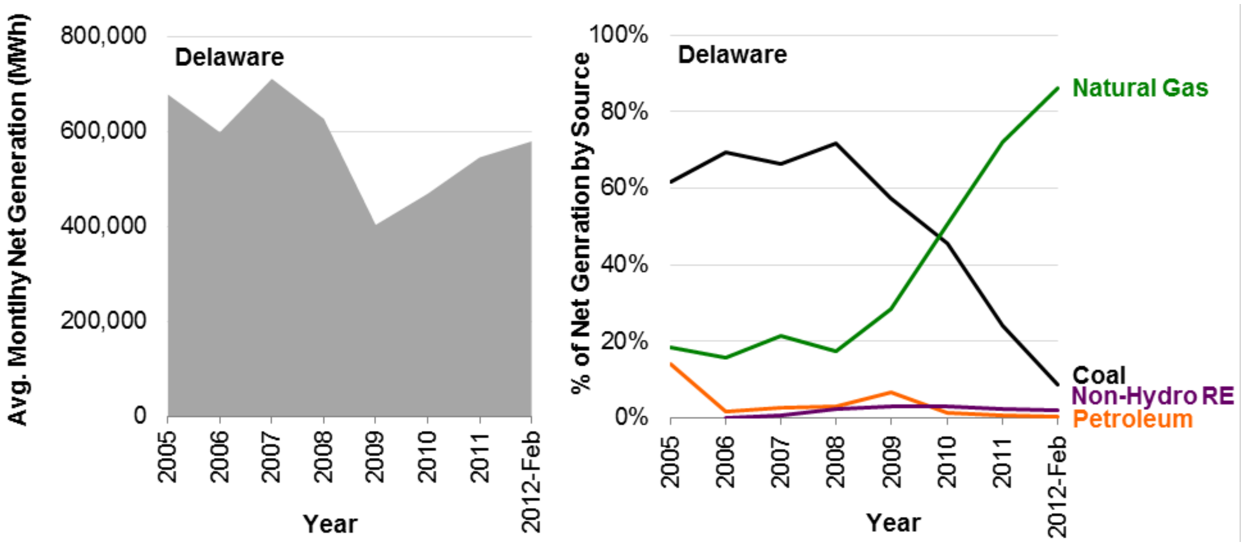


Figure 42. Changes in generation mix in Delaware; 2005–early 2012

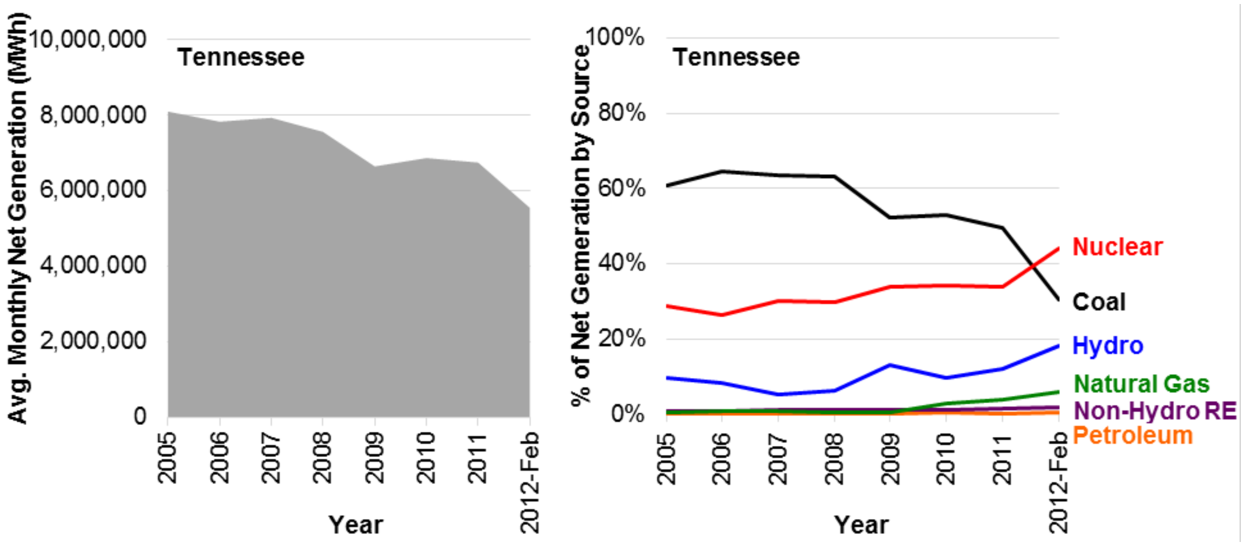


Figure 43. Changes in generation mix in Tennessee; 2005–early 2012

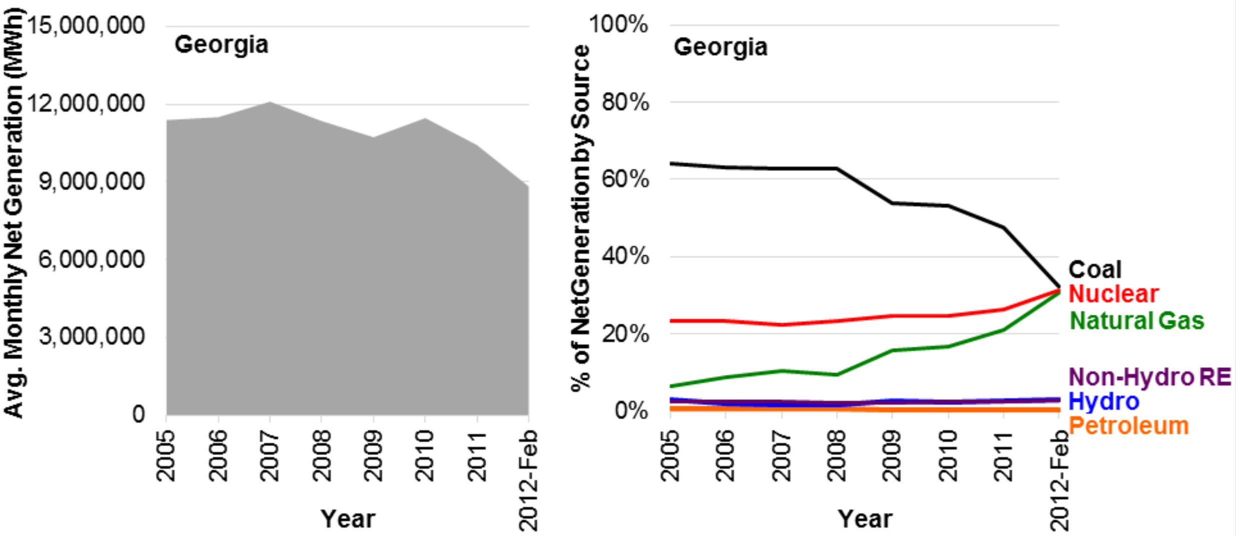


Figure 44. Changes in generation mix in Georgia; 2005–early 2012

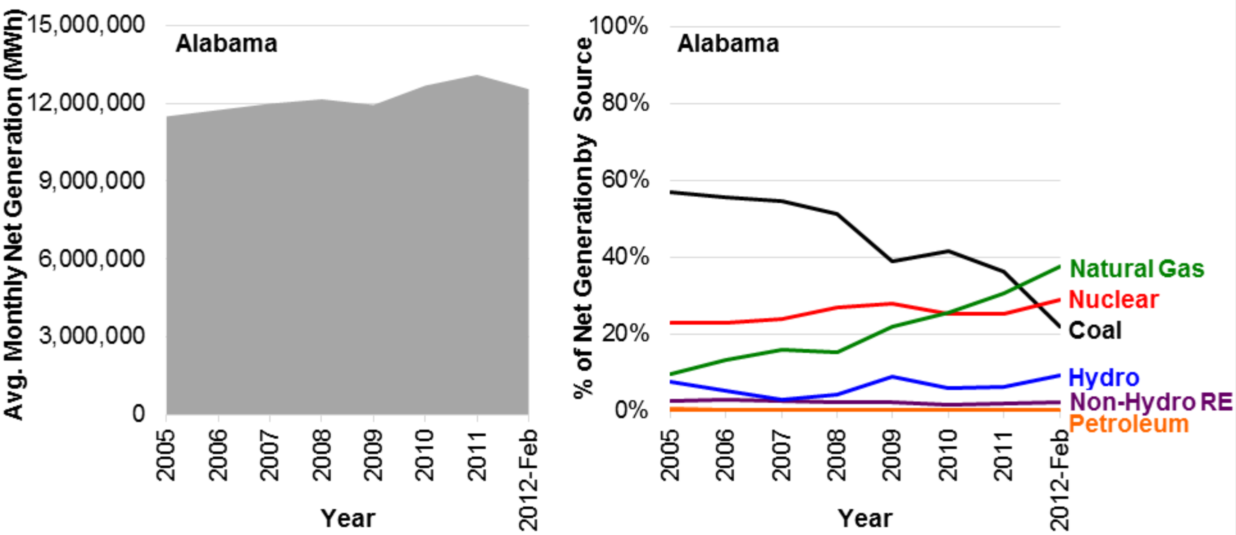


Figure 45. Changes in generation mix in Alabama; 2005–early 2012

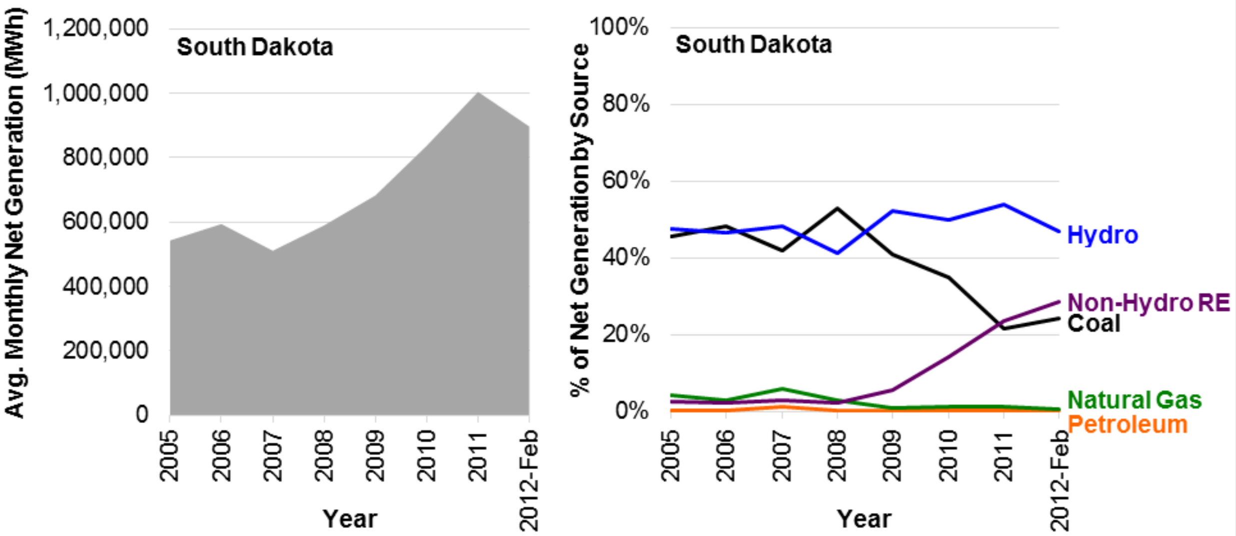


Figure 46. Changes in generation mix in South Dakota; 2005–early 2012

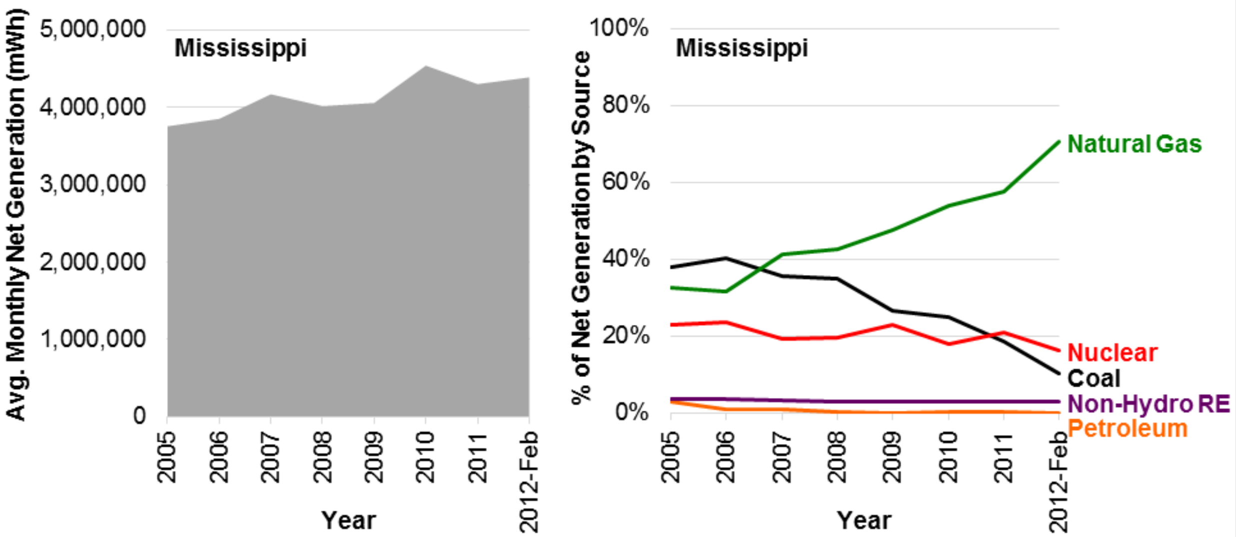


Figure 47. Changes in generation mix in Mississippi; 2005–early 2012

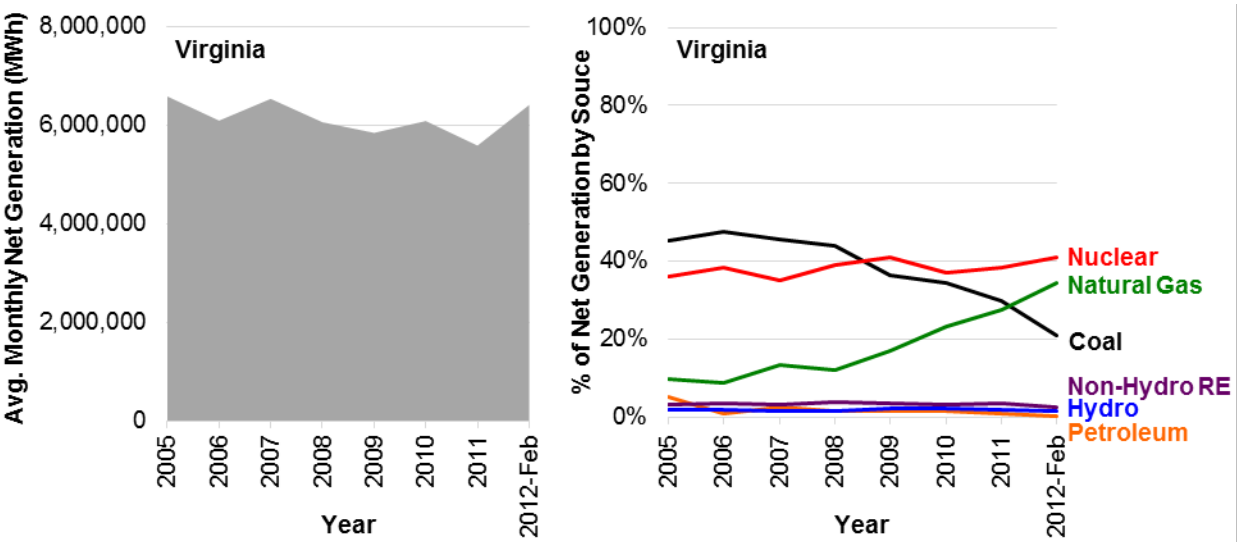


Figure 48. Changes in generation mix in Virginia; 2005–early 2012

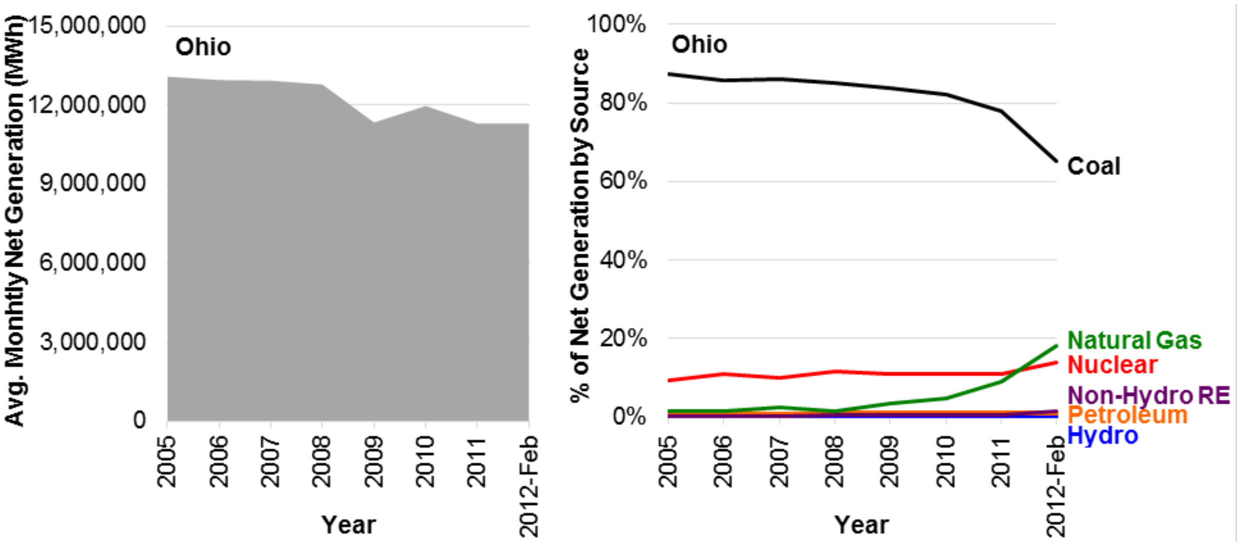


Figure 49. Changes in generation mix in Ohio; 2005–early 2012

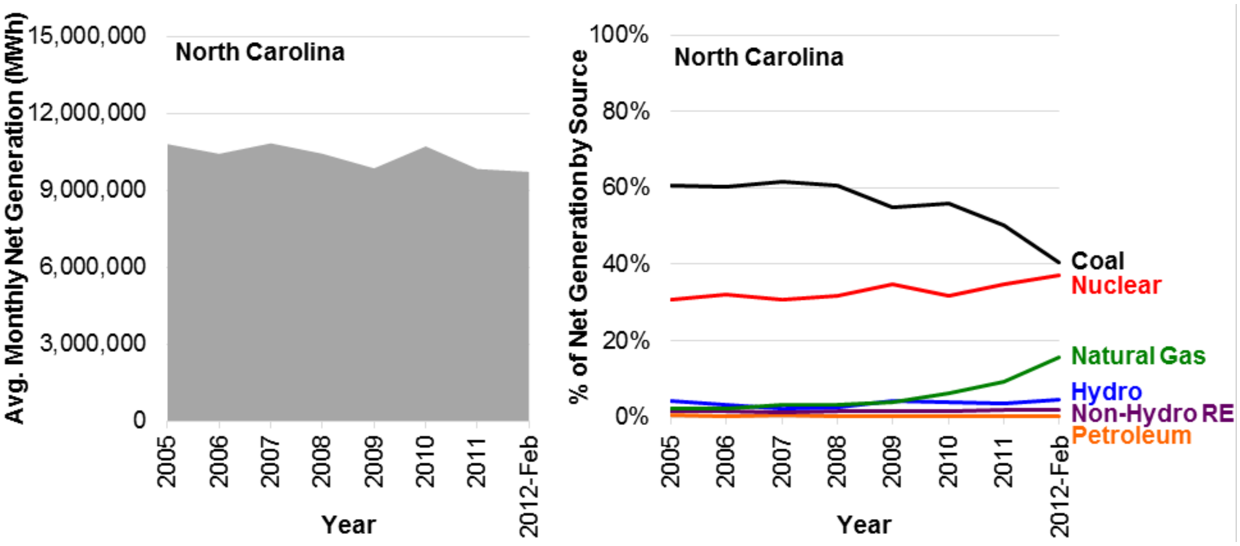


Figure 50. Changes in generation mix in North Carolina; 2005–early 2012

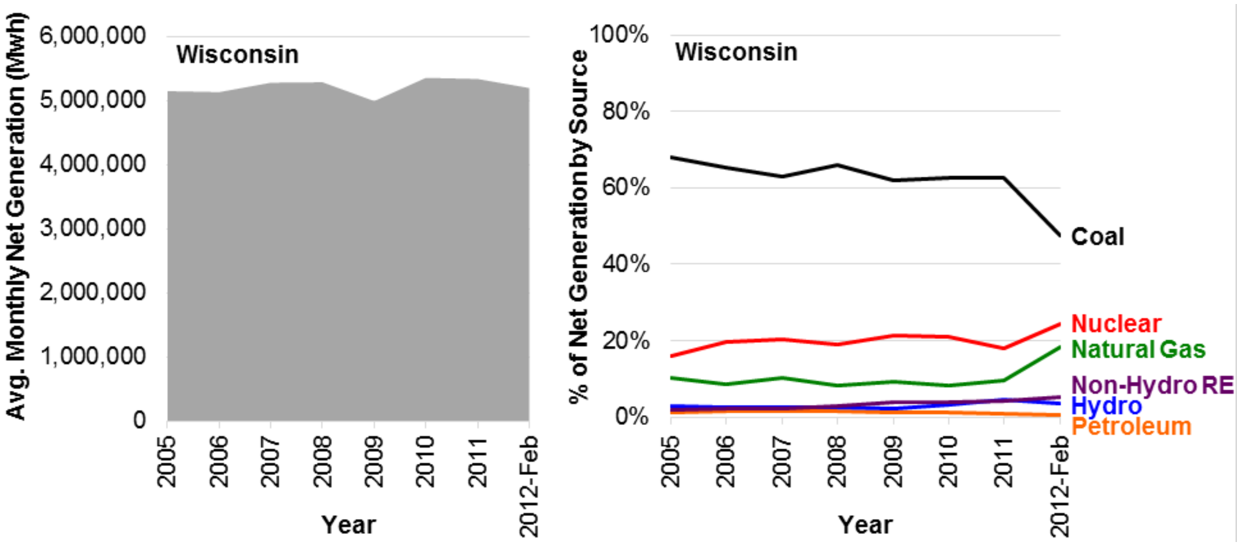


Figure 51. Changes in generation mix in Wisconsin; 2005–early 2012

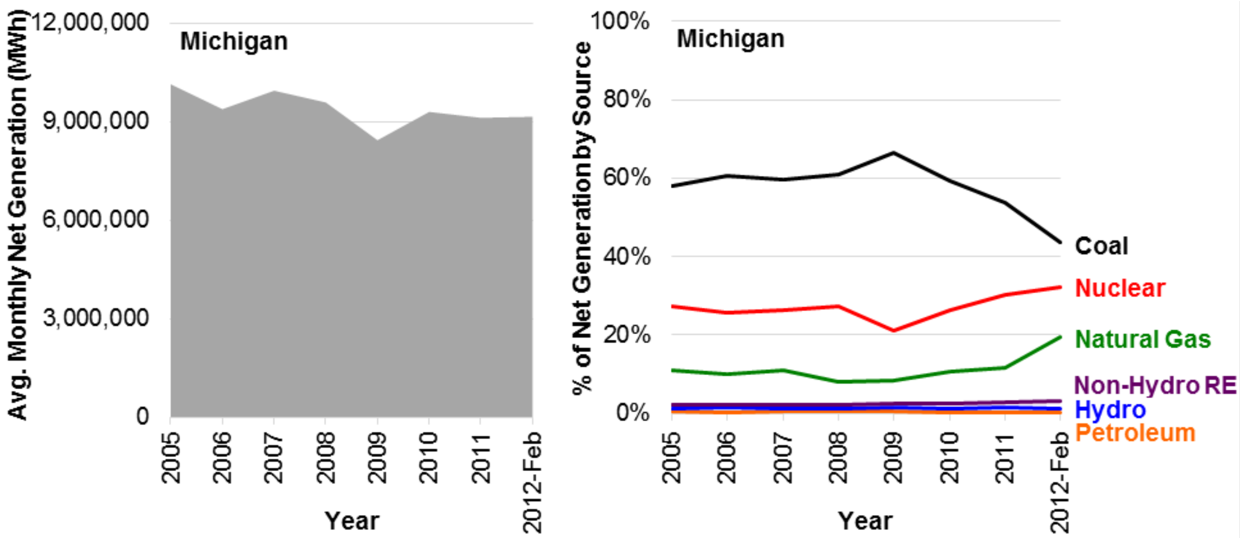


Figure 52. Changes in generation mix in Michigan; 2005–early 2012

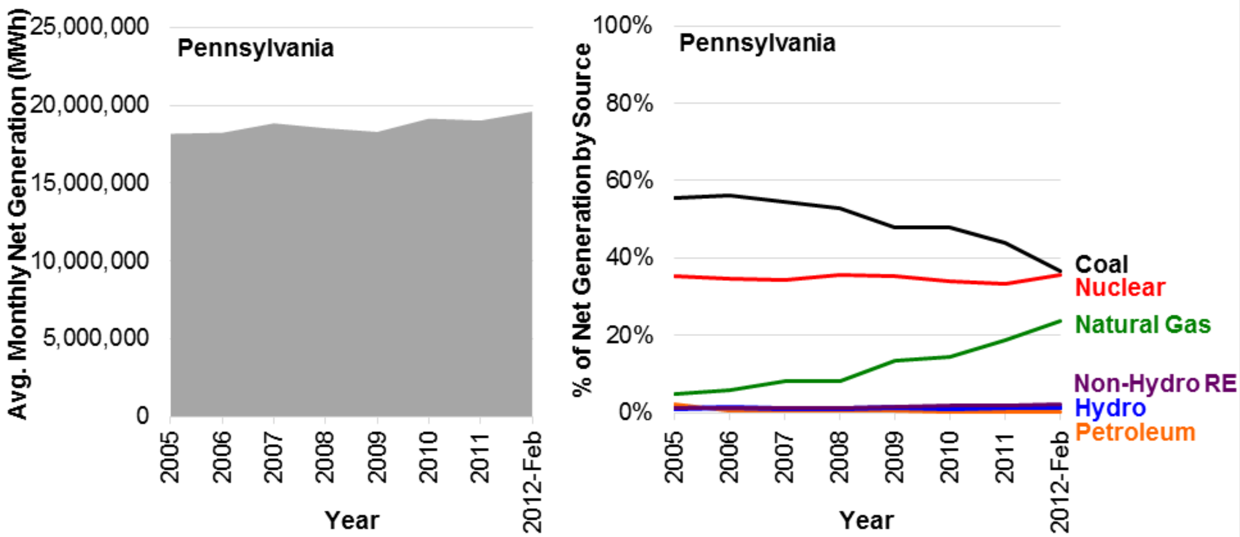


Figure 53. Changes in generation mix in Pennsylvania; 2005–early 2012

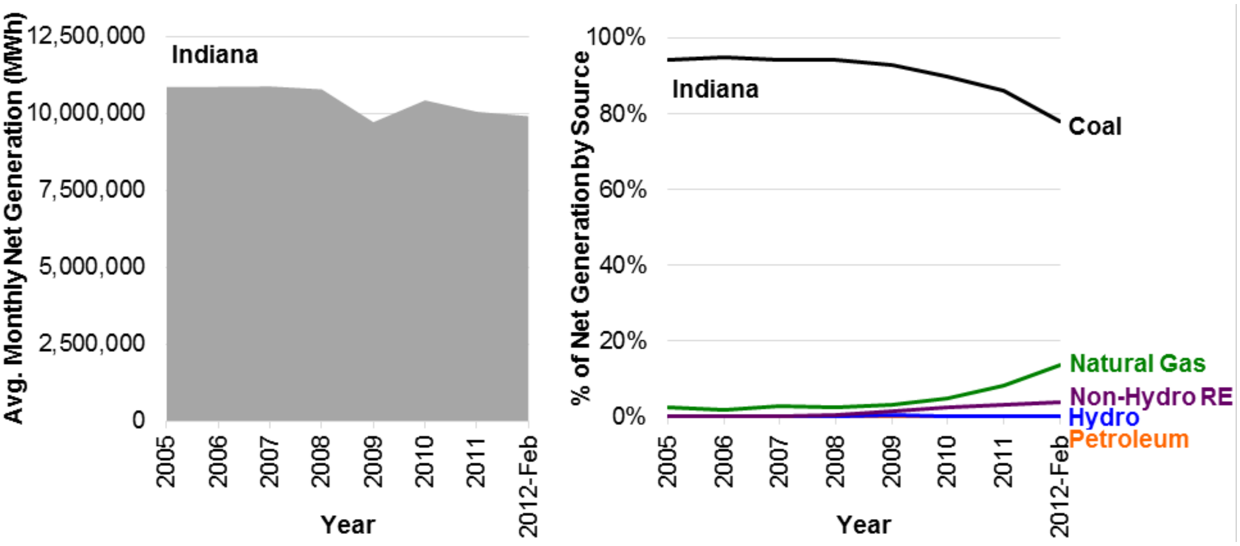


Figure 54. Changes in generation mix in Indiana; 2005–early 2012

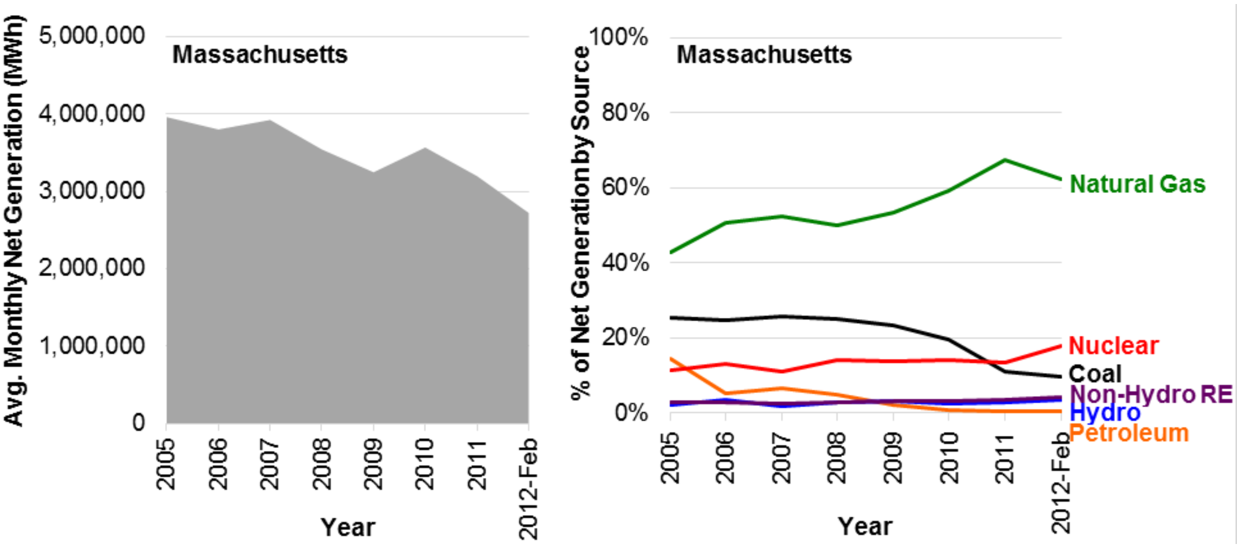


Figure 55. Changes in generation mix in Massachusetts; 2005–early 2012

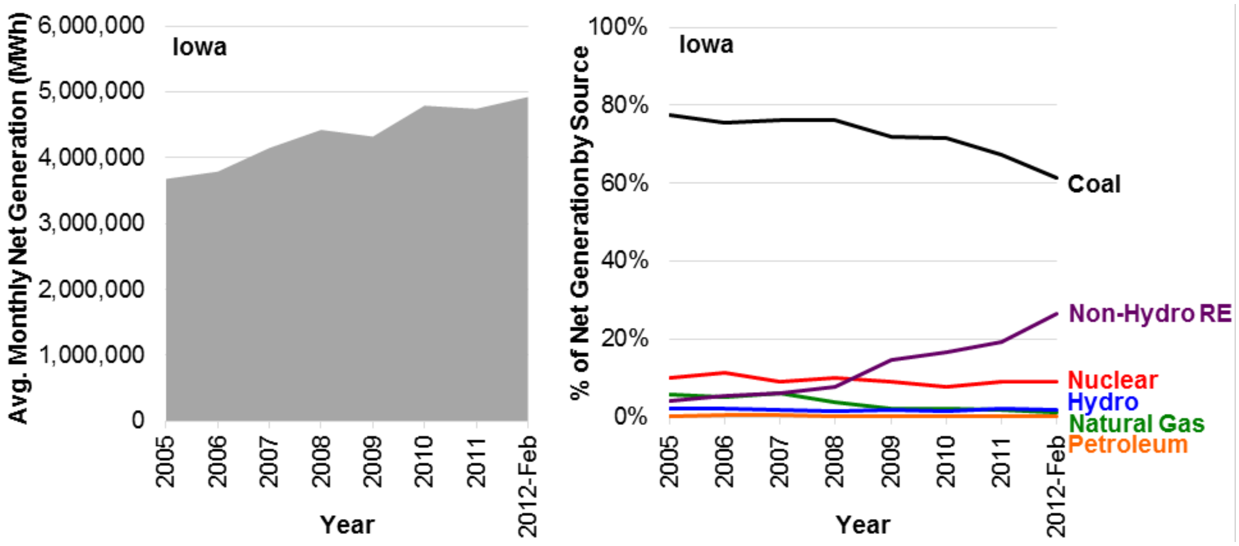


Figure 56. Changes in generation mix in Iowa; 2005–early 2012

Appendix B: Details and Considerations of Methods

This appendix offers details of data, methods, and results for Chapter 1. First, we define several terms relevant to estimating GHG emission factors from the TCEQ inventories.

The *basin* refers to 22 counties under which the Barnett Shale is being developed. Therefore, production in the basin includes production from the Barnett Shale as well as a small amount of additional production from other geological formations contained within the 22 counties.

As defined by the TCEQ (2010: p.23), "any source capable of generating emissions (for example, an engine or a sandblasting area) is called a facility. Thus, facility and emissions source, or 'source' for short, are synonymous." To avoid confusion, we use the term *source* to refer to any individual such facility.

Sources can be characterized into common types called *profiles*. Common examples of profiles include engines, turbines, fugitives, and tanks. Profiles are designated such that the emissions from sources with the same profile can all be estimated with a common method.

The term *site* refers to a physical location for which data are reported to the inventories, where each site consists of multiple different emissions sources. Each site is associated with a unique TCEQ account number and site name. Common examples of types of sites include wells, compressor stations, and gas processing plants. In the Special Inventory, sites are referred to as *leases*.

Production gas refers to the raw, unprocessed gas captured through development activities, and *pipeline gas* refers to the saleable final natural gas product. *Emissions* refer to tons of the specified pollutant(s) emitted per year, whereas *emission factors* refer to the amount of emissions associated with a unit of gas production. This report follows the EPA and TCEQ convention of referring to the set of non-methane, non-ethane hydrocarbons as *VOCs*.

TCEQ Inventory Data

The TCEQ collects an annual, statewide emissions inventory for sources classified as point sources per 30 Texas Administrative Code §101.10. For this study, data were obtained for any sources within this inventory with Standard Industrial Classification (SIC) codes pertaining to the production and processing of natural gas. From the point-source inventory data, GHG emissions are estimated from amine units, boilers, compressor engines, flares, fugitives, glycol dehydrators, heaters, produced-water loadings, produced-water tanks, natural gas turbines, and vents.

To complement the point-source inventory, the TCEQ performs an Area Source Inventory every three years. Data were obtained from the 2008 Area Source Inventory on VOC emissions from pneumatics and produced-water disposal activities, which were not available in the other inventories. These data are reported only at the county level. To combine emissions estimated from pneumatics with those estimated from other inventories, these profile's emissions are adjusted by a factor equal to the change in gas production between 2008 and 2009, at the county level, as shown:

$$Adjustment = \frac{Q_{GWgas,2009}}{Q_{GWgas,2008}}$$

where:

$Adjustment$ = the county-level adjustment from 2008 to 2009 emissions estimates (unitless)

$Q_{GWgas,2008}$ = volume of gas-well gas produced in 2008 (Mcf)

$Q_{GWgas,b,2009}$ = volume of gas-well gas produced in 2009 (Mcf).

In 2009, the TCEQ performed a Special Inventory, for which it requested detailed equipment and production information for stationary emissions sources associated with Barnett Shale oil and gas production, transmission, processing, and related activities. The Special Inventory data cover only stationary emissions sources on site for more than 6 months that were not reported to the 2009 Point Source Inventory. These sources are used in this study to estimate GHG emissions from amine units, boilers, heaters, compressor engines, flares, fugitives, glycol dehydrators, produced-water loadings, produced-water tanks, and vents.

Some emissions sources are not reported to the Special Inventory that nonetheless contribute to the reported site-level total in that inventory. These sources are likely omitted because their emissions are below thresholds for reporting requirements for that inventory. However, although they may be individually negligible, their collective impact is significant—with the sum of the VOC emissions reported for all individual sources equaling only 93% of the sum of all site-level totals reported, across the entire inventory. To account for this underreporting, emissions estimated from Special Inventory data are scaled at the site-level by the inverse of the percentage of site VOCs accounted for by the individual sources reported at each site, as follows:

$$Correction_{site} = \frac{1}{\left[\frac{\sum_{k \in K_n} VOC_k}{VOC_n}\right]} = \frac{VOC_n}{\sum_{k \in K_n} VOC_k} \geq 1$$

where:

$Correction_{site}$ = the site-level correction for non-reported sources (unitless)

VOC_k = the mass of VOCs emitted from source k annually, where $k \in K_n$ is the set of reported sources at site n (tonne/year)

VOC_n = the reported total mass of VOCs emitted from site n annually (tonne/year).

In addition, to account for a stated 98% level of completion for the Special Inventory, all emissions estimated from the inventory's data by the inverse of that completion rate are also adjusted by the inverse of this estimate, as follows:

$$Correction_{inventory} = \frac{1}{98\%} = 1.0204$$

Stages of the Natural Gas Life Cycle

Emissions factors are compiled from the profiles associated with each life cycle stage.

Pre-Production Stage

The pre-production process stage consists of episodic activities related to the preparation of wells. Activities in this stage include the drilling and construction of wells, hydraulic fracturing of shale to stimulate production, and various well-completion activities, which specifically involve the following:

- *Drilling rigs* are used for drilling an oil or gas well. For the purpose of estimating emissions, rigs consist of a collection of diesel-powered engines, which are associated with combustion-generated GHG emissions.
- *Hydraulic fracturing* involves complex liquids, pumps, and trucks for transporting equipment and fluids, which are associated both with combustion-generated GHG emissions and with emissions from off-gassing and fugitives.
- *Well-construction activities* are associated with combustion-generated GHG emissions due to the use of heavy construction equipment.
- *Well-completion activities* involve the release of natural gas from a well before and during the installation of the equipment necessary for recovery of that gas.

Natural Gas Production Stage

The production process stage consists of ongoing activities related to the extraction of natural gas at a gas well. Emissions sources include the following:

- *Compressor engines* are used to maintain well pressure and for other processes at the wellhead. These engines, which typically burn the production gas being extracted, are associated with combustion-generated GHG emissions.
- *Fugitives* occur from the unintentional release of production gas through leaks from equipment and connections throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found.
- *Vents and blowdowns* refer to the intentional release of gas from equipment throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found.
- *Pneumatics devices* are used to open and close valves and other control systems during natural gas extraction. These sources are associated with gas release emissions, which depend on the composition of their identified contents.
- *Miscellaneous material loading and tanks* refer to sources at production sites that are associated with any materials not expected to be co-products of natural gas processing, such as gasoline, diesel, or lubricating oil. These sources are associated with gas release emissions, which depend on the composition of their identified contents.
- *Condensate and crude-oil-related sources*, including loading areas and storage tanks, are associated with substantial VOCs but occur in the process chain only after the co-products have been separated from the natural gas process chain. Therefore, although these emissions sources sometimes are reported in natural gas emission inventories, they are outside the boundary of this analysis.

Natural Gas Processing Stage

The processing process stage consists of ongoing activities related to converting the extraction production gas to the required quality, composition, and compression of pipeline gas. Activities in this stage include separating the condensate co-product from the gas, removing naturally occurring acid gases such as CO_2, lowering the moisture content of the gas, and pressurizing and heating the gas. These activities can occur at either the wellhead or at separate processing facilities, and they are associated with the following emissions sources:

- *Compressor engines and natural gas turbines* are used to pressurize the gas and power other processing activities. These engines, which typically burn the production gas being processed, are associated with combustion-generated GHG emissions.
- *Boilers and heaters*, which typically burn the production gas being processed, are used for processing activities, including the separation of condensate from natural gas and the reduction of ice crystals in the gas stream. Boilers and heaters are associated with combustion-generated GHG emissions.
- *Amine units*, also known as acid gas removal (AGR) units, remove acid gases, such as CO_2, from the production gas to help bring the gas composition to that required for pipeline gas. Amine units are associated with the release of GHGs through venting.
- *Glycol dehydrators* remove water from the production gas to help bring the gas composition to that required for pipeline gas. Dehydrators are associated with the release of GHGs through venting.
- *Fugitives* occur from the unintentional release of production gas through leaks from equipment and connections throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found. Because the precise composition of the fugitive gas cannot be identified, it is assumed that all fugitives consist of production gas.
- *Vents and blowdowns* refer to the intentional release of gas from equipment throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found. Because the precise composition of the vented gas cannot be identified, it is assumed that assume all vents and blowdowns consist of production gas.
- *Produced water handling*, including loading areas and storage tanks, is associated with gas release emissions, which are assumed identical in composition to water flash gas.
- *Flares* are combustion-based emission control devices used to convert methane from gas-release emissions into CO_2 from combustion emissions. Flares are used as controls on a variety of gas-release emission sources, including produced-water tanks, condensate tanks, and glycol dehydrators.
- *Miscellaneous material loading and tanks* refer to sources at processing sites that are associated with any materials not expected to be co-products of natural gas processing, such as gasoline, diesel, or lubricating oil. These sources are associated with gas-release emissions, which depend on the composition of their identified contents.

- *Separators* are used for processing oil and natural gas; however, only separators at oil sites vent to the atmosphere. Therefore, separators at sites producing only natural gas and not oil should be associated with no VOC emissions. Although these emissions sources sometimes are reported in natural gas emission inventories, they are outside the boundary of this analysis.
- *Thermal oxidizers* are used for processing natural gas, but only a negligible number are reported in the inventories used because of prohibitive capital costs. Therefore, although these emissions sources sometimes are reported in natural gas emission inventories, they are outside the boundary of this analysis.

Waste Disposal Stage

Natural gas production and processing generates the byproduct of produced water, which must be disposed of because of its high level of contaminants, including salt, hydrocarbons, and various pollutants. Although these activities are associated with stationary and mobile emissions sources, the only tracked emission source for this category is that pertaining to tanks that store the produced water at disposal sites.

Identification of Source Profiles and Attribution to Process Stages

This study identifies the process stage (e.g., production, processing, or transport) to which each source belongs using the provided site names in both inventories. To attribute sources to process stages, the profile associated with each source must first be identified. In the Special Inventory, each source is explicitly identified with the profile under which it was reported to the TCEQ. For the sources in the Point Source Inventory, however, the profile of each source is identified using additional provided information.

The primary source of information for this profile identification is the Source Classification Code (SCC). As described by the TCEQ (2010: p. 90), “A facility’s SCC is an eight-digit EPA-developed code that associates emissions determinations with identifiable industrial processes. The TCEQ uses a facility’s SCC for modeling, rulemaking, and SIP-related activities; therefore, a facility’s SCC must be as accurate as possible. The EPA maintains a current list of SCCs under the ‘EIS Code Tables (including SIC)’ link at www.epa.gov/ttn/chief/eiinformation.html.”

Despite the regulatory importance of the SCC classification, the SCCs provided in the Point Source Inventory do not identify the associated source’s profile to the detail necessary for 254 (or 12%) of the 2,177 sources within the 22 counties of the basin. The remaining sources rely on the additional information within characteristics files provided by the TCEQ for specific profiles, such as tanks and engines, and by consistent coding schemes within the Facility Identification Number, which is self-designated by the respondents to the emissions inventory surveys. The study identifies 43 (or 2%) of the sources by characteristics files and 211 (or 10%) by the Facility Identification Number, which represent 1.4% and 2.0%, respectively, of the total VOCs reported for all reported sources within the 22 counties of the basin.

For those source categories that can exist at multiple types of process stages, the default assumption is that a location is a production facility (i.e., a well site), unless the site name (“Lease Name” in the Special Inventory and “Site Name” in the Point Source Inventory) is identifiable as belonging to a facility type associated with the processing stage, such as a processing plant or a compressor station, or with the disposal stage, such as salt-water disposal sites. In addition, four sites identified as disposal by this method are reassigned to production due to non-zero gas-well gas production statistics, which means all sources at those four sites are assigned to production, although some presumably relate to water-disposal activities instead. To the extent that this allocation method introduces an error, that error is not the omissions of emissions from the overall estimates, but rather, the incorrect allocation of total emissions across different process stages.

TCEQ inventory data are available for some pre-production processes, but such data cannot be used for original analysis because it incompletely covers the life cycle stage. Also, literature estimates available for supplementing the original analysis do not segregate between different processes as would be necessary for incorporation with the original analysis.

This study uses site-level allocation to select sources into the processing stage. The same site name in both the Point Source Inventory and the Special Inventory is used to positively identify processing sites, with the default stage for the remaining sites being production. Of the processing sites, following the recommendation of the TCEQ,[149] those that do not have any processing-related sources are designated as transmission sites, and accordingly, are considered outside the boundary of this analysis.

After site-level identification, processing-type sources at production sites are associated with the processing life cycle stage. Such equipment includes heaters, boilers, amine units, and dehydrators. In addition, following Stephenson et al. (2011), this study assumes that all tanks—and therefore, also all loading (which occurs after tanks in the process chain)—belong to the processing stage and not the production stage, regardless of where the tanks are physically located.

To avoid double counting with third-party emission factors for transmission, transmission sites (identified as non-well facilities without any processing equipment) are omitted from the analysis of TCEQ inventory data. Specifically, 833 sources are omitted from the special inventory and point-source inventory analyses as pertaining to transmission. This represents 5% of the total sources from these inventories, or about 10% of the CO_2 and the CH_4 emissions from these inventories.

Spatially Explicit Estimation of Production Gas Composition

An important differentiation of this study's estimation approach from similar studies is that this study attempts to estimate the composition of production gas in a specific area. The methods used in this study improve upon the use of a general gas composition developed from national-level averages by 1) developing a novel gas composition estimate that is specific to a region of interest, but also by (2) further recognizing the spatial heterogeneity of this composition within the 22-county basin. Specifically, this method collects data on speciation of production gas and the flash gas from produced water to calculate the CO_2 and CH_4 emissions from numerous sources in the TCEQ Special Inventory using spatially explicit estimates of gas composition. The following factors come from this speciation:

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[149] Personal communication (TCEQ 2012).

f_C == the fraction of carbon in the production gas by mass (unitless)

f_{CO_2}= the fraction of CO_2 in the production gas by mass (unitless)

f_{CH_4}= the fraction of CH_4 in the production gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless)

MW_{gas} = the molecular weight of the production gas (lb/lb-mole)

HHV = the higher heating value of the production gas (Btu/scf).

These data are collected from supplementary files from the TCEQ's Barnett Shale Phase Two Special Inventory. As part of the quality assurance procedures of this Special Inventory, the TCEQ requested supplementary files from respondents. These files consist of a record of the written correspondence between the respondent and TCEQ, which varies considerably in content and form across different respondents. To estimate gas composition across the Barnett Shale region, this analysis focuses on included reports from independent laboratory analyses of the gas compositions, identifiable as pertaining to relevant samples of either production gas or of leaked gas in the form of vents or gaseous fugitives. Due to the nature and the origin of these files, the inclusion and reporting of such gas content analyses are not consistent across different files. Detailed supporting information—such as the specific origin of the sample tested, both with respect to process and geographic location—is not consistently available; therefore, it cannot be confirmed in many cases.

Given the disparate nature of these files and the inconsistent reporting of identifying information, these analyses therefore omit many reported composition analyses due to a lack of clarity regarding the geographical or process-source of the analyzed sample. Instead, those analyses are retained that can be assigned a location and content type with a reasonable level of confidence. The creation of these supplementary files and selection of a subset of them for obtaining gas composition analyses is neither random nor intended to be representative; therefore, such elimination does not introduce selection bias created by such omissions. The randomness of the errors will lead to attenuation bias of the analytical results, which is typical in cases of measurement error where there is no reasonably expected consistent bias to the error. In this context, measurement error should reduce the impact of calculating the spatial variation in gas content versus using the central estimate of gas content across the entire region.

In a related limitation of this method, we identified a substantial number of duplicate analyses in these records associated with different lease locations and even across different counties, based on identifying identical laboratory-assigned sample numbers and identical compositions to the reported level of precision provided by the same company. We attempted to identify and remove duplicate analyses; but misspecification in the dataset is possible because it is unclear in some cases which analysis is the original source.

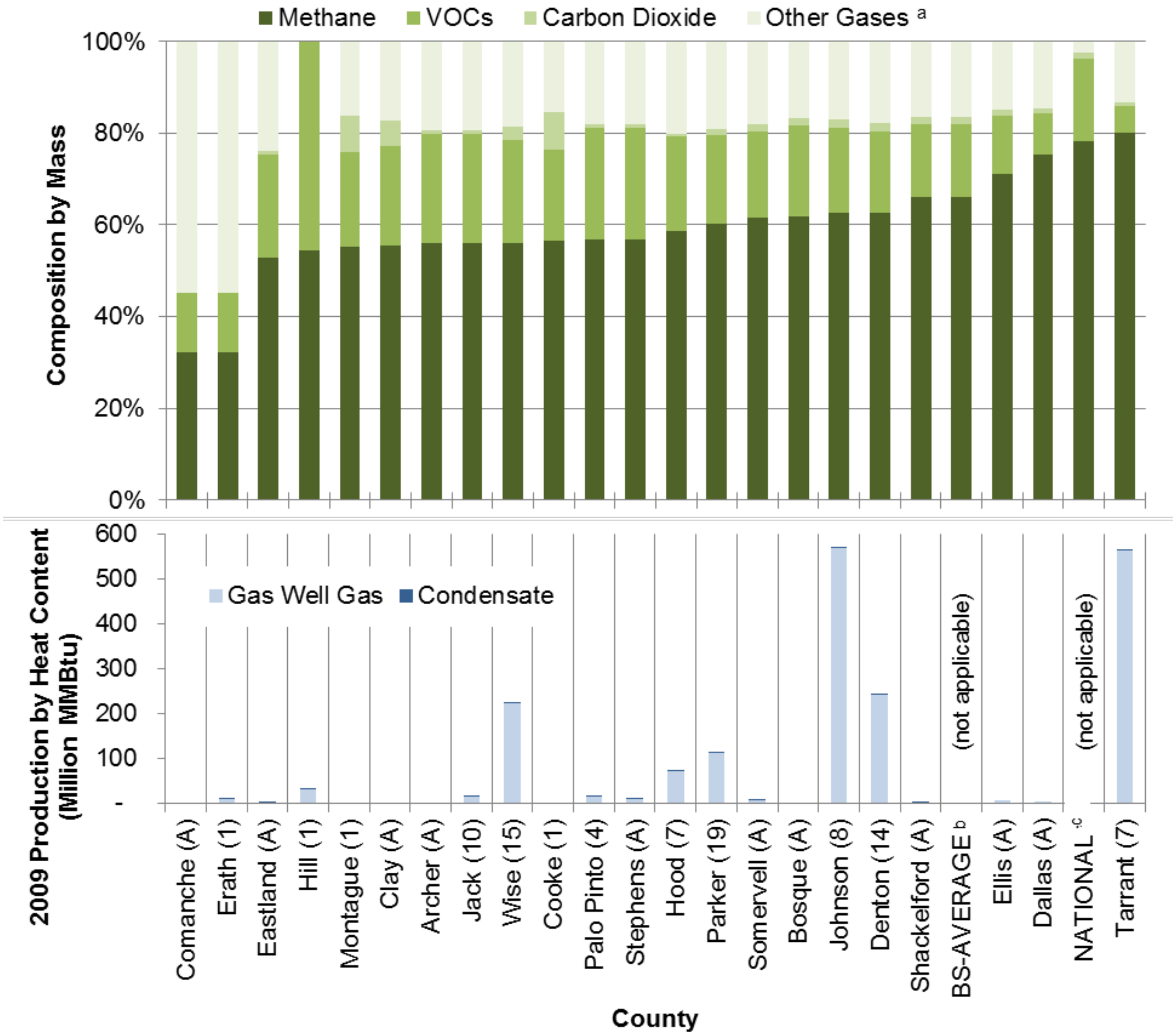
From these data, county-level estimates of gas composition are developed separately for production gas, condensate flash, oil flash, and produced-water flash. Counties with one or more available composition analyses are assigned the composition analysis with the median level percentage-by-weight of methane in the reported composition analyses. In addition to providing a central estimate of gas composition for each county, this estimation of central tendency buffers the results against the impact of misspecifications of location described above.

We used a production-weighted average of the median adjacent counties' estimates with reported composition analyses for counties with no reported composition analyses. A production-weighted average of all reported composition analyses across the Barnett Shale region is used for the few counties with no reported composition analyses either for that county or for all adjacent counties.

In addition to attempting to err on the side of caution in including gas composition analyses, we estimated the sensitivity of the analysis to the gas composition by comparing results of this study's method—which uses the county-level gas composition estimates as described above for emissions estimates—to results using the same emissions estimation calculations with two different sets of alternative gas compositions: one reflecting the production-weighted average of this study's gas analyses from the TCEQ Special Inventory supplementary files and another reflecting standard assumptions of gas composition identified in the literature. Given the imperfect source of information and the assumptions on which this study's analysis depends, substantial variation between these different methods makes a compelling case for the importance of using geographically appropriate gas compositions that are accurate to a reasonably fine scale when estimating GHG emissions from natural gas extraction and production. This study's approach provides the best-available approximation, using the best-available data, of a spatially explicit definition of gas compositions relevant to estimating GHG emissions. To improve on this analysis, future data collection efforts should emphasize the measurement and reporting of spatially explicit gas compositions.

Estimated Composition of Production Gas

The top panel of the Figure 57 presents the estimates of the main components of production gas from each of the 22 counties of the Barnett Shale play, as well as the Barnett Shale production-weighted average and the national average commonly used in the literature. Key parameters and production statistics for each county are also presented in Table 17 and Table 18. Components, which are shown in their mass percentage within the production gas, include methane, VOCs (as defined above to include all non-methane and non-ethane hydrocarbons), CO_2, and other gases. Primary gas species represented in the "other" category are nitrogen and ethane. The lower panel of Figure 57 depicts, for reference, the production volume for each county. Shown after each county's name is the number of unique analyses collected for that county—with counties estimated by a weighted average of adjacent county's compositions designated with an "A," rather than a number.



[a] "Other" gas include nitrogen, ethane, and any other non-methane, -VOC, or -carbon dioxide gases reported
[b] BS-AVERAGE refers to the production-weighted average gas composition in the 22-county Barnett Shale basin
[c] NATIONAL refers to the national average composition commonly used in the literature (EPA 2011)

Figure 57. Composition of production gas by county

NOTE: number of gas composition samples is reported in parentheses following each county name, where "A" denotes counties with no samples such that samples from adjacent counties were substituted.

The gas composition estimates for the six counties that represent the vast majority of production volumes are supported by high numbers of estimates. However, reflecting this study's non-random, targeted strategy for seeking these estimates, many of the estimates for the remaining counties come from either a small number of estimates or the weighted average of adjacent counties. Specifically, no usable estimates were found for 10 of the 22 counties.

The uncertainty inherent to this approach for obtaining gas analyses is highlighted by the difference in gas composition in Comanche County and Erath County versus the majority of the counties. These compositions, which are both estimated by a single analysis from Erath County, show an abnormally large presence of nitrogen—and thus, are suspect of contamination with ambient air. However, the available information offers no verifiable support of such suspicion. The presence of such uncertainty emphasizes the need for better documentation of gas composition if this factor is to be used in further analysis or other factors, such as implementing regulations. However, it is important to note that the very low production volumes associated with these two counties means that their analyses have a nearly negligible impact on the overall results.

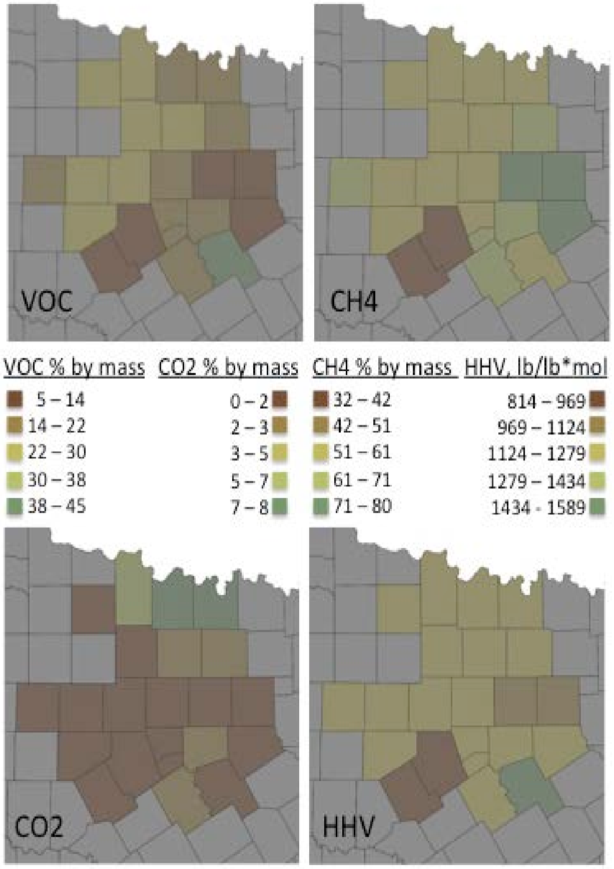


Figure 58. Variation among gas compositions across the 22 counties of the Barnett Shale play

The variation among gas compositions is demonstrated as being patterned across the 22 counties of the Barnett Shale play differently for different key parameters, as shown Figure 58. Such patterned distribution is to be expected if the observed variation reflects geological heterogeneity rather than simply uncertainty in the sampling methodology. The counties represented by weighted averages are located primarily on the western and eastern periphery of the region; therefore, the central north-south corridor represents both the majority of production and the estimates supported by larger samples. Along this corridor, parameters can be observed to vary relatively smoothly, although the differentiation between different parameters demonstrates the complexity of the variation in gas composition. In other words, this map demonstrates that gas composition varies across space, but also, it suggests that the complexity of this variation might extend to finer scales than the county level.

Table 17. Composition of Production Gas and Produced-Water Flash Gas in Barnett Shale Counties

	Production Gas						Produced-Water Flash Gas		
County	**Molecular Weight (lb/lb-mole)**	**Higher Heating Value (Btu/scf)**	**Carbon Content (% by mass)**	**Methane (% by mass)**	**VOCs (% by mass)**	**Carbon Dioxide (% by mass)**	**Methane (% by mass)**	**VOCs (% by mass)**	**CO_2 (% by mass)**
Comanche	23.86	813.78	43.6	32.2	12.9	0.2	33.5	24.8	31.1
Erath	23.86	813.78	43.6	32.2	12.9	0.2	43.1	34.8	7.8
Eastland	22.07	1,188.04	69.3	52.8	22.4	0.7	27.7	52.0	6.4
Hill	26.92	1,589.66	79.2	54.5	45.6	0.0	38.3	5.8	54.8
Montague	21.99	1,216.13	72.6	55.1	20.7	8.1	53.3	17.4	13.0
Clay	21.86	1,229.52	73.2	55.4	21.8	5.5	26.7	6.2	61.1
Archer	21.63	1,253.47	74.2	55.9	23.8	1.0	26.7	6.2	61.1
Jack	21.63	1,253.47	74.2	55.9	23.8	1.0	26.7	6.2	61.1
Wise	21.79	1,274.01	75.5	56.0	22.6	2.9	59.5	19.9	1.9
Cooke	21.76	1,199.75	72.2	56.5	20.0	8.1	46.8	17.2	18.0
Palo Pinto	21.72	1,261.53	74.3	56.9	24.3	0.8	27.7	52.0	6.4
Stephens	21.72	1,261.53	74.3	56.9	24.3	0.8	27.7	52.0	6.4
Hood	21.19	1,248.33	75.2	58.5	20.8	0.6	48.2	29.1	8.2
Parker	20.85	1,242.78	75.9	60.3	19.3	1.2	16.3	52.4	1.1
Somervell	20.71	1,224.89	75.3	61.5	19.0	1.6	40.1	10.0	46.4
Bosque	20.89	1,236.59	75.5	61.7	19.8	1.7	38.3	5.8	54.8
Johnson	20.57	1,226.04	75.8	62.5	18.7	1.8	38.3	5.8	54.8
Denton	20.54	1,218.65	75.4	62.5	17.9	1.9	34.8	14.5	33.3
Shackelford	20.12	1,191.89	74.8	66.2	15.9	1.6	33.5	24.8	31.1
Ellis	19.41	1,159.09	74.6	71.0	12.9	1.3	32.5	19.4	43.2
Dallas	18.63	1,112.74	73.9	75.4	9.0	1.1	23.9	39.5	23.1
Tarrant	17.92	1,072.83	73.3	80.2	5.6	0.9	20.7	46.7	20.1
Barnett Shale Average[a]	20.12	1,191.89	74.8	66.2	15.9	1.6	33.5	24.8	31.1
National Average[b]	17.40	1,027.00	75.0	78.3	17.8	1.5			

[a] Barnett Shale average is a production-weighted average of counties for which original gas compositions could be obtained

[b] National average production gas reported in EPA (2011)

Table 18. 2009 Production Volumes from Barnett Shale Counties

Heat Content (MMBtu)

County	Oil	Condensate	Casinghead Gas	Gas-Well Gas	Combined Gas	County Total
Archer	6,018,590	737	458,853	21,351	480,205	6,499,532
Bosque	0	98	0	354,480	354,480	354,578
Clay	3,514,046	37,503	494,346	351,615	845,961	4,397,511
Comanche	31,946	8,046	54,996	513,967	568,963	608,955
Cooke	11,740,372	43,729	4,394,033	485,521	4,879,554	16,663,655
Dallas	0	0	0	4,923,785	4,923,785	4,923,785
Denton	486,574	2,516,461	1,023,276	241,825,407	242,848,683	245,851,717
Eastland	1,491,957	314,574	834,641	3,916,728	4,751,369	6,557,901
Ellis	6,125	0	0	7,552,672	7,552,672	7,558,797
Erath	34,829	218,806	123,445	10,657,734	10,781,179	11,034,814
Hill	7,267	471	0	31,983,129	31,983,129	31,990,868
Hood	16,553	2,660,894	156,109	72,781,121	72,937,230	75,614,677
Jack	3,999,135	878,025	2,261,462	16,294,739	18,556,202	23,433,361
Johnson	0	318,855	0	570,667,212	570,667,212	570,986,067
Montague	11,979,935	34,090	9,682,791	350,290	10,033,081	22,047,106
Palo Pinto	3,232,091	525,481	6,957,154	16,076,018	23,033,172	26,790,743
Parker	73,886	1,672,455	730,069	112,696,107	113,426,176	115,172,517
Shackelford	4,108,140	66,203	849,166	2,234,492	3,083,658	7,258,000
Somervell	0	65,812	0	7,485,891	7,485,891	7,551,704
Stephens	12,811,777	291,120	3,525,626	11,751,922	15,277,548	28,380,445
Tarrant	0	241,264	0	563,514,077	563,514,077	563,755,341
Wise	2,400,875	5,017,491	6,426,006	222,654,526	229,080,532	236,498,898
Basin Total	**61,954,098**	**14,912,113**	**37,971,973**	**1,899,092,788**	**1,937,064,761**	**2,013,930,972**

Co-Product Allocations

In addition to natural gas, the sources reported in the TCEQ inventories are associated with the marketed products of condensate and, in some cases, oil. In fact, gas companies are focusing all of their new investment in areas with wet gas, which has a higher VOC content, for its higher value. The principle of co-product allocation is that when there are multiple valued products from a single system, the burdens of that system should be shared among all products. This study uses energy-based co-product allocation, which weights the burdens (i.e., emissions) of each process by the ratio of energy contained in all co-products that is embodied in the product of interest.

The factor that is applied depends on the relevant life cycle stage of a source. For production sources, we use the finest grain of spatial resolution available. Specifically, emissions for all production sources in the Special Inventory are allocated among condensate, oil, and natural gas products at the *site level* using site-level production statistics, as follows:

$$Allocation_{site} = \frac{\left(Q_{GWgas,s}\right) * HHV_{pipe\ gas}}{\left(Q_{GWgas,s} + Q_{Cgas,s}\right) * HHV_{pipe\ gas} + Q_{oil,s} * HHV_{oil} + Q_{cond,s} * HHV_{cond}}$$

where:

$Allocation_{site}$ = the site-level, energy-basis co-product factor for gas produced by gas wells (unitless)

$Q_{GWgas,s}$ = the volume of gas-well gas produced at the site annually (Mcf)

$Q_{Cgas,s}$ = the volume of casinghead gas produced at the site annually[150] (Mcf)

$Q_{oil,s}$ = the volume of oil produced at the site annually (bbl)

$Q_{cond,s}$ = the volume of condensate produced at the site annually (bbl)

$HHV_{pipe\ gas}$ = the energy content of natural gas product (i.e., pipeline gas)

- 1,027,000 Btu/Mcf for pipeline-quality gas

HHV_{oil} = the energy content of oil

- 5,800,000 Btu/bbl for crude oil[151]

HHV_{cond} = the energy content of condensate

- 5,418,000 Btu/bbl for plant condensate.[152]

As Figure 59 depicts, the majority of these site-level co-product allocation factors are at or close to 1—reflecting the fact that the majority of production within these counties is natural gas. However, Figure 59 also shows that 15% of the sites included within the Special Inventory produce no gas-well gas and, accordingly, the emissions from these sites do not contribute to the total emissions allocated to natural gas.

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[150] Note that casinghead gas is a natural gas that is a co-product of oil production (produced by oil wells).

[151] API (2009), Table 3-8

[152] EIA (2011), Appendix A

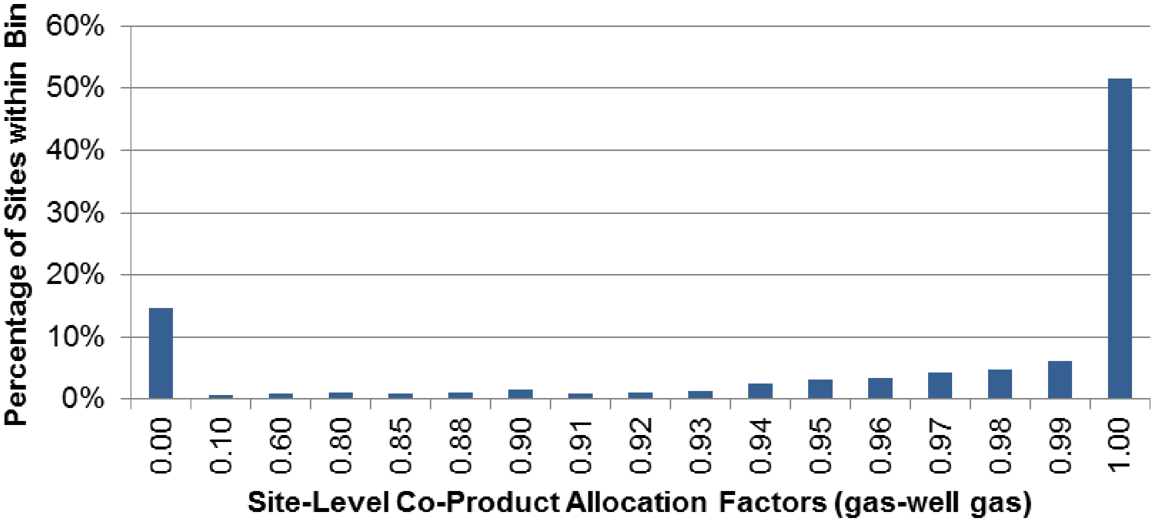

Figure 59. Distribution of site-level emissions allocated to gas

Site-level production statistics are not available for sites in the Point Source Inventory, and relevant counties have negligible oil production, lowering the chance that production-stage point sources emissions are associated with oil production. Therefore, emissions are allocated for all production sources in the Point Source Inventory among condensate and natural gas products at the *county level* using county-level production statistics (Figure 60). Similarly, Area Source Inventory data are available only at the county-level; so they are most appropriately allocated among co-products at this scale. This allocation is calculated as follows:

$$Allocation_{county} = \frac{Q_{GW\ gas,c} * HHV_{pipe\ gas}}{Q_{GW\ gas,c} * HHV_{pipe\ gas} + Q_{cond,c} * HHV_{cond}}$$

where:

$Allocation_{county}$ = the county-level, energy-basis co-product factor for gas (unitless)

$Q_{GWgas,c}$ = the volume of gas-well gas produced in the county annually (Mcf)

$Q_{cond,c}$ = the volume of condensate produced in the county annually (bbl)

$HHV_{pipe\ gas}$ = the energy content of natural gas product (i.e., pipeline gas) (Btu/Mcf)

HHV_{cond} = the energy content of condensate (Btu/bbl).

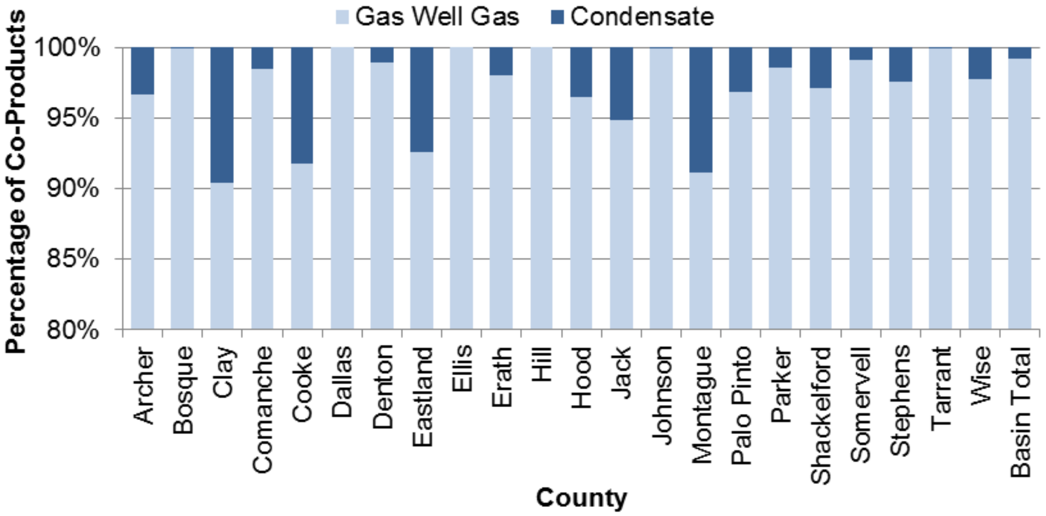

Figure 60. County-level gas production co-products by heat content

Regardless of the inventory in which the sources are described, emissions from processing sources are allocated at the *basin level* using basin-level production statistics, The relevant co-product allocation includes casinghead gas volumes as well as gas-well gas volumes because all natural gas—regardless of whether the production source is a gas or oil well—is processed at these sites. Some of these processing steps might occur after the condensate is separated, but the order of processing steps varies by site and is not identifiable in the data of the TCEQ inventories. Therefore, co-products are allocated as follows:

$$Allocation_{basin} = \frac{\left(Q_{GW\ gas,b} + Q_{Cgas,b}\right) * HHV_{pipe\ gas}}{\left(Q_{GW\ gas,b} + Q_{Cgas,b}\right) * HHV_{pipe\ gas} + Q_{cond,b} * HHV_{cond}}$$

where:

$Allocation_{basin}$ = the basin-level, energy-basis co-product factor for gas (unitless)

$Q_{GWgas,b}$ = the volume of gas-well gas produced in the basin annually (Mcf)

$Q_{Cgas,s}$ = the volume of casinghead gas produced in the basin annually (Mcf)

Q_{cond}, b = the volume of condensate produced in the basin annually (bbl)

$HHV_{pipe\ gas}$ = the energy content of natural gas product (i.e., pipeline gas) (Btu/Mcf)

HHV_{cond} = the energy content of condensate (Btu/bbl).

Note that some processing profiles pertain to processes that might occur after the condensate is separated from the process stream and, therefore, should not be partially allocated to that co-product. However, the specific order of processing steps is not readily identifiable in the data. In addition, the impact of neglecting this is small because condensate contributes less than 1% to the denominator of the allocation factor (Figure 61).

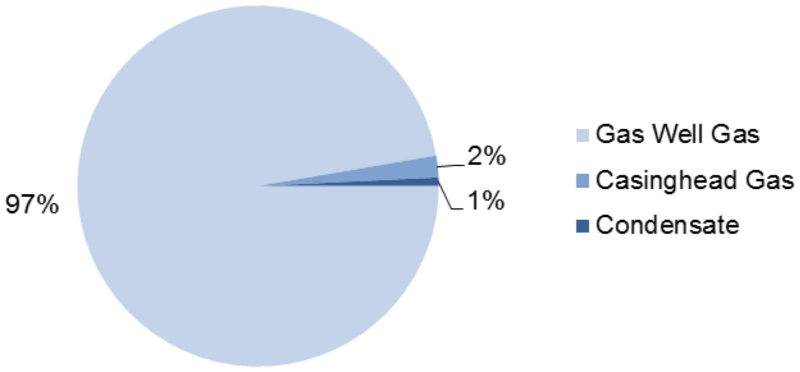

Figure 61. Basin-level gas processing co-products by heat content

In addition, because condensate and crude oil are separately marketable products, co-product allocation means that the substantial VOCs in the TCEQ Inventories corresponding to the storage and handling of these co-products—once separated from the natural gas stream—are outside the boundary of natural gas production and processing. Therefore, this study omits about 25% of the individual sources reported in the two inventories, which collectively represent 60% of the total reported VOC emissions, because they are associated only with the production and processing of the co-products of crude oil and condensate.

Regarding the co-production of oil within the counties of the basin, note that the 84 sites identified as production sites in the Point Source Inventory are all located within the 7 counties listed below—which include their respective percentage of the co-product energy associated with oil production:

- Denton: 0.2% from oil
- Hood: 0.0% from oil
- Johnson: 0.0% from oil
- Palo Pinto: 12.1% from oil
- Parker: 0.1% from oil
- Tarrant: 0.0% from oil
- Wise: 1.0% from oil.

With the exception of Palo Pinto County, these values suggest the co-production of oil represents a negligible amount, and the sole production site in Palo Pinto County identified in the Point Source Inventory is a gas well, associated with zero oil production, as verified through an online query of the Texas Railroad Commission’s production statistics database. Therefore, this study does not attribute any production-related emissions from the Point Source Inventory to a co-product of oil.

Overall, 1% of the estimated GHG emissions are allocated to condensate instead of natural gas. For comparison, note that Skone et al. (2011) base their co-product allocation on their reported

12% non-methane VOC whereas Stephenson et al. (2011) report 16.4% allocation to condensate, ethane, and liquid petroleum gas. However, this proportion varies substantially across the 22 counties of the Barnett Shale play, as shown in Figure 62. Even among top-producing counties, which are shown by the larger bars in the lower panel of the figure, significant portions of GHGs are attributed to condensate instead of natural gas—ranging from 0.5% condensate for Johnson County and Tarrant County to 1.7% for Wise County. More strikingly, only 91.7% and 92.7% of emissions in Montague County and Cooke County, respectively, are associated with the natural gas product.

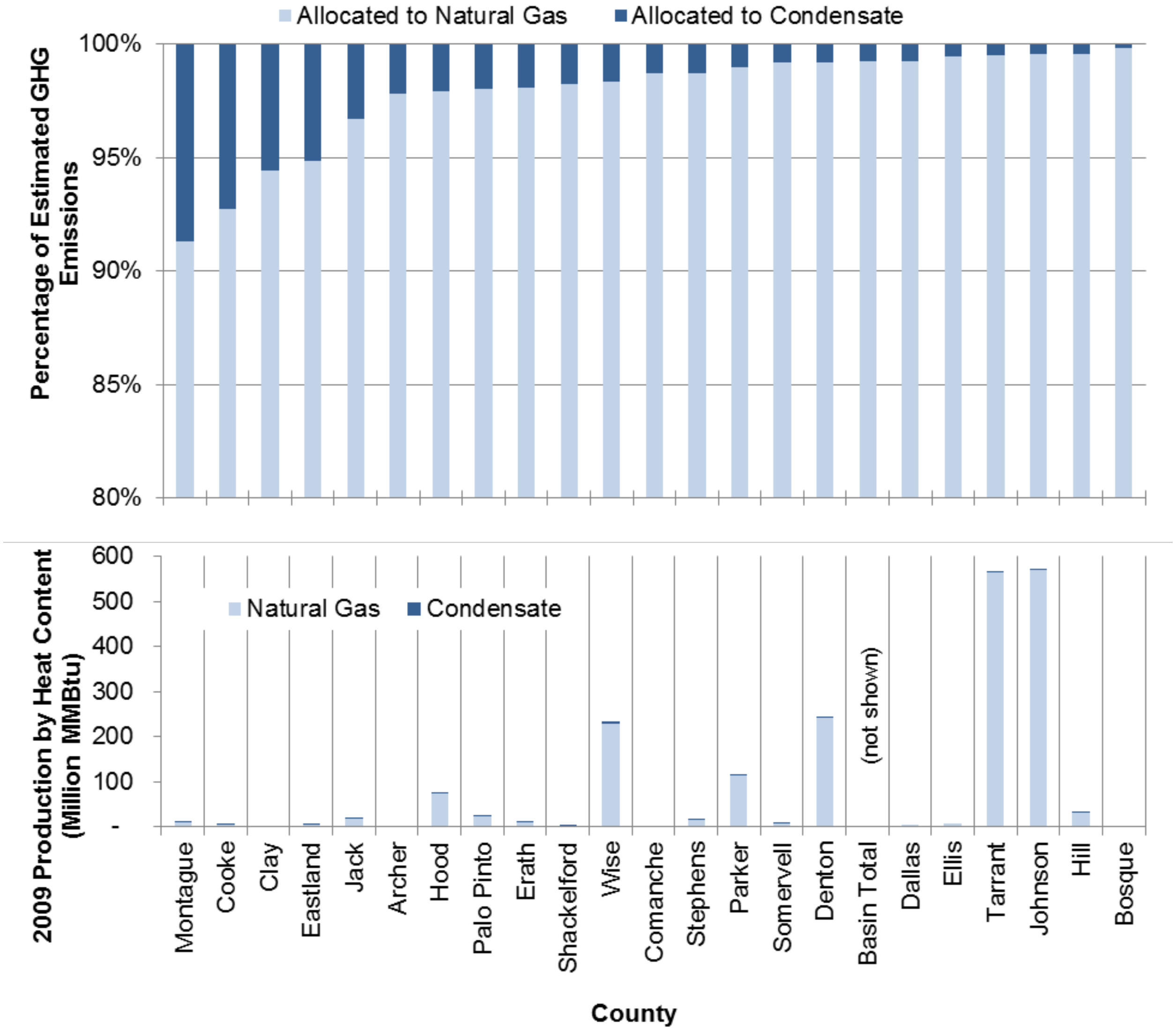

Figure 62. Proportion of GHG emissions associated with co-products

Estimation of Emissions by Source Profile

Emissions estimations generally use a "black box" approach, where a profile is associated with a life cycle stage by the purpose it serves rather than by its physical location. However, for those profiles possibly related to multiple stages, such as compressor engines and fugitives, each source is associated with the life cycle stage by the categorization of the site at which the source is found.

In general, emission sources can be categorized into two broad types of profiles: *combustion sources* and *gas-release sources*, with certain unique characteristics of certain processing activities leading to a third category. A tiered approach is used to calculate emissions, in which secondary calculation methods are applied when the data requirements for preferred methods are not met for an individual source. If neither method is possible with the available data, median estimates from other sources of the same profile are used. Overall, preferred methods were used for 79% of sources, secondary for 18%, and tertiary for the remaining 2%. The following paragraphs introduce the main categories and methodologies, which are adapted from the methodologies presented by ENVIRON (2010), API (2009), and EPA (1995), as appropriate. These emissions estimates include both routine and non-routine emissions estimates for 2009.

Combustion sources include compressor engines, boilers, heaters, and turbines. In these profiles, CO_2 emissions primarily come from chemical reactions during combustion, and methane emissions primarily come from the incomplete combustion of the combusted fuel. The composition of the fuel gas therefore influences the emissions, as do source characteristics and details of the level of usage of the source. This study's preferred methodology for calculating emissions from combustion sources is based on the quantity of fuel combusted and the composition of the fuel gas—as determined by a county-level estimation of production gas composition, assuming that the natural gas fuel used in all cases is the production gas at that site.

Gas leakage sources include both intentional and unintentional releases of gas. Within this category, there is a differentiation between *potentially controllable leakage* and *fugitives*, where the former typically involves gas released from an isolatable emission point and therefore is potentially controllable, and the latter comes from dispersed leaks and therefore is less feasible to control. This study's preferred methodology for calculating GHG emissions from gas-release sources therefore is based on the reported emissions of total VOCs and the ratio of CO_2 and CH_4 to VOCs in the released gas, which means it depends on the speciation of the released gas. Estimating these emissions assumes that production gas is the released gas in all cases, except when the profile is associated specifically with produced water handling; in this case, the released gas is assumed to be equivalent to the produced-water flash gas.

In addition, some processing sources require specialized estimation methods. For example, AGR units specifically remove CO_2 from the production gas. Therefore, this study's method for estimating CO_2 emissions from AGR differs substantially from that used for other profiles. Specifically, AGR units are associated with CO_2 emissions equal to the difference in CO_2 contained within the production gas and that in the final pipeline-quality gas.

The estimation of GHG emissions for different profiles consistently assumes that the speciation of production gas varies spatially based on the geology of the Barnett Shale. This variation can be reasonably represented by variation at the county level, as spatially interpolated from the sample of gas composition analyses collected from supplementary Special Inventory files provided by the TCEQ.

Similarly, all natural gas represented in the following methodologies is assumed to be the production gas, except where explicitly noted (as in the AGR profile calculations). The speciation of this production gas is spatially explicit to the county level for production sources and the basin average composition for processing sources.

In addition, many profiles rely on standardized emission factors, which represent industry-level averages across the specifics of individual equipment. The majority of these emission factors are obtained from the EPA's AP-42, Compilation of Air Pollutant Emission Factors (EPA 1995). Factors applied are shown in Table 19.

Table 19. EPA's AP-42 Compilation of Air Pollutant Emission Factors

Profile	CO_2 Emission Factor	CH_4 Emission Factor	VOC Emission Factor
External Combustion, Natural Gas[a]	118 lb/MMBtu	2.25e-3 lb/MMBtu	5.39e-3 lb/MMBtu
External Combustion, Diesel[b,c]	2710 kg/$10^3$$m^3$	0.0062 kg/$10^3$$m^3$	0.0240 kg/$10^3$$m^3$
Internal Combustion, Natural Gas: 2-Stroke Lean-Burn[d]	110 lb/MMBtu	1.45 lb/MMBtu	1.20e-01 lb/MMBtu
Internal Combustion, Natural Gas: 4-Stroke Lean-Burn[e]	110 lb/MMBtu	1.25 lb/MMBtu	1.18e-01 lb/MMBtu
Internal Combustion, Natural Gas: 4-Stroke Rich-Burn[f]	110 lb/MMBtu	2.30e-01 lb/MMBtu	2.96e-02 lb/MMBtu
Internal Combustion, Diesel	164 lb/MMBtu[g]	3.15e-02 lb/MMBtu[h]	3.19e-01 lb/MMBtu[h]
Internal Combustion, Gasoline	154 lb/MMBtu[g]	1.89e-01 lb/MMBtu[h]	1.911e00 lb/MMBtu[h]
Natural Gas Turbine[i]	110 lb/MMBtu	8.60e-03 lb/MMBtu	2.10e-03 lb/MMBtu
Stationary Large-Bore Diesel Engines[j]	2745 kg/$10^3$$m^3$	0.1548 kg/$10^3$$m^3$	1.7415 kg/$10^3$$m^3$

[a] EPA (1995), Table 1.4-2

[b] Diesel fuel is also used as a proxy for crude oil.

[c] EPA (1995)

[d] EPA (1995), Table 3.2-1

[e] EPA (1995), Table 3.2-2

[f] EPA (1995), Table 3.2-3

[g] EPA (1995), Table 3.3-1

[h] EPA (1995), Table 3.3-1, where total organic compounds from Exhaust = 2.1 for gasoline and total organic compounds from Exhaust = 0.35 for diesel, and Table 3.4-1, which states that total organic compounds by weight is 9% CH_4 and 91% non-CH_4 for the one diesel engine measured

[I] EPA (1995), Table 3.1-2a

[j] EPA (1995)

Tiered Methods Counts

This study applies a tiered approach to the estimation of GHG emissions, in which preferred methods are applied when available data allow, and secondary methods otherwise. For those sources unable to use either method, we apply a tertiary method of assigning the median estimate for that profile. Table 20 demonstrates the count of the usability of each method across the two main inventories.

Table 20. Count of Usability for each GHG Emissions Estimation Method for CO_2 and Methane

	CO_2			Methane		
	Method 1	**Method 2**	**Method 3**	**Method 1**	**Method 2**	**Method 3**
Amine Units	n/a	–	–	4	–	–
Blowdowns and Vents	1,366	68	10	1,366	68	10
Boilers and Heaters	277	–	32	277	–	32
Engines	1,467	364	35	708	1,133	25
Flares	21	–	15	n/a	–	–
Fugitives	4,247	–	24	4,247	–	24
Glycol Dehydrator	79	21	14	79	21	14
Produced-Water Loading	1,948	–	11	1,948	–	11
Produced-Water Tanks	4,429	–	106	4,429	–	106
Special Inventory Total	13,834	453	247	13,058	1,222	222
Engines	–	673	–	–	673	–
Flares	–	17	–	n/a	–	–
Other combustion	–	264	–	–	264	–
Gas Leakage Sources	–	735	–	–	735	–
Produced-Water Tanks	90	–	–	90	–	–
Point-Source Inventory Total	90	1,689	0	90	1,672	0
Combined Total	13,924	2,142	247	13,148	2,894	222

General Leakage Profiles

General leakage profiles include *blowdowns*, *fugitives*, *pneumatics*, and *vents*. Data on blowdowns, fugitives, and vents are obtained from both the Point Source Inventory and the Special Inventory, and data on pneumatics are obtained from the Area Source Inventory. Although these different sources have different causes, they are calculated by similar methods. Because these profiles occur at both production and processing sites, sources are assigned to the stage to which the site belongs.

The primary methods for estimating CO_2 and methane emissions use the reported volume of gas released and this study's estimate of the composition of that gas. Where data are not available on volume of gas released, the secondary method uses the reported volume of VOC emissions and a ratio of the GHG to VOCs in the gas composition. These methods for calculating CO_2 and methane emissions for leakage sources are adapted from ENVIRON's (2010) discussion of leakage sources, including well-completion venting, well blowdowns, permitted fugitives, and unpermitted fugitives.

Note that unlike most profiles, inventory data on pneumatics come from the Area Source Inventory, which provides county-level data without individual source counts. Therefore, although emissions from pneumatics are calculated using methods analogous to other leakage profiles, such calculation occurs at the county level based on aggregated, county-level emissions reported in the inventory.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = Q_{vented} * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_{CO_2} * \frac{1tonne}{2204.62lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{vented} = the total annual volume of gas emitted through the leakage source (scf/year)

MW_{vented} = the molecular weight of the vented gas (lb/lb-mole)

f_{CO_2} = the fraction of CO_2 in the leaked gas by mass (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = E_{VOC} * \frac{f_{CO_2}}{f_{VOC}}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{CO_2} = the fraction of CO_2 in the production gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless).

Methane Emissions: Primary Method

$$E_{CH_4} = Q_{vented} * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_{CH_4} * \frac{1tonne}{2204.62lb}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

Q_{vented} = the total annual volume of gas emitted through the leakage source (tonne/year)

MW_{vented} = the molecular weight of the vented gas (lb/lb-mole)

f_{CH_4} = the fraction of CH_4 in the leaked gas by mass (unitless).

Methane Emissions: Secondary Method

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{CO_2} = the fraction of CO_2 in the production gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless).

Compression Engines Profile

Data on compressor engines are obtained from the Special Inventory and the Point Source Inventory. Because these profiles occur at both production and processing sites, the sources are assigned to the stage to which the site belongs.

The primary methods for estimating CO_2 and methane emissions use the reported volume of fuel combusted and this study's estimate of the composition of that fuel, as well as the engine characteristics in the case of methane. Where the volume of fuel combusted is not available, the secondary method for CO_2 emissions uses engine characteristics and operations data, some of which is based on standard assumptions; the secondary method for methane emissions uses the reported volume of VOC emissions and a ratio of the GHG-to-VOCs-related, profile-specific emission factors.

In addition to data availability, the secondary method is preferred for sources that failed a simple data-consistency screen, or "ratio test," based on the ratio of reported fuel consumption to an expected gas usage value, calculated as:

$$ratio = \frac{Q_{fuel}}{EFU} = \frac{Q_{fuel}}{MDC * \frac{t_{annual}}{HHV}}$$

where:

$ratio$ = the test value, where any ratio within a factor of 10 of matching (i.e., between 10% and 1000%) is accepted (unitless)

Q_{fuel} = the total annual amount of fuel combusted (MMscf/year)

EFU = the expected fuel usage (MMscf/year)

MDC = the reported maximum design capacity of the engine (MMBtu/hour)

t_{annual} = the annual hours of usage of the engine (hour/year)

HHV = a standardized higher heating value of the fuel, assumed to be 1,150 (Btu/scf).

A final criterion for using the primary method for methane emissions is the reported absence of emissions controls installed on the engine. Ideally, the primary method should be weighted by methane-control efficiency. However, the reported data on VOC control efficiency demonstrate substantial inconsistency, and standardized methane control ratings for engines are not readily available. So, this study assumes that any controls applied affect methane and VOCs equivalently and therefore applies our secondary method for all engines that report the presence of controls. Because the Point Source Inventory does not include information on controls, the secondary method is used, which accounts for the possibility of emissions controls, for all engines in that inventory.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = Q_{fuel} * \left(\frac{1.0 lb-mole}{379.3 scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44 g-CO_2}{12 g-C}\right) * \frac{1 tonne}{2204.62 lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

MW_{gas} = the molecular weight of the combusted gas (lb/lb-mole)

f_C = the fraction of carbon in the combusted fuel by mass (unitless)

f_O = the fraction of fuel carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = HP * LF * f_e * EF_{CO_2} * t_{annual}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

HP = the engine rating (hp)

LF = the load factor of the engine (unitless)

f_e = the energy-basis conversion factor for the engine (Btu/hp-hr)

EF_{CO_2} = the emissions factor of CO_2 on an energy basis (tonne/Btu)

t_{annual} = the annual hours of usage of the engine (hr/year).

Methane Emissions: Primary Method

$$E_{CH_4} = Q_{fuel} * HHV * EF_{CH_4}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

HHV = the higher heating value of the fuel (Btu/scf)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu).

Methane Emissions: Secondary Method

$$E_{CH_4} = E_{VOC} * \frac{EF_{CH_4}}{EF_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu)

EF_{VOC} = the emissions factor of VOCs on an energy basis (tonne/Btu).

In addition to the standard assumptions described above, these methods depend on the following assumptions:

- The load factor (LF) is assumed to be 0.8 for compressor engines with an engine rating greater than 500 hp and 0.7 otherwise, based on the results of a 2005 study of compressor engines in Texas performed by the TCEQ.[153]
- The energy-basis conversion factor (f_e) for all natural gas internal combustion engines is 7858 Btu/hp-hr.[154]
- The annual hours of usage of the engine (t_{annual}) are 8,760 hr/year for engines without specific usage data, which includes all engines in the Point Source Inventory.
- Any reduction in CO_2 released from the engine related to emissions controls is negligible.

Boilers, Heaters, and Turbines

Data on boilers and heaters are obtained from the Special Inventory, and data on boilers, heaters, and turbines are obtained from the Point Source Inventory. Although turbines substantially differ from boilers and heaters, estimation of emissions follows equivalent methods for all three profiles in the Point Source Inventory. Also, although boilers and heaters can occur at both production and processing sites, they are associated with natural gas processing; therefore, boilers and heaters are assigned to the processing stage.

The primary methods for estimating CO_2 and methane emissions use the reported volume of fuel combusted and this study's estimate of the composition of that fuel. Where the volume of fuel combusted is not available, the secondary method for estimating emissions uses the reported volume of VOC emissions and a ratio of the GHG-to-VOCs-related, profile-specific emission factors.

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[153] Personal communication with TCEQ (TCEQ 2012)

[154] ENVIRON (2010), p.84

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = Q_{fuel} * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44g-CO_2}{12g-C}\right) * \frac{1tonne}{2204.62lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

MW_{gas} = the molecular weight of the combusted gas (lb/lb-mole)

f_C = the fraction of carbon in the combusted fuel by mass (unitless)

f_O = the fraction of fuel carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = E_{VOC} * \frac{f_{CO_2}}{f_{VOC}}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{CO_2} = the emissions factor of CO_2 on an energy basis (tonne/Btu)

EF_{VOC} = the emissions factor of VOCs on an energy basis (tonne/Btu).

Methane Emissions: Primary Method

$$E_{CH_4} = Q_{fuel} * HHV * EF_{CH_4}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

HHV = the higher heating value of the fuel (Btu/scf)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu).

Methane Emissions: Secondary Method

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/yr)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu)

EF_{VOC} = the emissions factor of VOCs on an energy basis (tonne/Btu).

Amine Units / Acid Gas Removal

AGR, such as by amine units, removes CO_2 from the production gas. Therefore, this study's method for estimating CO_2 emissions from AGR differs substantially from that used for other profiles. AGR units are associated with CO_2 emissions equal to the difference in CO_2 contained within the production gas and that in the final pipeline-quality gas. Unlike other emissions sources, the CO_2 emissions from amine units are calculated as a single, aggregated basin-wide estimate that does not depend on the number of sources in the inventories.

Specifically, the estimated emissions are estimated as follows:

$$E_{CO_2} = \left[MW_{prod} * f_{CO_2 prod} - MW_{pipe} * f_{CO_2 pipe}\right] * Q_{prod} * \frac{1 lb - mole}{379.3\ scf}$$

where:

E_{CO_2} = mass of CO_2 emitted by all AGR sources in the basin annually (tonne/year)

MW_{prod} = the average molecular weight of production gas within the basin (lb/lb-mole)

$f_{CO_2 prod}$ = the average percentage CO_2, by mass, in the production gas (unitless)

MW_{pipe} = the molecular weight of pipeline-quality natural gas[155] (lb/lb-mole)

$f_{CO_2 prod}$ = the average percentage CO_2, by mass, in pipeline gas[156] (unitless)

Q_{prod} = the volume of natural gas produced within the basin annually (scf).

In contrast, methane emissions from AGR are estimated using calculation methods equivalent to those provided in that of General Leakage Sources, as previously discussed.

Dehydrators

GHG emissions from dehydrators are calculated using separate emissions factors depending on the life cycle stage of the site at which the source sites. In the Point Source Inventory, all dehydrators are all at processing sites; but in the Special Inventory, dehydrators exist at both production and processing sites. Therefore, following API (2009), this study uses an emission factor of 275.57 scf/MMscf gas processed for production sites, adjusting the CH_4 content from the 78.8 molar percentage assumed in that reference. Alternatively, if a dehydrator is identified at a processing site, this study uses an emission factor of 121.55 scf/MMscf gas processed and adjusts the molar CH_4 content from 86.8%.

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[155] Set to 17.4 lb/lb-mole, as provided by EPA (1995) and used by ENVIRON (2010)

[156] Set to 0.47%, as per EPA (2011). To the extent that this value overestimates the CO_2 content in pipeline-quality gas, it underestimates CO_2 emissions from acid gas removal, and vice versa.

For those dehydrators identified as having a control present in the Special Inventory, and assuming that all dehydrators in the Point Source Inventory have emission controls, this study assumes a 98% control efficiency for methane and a 0% efficiency for CO_2. Otherwise, this study assumes 0% efficiency of control for both emissions types. The 98% efficiency assumption is supported by standard efficiency assumptions for flares, as well as a reported 97% efficiency for separator-condensers (Schievelbein 1997), an alternative method of control for dehydrators.

Primary Methods

For dehydrators at production sites:

$$E_{CH_4} = P * 0.0052859 * \left[\frac{f_{CH_4,,county} * MW_{gas,county}}{16}\right] * \left[\frac{1}{0.788}\right] * (1 - CE)$$

$$E_{CO_2} = P * 0.0052859 * \left[\frac{f_{CH_4,,county} * MW_{gas,county}}{16}\right] * \left[\frac{1}{0.788}\right] * \frac{f_{CO_2,county}}{f_{CH_4,county}}$$

and for Dehydrators at Processing sites:

$$E_{CH_4} = P * 0.0023315 * \left[\frac{f_{CH_4,,basin} * MW_{gas,basin}}{16}\right] * \left[\frac{1}{0.868}\right] * (1 - CE)$$

$$E_{CO_2} = P * 0.0023315 * \left[\frac{f_{CH_4,,basin} * MW_{gas,basin}}{16}\right] * \left[\frac{1}{0.868}\right] * \frac{f_{CO_2,basin}}{f_{CH_4,basin}}$$

where CE = 0.98 if controlled, 0 otherwise, and P is the volume of gas processed. Controls do not affect CO_2 emissions, which are weighted by the ratio of CO_2 to CH_4 (by weight) in the production gas, by county.

Secondary Methods

For Dehydrators without P (which includes all Point Source Inventory dehydrators), the secondary method is based on VOC emissions:

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

$$E_{CO_2} = E_{VOC} * \left(\frac{1}{1-CE}\right) * \frac{f_{CO_2}}{f_{VOC}}$$

Flares

Due to a lack of sufficient information for identifying the specific source to which each flare is associated, this study identifies a flare’s process stage by the type of site at which it is found and assumes that all flares combust production gas. This approach will likely overestimate natural gas process-chain emissions due to some of the flares controlling emissions from condensate and crude oil tanks, which should be omitted through co-product allocation; but the overestimation is expected to be small because total flare emissions are small. Only those that can be identified as emissions control for condensate tanks are removed; those that can be identified as combined emissions control for an included profile and condensate tanks are kept. Although this leads to a likely overestimation of emissions from flaring, flares only account for a small proportion of overall emissions, so this overestimation is expected to be small.

For CO_2 emissions, the primary method, which depends on knowing the amount of gas combusted, treats flares equivalently to other combustion sources. The secondary method uses reported VOC emissions and an assumed 98% efficiency to back-calculate the volume of gas combusted. Methane emissions are assumed to be attributed to the original source that is controlled by the flares and therefore are neither calculated nor assigned to this profile.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = \left(Q_{waste} + Q_{pilot}\right) * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44g-CO_2}{12g-C}\right) * \frac{1tonne}{2204.62lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{waste} = the total annual amount of waste gas combusted (scf/year)

Q_{pilot} = the total annual amount of pilot gas combusted (scf/year)

MW_{gas} = the molecular weight of the combusted gas (lb/lb-mole)

f_C = the fraction of carbon in the combusted fuel by mass (unitless)

f_O = the fraction of fuel carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = E_{VOC} * \left(\frac{1}{f_{VOC}}\right) * \left(\frac{1}{1-CE}\right) * f_C * f_O * CE$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{VOC} = the fraction of VOCs in the combusted gas by mass (unitless)

CE = the assumed control efficiency of the flare, 98% (unitless)

f_C = the fraction of carbon in the combusted gas by mass (unitless)

f_O = the fraction of combusted gas carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Loading and Tanks

For produced-water loading and produced-water tanks, GHG emissions are calculated from VOC emissions and the ratio of VOCs to GHGs in the water flash gas.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = E_{VOC} * \frac{f_{CO_2}}{f_{VOC}}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{CO_2} = the fraction of CO_2 in the produced-water flash gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the produced-water flash gas by mass (unitless).

Methane Emissions: Primary Method

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/yr)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/yr)

f_{CO_2} = the fraction of CO_2 in the produced-water flash gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the produced-water flash gas by mass (unitless).

Calculations of Gas Losses from Production and Processing

Gas Release Sources

Profiles reporting gas release sources include amine units, blowdowns, fugitives, glycol dehydrators, and vents.

Natural Gas Lost, Method 1: From Reported Vented Volume

When the volume of gas vented is listed (only for some vents in the Special Inventory), the only calculation is a simple unit conversion, as follows:

$$Q_{NG,lost} = Q_{vented} * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

Q_{vented} = the total annual volume of gas emitted from the source (scf/year).

Natural Gas Lost, Method 2: From Reported VOC Emissions

For most gas leakage sources, the volume of gas released is not directly reported. For these, the volume of gas released can be calculated from the amount of VOC emissions, as follows:

$$Q_{NG,lost} = E_{VOC} * \frac{1}{f_{VOC}} * \left(\frac{2204.62lb}{1tonne}\right) * \left(\frac{1}{MW_{gas}}\right) * \left(\frac{379.3scf}{1.0lb - mole}\right) * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless)

MW_{gas} = the molecular weight of the production gas (lb/lb-mole).

Engines

Engines and other combustion sources (i.e., boilers and heaters) both sometimes include a direct report of the volume of fuel used. But only engines report the characteristics used for the ratio test, described in the section above on compressor engine emissions, and Method 2. Therefore, these combustion sources are calculated differently.

Natural Gas Lost, Method 1: From Reported Volume of Fuel Used

When the volume of gas combusted is listed (only relevant for some Special Inventory sources) and passes this study's Ratio Test for data entry issues, the value can be used directly, as follows:

$$Q_{NG,lost} = Q_{fuel}$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/yr)

Q_{fuel} = the total annual volume of fuel combusted by the source (MMscf/year).

Natural Gas Lost, Method 2: Using Engine Characteristics

The secondary method uses engine characteristics to estimate the amount of fuel used, which is equivalent to the natural gas lost for these sources.

$$Q_{NG,lost} = HP * LF * f_e * \frac{1}{HHV} * t_{anuual} * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

HP = the engine rating (hp)

LF = the load factor of the engine (0.8 or 0.7, depending on horsepower)

f_e = the energy-basis conversion factor for the engine (Btu/hp-hr)

HHV = the higher heating value of the fuel (Btu/scf)

t_{annual} = the annual hours of usage of the engine (hr/year).

Non-Engine Combustion

Engines and other combustion sources (i.e., boilers and heaters) both sometimes include direct report of the volume of fuel used. But only engines have the characteristics used both for the Ratio Test and Method 2. Therefore, these combustion sources are calculated differently.

Natural Gas Lost, Method 1: From Reported Volume of Fuel Used

When the volume of gas combusted is listed (which is only relevant for some Special Inventory sources), the value can be used directly, as follows:

$$Q_{NG,lost} = Q_{fuel}$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

Q_{fuel} = the total annual volume of fuel combusted by the source (MMscf/year)

Natural Gas Lost, Method 2: From Reported VOC Emissions

This alternative method only applies to Point Source Inventory non-engine combustion sources:

$$Q_{NG,lost} = E_{VOC} * \frac{1}{EF_{VOC}} * \left(\frac{2204.62lb}{1tonne}\right) * \left(\frac{1}{HHV}\right) * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{VOC} = the VOC emission factor for the source (lb/MMBtu)

HHV = the higher heating value of the fuel (Btu/scf).

Methane Lost, for All Sources: Convert from Natural Gas Lost

For all sources, the conversion from estimated natural gas lost to estimated methane lost is completed as shown:

$$Q_{CH_4,lost} = Q_{NG,lost} * \frac{MW_{gas}}{MW_{CH_4}} * f_{CH_4}$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

$Q_{CH_4,lost}$ = the volume of CH_4 lost or used by the source annually (MMscf/year)

f_{CH_4} = the fraction of CH_4 in the production gas by mass (unitless)

MW_{gas} = the molecular weight of the production gas (lb/lb-mole)

MW_{CH_4} = the molecular weight of CH_4 (16.0 lb/lb-mole).

Summary of Adjustments to Estimated Emissions

Emissions from production sources in the Point Source Inventory are adjusted by allocation across co-products at the county-level, as follows:

$$E_{final} = [E_{raw}] * [Allocation_{county}]$$

where:

E_{raw} = the unadjusted emissions estimate, e.g.,

$$E_{CO_2} = Q_{fuel} * \left(\frac{1.0lb - mole}{379.3scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44g - CO_2}{12g - C}\right) * \frac{1tonne}{2204.62lb}$$

$Allocation_{county}$ = the county-level allocation of emissions across co-products.

Emissions from production sources in the Area Source Inventory are adjusted by allocation across co-products at the county level and the adjustment for changes in production volumes, as follows:

$$E_{final} = [E_{raw}] * [Allocation_{county}] * [Adjustment_{county}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Allocation_{county}$ = the county-level allocation of emissions across co-products

$Adjustment_{county}$ = the county-level adjustment of emissions from 2008 to 2009 estimates.

Adjustments to emissions from production sources in the Special Inventory differ from this by (1) allocation across co-products at the site-level, rather than at the county-level, (2) requiring site-level and inventory-level corrections, and (3) not requiring the production volume adjustment, as follows:

$$E_{final} = [E_{raw}] * [Correction_{site}] * [Correction_{inventory}] * [Allocation_{site}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Correction_{site}$ = the site-level adjustment factor that accounts for the non-report of sources at the site that are below the reporting threshold for the Special Inventory

$Correction_{inventory}$ = the adjustment factor to all Special Inventory results that accounts for the "98% completion rate" of the inventory reported by the TCEQ

$Allocation_{site}$ = the site-level allocation of emissions across co-products.

Emissions from processing sources in the Point Source Inventory are adjusted by allocation across co-products at the basin-level, as follows:

$$E_{final} = [E_{raw}] * [Allocation_{basin}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Allocation_{basin}$ = the basin-level allocation of emissions across co-products.

Finally, emissions from processing sources in the Special Inventory are adjusted by the inventory-level and site-level corrections and by allocation across co-products at the basin level, as follows:

$$E_{final} = [E_{raw}] * [Correction_{site}] * [Correction_{inventory}] * [Allocation_{basin}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Correction_{site}$ = the site-level adjustment factor that accounts for the non-report of sources at the site that are below the reporting threshold for the Special Inventory

$Correction_{inventory}$ = the adjustment factor to all Special Inventory results that accounts for the "98% completion rate" of the inventory reported by the TCEQ

$Allocation_{basin}$ = the basin-level allocation of emissions across co-products.

Greenhouse Gas Emission Factors

To create emissions factors for process stages, the sum of estimated emissions for sources in each stage is divided by the production volume of gas associated with those emissions. The relevant statistics exist at the county level for production sources and at the basin level for processing sources.

For sources in the production stage, emissions and production can be associated at the county level. This emission factor focuses only on natural gas production from gas wells, omitting the casinghead gas produced as a co-product from oil wells. Specifically, for CH_4 emissions associated with production (and where CO_2 is calculated analogously):

$$EF_{CH_4,prod,i} = \frac{\sum_{n \in N_{prod,i}} E_{CH_4,n}}{Q_{GWgas,i}}$$

where:

$EF_{CH_4,prod,i}$ = the CH_4 emission factor for production in county i (tonne/Mcf)

$E_{CH_4,n}$ = the mass of CH_4 emitted from source *n* annually (tonne/year)

$N_{prod,i}$ = the set of production sources in county i

$Q_{GWgas,i}$ = the volume of gas produced from gas wells in county *i* annually (Mcf/year).

For sources in the processing stage, however, emissions and production can only be associated at the basin level because centralized processing sites likely process Barnett Shale gas produced in neighboring counties. In addition, the gas processed by these facilities includes gas produced both from gas wells and oil wells (i.e., casinghead gas), and the denominator includes the sum of these two volumes, accordingly. Specifically, for CH_4 emissions associated with processing (and where CO_2 is calculated analogously):

$$EF_{CH_4,proc} = \frac{\sum_{n \in N_{proc}} E_{CH_4,n}}{Q_{GWgas} + Q_{Cgas}}$$

where:

$EF_{CH_4,proc}$ = the CH_4 emission factor for processing in the basin (tonne/Mcf)

$E_{CH_4,n}$ = the mass of CH_4 emitted from source *n* annually (tonne/year)

N_{proc} = the set of processing sources in the basin

Q_{GWgas} = the volume of gas-well gas produced in the basin annually (Mcf/year)

Q_{Cgas} = the volume of casinghead gas produced in the basin annually (Mcf/year).

The estimation strategy for the processing stage is exposed to a risk of leakage of production volumes both into and out of the basin, where the former corresponds to emissions caused by the processing of gas not accounted for in the basin's production statistics and the latter to gas included in the production statistics that is not accounted for in the processing emissions because such processing occurs outside the basin. The potential for bias from leakage is expected to be small because of the costs incurred in shipping unprocessed gas unnecessarily, as well as the relatively small amount of production in neighboring counties (the sum of which is only 8% the sum of gas production within the basin). Further, the potential for leakage in both directions increases the likelihood that any bias introduced by one direction of leakage will be cancelled by that in the other direction. But if not completely cancelling, the small scale of production outside the basin suggests that the sum of leakage would be out of the basin, meaning the estimates will underestimate emission factors.

From Inventory to LCA

The final estimate of life cycle GHG emissions is calculated as:

$$EF_{LifeCycle} = \left(\frac{1}{TE}\right) * \left[\frac{EF_{PreProduction}}{L_1} + \frac{EF_{Production}}{L_2} + \frac{EF_{Processing}}{L_3} + \frac{EF_{Transmission}}{L_4} + \frac{EF_{Disposal}}{L_2}\right] + EF_{Combustion} + EF_{Construction} + EF_{Decommissioning}$$

where:

$EF_{LifeCycle}$ = the emission factor for the entire life cycle (g GHG/kWh generated)

TE = the thermal efficiency of the power plant (kWh-equivalent input/kWh generated)

$EF_{PreProduction}$ = the emission factor for all pre-production processes, including completions and workovers, amortized by the lifetime EUR (g GHG/kWh-equivalent extracted)

$EF_{Production}$ = the emission factor for all production processes (g GHG/kWh-equivalent produced)

$EF_{Processing}$ = the emission factor for all gas processing processes (g GHG/kWh-equivalent processed)

$EF_{Transmission}$ = the emission factor for all processed gas transmission processes (g GHG/kWh-equivalent transmitted)

$EF_{Disposal}$ = the emission factor for all produced-water disposal processes (g GHG/kWh-equivalent produced)

$EF_{Combustion}$ = the emission factor for combustion at the power plant, based on the assumed TE (g GHG/kWh generated)

$EF_{Construction}$ = the emission factor for all power-plant construction processes, amortized over the lifetime production of the power plant (g GHG/kWh generated)

$EF_{Decommissioning}$ = the emission factor for all power-plant decommissioning processes, amortized over the lifetime production of the power plant (g GHG/kWh generated)

L_1 = a loss factor representing the portion of gas extracted that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent extracted/kWh-equivalent input)

L_2 = a loss factor representing the portion of gas produced that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent produced/kWh-equivalent input)

L_3 = a loss factor representing the portion of gas processed that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent processed/kWh-equivalent input)

L_4 = a loss factor representing the portion of gas transmitted that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent transmitted/kWh-equivalent input).

Using this formula, life cycle GHG emissions are estimated as shown in Table 21.

Table 21. Life Cycle GHG Emissions Values (g CO_2e/kWh,100-yr)

		Not Separated	From CO_2	From Methane	Sum Base-EUR	Sum High-EUR	Sum Low-EUR
	EUR (bcf)				1.42	4.26	0.45
Fuel Cycle	Pre-Production (non-completions)[a]		13.9		13.9	4.6	44.6
	Completions and Workovers[b]			20.2	20.2	6.7	65.0
	Production		3.3	3.0	6.3	6.3	6.3
	Processing		15.6	2.4	18.0	18.0	18.0
	Produced Water Disposal		0.0	0.7	0.7	0.7	0.7
	Transmission[c]		3.2	16.2	19.4	19.4	19.4
Power Plant	Construction and Decommissioning[d]	1.2			1.2	1.2	1.2
	Combustion at Power Plant[e]		359.0		359.0	359.0	359.0
Overall	Life Cycle	1.2	395.0	42.4	438.6	415.8	514.1

[a] Although lower estimates for this stage have been published, reported emissions increase as the comprehensiveness of processes considered increase. So we use the highest published estimate for this stage that provided results in a form that could be adjusted by EUR (Santoro et al., 2011).

[b] Based on EPA (2011) estimate of 9,175 Mcf natural gas emission/completion, 1% of wells/year workover rate (EPA 2012b), 30-year assumed lifetime (Skone et al. 2011), and 22-county, Barnett Shale average natural gas molecular weight of 20.1 lb/lb-mol and 66.2% methane by mass.

[c] Based on Skone et al. (2011)

[d] Based on Skone and James (2010)

[e] Based on Skone et al. (2011)

Appendix C: Requirements, Standards, and Reporting

Table 22. State Revisions to Oil and Gas Laws

PA	Updated regulations in 2010. Particular emphasis on well construction, disclosure, handling and disposal of recovered fluids. New 2012 legislation also created new setbacks, environmental impact analysis requirements, new fees, floodplain drilling restrictions, restoration requirements, general containment requirements, public disclosure requirements, restricted local control.
NY	Proposed major overhaul of regulations in 2011 specifically to address high-volume hydraulic fracturing. Some of the most comprehensive rules in the nation. Added new subpart 560 containing definitions specific to high-volume hydraulic fracturing, setback, reporting, well construction, and reclamation standards.
CO	Major overhaul of regulations in 2009. In 2011, revised disclosure rule, added a requirement that operators must notify Commission within 48 hours of intention to fracture and provide landowners within 500 feet of proposed oil and gas location information regarding fracturing and how to collect baseline monitoring.
WY	Updated regulations in 2010. Revised disclosure and pit requirements; strengthened presumptive Best Available Control Technology requirements for air emissions (green completions in Jonah Pinedale Anticline Area and Concentrated Development Areas).
TX	Updated air rules and implemented disclosure rule in January 2012.
LA	Finalized new disclosure rule in October 2011.

Table 23. Fracking Fluid Disclosure Requirements

	Colorado	Louisiana	New York	Pennsylvania	Texas	Wyoming
State Code	COGCC Rule 205A	La. Admin Code. tit. 43, pt. XIX, § 118	Draft SGEIS 8.2.1.1	Act 13, §3222, 3222.1	16 Tex. Admin Code § 3.29	WOGCC Rules, Ch. 3 § 45
Takes Effect	February 1, 2012	October 20, 2011	Proposed 2011	April 16, 2012[157]	February 1, 2012	October 17, 2011
Duty to Report?	Yes. Names of products in fracking fluids, chemicals in fracking fluids, associated chemical abstract numbers.	Yes. Names of products in fracking fluid, chemical ingredients in fracking fluid, chemical concentrations of hazardous chemicals.	Yes. Fracking fluid additive products and material safety data sheets	Yes. Names of products in fracking fluid, chemicals in fracking fluid, associated chemical abstract service numbers.	Yes. Names of products in fracking fluid, chemicals in fracking fluid, associated chemical abstract numbers, volume of fracking fluid.	Yes. Names of products in fracking fluid, chemicals present in fluid, associated chemical abstract service numbers, volume of fracking fluid.
To Whom?	Yes, to Frac Focus provided public can search information by company, chemical ingredient, geographic area, and other criteria by Jan. 1, 2013. If not, COGCC will build its own searchable database. Must also provide landowners within 500 feet of the well with information regarding fracking and baseline water sampling.[158]	Office of Conservation, district manager or Frac Focus	NY Department of Environmental Conservation for public disclosure	PA Department of Environmental Protection or Frac Focus. Similar requirement to CO that Frac Focus must be searchable by Jan. 1, 2013, or DEP may require other form of public disclosure.	Yes, to Frac Focus.	Yes to WOGCC website.

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[157] Note, however, that Act is enjoined pending resolution of legal challenge to its constitutionality on other grounds.

[158] 2 CCR 404-1, R. 305.e.(1).A. (2012).

	Colorado	Louisiana	New York	Pennsylvania	Texas	Wyoming
When?	No later than 60 days after completion of fracking operation or no later than 120 days after commencement of fracking operation.	Within 20 days after operations are complete.	Prior to drilling.	Within 60 days of completion of well completion	On or before date operator submits Well Completion Report; operator must also upload required information to Disclosure Registry.	Before fracking begins (APD) and after operation is complete (Well Completion Report Form).
Trade Secret Exemption?	Yes, for chemicals but not for chemical family name.	Yes, for chemicals but not for chemical family.	Yes, but must still disclose information regarding properties and effects of hazardous chemical.	Yes, for chemicals but not for chemical family. Claims governed by PA's "Right to Know" law, which requires companies submit trade secret information to the DEP. Citizens may challenge information.	Yes, for chemicals but not for chemical family.[159]	Yes, operator can make a request to WOGCC to keep proprietary information confidential.
Trade Secret Disclosure?	Yes, trade secrets must be disclosed to medical professional in event of medical emergency, to Commission to respond to a spill, release or complaint or if needed for diagnosis or treatment of exposed individual. Disclosure must be kept confidential.	Yes, if required to be provided to a health care professional, doctor, or nurse.	Yes to health professionals, employees and designated representatives.	Yes, if required to be provided to a health care professional in event of an emergency. Disclosure must be kept confidential.	Yes, to health professionals and emergency responders to diagnose, treat, or otherwise respond to an emergency. Disclosure must be kept confidential.	No.

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[159] The Texas law contains provisions that allow landowners on whose property operations are taking place, landowners with adjacent property to operations, or state departments and agencies with jurisdiction over matters relevant to trade secret information to challenge a claim of trade secret.

Table 24. Water Acquisition Requirements

Play/Basin	Permit for Withdrawal	Reporting	Other Requirements	Recycling
North San Juan (Colorado)	Permit for groundwater withdrawal outside designated ground water basin.[160]	Must report total volume of water used in fracking job to Frac Focus.[161]	Local requirements apply.[162]	None.[163]
Upper Green River (Wyoming)	Yes[164]	Yes, limited to amount, not source.[165]	None identified.	None.
Marcellus (New York)	Yes[166]	Operator must identify source of water in permit and report annually on aggregate amounts withdrawn or purchased.[167]	Monitoring and other requirements to ensure no degradation to water quality and quantity.[168]	Must develop a wastewater source reduction strategy identifying the methods and procedures operators will use to maximize recycling and reuse of flow back or production fluid either to fracture other wells or for approved beneficial uses.[169]

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[160] C.R.S. §§ 37-90-137, 37-92-308 (2011). See also http://cogcc.state.co.us/Library/Oil_and_Gas_Water_Sources_Fact_Sheet.pdf. The Colorado Ground Water Commission may define and alter designated groundwater basins within the state based on adequate factual information. See C.R.S. §37-90-106 (2012).

[161] COGCC R. 205A(b)(2)(A)(viii) (2012).

[162] See, for example, Archuleta County Land Use Code Section 9.2: Archuleta County's Oil and Gas Development Permit Provisions (Amended Dec. 2010) http://www.archuletacounty.org/Planning/Section%209%20-%20Mining%20December%202010.pdf.

[163] *See* Response of the Colorado Oil and Gas Conservation Commission to the STRONGER Hydraulic Fracturing Questionnaire, 32, http://cogcc.state.co.us/Library/HydroFracStronger/COGCC_Response_To_STRONGER_06132011.pdf (noting that R. 907(a)(3) encourages recycling by encouraging operators to submit waste management plans that may provide for reuse of waste water. Rules 903 and 907 encourage recycling by providing for multi-well pits. R. 902.e and 903.a.(4) creates new pit classification for multi-well pits. "These pits are often centrally located in the oil or gas field, are used to store fluids from multiple wells, and may include treatment areas where fracturing flowback fluids and produced water can be brought up to specifications. COGCC is also working with several operators on waste sharing plans that will facilitate the reuse and recycling of fracturing fluids and produced water."

[164] National Conference of State Legislatures, "State Water Withdrawal Regulations," http://www.ncsl.org/issues-research/env-res/state-water-withdrawal-regulations.aspx.

[165] Conversation with Rick Marvel, engineer, WOGCC, May 29, 2012.

[166] NYSGEIS § 7.1.1.1. Withdrawal permits will include conditions to monitor and enforce water quality and quantity standards and requirements. If withdrawing from within 500 feet of wetlands, must require monitoring during pump test. Lowering groundwater levels at or below wetlands is a significant impact triggering site-specific State Environmental Quality Review Act review. Withdrawals from groundwater within 500 feet of private wells also trigger site-specific State Environmental Quality Review Act reviews.

[167] *Id.*

[168] See *Id* (discussing various standards such as passby flow requirements, water conservation practices, and protections for aquatic life that may be included by permit).

[169] NYSGEIS § 5.12.

Play/Basin	Permit for Withdrawal	Reporting	Other Requirements	Recycling
Marcellus (Pennsylvania)	Cannot withdraw without approved water management plan.[170]	Report list of water sources used under approved water management plan and volume of water.[171]	Water management plan that includes plan for reuse of fluids.[172]	Water management plan must include plan for reuse of fluids used to fracture wells.[173] Well completion report must include total volume of water recycled.[174]
Haynesville (Louisiana)	None identified.	Must report water source and volumes after completion or recompletion.[175]	None.	Regulations recognize processing of E&P waste into reusable materials as alternative to other means of disposal and authorizes commercial facilities for the purpose of generating reusable material.[176]
Eagle Ford (Texas)	Yes.[177]	Report total volume of water used in fracking to Frac Focus.[178]	None identified.	None.
Barnett (Texas)	Yes.	Report total volume of water used in fracking to Frac Focus.[179]	None identified.	None.

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[170] 58 PA Con. Stat. ch. 32, § 3211(m). Condition of all permits to hydraulically fracture natural gas wells in unconventional formations.

[171] *Id.* § 3222(b.1)(1)(vi) (2012).

[172] 58 PA Con. Stat. ch. 32, § 3211(m). Operators must develop water management plan, which must be approved by DEP, governing withdrawals or use of water. Approval of plan is contingent on determination that withdrawal/use will not adversely affect quantity or quality of water, will protect and maintain designated and existing uses of water supply, will not cause adverse impact to water quality in watershed and will include a reuse plan for fluids for hydraulically fractured wells. If plan is operated in accord with conditions established by the Susquehanna River Basin Commission, the Delaware River Basin Commission or the Great Lakes Commission, it is presumed to meet above conditions.

[173] 58 PA Con. Stat. ch. 32, §. 3211(m)(2)(iv).

[174] *Id.* § 3222(b.1)(1)(vi) (2012).

[175] Well History and Work Resume Report, Form WH-1, Louisiana Hydraulic Fracturing State Review, 5 (March 2011), http://www.strongerinc.org/documents/Final%20Louisiana%20HF%20Review%203-2011.pdf.

[176] La. Admin. Code tit. 43:XIX, § 565 (2010).

[177] Tex. Water Code, tit. 2, ch. 11. *See also* http://www.rrc.state.tx.us/barnettshale/wateruse.php Short-term permits issued by Texas Commission on Environmental Quality Regional Offices and permits for more than 10 acre-feet of water or for a term lasting more than 1 year are issued by the Commission's Water Rights Permitting Team.

[178] 16 Tex. Admin. Code § 3.29(c)(2)(A)(viii) (2011).

[179] *Id.*

Table 25. Well Construction Standards

Play/Basin/ Jurisdiction	Cement Bond Log	Minimum Surface Casing Depth	Pressure Tests for Casing	Monitor Bradenhead Annulus Pressure
Federal Lands[180]	Yes.	None.	Yes. Mechanical integrity test required before each well stimulation operation.	No. But must continuously monitor and record pressure during well stimulation and notify if annulus pressure increases by more than 500 lbs per square inch.
North San Juan (Colorado)	Yes. Required on all production casing, or in the case of production liner, the intermediate casing.[181]	None specified in rules, but OGCC requires casing be set at least 50 feet below aquifer to ground surface.	Yes. Must test production casing during completion and production. [182]	Must monitor and record bradenhead annulus pressure during fracking and notify COGCC of conditions indicating fracking fluids have escaped producing reservoir.[183]
Upper Green River (Wyoming)	No specific requirement.[184]	None specified but casing must be run below known or reasonably estimated utilizable fresh water levels.[185]	No. Mechanical integrity tests may be required but not mandatory.[186]	No
Barnett (Texas)	No.	None specified but all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm.[187]	All casing must be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to max. pressure to which pipe will be subjected in the well	All wells must be equipped with a bradenhead. Must notify district office when pressure develops between any two strings of casing. Must perform a pressure test with bradenhead if well shows pressure on the bradenhead.[188]

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[180] BLM (2012). "Proposed Rule: Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands," Department of Interior, May 4, 2012, http://www.doi.gov/news/pressreleases/loader.cfm?csModule=security/getfile&pageid=293916.

[181] COGCC R. 317(o).

[182] *Id*. at 317(j).

[183] *Id*. at 341.

[184] WOGCC Rules, ch. 3, §§ 12, 21, requires submission of well logs, which includes "electrical, radioactive, or other similar log runs," which may, but does not necessarily, include cement bond logs.

[185] *Id.* § 22(a)(i).

[186] *Id.* § 45.

[187] 16 Tex. Admin. Code § 3.13.

[188] *Id.* § 3.17.

Play/Basin/ Jurisdiction	Cement Bond Log	Minimum Surface Casing Depth	Pressure Tests for Casing	Monitor Bradenhead Annulus Pressure
Eagle Ford (Texas)	No.	None specified but all usable-quality water zones must be isolated and sealed off to effectively prevent contamination or harm.[189]	All casing must be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to the maximum pressure to which pipe will be subjected in the well.	All wells must be equipped with a bradenhead. Must notify district office when pressure develops between any two strings of casing. Must perform a pressure test with bradenhead if well shows pressure on the bradenhead.[190]
Haynesville (Louisiana)	Yes, operator must run cement bond log, temperature survey, X-ray log, density log, or other acceptable test.[191]	None.[192]	Surface, intermediate, and producing casing must be tested depending on their depth.[193]	No.
Marcellus (New York)	Department may require a cement bond long or other measures to ensure adequacy of the bond.[194]	Must be set to at least 75 feet beyond deepest fresh water zone or bedrock, whichever is deeper.	No.[195]	No.
Marcellus (Pennsylvania)	In response to a potential natural gas migration incident, the department may require operator to evaluate adjacent oil and gas wells with different measures, including cement bond logs.[196]	Must be set 50 feet below deepest fresh groundwater or at least 50 feet into consolidated rock, whichever is deeper.[197]	Yes. New casing must have an internal pressure rating that is at least 20% greater than anticipated maximum pressure to which casing will be exposed. Used casing must be pressure tested after cementing and before continuation of drilling.[198]	No.

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[189] *Id*. § 3.13.

[190] *Id*. § 3.17.

[191] La. Admin. Code, tit. 43, pt. XIX, §419(A)(3).

[192] *Id*. § 109.

[193] *Id*.

[194] N.Y. Comp. Codes R. & Regs. tit. 6, ch. V, §559.6(d)(2).

[195] *Id*. § 557.2.

[196] 25 Pa. Code § 78.89.

[197] *Id*. § 78.83.

[198] *Id*. § 78.84.

Table 26. Baseline Monitoring Requirements

Play/Basin	Requirement
North San Juan (Colorado)	Operators drilling within 301–2,640 feet of surface water intended to be used for drinking water must collect baseline water samples from the surface water prior to drilling and 3 months after the conclusion of drilling or completion.[199] Operators must collect water well samples from nearby wells prior to drilling, as well as 1, 3, and 6 years after completion.[200] Operators must provide landowners within 500 feet of proposed oil and gas location with instruction as to how to collect baseline water samples.[201]
Marcellus (New York)	Operator must make reasonable attempt to sample and test all residential water wells within 1,000 feet of a wellpad; must be sampled prior to commencing drilling. If no well is located within 1,000 feet, or the surface owner denies permission, then the operator must sample all wells within a 2,000-foot radius. Monitoring continues at specified intervals as determined by the DEC.[202]
Marcellus (Pennsylvania)	PA law provides for a rebuttable presumption that a well operator is responsible for pollution of a private or public water supply if the supply is within 2,500 feet of an unconventional well and the pollution occurred within 12 months of the later of the completion, drilling, stimulation or alteration of the well. Operators can overcome this presumption by undertaking a pre-drilling or pre-alteration survey that demonstrates pre-existing contamination or if landowner or water purveyor refuses to allow the operator to test.[203]

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[199] 2 Colo. Code Regs. § 404-1; COGCC R. 317B(d)(e). Samples must be tested for BTEX, TDS, metals, and other specified parameters in the rules.

[200] Various Commission Orders. *See* COGCC Response to STRONGER, 4, available at http://cogcc.state.co.us/Library/HydroFracStronger/COGCC_Response_To_STRONGER_06132011.pdf. R. 608 extends the requirements set forth in Commission Orders to other parts of the state with CBM wells and requires operators to identify all plugged and abandoned wells within ¼ mile of proposed CBM well, assess the risk of leaking gas or water, make a reasonable good-faith effort to conduct pre-production soil gas survey of all plugged and abandoned wells within ¼ mile of proposed CBM well and post-production survey 1 and every 3 years after production has commenced, and sample water wells located within ¼ or ½ mile from proposed CBM well and within 1, 3, and 6 years thereafter.

[201] 2 Colo. Code Regs. § 404-1; COGCC R. 305.e.(1).A. (2012).

[202] N .Y. Comp. Codes R. & Regs. tit 6, § 560.5(d).

[203] 58 Pa. Cons. Stat § 3218(c).

Table 27. Closed-Loop or Pitless Drilling Requirements

Play/Basin	Requirement	Date Adopted
North San Juan (Colorado)	Pitless drilling within 301–500 feet of surface water intended to be used for drinking water. Pitless drilling or containment of all flowback and stimulation fluids in liner pits within 501–2,640 feet of surface water intended to be used for drinking water unless operator can demonstrate pit will not adversely affect waters.[204]	2008
Upper Green River (Wyoming)	Closed system required where groundwater is less than 20 feet below surface.[205]	2010
Marcellus (New York)	Closed-loop tank system for drilling fluids and cuttings produced from horizontal drilling unless an acid rock drainage mitigation plan for on-site burial of such cuttings is approved by department.[206] Cuttings contaminated with oil-based mud or polymer-based mud must be contained and managed in a closed-loop tank system.[207]	Proposed 2011
Marcellus (Pennsylvania)	Prohibits storage and disposal of production fluids and brine in pits unless permitted under Clean Streams Law.[208]	2010
Barnett (Texas)	Closed-loop mud system required for all drilling and reworking operations unless operations located on open space of at least 25 acres and not within 1,000 feet of residence or certain public places.[209]	2009

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[204] COGCC R. 317B(d)(1), (e)(1); R. 904. Colorado does not define pitless drilling. The definition of *pit* is a "natural or man-made depression in the ground used for oil or gas exploration or production purposes. Pit does not include steel, fiberglass, concrete or other similar vessels which do not release their contents to surrounding soils." COGCC R. 100.

[205] WY ADC Oil Gen. ch. 4, § 1(u). Commission has authority to require closed system in other instances to protect surface and ground water, human beings, wildlife and livestock. *Id*. Closed system "includes, but is not limited to, the use of a combination of solids control equipment (e.g., unconventional shakers, flow line cleaners, desanders, desilters, mud cleaners, centrifuges, agitators, and necessary pumps and piping) incorporated in a series on the rig's steel mud tanks, or a self-contained unit that eliminates the need for a reserve pit for the purpose of dumping and dilution of drilling fluids for the removal of entrained drilling solids. A closed system for the purpose of the Commission's rules does not automatically include the use of a small pit, even to receive cuttings." WY ADC Oil Gen. ch.1, § 2(k).

[206] NY Dept. of Envtl Conservation Proposed Rules, 6 N.Y. Comp. Codes R. & Regs. § 560.6. Closed-loop drilling system means a pitless drilling system where all drilling fluids and cuttings are contained at the surface within piping, separation equipment and tanks. 6 N.Y. Comp. Codes R. & Regs. § 750-3.2.

[207] New York Department of Environmental Conservation Proposed Rules, 6 N.Y. Comp. Codes R. & Regs. § 560.7.

[208] PA Office of Oil and Gas Mgmt. Rules, ch. 78.57.

[209] Fort Worth, Tex. Ordinance, § 15-42(A)(3), (A)(38)(b) (2009).

Table 28. Produced Water Disposal

State	Direct	Indirect	Underground Injection Control	Ponds	Land	Reuse
CO	Yes, if water meets criteria for wildlife or agricultural propagation. CBM discharges via permit.[210]	Yes	Yes	Yes	Yes, water must meet state water-quality standard for agricultural/livestock use.[211]	Encouraged[212]
WY	Yes, if water meets criteria for wildlife or livestock watering or other agricultural uses.[213]	Yes	Yes	Yes	Yes, with permission.[214]	Encouraged[215]
TX	Yes[216]	No[217]	Yes	Yes, with permit.[218]	No[219]	No provisions
PA	No	Yes, for new and expanded discharges meeting standards.	Yes	Yes	Yes[220]	Yes[221]
NY	No	Yes operator must analyze POTW capacity and create contingency plan if the primary wastewater disposal is at POTW.	Yes[222]	No	Only with permission.[223]	Encouraged[224]

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[210] Colorado follows national effluent limitations. 2 Colo. Code Regs. §404-1; COGCC R. 907.
[211] 2 Colo. Code Regs. §404-1, COGCC R. 907. Standard is 3,500 mg/l.
[212] No specific requirements but COGCC R. 907(a)(3) encourages recycling by encouraging operators to submit waste management plans which may provide for reuse of waste water, see http://cogcc.state.co.us/Library/HydroFracStronger/COGCC_Response_To_STRONGER_06132011.pdf
[213] WY Water Quality Rules & Regs, ch. 2, appendix H. *See also* WOGCC Rules, ch. 4 §1 (ee).
[214] WOGCC Rules, ch. 4 §1 (mm)
[215] *Id.* § 1(z). No specific requirements although "Commission encourages the recycling of drilling fluids and by administrative action approves the transfer of drilling fluids intended for recycling.
[216] Personal communication with John Becker, Texas Railroad Commission.
[217] Based on conversation with Phillip Urbany, engineer, TX Commission on Environmental Quality, May 29, 2012.
[218] 16 Tex. Admin. Code §3.8(d)(2).
[219] Our research did not identify any prohibition on land application but also no clear authorization.
[220] 25 Pa. Code §78.63.
[221] AB 13, Sec. 3211(m).

State	Direct	Indirect	Underground Injection Control	Ponds	Land	Reuse
LA	No[225]	Discharge to a POTW is not a permissible disposal method for produced water in Louisiana.[226]	Yes	Yes	Yes[227]	No provisions

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[222] N.Y. Comp. Codes R. & Regs. tit. 6, §750-1.24. *See also* 40 C.F.R. 144 & 146.

[223] Revised SGEIS at 7-60: Those wanting to road spread production brine must petition for a beneficial use determination. NORM concentrations in Marcellus Shale likely won't allow road spreading of brine, but "[a]s more data becomes available, it is anticipated that petitions for such use will be evaluated by the Department."

[224] Proposed N.Y. Comp. Codes R. & Regs., tit. 6, §560.7. Removed pit fluids must be disposed, recycled or reused as described in approved fluid disposal plan. Operator must submit fluid disposal plan (see regs at 750. 3.12).

[225] EPA National effluent limitation, *see* 40 CFR ch. I, subch. N; see also http://www.deq.louisiana.gov/portal/Portals/0/planning/Permits%20Docs/Timeline022912mcm-Version%204.pdf (discharges prohibited onto vegetated areas, soil, intermittently exposed sediment surface, lakes, rivers, streams, bayous, canals, or other surface waters regionally characterized as upland, freshwater swamps, freshwater marshes, natural or manmade water bodies bounded by freshwater swamp/marsh).

[226] *See* La. Admin Code titl. 43, pt. XIX, §313.

[227] *Id*. §313(D).

Table 29. Green Completion Requirements

Play/Basin/Jurisdiction	Requirement	Flaring/Venting Allowed	Local
Federal[228]	Hydraulically fractured gas production wells must capture and route all saleable gas to a sales line during flowback starting in 2015. Exception for low-pressure wells. Does not apply to exploratory or delineation wells.	Pit flaring allowed until 2015 and thereafter allowed for non-recoverable gas. Venting allowed where flaring presents safety hazard or if flowback is noncombustible.	N/A
North San Juan (Colorado)[229]	Must use green completion practices to route saleable gas to sales line as soon as practicable. Does not apply to low-pressure or wells with less than 500 MCFD of naturally flowing gas. Exception for exploratory wells and wells not sufficiently proximate to sales lines.	Gaseous phase of non-flammable effluent may be flared or vented until flammable gas is encountered for safety reasons. During upset conditions. If variance granted.	Cannot vent or flare well directly to atmosphere without first going to separation equipment or portable tank.[230]
Upper Green River (Wyoming)[231]	Must eliminate VOCs and hazardous air pollutants to the extent practicable by routing liquids to tanks and gas to sales line or collection system. Does not apply to exploratory wells.	Permitted when required by specific operational events or circumstances.	None

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[228] U.S. EPA, Final Rule, Oil and Natural Gas Sector: "New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," (2012).

[229] COGCC R. 805(b)(3).

[230] Archuleta County Land Use Code Sec. 9.2.6.3: Archuleta County's Oil and Gas Development Permit Provisions (Amended Dec. 2010) http://www.archuletacounty.org/DocumentView.aspx?DID=295.

[231] Wyoming Oil and Gas Production Facilities, ch. 6, § 2 Permitting Guidance (March 2010), http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf.

Play/Basin/Jurisdiction	Requirement	Flaring/Venting Allowed	Local
Barnett (Texas)	None	N/A	All wells that have a sales line must use techniques or methods that minimize the release of natural gas and vapors to the environment during flowback except wells permitted prior to July 1, 2009, or the first well on a pad site.[232]
Marcellus (New York) *– Proposed*	REC whenever sales line available.[233]	Yes, if no sales line available.	None identified

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[232] Fort Worth, Tex., Ordinance No. 18449-02-2009, § 15-42(A)(28).

[233] Proposed mitigation requirement via permit condition. New York Department of Environmental Compliance, Revised Draft SGEIS, §7.6.8.

Table 30. Setback Requirements

Play/Basin	State-Distance from home	State-Distance from Private Water Well	State-Distance from source of drinking water	Local	Vertical fragmentation?
Barnett (Texas)	200 feet[234]	None	None	600 feet from home, 200 feet to fresh water well[235]	Yes
Eagle Ford (Texas)	200 feet	None	None	500 feet from home,[236] 200 feet from home[237]	Yes
Haynesville (Louisiana)	500 feet[238]	None	None	None	No
Marcellus (Pennsylvania)	500 feet[239]	500 feet[240]	1,000 feet[241]	200 feet from home or water well[242]	Yes, under current law[243]
Marcellus (New York)	None	500 feet[244]	500 feet[245]	N/A[246]	Yes, in that localities have banned development altogether, and if the state moratorium is lifted, it seems likely localities will attempt to regulate this area

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[234] Tex. Local Gov't Code 253.005(c).

[235] Fort Worth, Tex.; Ordinance No. 18449-02-2009.

[236] City of Burleson, Tex., Ordinance B-790-09.

[237] Fayette County, Tex., Ordinance. Local zoning ordinance provides for the same 200-foot setback limit from residential homes but ordinance notes "Zoning Hearing Board may attach additional conditions to protect the public's health, safety, and welfare, including increased setbacks."

[238] State of La. Office of Conservation, Order No. U-HS (Aug. 1, 2009),http://dnr.louisiana.gov/assets/docs/news/2009/U-HS.pdf. *See also Louisiana Hydraulic Fracturing State Review,* (Mar. 2011), 5.

[239] Act 13, § 3215(a) (Unconventional wells cannot be drilled within 500 ft. of building or water well, without the consent of the owner of the building or well).

[240] *Id*. DEP shall grant a variance from specified setback requirements if the restriction deprives the owner of the oil and gas rights of the right to produce or share in the oil or gas underlying the surface tract. Note, the statute also provides for a 300-foot setback from streams, springs, other bodies of water identified on a U.S. Geological Survey map, or wetlands, although these "shall" also be waived upon submission of a plan containing additional measures to protect waters. *Id*. § 3215(b).

[241] *Id*.

[242] South Franklin Township, Pa.; Ordinance No. 4-2008 (Wells may not be drilled within 200 feet from an existing habitable structure or existing water well without express written consent of the owner).

[243] Act 13 supersedes all local ordinances purporting to regulate oil and gas operations, other than those adopted pursuant to Pennsylvania municipalities and planning code and Flood Plain Management Act. However, implementation of this provision of the law has been enjoined pending resolution of a legal challenge brought by a number of local governments.

[244] Proposed 6 N.Y. Comp. Codes R. & Regs. 560.4(a)(1) (Well pad must be at least 500 ft. from a private water well unless waived by water well owner).

[245] *Id*. at 560.4(a)(2) (Well pads may not be located within 500 feet of the boundary of a primary aquifer). In addition, NY prohibits well pads within a primary aquifer, 100-year floodplain, and within 2,000 ft. of any public

Play/Basin	State-Distance from home	State-Distance from Private Water Well	State-Distance from source of drinking water	Local	Vertical fragmentation?
North San Juan (Colorado)	150 feet[247]	None	Buffer Zones to protect surface water intended for drinking water	450 from home without consent[248]	Yes
Upper Green River (Wyoming)	350 feet[249]	None	None	None	No

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water supply well, reservoir, natural lake or man-made impoundment except those constructed for fresh water storage associated with hydraulic fracturing, and river or stream intakes. *Id.* at 560.4(a)(2)-(4).

[246] Our research did not identify any local laws directly regulating unconventional gas development in NY.

[247] COGCC R. 603(a). In high-density areas, wellheads must be at least 350 ft. from buildings. *Id*. at 603.e(2).

[248] Chapter 90 – La Plata County's Oil and Gas regulations, § 90-122: http://co.laplata.co.us/sites/default/files/departments/planning/chapter_90_adopted_12_7_2010.pdf ; Archuleta County Land Use Code Section 9.2.6.2: Archuleta County's Oil and Gas Development Permit Provisions (Amended Dec. 2010) http://www.archuletacounty.org/DocumentCenter/Home/View/295.

[249] Pits, wellheads, pumping units, tanks and treaters shall be located no closer than 350 ft. from designated public places. Supervisor may extend setbacks or grant exceptions for good cause. WY ADC Oil Gen. ch. 3, § 22(b).

Appendix D: Risk Factor Data

This appendix provides more detailed information on the six selected shale plays considered in this study. For each play, where data are available, we provide 1) an overview of the shale play geology and resource potential, 2) trend data on the number of wells being drilled, 3) information about water usage per well, 4) information on produced water volumes and wastewater management practices, 5) issues associated with freshwater acquisition, and 6) reported data on violations. In addition, this appendix provides more information about the severity index used for water violations (D.7).

Marcellus Shale Play, Pennsylvania

Overview

The Marcellus Shale formation extends across 600 miles within four states, covering an area of about 54,000 square miles. The thickness of the formation varies, but is typically thicker in the east (up to 250 feet) and thins toward the west (Sumi 2008). The Marcellus Shale is the middle Devonian layer between the upper Middle Devonian Mahantango and underlying Middle Devonian Onodaga Limestone formation (USGS 2011). Estimates of the total economically recoverable natural gas in the basin have changed significantly over the years—from an initial estimate of 1.9 trillion cubic feet (Tcf) in 2002 to 168–516 Tcf in 2008 (UM 2010). The U.S. Geological Survey recently estimated mean undiscovered resources for natural gas liquids of 3,379 million barrels and for natural gas of 84,198 billion cubic feet (USGS 2011).

Figure 63 shows the extent and approximate depth of the Macellus formation, which underlies New York, Pennsylvania, Maryland, West Virginia, and Ohio.

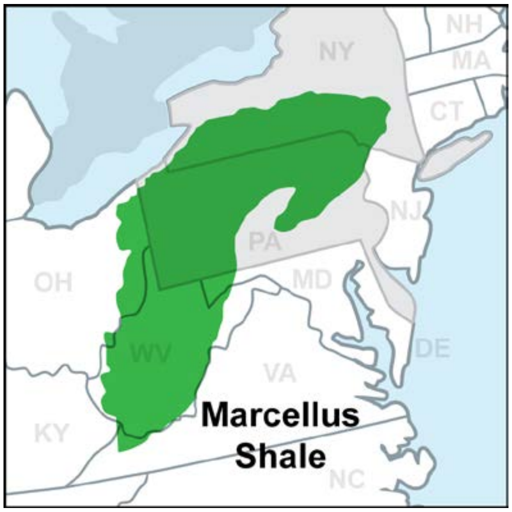

Figure 63. Extent of Marcellus Shale

Number of Wells

As of December 15, 2011, the Marcellus Shale Basin had 88 active operators. More than 9,600 permits have been submitted, with 9,328 issued. Only 36 permits have been denied since 2005 (PA DEP 2011a).The operators with the most permits in the Marcellus Shale include Chesapeake

Appalachia LLC with 1,614 drilling permits, Range Resources Appalachia LLC with 917 permits, and Talisman Energy USA Inc., with 896 permits (PA DEP 2012e).

However, the number of permits does not necessarily reflect the number of wells drilled. Only 44% of the permits resulted in a drilled well (PA DEP 2011b). Figure 64 shows the total number of permits vs. wells drilled in 2010. Figure 65 shows the total number of wells drilled in 2011.

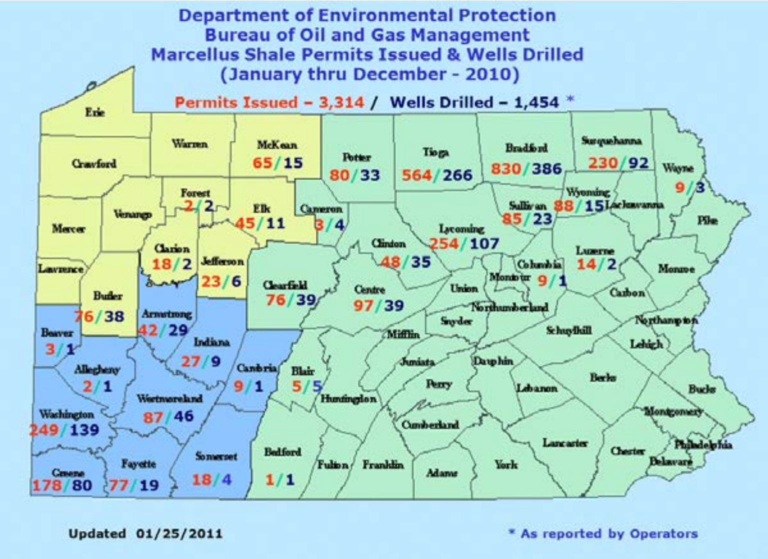

Figure 64. Marcellus Shale permits issued vs. number of wells drilled (PA DEP 2011b)

Water Usage per Well

Some 102 wells in the Marcellus Shale of Pennsylvania were randomly selected for an analysis of water usage per well. The total volume of water per well was acquired through fracfocus.org, and all other information (e.g., latitude, longitude, spud date) was gathered from the fractracker.com data set, "All Wells Marcellus," a compilation of data from the Pennsylvania Department of Environmental Protection (DEP). API numbers and well location files were cross checked between the fractracker and fracfocus data sets. Reporting to fracfocus is voluntary, causing some data to not match official API numbers and latitude/longitude found in regulated DEP data. If discrepancies occurred, then fracfocus data were discarded and a new well was chosen. Table 31 shows results for the 102 wells in Pennsylvania.

Table 31. Analysis of Water Usage per Well (gallons) for 102 Marcellus Wells (fracfocus.org)

Mean	**Max**	**Min**	**Range**	**Standard Deviation**
4,842,070	9,548,784	430,584	9,118,200	1,690,457
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
4,567,320	5,802,941	3,912,996	1,889,945	0.4422

As seen in Table 31, the average volume per well was about 4,842,000 gallons. It is important to note the large range of values—with a minimum of 430,584 gallons and a maximum of 9,548,784 gallons. A histogram (Figure 66) displaying the total volume of water was created by evenly distributing the range of values into twenty bins and then counting the total number of wells for each bin.

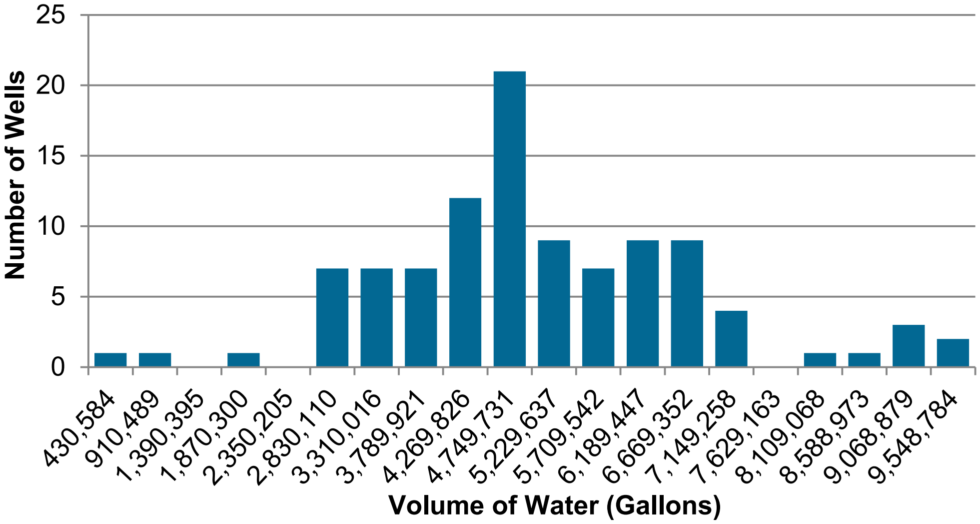

Figure 66. Histogram for 100 wells of total volumes (gallons) (fracfocus.org)

Table 32. Average Water Volume per Well by Well Type (gallons) (fracfocus.org)

Well Type	**Vertical**	**Horizontal**
Average	5,431,035	4,756,042
Sample Size	13	89

The effect of a small sample size can be seen in the comparison of average water used by type in vertical and horizontal wells in Table 32. In general, horizontal wells use much more water than vertical wells—a vertical well typically uses 0.5 to 1 million gallons of water, whereas a horizontal well uses between 4 to 8 million gallons of water (Natural Gas 2010). Further data collection is needed to provide a better comparison of vertical and horizontal wells.

Produced Water

The DEP has official production and waste reporting data on its Oil and Gas Reporting website (PA DEP 2012b). The website contains statewide data that can be downloaded on production and waste on a yearly basis. Each waste data set contains the total waste for each well per year, with the waste described by quantity, waste type, and disposal method. Before 2010, waste reports were not well organized, and an online reporting system had not yet been created, causing many wells to be excluded from the data sets. Furthermore, a server malfunction caused the loss of any relevant 2007 data. Since 2010, all waste produced by all wells in Pennsylvania have been accurately reported. However, reporting period dates have changed to biannual, rather than annual.

Brine production and fracking fluid flowback were analyzed. Although the DEP does not have an official definition of flowback and brine, flowback can be considered the water produced before the well is put into production on a gas line.

For our analysis, natural gas wells in the Marcellus Basin were filtered out from DEP data. We observed that portions of a well's waste were reported multiple times if the waste was taken to more than one treatment facility. The duplicate data were removed from the analysis.

Brine and fracking fluid wastes were divided and analyzed separately. The results can be seen in Tables 33 and 34, along with Figures 67 and 68, with all units in gallons.

Table 33. Summary of Brine Produced (thousands of gallons) (PA DEP 2012b)

				Disposal Method						
Year	**Total Wells**	**Total Volume**	**Average Volume Per Well**	**Brine/ Industrial Water Treatment Plant**	**Injection Disposal Well**	**Municipal Sewage Treatment Plant**	**Other**	**Reuse Other Than Road Spreading**	**Road Spreading**	**Landfill**
2006	14	160.4	14.2	124.9	0	30.6	0	0	4.8	0
2008	204	50,211.0	246.1	1,345.1	775.9	40,067.1	3,457.8	4,501.9	63.0	0
2009	445	231,316.3	519.7	169,860.5	4,707.5	36,402.4	16,466.8	3,875.8	3.1	0
July 2010-June 2011	1,614	287,088.1	177.8	123,623.9	35,541.3	2,711.6	19,931.4	105,248.4	7.8	23.3

Table 34. Summary of Fracking Fluid Produced (thousands of gallons) (PA DEP 2012b)

				Disposal Method						
Year	**Total Wells**	**Total Volume**	**Average Volume Per Well**	**Brine/ Industrial Water Treatment Plant**	**Injection Disposal Well**	**Municipal Sewage Treatment Plant**	**Other**	**Reuse Other Than Road Spreading**	**Road Spreading**	**Landfill**
2006	2	255.4	127.7	255.4	0	0	0	0	0	0
2008	106	46,881.9	442.3	8,792.4	0	25,238.7	11,717.3	1,133.3	0	0
2009	225	105,869.6	470.5	24,505.2	610.2	46,570.4	26,371.2	7,812.4	0	0
July 2010-June2011	1,128	249,336.3	221.0	110,377.0	945.1	284.9	646.1	137,009.5	138.1	73.4

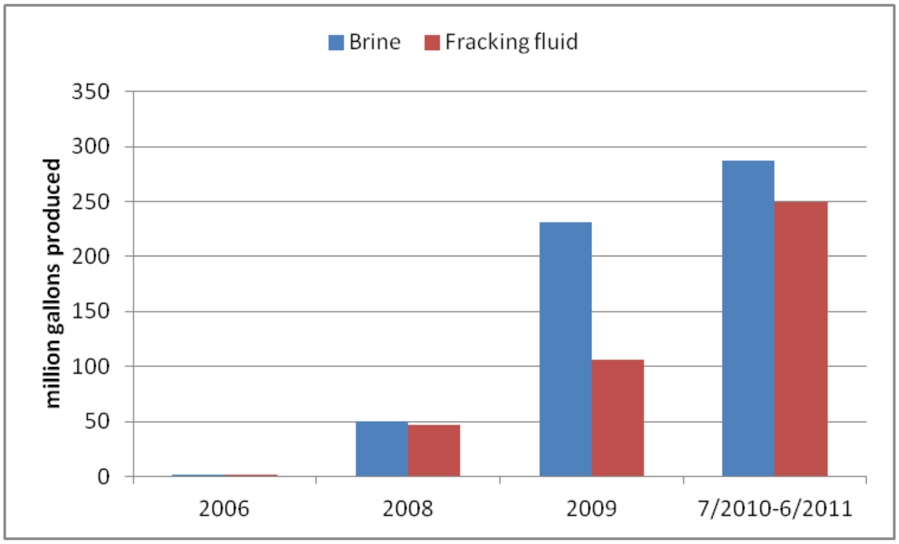

Figure 67. Total volume of produced water, 2006–2011 (PA DEP 2012b)

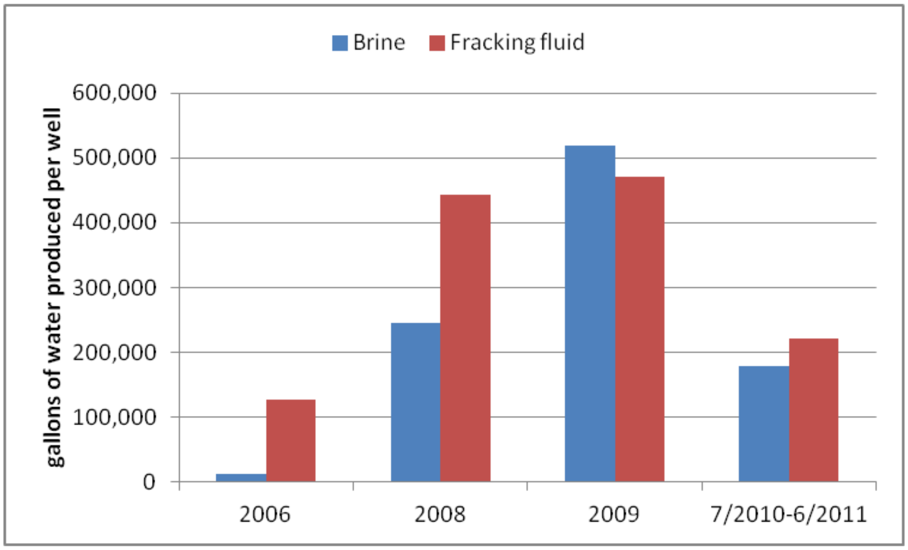

Figure 68. Average volume of produced water per well, 2006–2011 (PA DEP 2012b)

Based on Figure 67, the quantity of both produced brine and fracking fluid are clearly increasing each year—due to the increasing number of wells drilled each year. The final reporting period (July 2010–June 2011) had 1,614 wells producing brine, which is 1,169 more wells than the 2009 period (PA DEP 2012b). As seen in Figure 68, the increase in total brine and fracking fluid does not correlate with average produced brine and fracking fluid per well. There is no recognizable trend in produced water per well, as 2009 had a higher average than any other year.

Water Acquisition

Water withdrawal permit information for the Marcellus in this study focused on the Susquehanna River Basin (SRB). The Marcellus formation underlies 72% of the SRB, covering most of Pennsylvania and part of New York (Arthur 2010). The Susquehanna River Basin Commission

(SRBC) has been the forerunner in determining water usage regulations, monitoring, and permits. The SRBC actively regulates water withdrawal by oil and gas operators; all water withdrawal outside of the SRB is regulated by the DEP.

SRBC issues a report on all approved water sources for natural gas development in the SRB (SRBC 2012a). These permits include the fresh-water source, as well as the maximum allowed uptake per day. These uptakes are rarely at capacity and, according to the SRBC, many sources are used for redundancy due to passby flow conditions when water levels are low (SRBC, 2012a). It is possible to source where operators obtain their water. For example, SWEPI, LP has three different public water suppliers in three different counties. Public water supply does not have a maximum allowed daily uptake, whereas all other supplies do. SWEPI only has one docket approval for a fresh-water source—the Allegheny River in Warren County. This permit allows up to 3 million gallons per day (mgd) of water to be used. SWEPI sources the rest of its water from other drilling companies who share their water permits. Overall, SWEPI has eight different water sources, ranging from 0.217 to 3 mgd. Additional information is available regarding percentage of ground-water to surface-water permits and amounts of water used (SRBC 2011a).

Cost of Acquisition

Fees are associated with fresh-water withdrawal permits. The schedule includes a breakdown of a tiered fee system based on withdrawal amount, as well as consumptive vs. non-consumptive use (SRBC 2011a). Consumptive use is defined in 18 CFR § 806.3 as, “The loss of water transferred through a manmade conveyance system or any integral part thereof… injection of water or wastewater into a subsurface formation from which it would not reasonably be available for future use in the basin, diversion from the basin, or any other process by which the water is not returned to the waters of the basin undiminished in quantity (e-CFR 2012).”

On a per gallon basis, the SRBC fees range from $0.00685–0.1425/gallon for consumptive use, and $0.0030–0.07475/gallon for non-consumptive withdrawals (SRBC 2011a).

Considering SWEPI, LP, it can be seen that a typical docket of 0.250 mgd of surface water would cost $9,975 if the water was not used consumptively. If the use is consumptive, then $1,000 is added as an annual compliance and monitoring fee. There will also be a consumptive-use mitigation fee if the company wishes to use the fee as a method of compliance with 18 CFR §806.22(b). This section states that during low flow periods, several steps may be taken to mitigate consumptive use. One option is to reduce water withdrawal from a source equal to the consumptive use of the operator. Another option is to take water from another approved source. If these or the other provided options are not chosen, the company may choose to pay a fee of $0.29 per 1,000 gallons of water consumed. In the case of SWEPI, this may be an additional cost of $72.50. Companies pay for metering systems and report to the SRBC on a daily basis for each well on its water use.

Another source of fresh water is public supply. The cost of this source varies from utility to utility, but most rates can be found on utility websites. Rates vary significantly from supplier to supplier, and oftentimes unique deals are made between supplier and operator. The deal between East Resources Management, LLC and Morningside Heights Water District approves up to 400,000 gallons per day at a rate of $0.0145 per gallon (Pressconnects 2010). This is 60% greater than water supplier P.A. American Water, which charges $0.008979 per gallon (American Water 2012).

The above costs refer to obtaining water and do not cover the price of transporting the water. Most water is transported by either pumping or trucking. PSU estimates average trucking costs of $0.2 per gallon (Pressconnects 2010). Further analysis of water-supply distances to wells would need to be studied using GIS to assess the actual cost of water transportation.

Violations

The majority of the violations reported from 2009–2011 fall under the category of "minor - no effect" (Figure 69 and Table 35) (NEPA 2012). "Procedural" violations account for about 20%, and "minor effect" and "substantial" account for about 10%. Also, it should be noted that there are no "major" violations. This data set includes all of the violations from 2009–2011 (NEPA 2012). Further information on violations can be found in D.7 of this appendix.

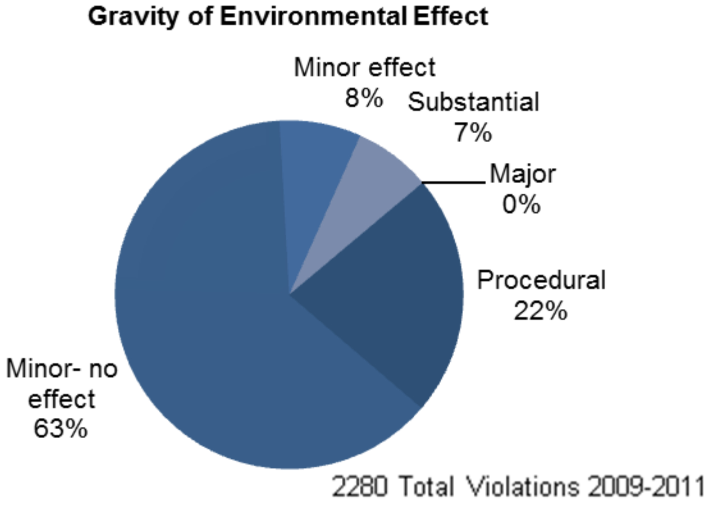

Figure 69. Pennsylvania violations (NEPA 2012)

Table 35. Pennsylvania Violations (NEPA 2012)

Procedural	510	22.4%
Minor - no effect	1433	62.9%
Minor effect	173	7.6%
Substantial	164	7.2%
Major	0	0.0%
Total	2280	

Barnett Shale Play, Texas

Overview

In the early 1900s, geological mapping noted a thick, black, organic-rich shale in an outcrop near the Barnett stream (TRRC 2012e). The Barnett Shale formation exists under extensive areas in Texas and crops out on the flanks of the Llano Uplift, 150 miles to the south of the core area (Figure 70). Current boundaries of the formation are due primarily to erosion (TDWB 2007). The Fort Worth Basin is bounded by tectonic features to the east—notably, the Ouachita Overthrust, an eroded, buried mountain range—and to the north by the uplifted Muenster and Red River Arches. The Barnett Shale dips gently toward the core area and the Muenster Arch from the south where it crops out and thins considerably to the west; its base reaches a maximum depth of ~8,500 ft (subsea) in the northeast. The depth to the top of the Barnett ranges from ~4,500 ft in northwestern Jack County, to ~2,500 ft in southwest Palo Pinto County, to ~3,500 ft in northern Hamilton County, to ~6,000 ft in western McLennan County, to ~7,000 to 8,000 ft in the Dallas-Fort Worth area. Further west in Throckmorton, Shackelford, and Callahan Counties, the depth to the Barnett ranges between ~4,000 and 2,000 ft (TDWB 2007).

The U.S. Geological Survey (USGS) estimated the mean gas resources at 26.7 Tcf (USGS 2004).

Figure 70. Extent of Barnett Shale

Figure 70 shows the extent of the Barnett Shale in Texas. The formation is actually considered to be a hydrocarbon source, reservoir, and trap, all at the same time. As a reservoir, it is known as a "tight" gas reservoir, indicating that the gas is not easily extracted. However, hydraulic fracturing technology has made it possible to extract the gas (TRRC, 2012d). For the Barnett Shale, permeability ranges from microdarcies to nanodarcies, porosity ranges from 0.5% to 6%, and water saturation is below 50%.

Future development will be hampered, in part, because major portions of the field are in urban areas, including the rapidly growing Dallas-Fort Worth Metroplex. Some local governments are researching means by which they can drill on existing public land (e.g., parks) without disrupting other activities so they may obtain royalties on any minerals found. Others are seeking compensation from drilling companies for roads damaged by overweight vehicles, because many of the roads are rural and not designed for use by heavy equipment. In addition, drilling and exploration have generated significant controversy (TRRC, 2012d).

Number of Wells

The Barnett Shale has experienced substantial development over the last decade, as evidenced by the number of wells (Figure 71) and estimates of total gas production (Figure 72).

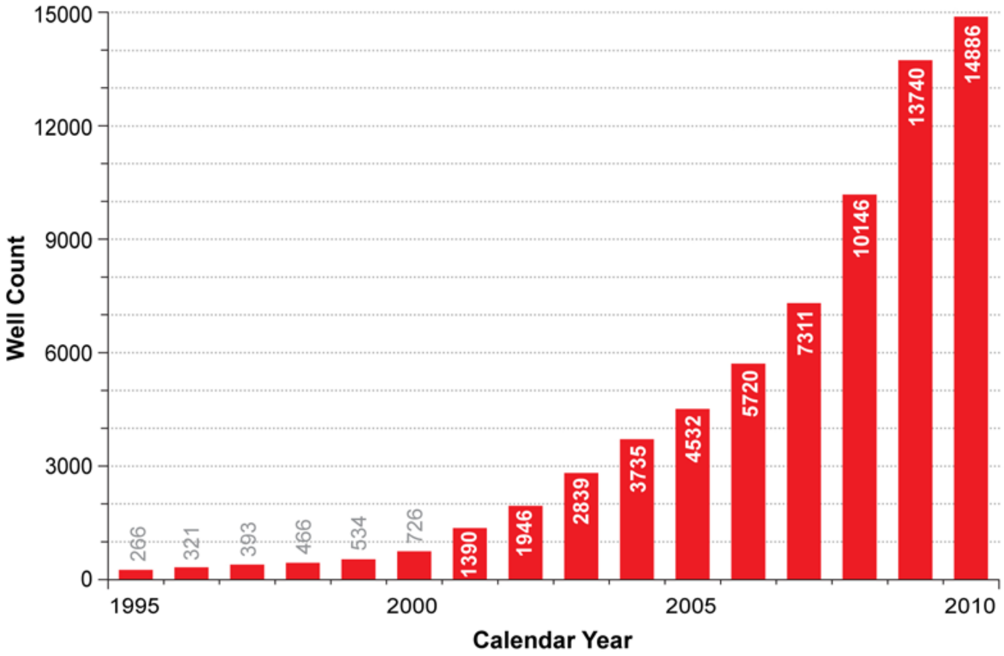

Figure 71. Wells in Barnett Shale, 1995-2010 (TRRC, 2012c)

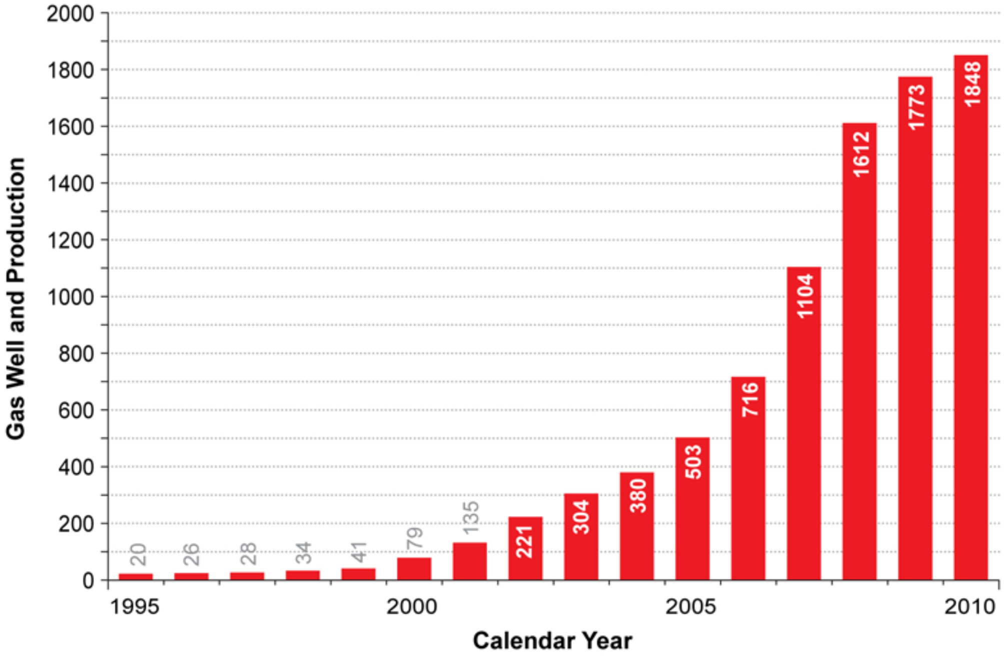

Figure 72. Gas production in the Barnett Shale (bcf), 1995-2010 (TRRC, 2012e)

Water Usage per Well

Table 36 shows the analysis results on 100 Barnett Shale wells selected randomly from fracfocus.org.

Table 36. Statistics of Water Use (Gallons) (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
2,537,853.848	26,315,125	29,186	26,285,939	3,512,472.559
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
1,293,306	4,298,286	86,751	4,211,535	3.500964058

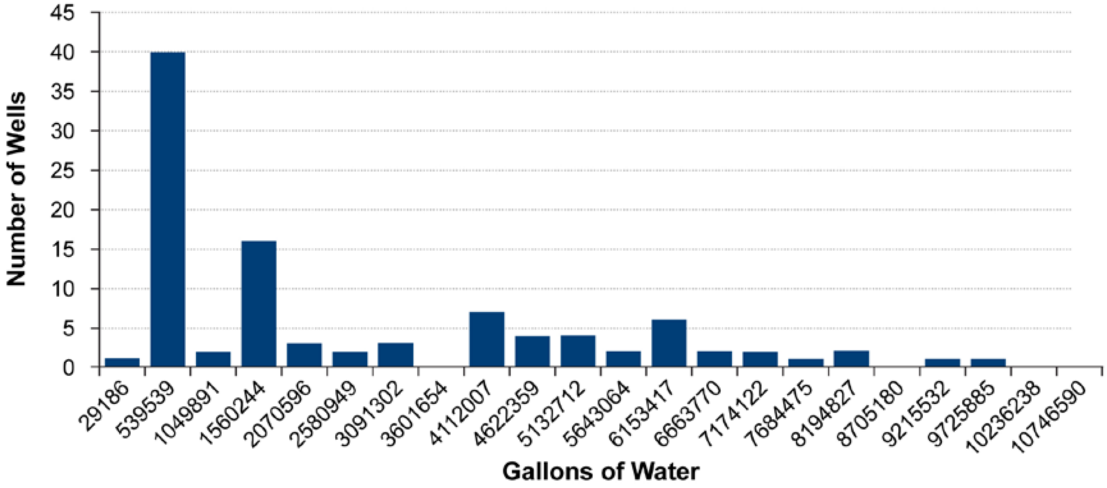

Figure 73. Histogram of 100 wells for total water volume (gallons) (fracfocus.org)

As seen in Table 36, the average volume per well was 2,537,853 gallons, with values ranging from 29,186 gallons to 26,315,125 gallons (fracfocus.org). Figure 73 is a histogram displaying the total volume of water, created by evenly distributing the range of values into twenty bins and then counting the total number of wells for each bin.

Produced Water

No produced water data are available for Barnett shale. However, the Railroad Commission (RRC) of Texas requires every operator to report—into a query system—how much water is disposed. The current method used for disposal in the Barnett Shale is deep-well injected. The Injection Volume Query from the RRC database was used and monthly county-wide or operator-wide injected volumes can be obtained (TRRC 2011).

Violations

Figure 74 expresses the violations from 2009–2011 in Texas according to the severity of environmental effect (Wiseman 2012). Of the 35 total violations (Table 37), 35% of the violations are “minor - no effect” and “substantial.” “Procedural” account for about 20%, and “major” and “minor effect” account for 3%. It should be noted that these violations only include wells for which formal compliance or administrative orders were issued. Therefore, these data are not comprehensive and do not represent the total number of violations. Further information on violations can be found in D.7 of this appendix.

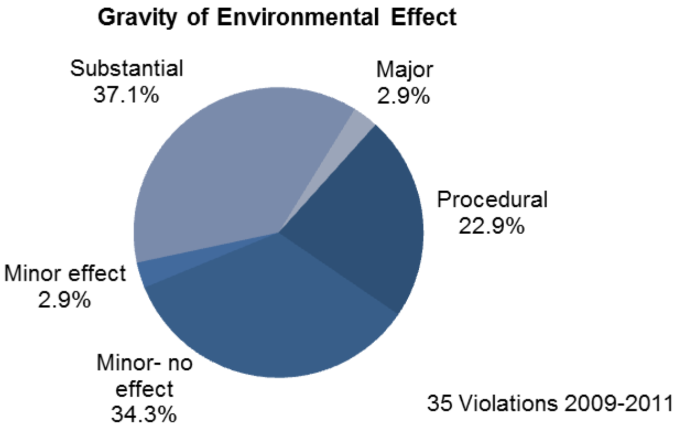

Figure 74. Texas violations (Wiseman 2012)

Table 37. Texas Violations (Wiseman 2012)

Texas		
Procedural	8	22.9%
Minor - no effect	12	34.3%
Minor effect	1	2.9%
Substantial	13	37.1%
Major	1	2.9%
Total	35	

Eagle Ford Shale Play, Texas

Overview

The Eagle Ford Shale play extends across 23 counties, covering an area of 20,000 square miles (Figure 75). The Eagle Ford Shale has an average thickness of 250 feet and contains an estimated 21 Tcf of shale gas and 3 billion barrels of shale oil (EIA 2011).

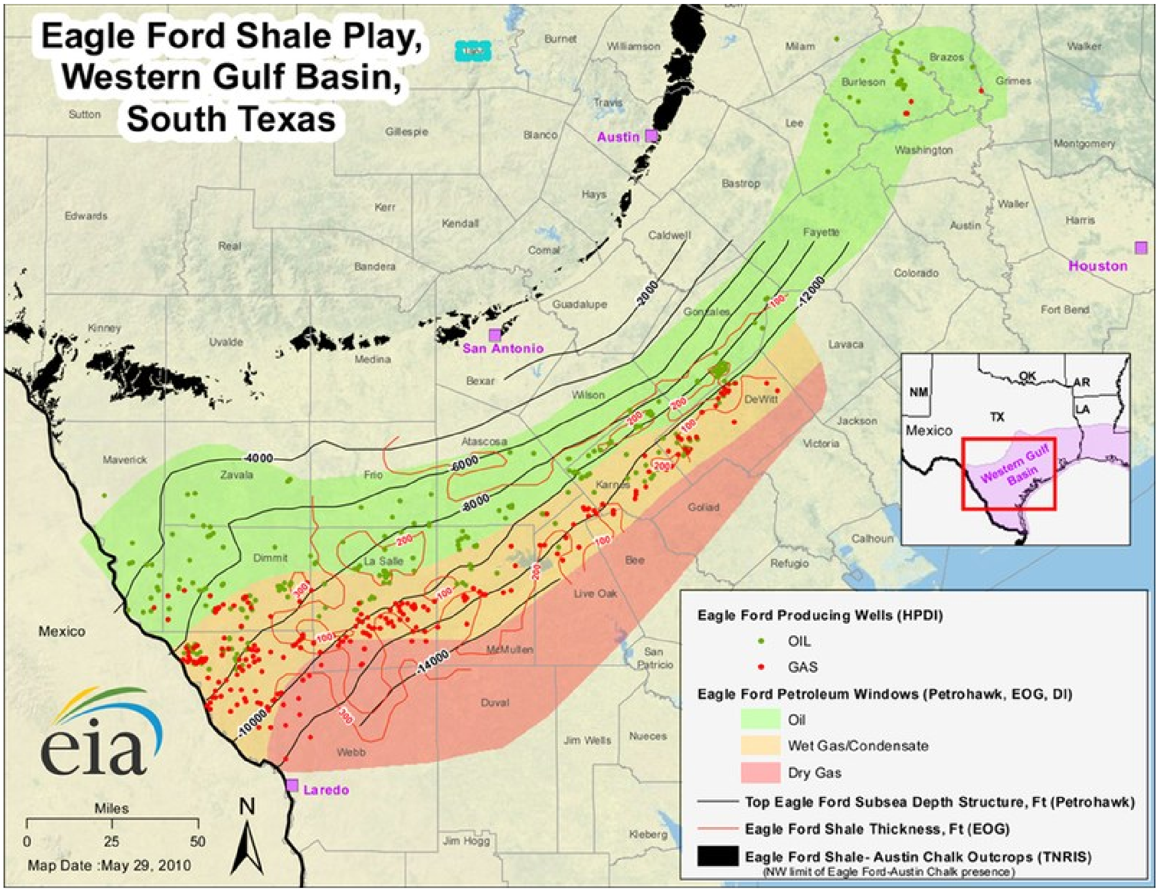

Figure 75. Extent of Eagle Ford Shale play (Eagle Ford Shale 2012)

Number of Wells

In 2008, Petrohawk drilled the first well in the Eagle Ford Shale, and since then, gas production has more than doubled—from 108 bcf in 2010 to 287 bcf in 2011. Oil production increased from more than 4 million barrels in 2010 to more than 36 million barrels in 2011 (TRRC 2012a). Increased production reflects the increases in drilling permits issued and in the number of oil and gas wells. Figure 76 shows the total number of producing oil and gas wells over the past three years.

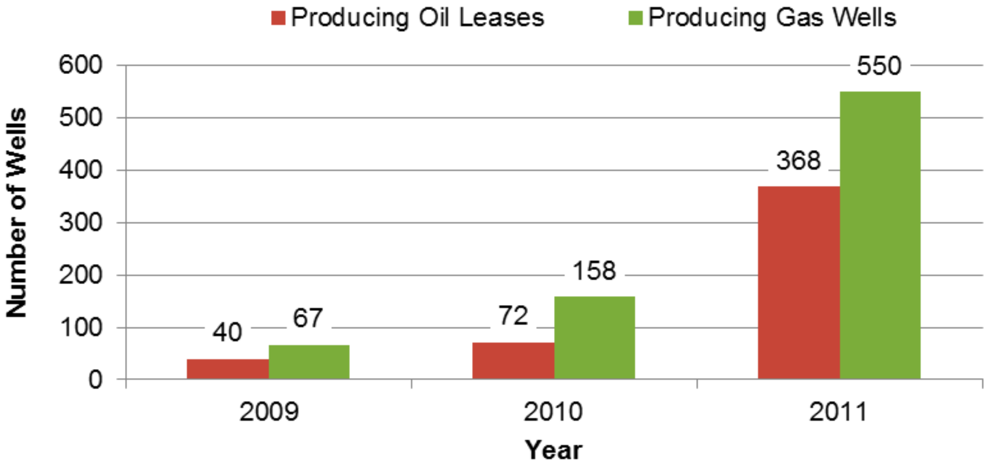

Figure 76. Number of producing oil and gas wells in Eagle Ford (Eagle Ford Shale 2012)

With 2,826 issued drilling permits in 2011 alone, the well count in Eagle Ford may steadily increase (Eagle Ford Shale 2012).

Water Usage per Well

Wells in the Eagle Ford Shale were randomly selected from fracfocus.org. Figure 77 shows a histogram of the water used per well, and Table 38 shows the average, maximum, and minimum water used per well.

Table 38. Fresh Water Use in Eagle Ford (in gallons) (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
3,751,751	7,084,098	77,658	7,006,440	1,276,506
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
3,608,905	4,386,965	3,116,039	1,270,927	-0.079

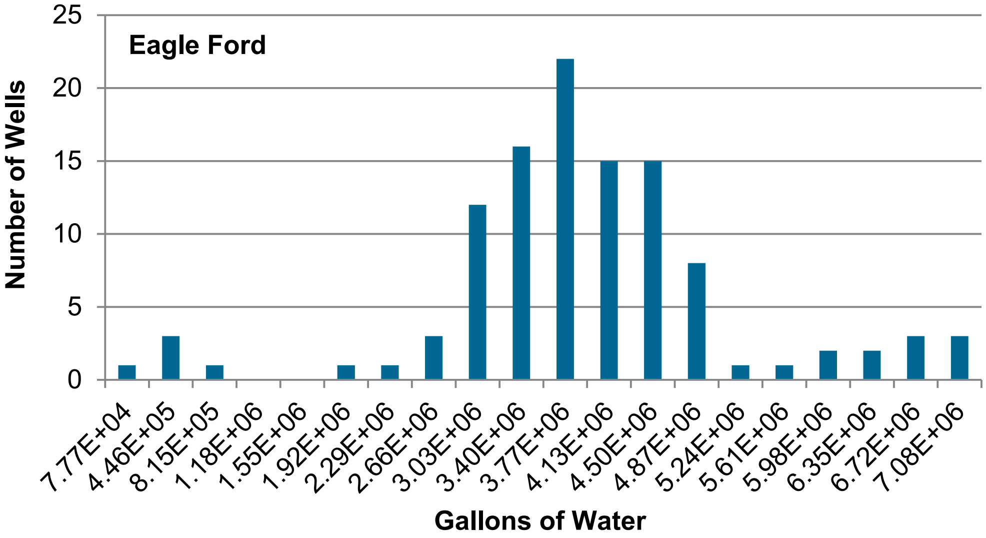

Figure 77. Fresh-water use in Eagle Ford per well (fracfocus.org)

The Texas Commission of Environmental Quality monitors surface water use in Texas. Surface water rights are issued to operators, and withdrawal amounts can be found on the TCEQ website (http://www.tceq.texas.gov/). However, withdrawal information is based on water-right number and is not shown on a well-to-well basis (TCEQ 2012).

Haynesville Shale Play, Louisiana

Overview

The Haynesville Shale extends over large sections of southwestern Arkansas, northwest Louisiana, and East Texas (Figure 19). It is up to 10,500 to 13,000 feet below the surface, with an average thickness of about 200–300 feet, and overs an area of about 9,000 square miles (TRRC 2012f).

Haynesville Shale is an important shale gas play in East Texas and Louisiana. Estimated recoverable reserves are as much as 60 Tcf, with each well producing 6.5 bcf on average (Hammes 2009). The formation came into prominence in 2008 as a potentially major shale gas resource, and production has boomed since late March 2008 (TRRC 2011). Producing natural gas from the Haynesville Shale requires drilling wells from 10,000 to 13,000 feet deep, with the formation being deeper nearer the Gulf of Mexico. The Haynesville Shale has recently been estimated to be the largest natural gas field in the contiguous 48 states, with an estimated 250 Tcf of recoverable gas (Nossiter 2008).

Figure 78. Extent of Haynesville Shale

The Haynesville Shale is lithologically heterogeneous, but is often an organic-rich mudstone. The composition varies greatly according to the geographic location and stratigraphic position of the mudstones—from calcareous mudstone near the ancient carbonate platforms and islands, to argillaceous mudstone in areas where submarine fans prograded into the basin and diluted organic matter. The Haynesville formation was deposited about 150 million years ago in a shallow offshore environment (Geology.com, 2012b).

Number of Wells

The State of Louisiana, Department of Natural Resources, provides information on monthly well counts. Well counts (Figure 79) have varied from 2009–2011 as old wells are abandoned and new wells are drilled and leased. However, total gas production (Figure 80) has increased from 2009–2011.

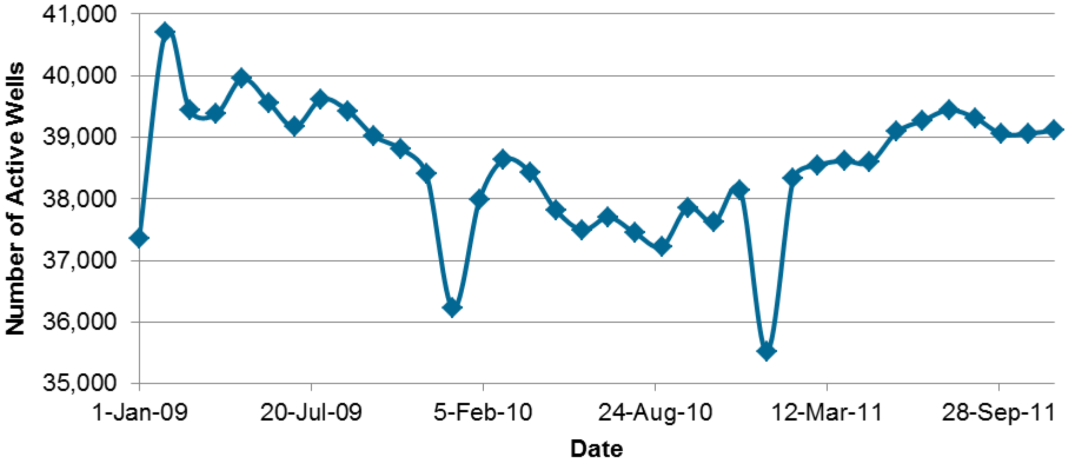

Figure 79. Monthly well count (2006–2011) (LADNR 2012b)

The total number of wells shows a significant drop at the end of 2010, after some natural fractures were seen in the formation cores extracted during test drilling. These fractures suggest the risk of anthropogenic faulting of the surrounding land; however, drilling continued after these problems were resolved.

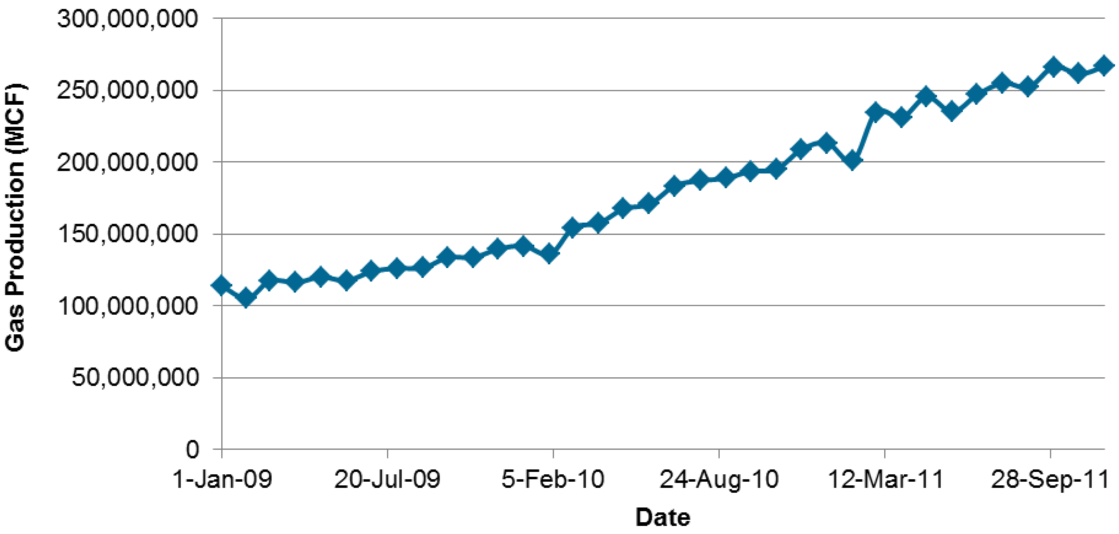

Figure 80. Monthly gas production (2009–2011) (EIA 2011)

Production is increasing almost linearly, despite a drop in well count. At the end of 2011, production was twice that in 2009.

Water Usage per Well

One hundred wells in the Haynesville Shale were randomly selected. Table 39 gives statistics on water usage, and Figure 81 is a histogram of the distribution of water usage distributed evenly into twenty bins.

Table 39. Analysis of Water Usage for 100 Haynesville Shale Wells (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
4,568,683	9,567,936	8,736	9,559,200	2,243,797
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
4,925,256	6,255,663	3,875,203	2,380,460	-0.578

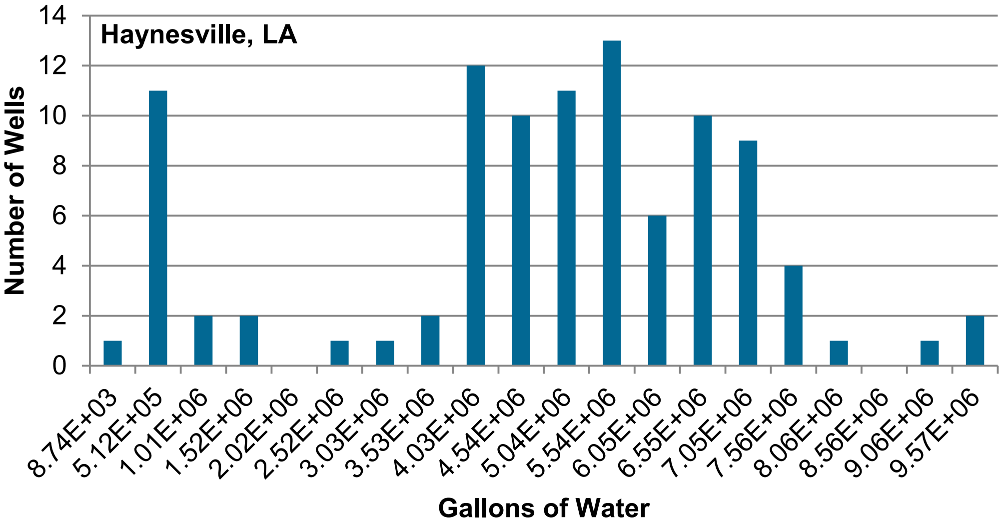

Figure 81. Fresh-water use for 100-well sample (fracfocus.org)

Violations

Figure 82 expresses the violations from 2008–2011 in Louisiana according to the severity of environmental effect. A majority of the violations are in the "procedural" category (Table 40). "Minor - no effect" violations make up about 30%, and "minor effect," "substantial," and "major" account for less than 10% (Wiseman 2012). These data include mostly Haynesville wells with compliance orders from January 1, 2008 through July 14, 2011. About 83 additional well incidents had insufficient information to be categorized. Further information on violations can be found in D.7 of this appendix.

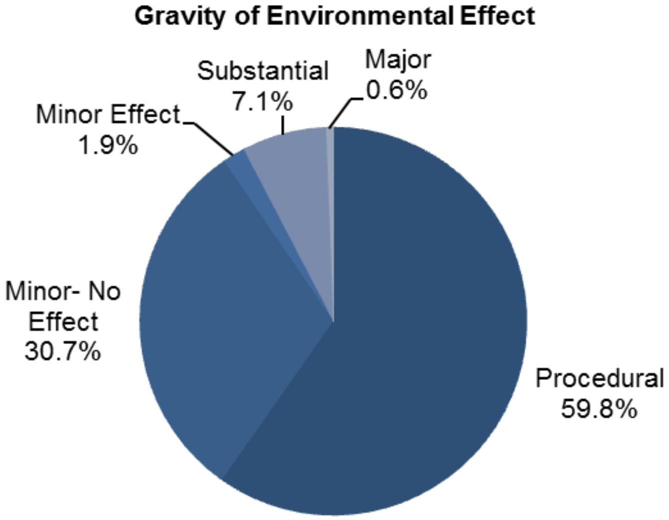

Figure 82. Louisiana violations (Wiseman 2012)

Table 40. Louisiana Violations (Wiseman 2012)

Procedural	95	59.8%
Minor - no effect	49	30.7%
Minor effect	3	1.9%
Substantial	11	7.1%
Major	1	0.6%
Total	158	

Upper San Juan Basin, Colorado, New Mexico

Overview

The San Juan Basin covers an area of about 7,500 square miles across the Colorado and New Mexico border in the Four Corners region (Figure 83). It spans about 100 miles north-south in length and 90 miles east-west in width. In the San Juan Basin, the total thickness of all coalbeds ranges from 20 to more than 80 feet. Coalbed methane production occurs primarily in coals of the Fruitland Formation, but some coalbed methane is trapped within the underlying and adjacent Pictured Cliffs Sandstone; many wells are present in both zones (EPA 2004).

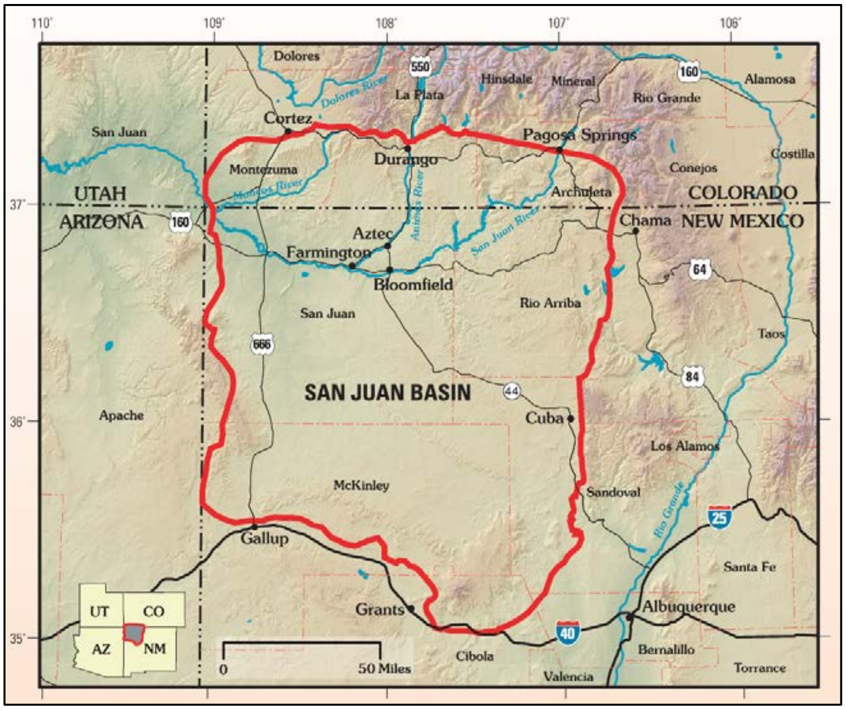

Figure 83. Extent of the San Juan Basin (USGS 2002a)

The Fruitland Formation is the primary coal-bearing unit of the San Juan Basin, as well as the target of most coalbed methane production. The Fruitland coals are thick and have individual beds up to 80 feet thick. The formation is composed of interbedded sandstone, siltstone, shale, and coal. Some of the most important natural-gas-producing formations include the Fruitland, Pictured Cliffs, Mesaverde, Dakota, and Paradox formations and are located in La Plata County. Early development of natural gas began here in the 1920s. In La Plata County, coalbed methane production began in the late 1970s. Traditional natural gas reserves have been—and continue to be—developed at a steady pace (USGS 2002a).

Two types of natural gas wells exist within La Plata County: conventional and coalbed. Conventional gas wells are usually deeper—3,500 to 10,000 feet—and extract gas and oil from sandstone formations such as the Mesaverde and Dakota (La Plata Energy Council 2012). The shallower coalbed gas wells generally range from 1,000 to 4,000 feet deep and extract gas from coal-bearing formations (EPA 2004). The Fruitland formation is La Plata County's methane-rich coalbed formation.

Produced Water

Conventional wells initially produce large volumes of gas and very little water. Over time, gas production declines and water increases. Coalbed wells are just the opposite, producing large quantities of water and low gas quantities at the beginning; later, water production declines and gas production increases. Table 41 shows oil, gas, and water production from 2007–2011.

Table 41. Oil, Gas, and Water Production in La Plata County (COGCC 2012a)

Year	Oil Production (bbl)	Gas Production (Mcf)	Water Production (bbl)
2007	35,883	412,488,324	24,032,308
2008	38,038	425,541,599	20,154,062
2009	33,975	425,439,680	24,177,214
2010	33,396	422,450,451	31,942,703
2011	26,747	373,116,167	21,231,213

Based on the database provided by the Colorado Oil and Gas Conservation Commission (COGCC), five methods are used to dispose of water in La Plata County: disposal in a central pit well, injection on lease, disposal at a commercial disposal facility, evaporation in an onsite pit, and through surface discharge (COGCC 2012a). Table 42 and Figure 84 show disposal methods in La Plata County from 2007 to 2011.

Table 42. Produced Water and Disposal Method in La Plata County (Million Gallons) (COGCC 2012a)

Disposal Method	2011	2010	2009	2008	2007	Average
Central Disposal Pit Well	637	1,213	726	646	736	791
Injected on Lease	350	362	175	201	179	253
Commercial Disposal Facility	47	60	61	53	37	52
Onsite Pit	2	2	1	2	1	1
Surface Discharge	NON	NON	NON	NON	NON	
SUM	1,036	1,638	963	901	953	1,098
Percentage	60%	61%	51%	48%	57%	55%
Estimation	1,725	2,697	1,876	1,872	1,674	1,969

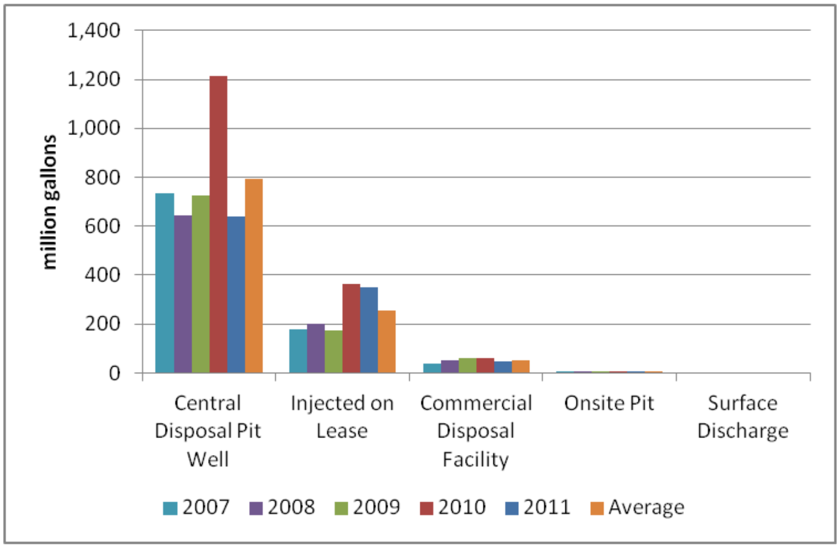

Figure 84. Water disposal volumes and methods in La Plata County (million gallons) (COGCC 2012a)

There is no surface discharge in La Plata County and minimal use of onsite pits. The most widely used method of disposal in La Plata County is a central disposal pit well. Some 70% of produced water is disposed in a central disposal pit well, 23% of produced water is injected on the lease, and 4.7% goes to a commercial disposal facility. Trends in the state of Colorado (Table 43) differ from those in La Plata County (Table 42).

Table 43. Produced Water and Disposal Method in the State of Colorado (Million Gallons) (COGCC 2012a)

Disposal Method	2011	2010	2009	2008	2007	Average
Central Disposal Pit Well	4,609	3,314	3,237	3,135	3,678	3,595
Injected on Lease	8,095	11,243	6,715	7,194	11,666	8,983
Commercial Disposal Facility	1,248	2,266	1,665	1,303	962	1,489
Onsite Pit	3,001	2,962	3,213	5,128	3,588	3,579
Surface Discharge	2,191	1,218	1,219	283	677	1,117
Sum	19,144	21,003	16,049	17,042	20,572	18,762

Violations

For the state of Colorado, the only publicly accessible statistics related to violations are Notices of Alleged Violations (NOAVs). The number of NOAVs does not represent the number of violations because violations do not necessarily lead to the issuance of NOAVs. Additionally, when NOAVs are issued, they may cite violations of more than one rule, order, or permit condition. Colorado violations could not be acquired.

Green River Basin, Wyoming

Overview

The Green River Basin Oil Shale Field, as seen in Figure 85, is located in Wyoming, Utah, and Colorado, on the western flank of the Rocky Mountains. The main part of the Green River Basin Formation is located in the southwest portion of Wyoming. The Colorado oil shale is expected to hold the largest amount of oil from shale. Specifically, the Piceance Creek Basin is the large producer for oil shale in the Green River Formation (Oil Shale Gas 2012).

The estimates of the oil resource within the Green River Formation range from 1.3 to 2.0 trillion barrels. Because not all resources are recoverable, a moderate estimate of recoverable oil is about 800 billion barrels (Oil Shale Gas 2012).

Figure 85. Extent of Green River Formation

The Jonah Field is located in the northern part of the Green River Basin and has produced more than 1.0 Tcf of gas since production commenced in 1992 (Oil Shale Gas 2012). Development of this field resulted from applying advanced fracture stimulation techniques. The field has undergone several iterations of development, with some sections of the field currently being developed on 10-acre well spacing; the current well spacing is around 20 acres. The field produces from a series of stacked reservoirs within the Cretaceous Mesaverde and Lance Formations. The field is bounded between two faults forming a wedge-shaped field.

Water usage per well

One hundred wells in the Green River Formation were randomly selected. Table 44 gives statistics about water usage, and Figure 86 is a histogram of water usage distributed evenly into twenty bins.

Table 44. Analysis of Water Usage for 100 Green River Formation Wells (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
1,076,417	4,451,034	14,467	4,436,567	1,230,306
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
367,522	1,665,741	201,280	1,464,461	1.40

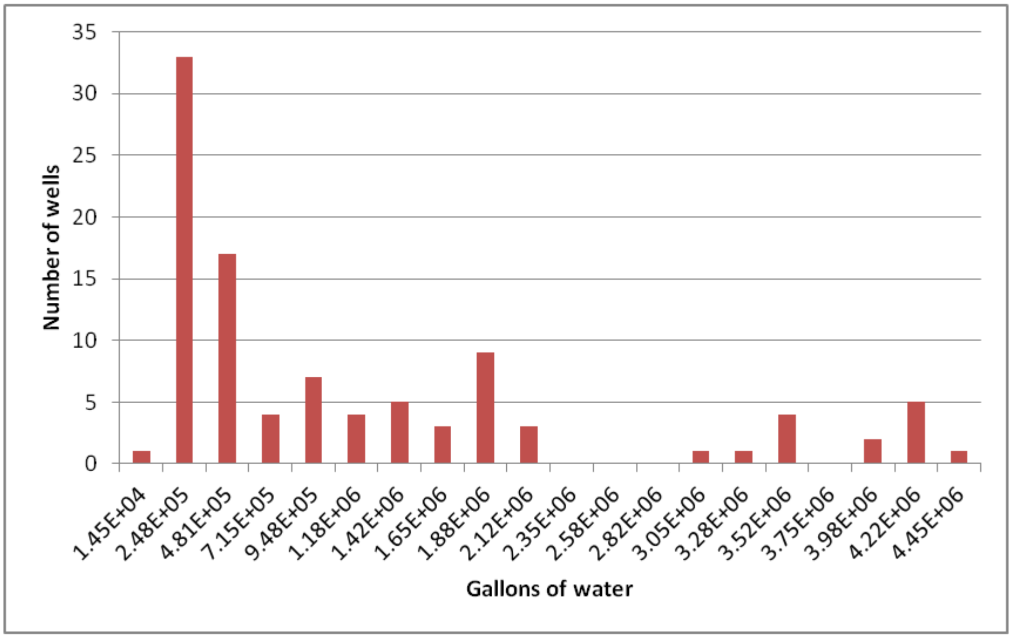

Figure 86. Fresh-water use for 100-well sample (fracfocus.org)

Figure 87 shows the volumes of hydraulic fracturing fluids used in Wyoming by county.

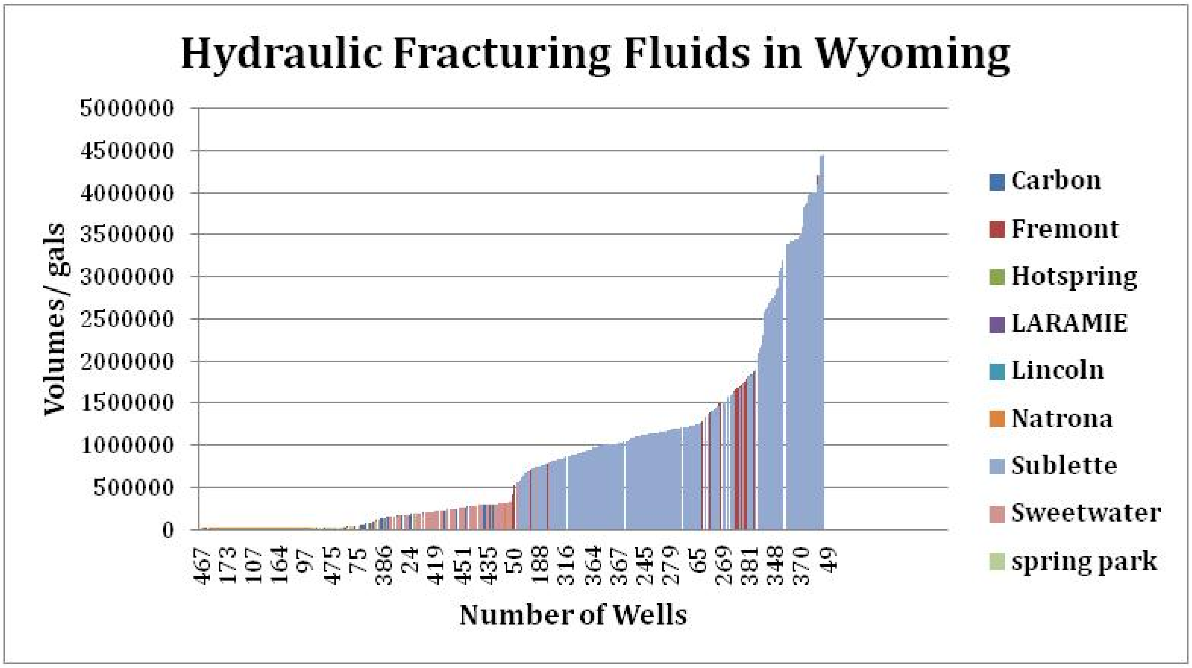

Figure 87. Volumes of hydraulic fracturing water (fracfocus.org)

Produced Water

Table 45 expresses the total oil, gas, and water produced within the Green River Basin from 2007–2011.

Table 45. Production of Oil, Gas, and Water in Green River Basin (WOGCC 2012)

Year	Oil Production (barrels)	Gas Production (Mcf)	Water Production (Barrels)
2007	15,491,483	1,218,888,397	125,613,453
2008	15,824,924	1,371,741,392	150,830,391
2009	15,925,806	1,428,200,434	158,560,401
2010	20,544,588	1,418,379,334	169,901,204
2011	15,385,222	1,347,348,632	177,151,681

Table 46 provides injection volumes by field, although not all fields are represented.

Table 46. Injection Volumes (WOGCC 2012)

Field	2007 (bbl)	2008 (bbl)	2009 (bbl)	2010 (bbl)	2011 (bbl)
Big Piney	577,239	167,646	189,178	70,354	40,247
Bison Basin	1,989,960	2,564,857	2,223,756	2,354,332	2,296,464
Brady	4,419,146	2,612,544	1,943,879	2,003,854	4,688,163
Cow Creek	4,406,339	8,174,082	4,635,125	5,517,186	6,288,081
Fontenelle	111,267	117,390	115,376	110,948	102,167
Green River Bend	592,890	381,857	549,775	616,873	432,311
Jonah	1,367,707	2,010,190	1,588,080	1,991,187	2,703,926

Field	**2007 (bbl)**	**2008 (bbl)**	**2009 (bbl)**	**2010 (bbl)**	**2011 (bbl)**
LaBarge	167,441	1,653,772	1,752,291	2,079,953	1,344,187
Lost Soldier	23,577,864	25,017,789	32,557,565	29,490,274	37,367,198
Mahoney Dome	926,644	721,983	1,188,006	1,085,123	1,111,673
McDonald Draw	535,996	494,630	414,810	388,833	377,482
Patrick Draw	1,551,255	4,012,343	1,196,017	1,020,284	1,179,744
Pinedale	954,458	6,749,055	11,951,930	12,027,080	11,482,543
Saddle Ridge	221,413	206,610	227,843	231,330	208,498
Star Corral	288,567	221,015	172,686	190,853	175,222
Tierney	1,083,636	1,813,532	1,660,262	1,831,283	1,004,778
Tip Top	455,781	548,822	427,670	387,878	389,175
WC	16,900,921	33,853,193	31,456,801	24,984,327	12,428,968
Wertz	20,610,169	25,384,888	1,953,919	24,188,672	30,240,574

Severity of Environmental Impact Matrix

Table 47 shows the categorization of environmental impacts for shale gas operations.

Table 47. Severity of Environmental Impact (Wiseman 2012)

Severity of environmental effect	Activity for which violation occurred	Enforcement action	Environmental factors
Procedural	- Permitting - Reporting - Testing - Financial assurance	"All ranges (violation noted" through notice of violation and/or administrative order)	No indication in violation/field notes that failure to obtain permit, report, conduct a test, or provide financial guarantee resulted in environmental damage
Minor - no effect	- Equipment failures - Pit construction, operation, and maintenance - Failure to prevent oil and gas waste - Commingling oil and gas - Site maintenance, such as moving weeds - Sign posting and hazard labels	"All ranges (violation noted" through notice of violation and/or administrative order)	No indication in field notes that violation resulted in any environmental damage
Minor effect	- Equipment failures that led to release - Pit construction, operation, and maintenance that led to release - Air pollution - Spills - Disposal	Violation noted, or NOV/administrative order paired with very small environmental effect	Small spills and improperly disposed wastes (typically less than 5 barrels of produced water or oil) that did not move offsite or otherwise suggest substantial environmental damage. Small quantities of air emissions (e.g., slightly over the daily limit).
Substantial	- Equipment failures that led to release - Pit construction, operation, and maintenance that led to release - Failure to plug well twelve months after abandonment or inactivity - Air pollution - Spills - Disposal	Violation noted, or NOV/administrative order + substantial environmental effect; remediation order	Medium spills and improperly disposed wastes (typically more than 5 barrels and less than 10 for produced water or oil that stayed on site). For fracturing fluid spills, any spill more than 1 barrel was considered major.
Major	- Equipment failures that led to release - Pit construction, operation, and maintenance that led to release - Air pollution - Spills - Disposal	Violation noted, or NOV/administrative order + > substantial environmental effect (or high penalty + substantial environmental effect); remediation order + major environmental effect	Large spills or improperly disposed of wastes (typically 10 or more barrels, small to large spills that moved off site and impacted a resource (e.g., drainage ditch, wetland). Any spill of fracturing fluid > 1 barrel.

Appendix E: Assumptions Used in ReEDS

What is ReEDS?[250]

The Regional Energy Deployment System is an optimization model used to assess the deployment of electric power generation technologies and transmission infrastructure throughout the contiguous United States into the future. The model, developed by NREL, is designed to analyze critical energy issues in the electric sector, especially with respect to the effect of potential energy policies such as clean energy and renewable energy standards or carbon restrictions.

ReEDS provides a detailed treatment of electricity-generating and electrical storage technologies, and specifically addresses a variety of issues related to renewable energy technologies—including accessibility and cost of transmission, regional quality of renewable resources, seasonal and diurnal generation profiles, variability of wind and solar power, and the influence of variability on the reliability of the electrical grid. ReEDS addresses these issues through a highly discretized regional structure, explicit statistical treatment of the variability in wind and solar output over time, and consideration of ancillary services requirements and costs.

Qualitative Model Description

To assess competition among the many electricity generation, storage, and transmission options throughout the contiguous United States, ReEDS chooses the cost-optimal mix of technologies that meet all regional electric power demand requirements, based on grid reliability (reserve) requirements, technology resource constraints, and policy constraints. This cost-minimization routine is performed for each of twenty 2-year periods from 2010 to 2050. The major outputs of ReEDS include the amount of generator capacity and annual generation from each technology, storage capacity expansion, transmission capacity expansion, total electric sector costs, electricity price, fuel prices, and CO_2 emissions. Time in ReEDS is subdivided within each 2-year period, with each year divided into four seasons with a representative day for each season, which is further divided into four diurnal time slices. Also, there is one additional summer-peak time slice. These 17 annual time slices enable ReEDS to capture the intricacies of meeting electric loads that vary throughout the day and year—with both conventional and renewable generators.

Although ReEDS includes all major generator types, it has been designed primarily to address the market issues that are of the greatest significance to renewable energy technologies. As a result, renewable and carbon-free energy technologies and barriers to their adoption are a focus. Diffuse resources such as wind and solar power come with concerns that conventional dispatchable power plants do not have, particularly regarding transmission and variability. The ReEDS model examines these issues primarily by using a much greater level of geographic disaggregation than do other long-term, large-scale, capacity expansion models. ReEDS uses 356 different resource regions in the continental United States. These 356 resource supply regions are grouped into four levels of larger regional groupings—balancing areas, reserve-sharing groups,

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[250] "What is ReEDS?" is taken from the 2011 detailed documentation for the ReEDS model.
Short, W., et al., Regional Energy Deployment System (ReEDS). NREL Technical report NREL/TP-6A20-46534, August 2011. http://www.nrel.gov/analysis/reeds/.

North American Electric Reliability Council regions,[251] and interconnects. States are also represented for the inclusion of state policies.

Many of the data inputs in ReEDS are tied to these regions and derived from a detailed GIS model/database of the wind and solar resource, transmission grid, and existing plant data. The geographic disaggregation of renewable resources enables ReEDS to calculate transmission distances, as well as the benefits of dispersed wind farms, PV arrays, or CSP plants supplying power to a demand region. Offshore wind is distinguished from onshore wind both in terms of technology cost/performance and resources. The wind and CSP supply curves are subdivided into five resource classes based on the quality of the resource—strength and dependability of wind or solar isolation.

Regarding resource variability and grid reliability, ReEDS also allows electric and thermal storage systems to be built and used for load shifting, resource firming, and ancillary services. Four varieties of storage are supported: pumped hydropower, batteries, compressed air energy storage, and thermal storage in buildings.

Along with wind and solar power data, ReEDS provides supply curves for hydropower, biomass, and geothermal resources in each of the 134 balancing areas. The geothermal and hydropower supply curves are in megawatts of recoverable capacity, and the biomass supply curve is in million British thermal units of annual feedstock production. In addition, other carbon-reducing options are considered. Nuclear power is an option, as is CCS on some coal and natural gas plants. CCS is treated simply, with only an additional capital cost for new coal and gas-fired power plants for the extra equipment and an efficiency penalty to account for the parasitic loads of the separation and sequestration process. Also, a limited set of existing coal plants can choose to retrofit to CCS for an associated cost, as well as a performance, penalty. The major conventional electricity-generating technologies considered in ReEDS include hydropower, simple- and combined-cycle natural gas, several varieties of coal, oil/gas steam, and nuclear. These technologies are characterized in ReEDS by the following:

- Capital cost ($/MW)
- Fixed and variable operating costs ($/MWh)
- Fuel costs ($/MMBtu)
- Heat rate (MMBtu/MWh)
- Construction period (years)
- Equipment lifetime (years)
- Financing costs (such as nominal interest rate, loan period, debt fraction, debt-service-coverage ratio)
- Tax credits (investment or production)

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[251] North American Electric Reliability Corporation, October 2010. “2010 Long-Term Reliability Assessment.” http://www.nerc.com/files/2010%20LTRA.pdf. Accessed November 2, 2011.

- Minimum turndown ratio (%)
- Quick-start capability and cost (%, $/MW)
- Spinning reserve capability
- Planned and unplanned outage rates (%).

Renewable and storage technologies are governed by similar parameters—accounting for fundamental differences. For instance, heat rate is replaced with round-trip efficiency in pure storage technologies, and the dispatchability parameters—such as fuel cost, heat rate, turndown ratio, and operating reserve capability—are not used for non-dispatchable wind and solar technologies. These variable generation technologies are further characterized by changes in generation levels over the course of a year.

The model includes consideration of distinguishing characteristics of each conventional generating technology. There are several types of coal-fired power plants within ReEDS, including pulverized coal with and without sulfur dioxide scrubbers, advanced pulverized coal, integrated gasification combined cycle, biomass co-firing, and integrated gasification combined cycle with CCS options. Coal-plant generation is discouraged from daily cycling via a cost penalty, which represents a combination of additional fuel burned, heat rate drop-off, and mechanical wear-and-tear. Natural gas plants represented in ReEDS include simple-cycle combustion turbines, combined-cycle plants, and combined-cycle with CCS plants. Combined-cycle natural gas plants can provide some spinning reserve and quick-start capability, and simple-cycle gas plants can be used cheaply and easily for quick-start power. Nuclear power is represented as one technology in ReEDS and is considered to be baseload.

Retirement of conventional generation and hydropower can be modeled through exogenous specification of planned retirements or based on usage characteristics of the plants. All retiring non-hydro renewable plants are assumed to be refurbished or replaced immediately because the site is already developed and has transmission access and other infrastructure.

ReEDS tracks emissions of carbon and sulfur dioxide from both generators and storage technologies. Caps can be imposed at the national level for these emissions, and constraints can also be applied to impose caps at state or regional levels. There is another option of applying a carbon tax instead of a cap; the tax level and ramp-in pattern can be defined exogenously. In addition, ReEDS can impose clean energy or renewable energy standards at the regional or national level.

Annual electric loads and fuel price supply curves are exogenously specified to define the system boundaries for each period of the optimization. To allow for the evaluation of scenarios that might depart significantly from the Reference scenario, price elasticity of demand is integrated into the model: the exogenously defined demand projection can be adjusted up or down based on a comparison of an estimated business-as-usual electricity price path and a calculation of electricity price within the model for each of the twenty 2-year periods. For coal and natural gas pricing, supply curves based on the Annual Energy Outlook[252] have been developed and used in ReEDS.

Natural Gas Supply Curve Background and Development

The EIA's Annual Energy Outlook 2011 has two specific scenarios that attempt to model the effects of high or low abundance of natural gas supply: High-EUR and Low-EUR. The High-EUR scenario increases the total unproved technically recoverable shale gas resource from 827 Tcf in the Mid-EUR baseline scenario to 1,230 Tcf. In addition, the ultimate recovery per shale gas well is 50% higher than in the baseline scenario. Low-EUR reduces recoverable shale gas resource to 423 Tcf and 50% lower ultimate recovery per shale gas well than in the Mid-EUR baseline scenario.

Deriving the coefficients for this study relied on assuming a linear regression model and employing an ordinary least-squares method. Linear regression is a statistical technique that examines the relationship between one dependent variable (Y) and multiple explanatory variables, or regressors (X), taking the linear form:

$$Y_i = \beta_0 + \beta_1 * X_1 + \beta_2 * X_2 + \cdots \beta_n * X_n + \varepsilon_i$$

The estimated coefficients represent the marginal impact of a 1-unit change in each independent variable $\mathbf{X_i}$ on Y. Linear regression is often used for prediction or forecasting.[253]

In this case, because the objective was to develop a model to closely model the relationship between natural gas in the electric sector and consumption in the electric sector in different scenarios, the electric-sector price was modeled based on the following predictors: electric-sector consumption, economy-wide consumption, year (2012–2035), and the natural gas scenario case.[254] Each electric-sector price for each of the Annual Energy Outlook scenarios from 2012–2035 was treated as an independent observation used to estimate coefficients in the following model:

$$\begin{aligned} Electric\ Sector\ Price_i \\ &= \beta_0 + \beta_1 * Electric\ Sector\ Consumption_i + \beta_2 \\ &* Economy - wide\ Consumption_i \\ &+ \sum_{j=1}^{12} \beta_j * Year + \sum_{k=1}^{4} \beta_k * Natural\ Gas\ Scenario + \varepsilon_i \end{aligned}$$

Observations that occurred in High-EUR and Low-EUR were coded accordingly, creating two additional intercept shifter "dummy" variables. The year, rather than coded as continuous, was coded as a dummy variable to capture non-linear variation from year to year. To account for the

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[252] Annual Energy Outlook 2011. DOE/EIA-0383. Washington, DC: U.S. Energy Information Administration.

[253] Damodar, Gujarati. Basic Econometrics (5th edition). McGraw Hill, 2007.

[254] Data for 2008–2011 as well as outlier scenarios (polmax0314a, polmaxlco20321a, polmaxlp0316a, lgbama050218a, lgbama200218a, aeo2010r1118a, oghtec110209a, ogltec110209a, hilng110209a, lolng110209a) were removed when running the model.

predictor influence of economy-wide consumption, the average value for the year and the scenario for each data point were multiplied by β_2 (the derived electric-sector consumption coefficient). As a result, the intercept varied by year and by scenario, while the slope remained the same across year and scenario. The intercept and shifter for the years 2036–2050 was held constant with model results in 2035.

The following tables summarize the assumptions used in ReEDS for: technology costs and performance (Table 48), wind performance (Table 49), CSP performance (Table 50), and utility-scale PV performance (Table 51).

Table 48. Technology Cost ($2010) and Performance Assumptions Used in ReEDS

	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (MMBtu/MWh)
Coal Integrated Gasification Combined-Cycle CCS				
2010	4,075	7	32	9.0
2020	4,075	7	32	9.0
2030	4,075	7	32	7.9
2040	4,075	7	32	7.9
2050	4,075	7	32	7.9
CSP				
2010	7,179 (8,217)[a]	NA	50 (80)	NA
2020	6,639 (4,077)	NA	50 (66)	NA
2030	5,398 (2,983)	NA	50 (51)	NA
2040	4,778 (2,983)	NA	50 (47)	NA
2050	4,778 (2,983)	NA	50 (45)	NA
Combined-Cycle Plants				
2010	1,250	4	6	7.5
2020	1,250	4	6	6.7
2030	1,250	4	6	6.7
2040	1,250	4	6	6.7
2050	1,250	4	6	6.7
Combined-Cycle Plants CCS				
2010	3,348	10	19	10.0
2020	3,267	10	19	10.0
2030	3,267	10	19	10.0
2040	3,267	10	19	10.0
2050	3,267	10	19	10.0
Simple-Cycle Combustion Turbines				
2010	661	30	5	12.5
2020	661	30	5	10.3
2030	661	30	5	10.3
2040	661	30	5	10.3
2050	661	30	5	10.3

		Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (MMBtu/MWh)
New Coal					
	2010	2,937	4	23	10.4
	2020	2,937	4	23	9.4
	2030	2,937	4	23	9.0
	2040	2,937	4	23	9.0
	2050	2,937	4	23	9.0
Nuclear					
	2010	6,199 (3,100)	NA	129	9.7
	2020	6,199 (3,100)	NA	129	9.7
	2030	6,199 (3,100)	NA	129	9.7
	2040	6,199 (3,100)	NA	129	9.7
	2050	6,199 (3,100)	NA	129	9.7
Utility-Scale PV					
	2010	4,067 (4,067)	NA	51 (21)	NA
	2020	2,560 (2,013)	NA	46 (20)	NA
	2030	2,351 (1,912)	NA	42 (15)	NA
	2040	2,191 (1,797)	NA	38 (13)	NA
	2050	2,058 (1,720)	NA	33 (9)	NA
Wind Offshore					
	2010	3,702 (3,702)	0 (23)	101 (16)	NA
	2020	3,355 (3,284)	0 (17)	101 (16)	NA
	2030	3,042 (2,912)	0 (14)	101 (16)	NA
	2040	3,042 (2,744)	0 (12)	101 (16)	NA
	2050	3,042 (2,744)	0 (12)	101 (16)	NA
Wind Onshore					
	2010	2,012 (2,012)	0 (8)	60 (12)	NA
	2020	2,012 (1,964)	0 (5)	60 (12)	NA
	2030	2,012 (1,865)	0 (5)	60 (12)	NA
	2040	2,012 (1,805)	0 (5)	60 (12)	NA
	2050	2,012 (1,805)	0 (5)	60 (12)	NA

[a] Advanced RE Scenario assumptions displayed in parentheses

Table 49. Wind Performance Assumptions

	Wind Power Class	On-Shore Wind	Off-Shore Wind
2010			
	Class 3	0.32 (0.35)[a]	0.36 (0.37)
	Class 4	0.36 (0.39)	0.39 (0.41)
	Class 5	0.42 (0.43)	0.45 (0.44)
	Class 6	0.44 (0.46)	0.48 (0.48)
	Class 7	0.46 (0.50)	0.50 (0.52)

	Wind Power Class	On-Shore Wind	Off-Shore Wind
2020			
	Class 3	0.33 (0.38)	0.37 (0.39)
	Class 4	0.37 (0.42)	0.39 (0.44)
	Class 5	0.42 (0.45)	0.45 (0.47)
	Class 6	0.44 (0.48)	0.48 (0.51)
	Class 7	0.46 (0.52)	0.50 (0.55)
2030			
	Class 3	0.35 (0.38)	0.38 (0.40)
	Class 4	0.38 (0.43)	0.40 (0.45)
	Class 5	0.43 (0.46)	0.45 (0.48)
	Class 6	0.45 (0.49)	0.48 (0.51)
	Class 7	0.46 (0.53)	0.50 (0.55)
2040			
	Class 3	0.35 (0.38)	0.38 (0.40)
	Class 4	0.38 (0.43)	0.40 (0.45)
	Class 5	0.43 (0.46)	0.45 (0.48)
	Class 6	0.45 (0.49)	0.48 (0.51)
	Class 7	0.46 (0.53)	0.50 (0.55)
2050			
	Class 3	0.35 (0.38)	0.38 (0.40)
	Class 4	0.38 (0.43)	0.40 (0.45)
	Class 5	0.43 (0.46)	0.45 (0.48)
	Class 6	0.45 (0.49)	0.48 (0.51)
	Class 7	0.46 (0.53)	0.50 (0.55)

[a] Advanced RE Scenario assumptions displayed in parentheses

Table 50. CSP Performance Assumptions

	Wind Power Class	Capacity Factor
2010		
	Class 1	0.28 (0.28)[a]
	Class 2	0.37 (0.37)
	Class 3	0.42 (0.42)
	Class 4	0.44 (0.44)
	Class 5	0.46 (0.46)
2020		
	Class 1	0.28 (0.37)
	Class 2	0.37 (0.47)
	Class 3	0.42 (0.52)
	Class 4	0.44 (0.54)
	Class 5	0.46 (0.56)
2030		
	Class 1	0.37 (0.37)

	Wind Power Class	Capacity Factor
	Class 2	0.47 (0.47)
	Class 3	0.52 (0.52)
	Class 4	0.54 (0.54)
	Class 5	0.56 (0.56)
2040		
	Class 1	0.37 (0.37)
	Class 2	0.47 (0.47)
	Class 3	0.52 (0.52)
	Class 4	0.54 (0.54)
	Class 5	0.56 (0.56)
2050		
	Class 1	0.37 (0.37)
	Class 2	0.47 (0.47)
	Class 3	0.52 (0.52)
	Class 4	0.54 (0.54)
	Class 5	0.56 (0.56)

[a] Advanced RE Scenario assumptions displayed in parentheses

Table 51. Utility-Scale PV Performance Assumptions

Year	Capacity Factor
2010	0.16–0.27
2020	0.16–0.27
2030	0.16–0.27
2040	0.16–0.27
2050	0.16–0.27

Treating Plant Retirement in ReEDS[255]

Assumptions about the retirement of conventional-generating units can have considerable cost implications. Considerations that go into the decision-making process on whether or not an individual plant should be retired involve a number of factors—specifically, the economics of plant operations and maintenance. Projecting these economic considerations into the future given the uncertainties involved is beyond the scope of ReEDS. Instead, ReEDS uses the following three retirement options that are not strictly economic:

- *Scheduled lifetimes for existing coal, gas, and oil.* These retirements are based on lifetime estimate data for power plants from Ventyx (2010). Near-term retirements are based on the officially reported retirement date as reported by EIA 860, EIA 411, or Ventyx unit research (Ventyx 2010). If there is no officially reported retirement date, a lifetime-based

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[255] This section was taken from existing documentation of the ReEDS model.
Short, W. et al. (2011). "Regional Energy Deployment System (ReEDS)," NREL Technical report NREL/TP-6A20-46534, August 2011. http://www.nrel.gov/analysis/reeds/.

retirement is estimated based on the unit's commercial online date and the following lifetimes:

  - Coal units (< 100 MW) = 65 years
  - Coal units (> 100 MW) = 75 years
  - Natural gas combined-cycle unit = 55 years
  - Oil-gas-steam unit = 55 years

- *Usage-based retirements of coal.* In addition to scheduled retirements, coal technologies, including co-fired coal with biomass, can retire based on proxies for economic considerations. Any capacity that remains unused for energy generation or operating reserves for 4 consecutive years is assumed to retire. Coal capacity is also retired by requiring a minimum annual capacity factor; after every 2-year investment period, if a coal unit has a capacity factor of less than this minimum capacity factor during the 2-year period, an amount of coal capacity is retired such that the capacity factor increases to this minimum threshold (10% in 2030, 20% in 2040, and 30% in 2050). Coal plants are not retired under this algorithm until after 2020.
- *Scheduled nuclear license-based retirements.* Nuclear power plants are retired based on the age of the plant. Under default assumptions, older nuclear plants that are on line before 1980 are assumed to retire after 60 years (one re-licensing renewal), whereas newer plants (on line during or after 1980) are assumed to retire after 80 years (two relicensing renewals). Other options can be implemented, such as assuming 60- or 80-year lifetimes for all nuclear plants.

Glossary

annulus	The space between two concentric lengths of pipe or between pipe and the hole in which it is located.
associated gas	Natural gas that occurs with crude oil reservoirs, either as free gas or dissolved in solution. It is usually produced with crude oil.
basin	A petroleum geology term that refers to a dip in the Earth's crust usually filled or being filled with sediment. Basins are usually relatively large areas where oil and gas can be found.
billion cubic feet (bcf)	Unit used to measure large quantities of gas, approximately equal to 1 trillion British thermal units.
billion cubic feet per day (bcf/d)	Unit used to measure the daily volume of gas produced, stored, transported, or consumed.
bradenhead	A device that is used during inner-string grouting or pressure grouting operations. The bradenhead is situated at the top of the well casing, where it allows a drill pipe to be extended into the well while the well head is sealed and the annulus between the well casing and drill pipe is pressurized. Also termed casing head, cement head, or largen head.
British thermal unit (Btu)	An energy unit equivalent to the amount of energy needed to raise the temperature of 1 pound of water 1°F from 58.5°F to 59.5°F under standard pressure of 30 inches of mercury. Commonly used for measuring gas and other energy sales quantities.
burner tip	The point of end-use consumption of a particular fuel.
cement bond log	A representation of the integrity of the cement job, especially whether the cement is adhering solidly to the outside of the casing. The log is typically obtained from one of a variety of sonic-type tools.
coal-bed methane (CBM)	Natural gas, primarily methane, generated during coal formation and recovered by pumping water from coal seams, allowing gas to escape through shallow wells. It is generally referred to as one type of unconventional gas.
closed-loop drilling	Drilling and fracturing operation that contains all fluids in tanks and other closed-to-the-atmosphere equipment. Closed-loop drilling does not use open pits and therefore can reduce the risks of leaks and spills.
Combined-cycle	An electric generating technology in which conventional gas combustion turbines are combined with heat-recovery, steam-powered generation units, increasing the overall efficiency of the generating facility. Electricity is produced from both the feed gas, as well as from otherwise lost waste heat exiting gas turbines. In a conventional steam power generating facility, electricity is generated only from the feed gas.
completion	Preparing a newly drilled well for production; usually involves setting casing (pipe that lines the interior of a well to prevent caving and protect against ground-water contamination) and perforating the casing to establish communication with the producing formation.
compressed natural gas	Highly compressed natural gas stored and transported in high-pressure containers, typically greater than 3,000 pounds per square inch (200 bar); commonly used for transport fuel.
condensates	Light hydrocarbon compounds that condense into liquid at surface temperatures and pressures. They are generally produced with natural gas.
cubic feet (cf)	Common unit of measurement of gas volume equivalent to the amount of gas required to fill a volume of 1 cubic foot under given temperature and pressure conditions.

deep-well injection	Technique for disposal of frac flowback or produced water in deep formations isolated from producing zones and fresh-water aquifers.
dry gas	Natural gas, mainly methane, that remains after liquid hydrocarbon components have been removed, making it suitable for pipeline shipping, liquefied natural gas processing, or industrial usage.
ethane (C_2H_6)	A normally gaseous natural gas liquid hydrocarbon extracted from natural gas or refinery gas streams.
flaring	The process of disposing uncommercial or otherwise unwanted gas by burning. Operators often flare associated gas in regions with limited gas markets.
formation	Refers to either a certain layer of the Earth's crust, or a certain area of a layer; often refers to the area of rock where a petroleum or natural gas reservoir is located.
fracturing (or fracking)	See hydraulic fracturing.
frac flowback	Fluids that are returned to the surface immediately following hydraulic fracturing that include mostly the injected water, sand, and chemicals used for the fracturing.
geographic information system (GIS)	Integrated hardware, software, and data used for capturing, managing, analyzing, and displaying all forms of geographically referenced information.
gas-to-liquids process	A process that converts natural gas into synthetic liquid petroleum products, such as diesel fuel and blending feedstock.
glycol dehydrators	Facilities in which a glycol-based process removes water from produced natural gas, often in the field and before processing. The removal of water is needed to prevent corrosion and water freezing in pipelines.
green completion	Using technology to recover gas that may otherwise be vented or flared during the completion phase of a natural gas well. Also known as reduced emission completions.
harmonization	A meta-analytical procedure for adjusting published estimates from life cycle assessment to develop a set of directly comparable estimates. Harmonization clarifies a body of published estimates in ways useful to decision-making and future analyses. See nrel.gov/harmonization for further description and resources.
hydraulic fracturing (or hydrofracking)	The process of creating fractures in non-porous rock using specially formulated, water-based solutions forced into wells at extremely high pressure; the cracks in the rock allow for the release and collection of the natural gas. Fracking can be done in vertical or horizontal wells.
induced seismicity	Seismic activity (e.g., earthquakes) that is caused by injection of fluids into deep formations in proximity to natural faults.
life cycle assessment (LCA)	A technique to assess environmental impacts associated with all stages of a product's life from "cradle to grave" (i.e., from raw material extraction through materials processing, manufacture, distribution, use, repair and maintenance, and disposal or decommissioning). LCAs can be applied to water, energy, greenhouse gas emissions, or other metrics of interest.
liquefied natural gas (LNG)	Natural gas, mainly methane, that has been cooled to very low temperature (-259°F) so that it will condense into a transportable colorless and odorless liquid.
methane (CH_4)	The lightest and most abundant of the hydrocarbon gases, it is the principal component of natural gas and LNG.
natural gas	Naturally occurring mixture of hydrocarbon gases from underground sources composed mainly of methane (more than 85% in some cases), ethane, propane, butane, pentane, and impurities including carbon dioxide, helium, nitrogen, and hydrogen sulfide.

natural gas liquids	Natural gas components—including ethane, propane, butane, pentane, and condensates—that are liquid at surface conditions. It does not include methane, which remains in gaseous phase at surface conditions.
New York Mercantile Exchange	The first U.S. exchange to trade natural gas futures contracts; the New York Mercantile Exchange has contracts with major delivery points.
play (shale play, shale gas play)	A geographic area that has been targeted for exploration due to favorable geoseismic survey results, well logs, or production results from a new well in the area. An area comes into play when it is generally recognized that there is an economic quantity of oil or gas to be found.
primacy (primary enforcement responsibility)	The authority to implement the Underground Injection Control Program. To receive primacy, a state, territory, or tribe must demonstrate to EPA that its Underground Injection Control Program is at least as stringent as the federal standards; the state, territory, or tribal Underground Injection Control requirements may be more stringent than the federal requirements. EPA may grant primacy for all or part of the Underground Injection Control Program (e.g., for certain classes of injection wells).
produced water	Water that is extracted with the oil and gas from the producing formation. Produced water is usually highly saline and not usable without treatment.
quad	A unit of energy equal to 10^{15} Btu, roughly equal to 1 Tcf.
reserves	Volumes of hydrocarbons that have a chance of being economically and technically producible.
reservoir	A subsurface rock or formation having sufficient porosity and permeability to store and transmit fluids such as gas, oil, and water. Reservoirs are typically composed of sedimentary rocks with an overlying or adjoining impermeable seal or cap rock.
shale gas	Shale gas is defined as a natural gas produced from shale rock. Shale has low matrix permeability; therefore, gas production in commercial quantities requires fracturing or other stimulation to improve permeability.
social license to operate	A project that has the ongoing approval within the local community and other stakeholders, ongoing approval or broad social acceptance, and, most frequently, as ongoing acceptance.
trillion cubic feet (Tcf)	Unit used to measure large quantities of gas, typically reserve sizes. Approximately equal to 1 quad of energy.
unconventional gas	Unconventional gas refers to gas produced from coal seams (coal-bed methane), shale rocks (shale gas), and rocks with low permeability (tight gas). Once gas is produced from these reservoirs, it has the same properties of gas produced from conventional (i.e., sedimentary reservoirs with high porosity and permeability) sources. Unconventional gas may have high levels of natural gas liquids (an exception is coal-seam gas, which tends to be very dry with high proportion of methane versus natural gas liquids) and may have low or high levels of carbon dioxide and high and low levels of sulfur (sour or sweet). Because unconventional reservoirs have low permeability, artificial methods to increase gas flows, such as mechanical or chemical fracking, is often required before the wells are able to produce commercial quantities of gas.

Underground Injection Control Program	The program that EPA, or an approved state, is authorized to implement under the Safe Drinking Water Act that is responsible for regulating the underground injection of fluids. This includes setting the minimum federal requirements for construction, operation, permitting, and closure of underground injection wells. There are six categories of wells regulated under the Underground Injection Control ranging from Class I to Class VI. Class I wells are the most technologically sophisticated and are used to inject wastes into deep, isolated rock formations below the lowermost underground source of drinking water. Class I wells may inject hazardous waste, non-hazardous industrial waste, or municipal wastewater. Class II wells are typically used by the oil and gas industry to inject brines and other fluids associated with oil and gas production, or storage of hydrocarbons.
volatile organic compound (VOC)	Gases and vapors, such as benzene, released by petroleum refineries, natural gas drilling, petrochemical plants, plastics manufacturing, and the distribution and use of gasoline. VOCs include carcinogens and chemicals that react with sunlight and nitrogen oxides to form ground-level ozone, a component of smog.
water recycling	Collection of frac flowback or produced water and treating the fluid for beneficial use that include hydraulic fracturing, agriculture, or release to streams.
well completion	Well completion incorporates the steps taken to transform a drilled well into a producing one. These steps usually include casing, cementing, perforating, gravel packing, and installing a production tree.
well head	The assembly of fittings and valve equipment used for producing a well and maintaining surface control of a well.
wet gas	Natural gas with significant natural gas liquid components. Also sometimes called rich gas.
workover	Work performed in a well after its completion in an effort to secure production where there has been none, restore production that has ceased, or increase production. Workovers for unconventional wells involve re-fracturing (re-stimulation).

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Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation

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The U.S. Department of Energy (DOE) estimates that in the coming decades the United States' natural gas (NG) demand for electricity generation will increase. Estimates also suggest that NG supply will increasingly come from imported liquefied natural gas (LNG). Additional supplies of NG could come domestically from the production of synthetic natural gas (SNG) via coal gasification−methanation. The objective of this study is to compare greenhouse gas (GHG), SO_x, and NO_x life-cycle emissions of electricity generated with NG/LNG/SNG and coal. This life-cycle comparison of air emissions from different fuels can help us better understand the advantages and disadvantages of using coal versus globally sourced NG for electricity generation. Our estimates suggest that with the current fleet of power plants, a mix of domestic NG, LNG, and SNG would have lower GHG emissions than coal. If advanced technologies with carbon capture and sequestration (CCS) are used, however, coal and a mix of domestic NG, LNG, and SNG would have very similar life-cycle GHG emissions. For SO_x and NO_x we find there are significant emissions in the upstream stages of the NG/LNG life-cycles, which contribute to a larger range in SO_x and NO_x emissions for NG/LNG than for coal and SNG.

1. Introduction

Natural gas currently provides 24% of the energy used by United States homes (*1*). It is an important feedstock for the chemical and fertilizer industry. Low wellhead gas prices (less than \$3/thousand cubic feet (Mcf) (*2*)) spurred a surge in construction of natural-gas-fired power plants: between 1992 and 2003, while coal-fired capacity increased only from 309 to 313 GW, natural-gas-fired capacity more than tripled, from 60 to 208 GW (*3*). Adding to this was the Energy Information Agency's (EIA) prediction of continued low natural gas prices (around \$4/Mcf) through 2020 (*4*), lower capital costs, shorter construction times, and generally lower air emissions for natural-gas-fired plants that allowed power generators to meet the clean air standards (*5*). However, instead of remaining near projected levels, the average wellhead price of natural gas peaked at \$11/Mcf in October 2005 (*6*). This price increase made natural gas uneconomical as a feedstock, so most natural-gas-fired plants are operating below capacity (*7*). Despite these trends, natural gas consumption is expected to increase by 20% of 2003 levels by 2030. Demand from electricity generators is projected to grow the fastest. At the same time, natural gas production in the United States and pipeline imports from Canada and Mexico are expected to remain fairly constant (*8*). The gap between North American supply and U.S. demand can only be met with alternative sources of natural gas, such as imported liquefied natural gas (LNG) or synthetic natural gas (SNG) produced from coal. Current projections by EIA estimate that LNG imports will increase to 16% of the total U.S. natural gas supply by 2030 (*8*). Alternatively, Rosenberg et al. call for congress to promote gasification technologies that use coal to produce SNG. This National Gasification Strategy calls for the United States to produce 1.5 trillion cubic feet (tcf) of synthetic natural gas per year within the next 10 years (*7*), equivalent to 5% of expected 2030 demand.

The natural gas system is one of the largest sources of greenhouse gas emissions in the United States, generating around 132 million tons of CO_2 equivalents annually (*1*). Significant emissions of criteria air pollutants also come from upstream combustion life-cycle stages of the gas. Emissions from the emerging LNG life-cycle stages or from the production of SNG have not been studied in detail. If larger percentages of the U.S. supply of natural gas will come from these alternative sources, then LNG or SNG supply chain emissions become an important part of understanding overall natural gas life-cycle emissions. Also, comparisons between coal and natural gas that concentrate only on the emissions at the utility plant may not be adequate. The objective of this study is to perform a life-cycle analysis (*9*, *10*) of natural gas, LNG, and SNG. Direct air emissions from the processes during the life-cycle will be considered, as well as air emissions from the combustion of fuels and electricity used to run the process. A comparison with coal life-cycle air emissions will be presented, in order to have a better understanding of the advantages and disadvantages of using coal versus natural gas for electricity generation.

2. Fuel Life-Cycles

The natural gas life-cycle starts with the production of natural gas and ends at the combustion plant. Natural gas is extracted from wells and sent to processing plants where water, carbon dioxide, sulfur, and other hydrocarbons are removed. The produced natural gas then enters the transmission system. The U.S. transmission system also includes some storage of natural gas in underground facilities such as reconditioned depleted gas reservoirs, aquifers, or salt caverns to meet seasonal and/or sudden short-term demand. From the transmission and storage system, some natural gas goes directly to large-scale consumers, like electric power generators, which is modeled here. The rest goes into local distribution systems that deliver it to residential and commercial consumers via low-pressure, small-diameter pipelines.

The use of liquefied natural gas (LNG) adds three additional life-cycle stages to the natural gas life-cycle described above. Natural gas is produced and processed to remove contaminants and transported by pipeline relatively short distances to be liquefied. In the liquefaction process, natural gas is cooled and pressurized (*11*). Liquefaction plants are generally located in coastal areas of LNG exporting countries and dedicated LNG ocean tankers transport LNG

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to the United States. Upon arriving, the LNG tankers offload their cargo and the LNG is regasified. At this point the regasified LNG enters the U.S. natural gas transmission system.

The coal life-cycle is conceptually simpler than the natural gas life-cycle, consisting of three major steps: coal mining and processing, transportation, and use/combustion.

U.S. coal is produced from surface mines (67%), or underground mines (33%) (*1*). Mined coal is processed to remove impurities. Coal is then transported from the mines to the consumers via rail (84%), barge (11%), and trucks (5%) (*12*). More than 90% of the coal used in the United States is used by the electric power sector, which is modeled here (*8*).

The life-cycle of SNG is a combination of some stages from the coal life-cycle and some stages of the natural gas life-cycle. Coal is mined, processed, and transported, as in the coal life-cycle, to the SNG production plant. At this plant, syngas, a mixture of carbon monoxide (CO) and hydrogen (H_2), is produced by gasification and converted, via methanation, to methane and water. The SNG is then sent to the natural gas transmission system, described above, and on to the electric power generator.

3. Methods for Calculating Life-Cycle Air Emissions

In our study we investigate the life-cycle air emissions from coal, natural gas, LNG, and SNG use. All fossil fuel options are used to produce electricity and combustion emissions are included as a component of the each life-cycle. For GHG, the emissions factors at power plants used are 120 lb CO_2 equiv/MMBtu of natural gas and 205 lb CO_2 equiv/MMBtu of coal. The SO_x and NO_x emissions at power plants are presented in the results section and in the Supporting Information

3.1. Life-Cycle Air Emissions from Natural Gas produced in North America. In 2003, the total consumption of natural gas in the United States was over 27 trillion cubic feet (tcf). Of this, 26.5 tcf were produced in North America (U.S., Canada, and Mexico) (*13*). According to the Environmental Protection Agency (EPA), 1.07% of the natural gas produced is lost in its production, processing, transmission, and storage (*14*). Total methane emissions were calculated using the percentage of natural gas lost. It was also assumed that natural gas has an average heat content of 1030 Btu/ft^3 (*13*), and that 96% of the natural gas lost is methane, which has a density of 0.0424 lb/ ft^3 (*14*).

In 1993 the U.S. EPA established the Natural Gas STAR program to reduce methane emissions from the natural gas industry. Data from this program for the reductions in methane lost in the natural gas system, as described in the Supporting Information, were combined with the data described above to develop a range of methane emissions factors for the North American natural gas life-cycle stages.

Carbon dioxide emissions are produced from the combustion of natural gas used during various life-cycle stages and from the production of electricity consumed during transport. EIA provides annual estimates of the amount of natural gas used for the production, processing, and transport of natural gas. In 2003, approximately 1900 billion cubic feet of natural gas were consumed during these stages of the natural gas life-cycle (*13*). Total carbon dioxide emissions were calculated using a carbon content in natural gas of 31.90 lb C/MMBtu and an oxidation fraction of 0.995 (*1*). According to the Transportation Energy Data Book, 3 billion kWh were used for natural gas pipeline transport in 2003 (*15*). The average GHG emission factor from the generation of this electricity is 1400 lb CO_2 equiv/MWh (*16*). These CO_2 emissions were added to methane emissions to obtain the upstream combustion GHG emission factors for North American natural gas.

SO_x and NO_x emissions from the natural gas upstream stages of the life-cycle come from the combustion of the fuels used to produce the energy that runs the system, as given in the Supporting Information. Total emissions from flared gas were calculated using the AP 42 Emission Factors for natural gas boilers (*17*). A range of emissions from the combustion of the natural gas used during the upstream stages of the life-cycle was developed using the AP 42 Emissions Factors for reciprocating engines and for natural gas turbines (*17*). Emissions from generating the electricity used during natural gas pipeline operations were estimated using the most current average emission factors given by EGRID: 6.04 lb SO_2/MWh and 2.96 lb NO_x/MWh (*16*). Note that EGRID reports emissions of SO_2 only. Other references used in this paper report total SO_x emission. For this paper, sulfur emission will be reported in terms of SO_x emissions.

In addition to emissions from the energy used during the life-cycle of natural gas, SO_x emissions are produced in the processing stage of the life-cycle, when hydrogen sulfide (H_2S) is removed from the sour natural gas to meet pipeline requirements. A range of SO_x emissions from this processing of natural gas was developed using the AP 42 emissions factors for natural gas processing and for sulfur recovery (*17*). To use the AP 42 emission factors for sulfur recovery, we found that in 2003 1945 thousand tons of sulfur were recovered from 14.7 trillion cubic feet of natural gas resulting in a calculated average natural gas H_2S mole percentage of 0.0226. This was then used with the AP 42 emission factors for natural gas processing.

3.2. Air Emissions from the LNG Life-Cycle. In 2003, 500 billion cubic feet of natural gas were imported in the form of LNG (*13*). In 2003, 75% of the LNG imported to the United States came from Trinidad and Tobago, but this percentage is expected to decrease as more imports come from Russia, the Middle East, and Southeast Asia (*13*). According to EIA, the LNG tanker world fleet capacity should have reached 890 million cubic feet of liquid (equivalent to 527 billion cubic feet of natural gas) by the end of 2006 (*18*). There are currently 5 LNG terminals in operation in the United States, with a combined base load capacity of 5.3 billion cubic feet per day (about 2 trillion cubic feet per year). In addition to these terminals, there are 45 proposed facilities in North America, 18 of which have already been approved by the Federal Energy Regulatory Commission (FERC) (*19*).

Due to unavailability of data for emissions from natural gas production in other countries, it is assumed that natural gas imported to the United States in the form of LNG produces the same emissions from the production and processing life-cycle stages as North American natural gas. Those stages are incorporated for LNG. Most of the natural gas converted to LNG is produced from modern fields developed and operated by multinational oil and gas companies, so they are assumed to be operated in a similar way to those in the United States.

It is expected that transportation of natural gas from the production field to the liquefaction plant would have emissions similar to those of pipeline transport of domestic natural gas. But the emission factor for the U.S. system (which is included in the LNG life-cycle) is based on total pipeline distances of over 200 000 miles (*20*). Because LNG facilities are closely paired with gas fields, it is expected that the average distance from production field to a LNG facility would be much smaller than 200 000 miles. Also, because there were no reliable data for the myriad of fields and facilities and suspected impact on the overall life cycle would be minimal, this transport from the fields to the liquefaction terminals was ignored. This would slightly underestimate the emissions from the LNG life cycle.

Additional emission factors were developed for the liquefaction, transport, and regasification life-cycle stages of LNG. Tamura et al. have reported emission factors for the liquefaction stage in the range of 11−31 lb CO_2 equiv/MMBtu (*21*). The sources of these emissions are outlined in the Supporting Information.

LNG is shipped to the United States via LNG tankers. LNG tankers are the last ship type to use steam turbine technology in their engines. This technology allows for easy use of boil-off gas (BOG) in a gas boiler. Boil-off rates in LNG tankers range between 0.15% and 0.25% per day when loaded (*22*, *23*). When there is not enough BOG available, a fuel oil boiler is used to produce the steam. In addition to this benefit, steam turbines require less maintenance than diesel engines, which is beneficial to these tankers that have to be readily available to leave a terminal in case of emergency (*22*).

Most LNG tankers currently in operation have a capacity to carry between 4.2 and 5.3 million cubic feet of LNG (2.6 and 3.2 billion cubic feet of gas). There are smaller tankers available, but they are not widely used for transoceanic transport. There is also discussion about building larger tankers (8.8 million cubic feet), however none of the current U.S. terminals can handle tankers of this size (*18*).

The rated power of the LNG tankers ranges between 20 and 30 MW, and they operate under this capacity around 75% of the time during a trip (*24*, *25*). The energy required to power this engine is 11.6 MMBtu/MWh (*26*). As previously mentioned, some of this energy is provided by BOG and the rest is provided by fuel oil. A loaded tanker with a rated power of 20 MW, and 0.12% daily boil-off rate would consume 3.88 million cubic feet of gas per day and 4.4 tons of fuel oil per day. The same tanker would consume 115 tons of fuel oil per day on they way back to the exporting country operating under ballast conditions. A loaded tanker with a rated power of 30 MW, and a 0.25% daily boil-off rate would get all its energy from the BOG, with some excess gas being combusted to reduce risks of explosion (*22*). Under ballast conditions, the same tanker would consume 172 tons of fuel oil per day.

For LNG imported in 2003 the average travel distance to the Everett, MA LNG terminal was 2700 nautical miles (*13*, *27*). In the future LNG could travel as far as far as 11 700 nautical miles (the distance between Australia and the Lake Charles, LA LNG terminal (*27*)). This range of distances is representative of distances from LNG countries to U.S. terminals that could be located on either the East or West coasts. To estimate the number of days LNG would travel (at a tanker speed of 20 knots (*22*)), these distances were used. This trip length can then be multiplied by the fuel consumption of the tanker to estimate total trip fuel consumption and emissions, and these can then be divided by the average tanker capacity to obtain a range of emission factors for LNG tanker transport between 2 and 17 lb CO_2 equiv/MMBtu.

Regasification emissions were reported by Tamura et al. to be 0.85 lb CO_2 equiv/MMBtu (*21*). Ruether et al. report an emission factor of 3.75 lb of CO_2 equiv/MMBtu for this stage of the LNG life-cycle by assuming that 3% of the gas is used to run the regasification equipment (*28*). The emission reported by Tamura et al. differs because they assumed only 0.15% of the gas is used to run the regasification terminal, while electricity, which may be generated with cleaner energy sources, provides the additional energy requirements. These values were used as lower and upper bounds of the range of emissions from regasification of LNG.

As done for the carbon emissions, natural gas produced in other countries and imported to the United States in the form of LNG is assumed to have the same SO_x and NO_x emissions in the production, processing, and transmission stages of the life-cycle as for natural gas produced in North America. Emission ranges for the liquefaction and regasification of natural gas were calculated using the AP 42 emission factors for reciprocating engines and natural gas turbines (*17*). It is assumed that 8.8% of natural gas is used in the liquefaction plant (*21*) and 3% is used in the regasification plants (*28*). Emissions of SO_x, and NO_x from transporting the LNG via tanker were calculated using the AP 42 emission factor for natural gas boilers and diesel boilers, as well as the tanker fuel consumption previously described.

3.3. Air Emissions from the Coal Life-Cycle. Greenhouse gas emissions from the mining life-cycle stage were developed from methane releases and from combustion of fuels used at the mines. EPA estimates that methane emissions from coal mines in 1997 were 75 million tons of CO_2 equivalents, of which 63 million tons came from underground mines and 12 million tons came from surface mines (*1*). CO_2 is also emitted from mines through the combustion of the fuels that provide the energy for operation. The U.S. Census Bureau provides fuel consumption data for mines in 1997 (*29*). These data are available in the Supporting Information. Fuel consumption data were converted to GHG emissions using the carbon content and heat content of each fuel and an oxidation fraction given in EPA's Inventory of U.S. Greenhouse Gas Emissions Sources and Sinks (*1*) (see Supporting Information). Emissions from the generation of the electricity consumed were calculated using an average 1997 emission factor of 1400 lb CO_2 equiv/MWh (*16*). These total emissions were then converted to an emission factor using the amount of coal produced in 1997 and the average heat content of this coal.

Emissions from the transportation of coal were calculated using the EIO-LCA tool developed at Carnegie Mellon University (*30*). To use this tool, economic values for coal transportation were needed. In 1997, the latest year for which the EIO-LCA tool has data, 84% of coal was transported via rail, 11% via barge, and 5% via truck. The cost for rail transport, barge, and truck transport was 13.9, 9.5, and 142.7 mills/ton-mile respectively (*12*). For a million ton-miles of coal transported, EIO-LCA estimates that 43.6 tons of CO_2 equivalents are emitted from rail transportation, 5.89 tons of CO_2 equivalents from water transportation, and 69 tons of CO_2 equivalents from truck transportation (*30*). These emissions were then converted to an emission factor by using the average travel distance of coal in each mode (796, 337, and 38 miles by rail, barge, and truck, respectively), the weighted average U.S. coal heat content of 10 520 Btu/lb (*31*) and the coal production data for 1997 (see Supporting Information).

The energy consumption data used to develop carbon emissions from the mining life-cycle stage were used to develop SO_x and NO_x emission factors for coal. AP 42 emissions factors for off-road vehicles, natural gas turbines, reciprocating engines, light duty gasoline trucks, large stationary diesel engines, and gasoline engines were used to develop this range of emission factors (*17*, *32*). In addition, the average emission factors from electricity generation in 1997 (3.92 lb NO_x/MWh and 7.86 lb SO_2/MWh (*16*)) were used to include the emissions from the electricity used in mines.

SO_x and NO_x emissions for coal transportation were again calculated using EIO-LCA (*30*). EIO-LCA estimates that a million ton-miles of coal transported via rail results in emissions of 0.02 tons of SO_x and 0.4 tons of NO_x. A million ton-miles of coal transported via water would emit 0.07 tons of SO_x, and 0.36 tons of NO_x. Finally, a million ton-miles of coal transported via truck would emit 0.06 tons of SO_x, and 1.42 tons of NO_x (*30*). These data were added to emissions from mines to find the total SO_x and NO_x emission factors for the upstream stages of the coal life-cycle.

3.4. Air Emissions from the SNG Life-Cycle. Performance characteristics for two SNG plants are given in the Supporting Information. These plants have a higher heating value efficiency between 57% and 60% (*33*, *34*). Using these efficiencies, emissions from coal mining, processing, and

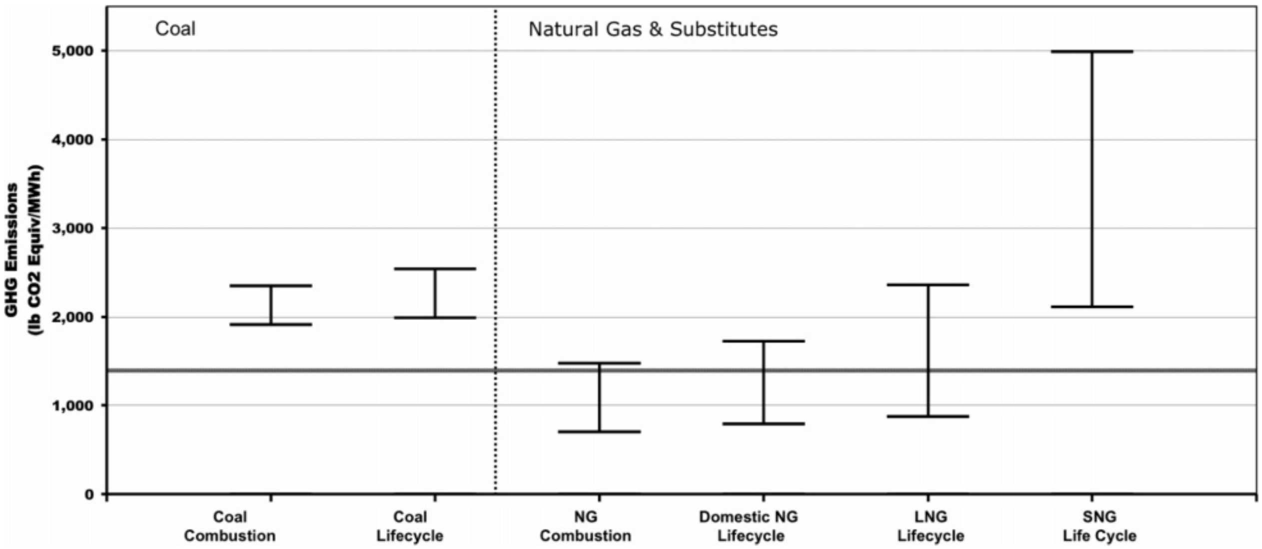

FIGURE 1. Fuel Combustion and Life-Cycle GHG Emissions for Current Power Plants.

transportation previously obtained were converted to pounds of CO_2 equiv/MMBtu of SNG. The data were also used to calculate the emissions at the gasification−methanation plant using a coal carbon content of 0.029 tons/MMBtu and a calculated SNG storage fraction of 37% (*1*). Finally, the emissions from transmission, storage, distribution, and combustion of SNG are the same as those for all other natural gas.

To develop the SO_x and NO_x emissions from the life-cycle of SNG, the emissions from coal mining and transport developed in the previous section in pounds per MMBtu of coal were converted to pounds per MMBtu of SNG using the efficiencies previously discussed. In addition, the emissions from natural gas transmission and storage were assumed to represent emissions from these life-cycle stages of SNG. The emissions from the gasification−methanation plant were taken from emission data for an Integrated Coal Gasification Combine Cycle (IGCC) plant, which operates with a similar process. Bergerson (*35*) reports SO_x emissions factors from IGCC between 0.023 and 0.15 lb/MMBtu coal (0.026−0.17 lb/MMBtu of coal if there is carbon capture), and a NO_x emission factor of 0.0226 lb/MMBtu coal (0.0228 lb/MMBtu of coal if there is carbon capture). These were converted to lb/MMBtu of SNG using the same coal-to-SNG efficiencies previously described.

4. Results

4.1. Comparing Fuel Life-Cycle Emissions for Fuels Used at Currently Operating Power Plants. Emission factors for the fuel life-cycles were calculated as pounds of pollutants per MMBtu of fuel produced, as presented in the Supporting Information. Since coal and natural gas power plants have different efficiencies, 1 MMBtu of coal does not generate the same amount of electricity as 1 MMBtu of natural gas/LNG/SNG. For this reason, emission factors given in Table 10S and Table 11S in the Supporting Information were converted to pounds of pollutant per MWh of electricity generated. This conversion is done using the efficiency of natural gas and coal power plants. According to the U.S. Department of Energy (DOE), currently operating coal power plants have efficiencies ranging from 30% to 37%, while currently operating natural gas power plants have efficiencies ranging from 28% to 58% (*36*). The life-cycle GHG emissions factors of natural gas, LNG, coal, and SNG described in the Supporting Information were converted to a lower and upper bound emission factor from coal and natural gas power plants using these efficiency ranges. Figure 1 shows the final bounds for the emission factors for each fuel cycle. The life-cycle for each fuel use includes fuel combustion at a power plant. The combustion-only emissions for each fuel are shown for comparison. The solid horizontal line shown represents the current average GHG emission factor for U.S. electricity generation: 1400 lb CO_2 equiv/MWh (*16*). Note that in this graph no carbon capture and storage (CCS) is performed at any stage of the life-cycle. CCS is a process by which carbon emissions are separated from other combustion products and injected into underground geologic formations such as saline formations or depleted oil/gas fields. A scenario in which CCS is performed at power plants as well as in gasification−methanation plants will be discussed in the following section.

It can be seen that combustion emissions from coal-fired power plants are higher than those from natural gas: the midpoint between the lower and upper bound emission factors for coal combustion is approximately 2100 lb CO_2 equiv/MWh, while the midpoint for natural gas combustions is approximately 1100 lb CO_2 equiv/MWh. This reflects the known environmental advantages from combustion of natural gas over coal. Figure 1 also shows that the life-cycle GHG emissions of electricity generated with coal are dominated by combustion, and adding the upstream life-cycle stages does not change the emission factor significantly, with the midpoint between the lower and upper bound life-cycle emission factors being 2270 lb CO_2 equiv/MWh. For natural-gas-fired power plants the emissions from the upstream stages of the natural gas life-cycle are more significant, especially if the natural gas used is synthetically produced from coal (SNG). The midpoint life-cycle emission factor for domestic natural gas is 1250 lb CO_2 equiv/MWh; for LNG and SNG it is 1600 lb CO_2 equiv/MWh and 3550 lb CO_2 equiv/MWh, respectively. SNG has much higher emission factors than the other fuels because of efficiency losses throughout the system. It is also interesting to note that the range of life-cycle GHG emissions of electricity generated with LNG is significantly closer to the range of emissions from coal than the life-cycle emissions of natural gas produced in North America. The upper bound life-cycle emission factor for LNG is 2400 lb CO_2 equiv/MWh, while the upper bound life-cycle emission factor for coal is 2550 lb CO_2 equiv/MWh.

To compare emissions of SO_x and NO_x from all life-cycles, the upstream emission factors and the power plant efficiencies from the Supporting Information are used. Emissions of these pollutants from coal and natural gas power plants in operation in 2003 were obtained from EGRID (*37*). Table 1

TABLE 1. SO_x and NO_x Combustion and Life-Cycle Emission Factors for Current Power Plants

fuel		SO_x (lb/MWh)		NO_x (lb/MWh)	
		min	max	min	max
current electricity mix		6.04		2.96	
coal	combustion	1.54	25.5	2.56	9.08
	life-cycle	1.60	25.8	2.83	9.69
natural gas	combustion	0.00	1.13	0.12	5.20
	life-cycle	0.04	1.49	0.17	9.40
LNG	life-cycle	0.094	2.93	0.25	15.4
SNG	life-cycle	0.30	3.88	0.65	8.08

shows life-cycle emissions for each fuel obtained by adding the combustion emissions from EGRID to the transformed upstream emissions. The current average SO_x and NO_x emission factors for electricity generated in the United States are also shown (*16*).

It can be seen that coal has significantly larger SO_x emissions than natural gas, LNG, or SNG. This is expected since the sulfur content of coal is much higher than the sulfur content of other fuels. SNG, which is produced from coal, does not have high sulfur emissions because the sulfur from coal must be removed before the methanation process.

For NO_x, it can be seen that the upstream stages of domestic natural gas, LNG, and even SNG make a significant contribution to the total life-cycle emissions. These upstream NO_x emissions come from the combustion of fuels used to run the natural gas system: for domestic natural gas, production is the largest contributor to these emissions; for LNG most NO_x upstream emissions come from the liquefaction plant; finally, for SNG most upstream NO_x emissions come from the gasification−methanation plant.

4.2. Comparing Fuel Life-Cycle Emissions for Fuels Used with Advanced Technologies. According to the DOE, by 2025 65 GW of inefficient facilities will be retired, while 347 GW of new capacity will be installed (*8*). Advanced pulverized coal (PC), integrated coal gasification combined cycle (IGCC), and natural gas combined cycle (NGCC) power plants could be installed. PC, IGCC, and NGCC plants are generally more efficient (average efficiencies of 39%, 38%, and 50%, respectively (*38*)) than the current fleet of power plants. In addition, CCS could be performed with these newer technologies. Experts believe that sequestration of 90% of the carbon will be technologically and economically feasible in the next 20 years (*5*, *38*). Having CCS at PC, IGCC, and NGCC plants decreases the efficiency of the plants to average of 30%, 33%, and 43%, respectively (*38*).

Figure 2 was developed using the revised efficiencies for advanced technologies and the GHG emission factors (in lb/MMBtu) described in the Supporting Information. This figure represents total life-cycle emissions for electricity generated with each fuel. Notice that emissions are shown with and without CCS. In the case of SNG with CCS, capture is performed at both the gasification−methanation plant and at the power plant. The solid horizontal line shown represents the current average GHG emission factor for electricity generation in the United States (1400 lb CO_2 equiv/MWh) (*16*). The upper and lower bound emissions in this figure are closer together than the upper and lower bounds in Figure 1, because only one power plant efficiency value is used, while for Figure 1 the upper and lower bound efficiency from all currently operating power plants was used (this is especially obvious for the domestic natural gas (NGCC) cases). It can be seen that, in general, life-cycle GHG emissions of electricity generated with the fuels without CCS would decrease slightly compared to emissions from current power plants that use the same fuel (due to efficiency gains). The most efficient natural gas plant currently in operation, however, could have slightly lower emissions than the lower bound for NGCC, LNGG, and SNGCC, due to efficiency differences. Three of the cases, however (PC, IGCC, and SNGCC), would still have higher emissions than the current average emissions from power plants. If CCS were used, however, there would be a significant reduction in emissions for all cases. In addition the midpoints between upper and lower bound emissions from all fuels are closer together, as can be seen in Figure 3. This figure also shows how the upstream from combustion emissions of fuels become significant contributors to the life-cycle emission factors when CCS is used.

Table 2 was developed using the upstream SO_x and NO_x emission factors obtained in this study and the combustion emissions reported by Bergerson (*35*) for PC and IGCC plants and by Rubin et al. for NGCC plants (*38*). These reported combustion emissions can be seen in the Table 12S in the Supporting Information.

As can be seen from Table 2, if advanced technologies are used there could be a significant reduction of NO_x and SO_x emissions, even if CCS is not available. It is interesting also to note that a PC plant with CCS could have lower life-cycle emissions than an IGCC plant with CCS. In the PC case all sulfur is removed through flue gas desulfurization. The removed sulfur compounds are then solidified and disposed of or sold as gypsum. In an IGCC plant with CCS, sulfur is removed from the syngas before combustion. In these plants, however, instead of solidifying the sulfur compounds removed and disposing them, the elemental sulfur is recovered in a process that generates some additional SO_x emissions (*35*). For NO_x, only LNG has higher life-cycle emissions than the average generated at current power plants.

5. Discussion

Natural gas is an important energy source for the residential, commercial, and industrial sectors. In the 1990s, the surge in demand by electricity generators and relatively constant natural gas production in North America caused prices to increase, so that in 2005 these sectors paid 58 billion dollars more than they would have paid if 2000 prices remained constant. Cumulative additional costs of higher natural gas prices for residential, commercial, and industrial consumers between 2000 and 2005 were calculated to be around 120 billion dollars. LNG has been identified as a source of natural gas that might help reduce prices, but even with an increasing supply of LNG, EIA still projects average delivered natural gas prices above $6.5/Mcf in the next 25 years. This is higher than the $4.5 /Mcf average projected price in earlier reports before the natural-gas-fired plant construction boom (*4*).

In addition to LNG, SNG has been proposed as an alternative source to add to the natural gas mix. The decision to follow the path of increased LNG imports or SNG production should be examined in light of more than just economic considerations. In this paper, we analyzed the effects of the additional air emissions from the LNG/SNG life-cycle on the overall emissions from electricity generation in the United States. We found that with current electricity generation technologies, natural gas life-cycle GHG emissions are generally lower than coal life-cycle emissions, even when increased LNG imports are included. However LNG imports decrease the difference between GHG emissions from coal and natural gas. SNG has higher life-cycle GHG emission than coal, domestic natural gas, or LNG. It is also important to note that upstream GHG emissions of NG/LNG/SNG have a higher impact in the total life-cycle emissions than upstream coal emissions. This is a significant point when considering a carbon-constrained future in which combustion emissions are reduced.

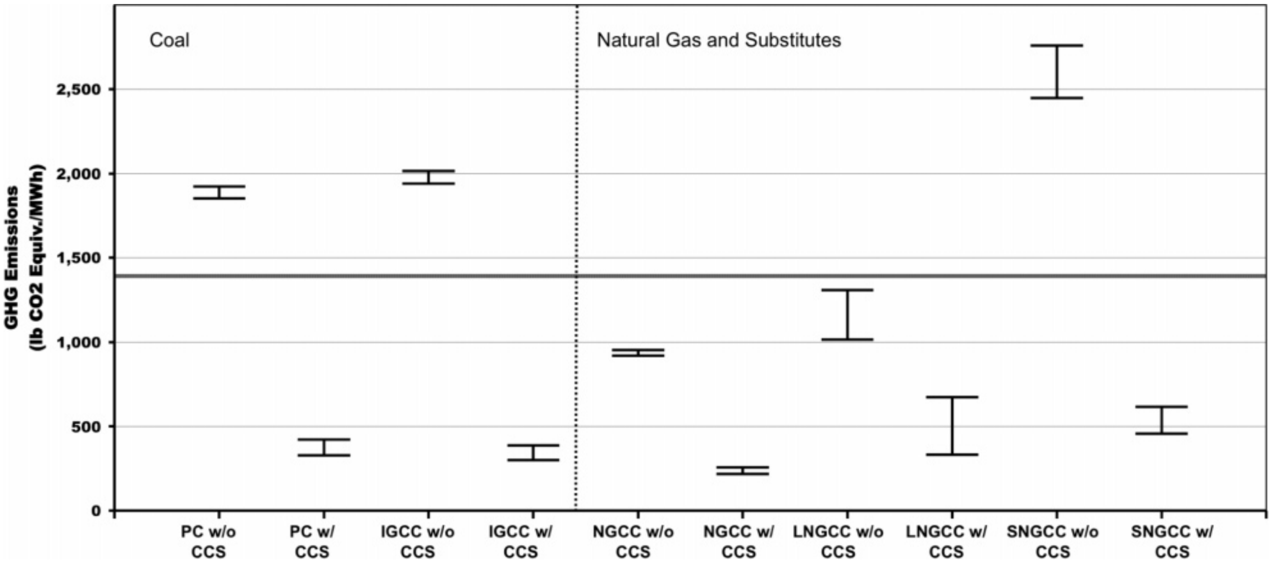

FIGURE 2. Fuel GHG Life-Cycle Emissions Using Advanced Technologies.

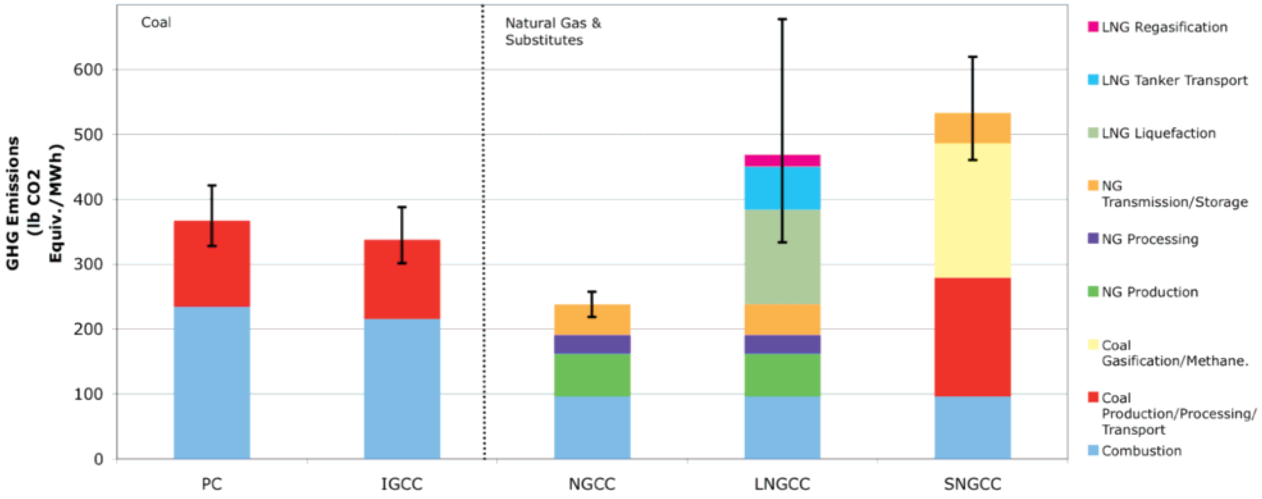

FIGURE 3. Midpoint Life-Cycle GHG Emissions Using Advanced Technologies with CCS.

TABLE 2. SO_x and NO_x Life-Cycle Emission Factors for Advanced Technologies

fuel		SO_x (lb/MWh)		NO_x (lb/MWh)	
		min	max	min	max
current electricity mix		6.04		2.96	
coal	PC w/o CCS	0.24	1.54	1.42	2.46
	PC w/ CCS	0.08	0.34	1.90	3.61
	IGCC w/o CCS	0.27	1.57	0.47	0.70
	IGCC w/ CCS	0.32	1.83	0.54	0.78
natural gas	NGCC w/o CCS	0.04	0.20	0.30	2.57
	NGCC w/ CCS	0.05	0.24	0.36	3.01
LNG	NGCC w/o CCS	0.25	1.04	0.39	5.89
	NGCC w/ CCS	0.30	1.23	0.46	6.91
SNG	NGCC w/o CCS	0.35	2.15	0.88	1.85
	NGCC w/ CCS	0.45	2.80	1.03	2.18

For emissions of SO_x, we found that with current electricity generation technologies, coal has significantly higher life-cycle emissions than any other fuel due to very high emissions at current power plants. For NO_x, however, this pattern is different. We find that with current electricity generation technologies, LNG could have the highest life-cycle NO_x emissions (since emissions from liquefaction and regasification are significant), and that even natural gas produced in North America could have life-cycle NO_x emissions very similar to those of coal. It is important to note that while GHG emissions contribute to a global problem, SO_x and NO_x are local pollutants and U.S. policy makers may not give much weight to emissions of these pollutants in other countries.

In the future, as newer generation technologies and CCS are installed, the overall life-cycle GHG emissions from electricity generated with coal, domestic natural gas, LNG, or SNG could be similar. Most important is that all fuels with advanced combustion technologies and CCS have lower life-cycle GHG emission factors than the current average emission factor from electricity generation. For SO_x we found that coal and SNG would have the largest life-cycle emissions, but all fuels have lower life-cycle SO_x emissions than the current average emissions from electricity generation. For NO_x, LNG would have the highest life-cycle emissions and would be the only fuel that could have higher emissions than the current average emission factor from electricity generation, even with advanced power plant design.

We suggest that advanced technologies are important and should be taken into account when examining the possibility of doing major investments in LNG or SNG infrastructure. Power generators hope that the price of natural gas will decrease as alternative sources of natural gas are added to the U.S. mix, so they can recover the investment made in natural gas plants that are currently producing well under capacity. We suggest that these investments should be viewed as sunk costs. Thus, it is important to re-evaluate whether investing billions of dollars in LNG/SNG infrastructure will lock us into an undesirable energy path that could make future energy decisions costlier than ever expected and increase the environmental burden from our energy infrastructure.

Acknowledgments

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Supporting Information Available

Graphical representation of the fuel life-cycles, emissions calculation information, summary of emissions from fuel life-cycles, power plant efficiency information, emissions from advanced technologies, and references, This material is available free of charge via the Internet at http://pubs.acs.org.

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Comparative Life-cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation

Supporting Information

1. Graphical Representation of the Fuel Life-cycles

Figure 1S and Figure 2S below, show the life-cycle stages on natural gas used by electric power generators, including the stages from the LNG life-cycle. Notice that local distribution of natural gas falls outside our analysis boundary.

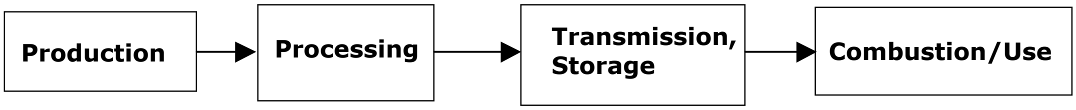

Figure 1S: Domestic Natural Gas Life-cycle.

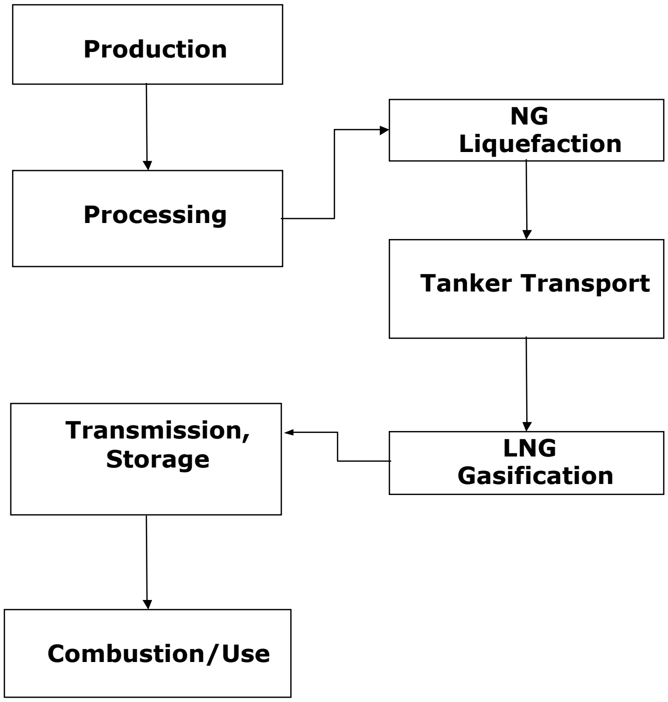

Figure 2S: LNG Life-cycle.

Figure 3S and Figure 4S show the life-cycle of coal and synthetic natural gas (SNG) derived from coal.

Figure 3S: Coal Life-cycle.

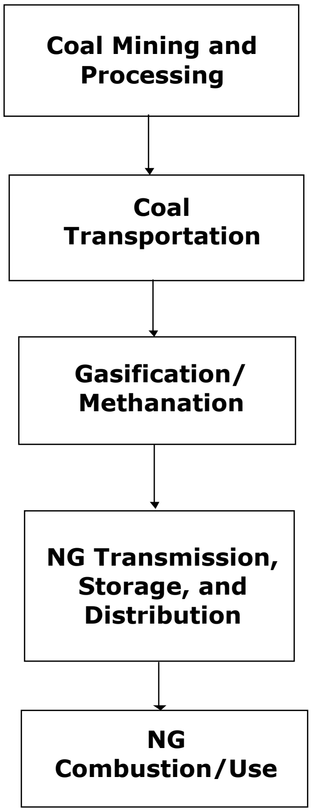

Figure 4S: SNG Life-cycle.

2. Calculating Emissions from the Domestic Natural Gas Life-cycle

During the late 1980s and early 1990s the U.S. Environmental Protection Agency (EPA) conducted a study to determine methane emissions from the natural gas industry (1). This comprehensive study developed hundreds of activity and emissions factors from all areas of the natural gas industry. These factors were developed using data collected from different sectors of the industry as well as from data collected in field measurements. Methane emissions from the U.S. natural gas system given as a percentage of natural gas produced can be seen in Table 1S. This data was used to develop methane emission factors, as described in the main document. Notice, that Table 1S includes an estimate for natural gas losses in the local distribution system. This estimate is given here for reference, but it was not included in our calculation of emissions of natural gas used to generate electricity.

In addition data from the EPA Natural Gas STAR program was used. The program is a voluntary partnership with the goal of encouraging the natural gas industry to adopt practices that increase efficiency and reduce emissions (for example by reducing natural gas leaks in the pipeline system). Consequently, since 1993, a cumulative total of 338 billion cubic feet of methane emissions have been eliminated. In 2003 alone, 52,900 million cubic feet of methane emissions were eliminated, a 9% reduction over projected emissions for that year without improved practices (2).

Table 1S: Methane Emissions from North American Gas Life-cycle as a Percentage of Natural Gas Produced (1).

Lifecycle Segment	Emissions as a Percentage of Gas Produced
Production	0.38%
Processing	0.16%
Transmission and Storage	0.53%
Distribution	0.35%

Carbon dioxide emissions from the different natural gas life-cycle stages were also calculated. These emissions were calculated using data on the amount of natural gas used to run the processes, as given in Table 2S, as well as an estimated 3 billion KWh of electricity used for pipeline transport. These data were also used to calculate SO_x and NO_x emissions from the life-cycle, as described in the main document. It should be mentioned that the pipeline fuel presented in Table 2S includes fuel used by the transmission system and the local distribution system. As previously described, natural gas used by electricity generators is bought directly from the transmission system, so that emissions from the distribution system are not included in our analysis. Due to data limitations, we were not able to disaggregate pipeline fuel and electricity consumption between the two systems. To deal with this issue, we use a range of emissions. The minimum value assumes that none of this fuel is consumed in the transmission system and the maximum value assumes that all is consumed in the transmission system.

Table 2S: Natural Gas Used During the Natural Gas Life-cycle. (3).

Use (as defined by EIA)	NG Life-cycle Stage	Amount (million ft^3)
Flared Gas	Production	98,000
Lease Fuel	Production	760,000
Pipeline Use	Transmission/Distribution	665,000
Plant Fuel	Processing	365,000

3. Calculating Emissions from the LNG Life-cycle

As mentioned in the main paper, Tamura et al (4) provide GHG emissions for liquefaction plants. Table 3S presents the sources of these emissions.

Table 3S: Liquefaction Emission Factors (Adapted from Tamura et al (4)).

Liquefaction	Emission Factors (lb CO_2 Equivalent/MMBtu)		
	Minimum	Average	Maximum
CO_2 from fuel combustion	11	12	13
CO_2 from flare combustion	0.00	0.77	1.5
CH_4 from vent	0.09	1.3	9.8
CO_2 in raw gas	0.09	4.0	6.6

Table 4S provides the distance from LNG exporting countries to two U.S. LNG terminals and the amount of LNG brought from each country in 2003. These two terminals were chosen because they are two of the largest terminals in the United States and they represent longest and shortest tanker travel distances for which route information is available. In addition, the range of distances provided is also representative of distances LNG would have to travel if a LNG terminal was located in the U.S. West Coast. Figure 5S shows the emission factors for LNG Tanker transport from each country to each of these terminals, obtained using the tanker information given in the main document. Emissions from tanker transport range between 2 and 17 pounds of CO_2 Equivalent per MMBtu of natural gas. These data was also used to calculate the SO_x and NO_x emission factors for tanker transport.

Table 4S: LNG Exporting Countries in 2003.

Exporting Country	Distance to Lake Charles Facility (nautical miles) (5)	Distance to Everett, MA Facility (nautical miles) (5)	2003 US Imports (million cubic feet NG) (3)
Algeria	5,000	3,300	53,000
Australia	12,000	11,000	0
Brunei	12,000	11,000	0
Indonesia	12,000	11,000	0
Malaysia	12,000	11,000	2,700
Nigeria	6,100	5,000	50,000
Oman	8,900	7,500	8,600
Qatar	9,700	8,000	14,000
Trinidad	2,200	2,000	380,000
UAE	9,600	7,959	0
Russia	9,600	11,000	0

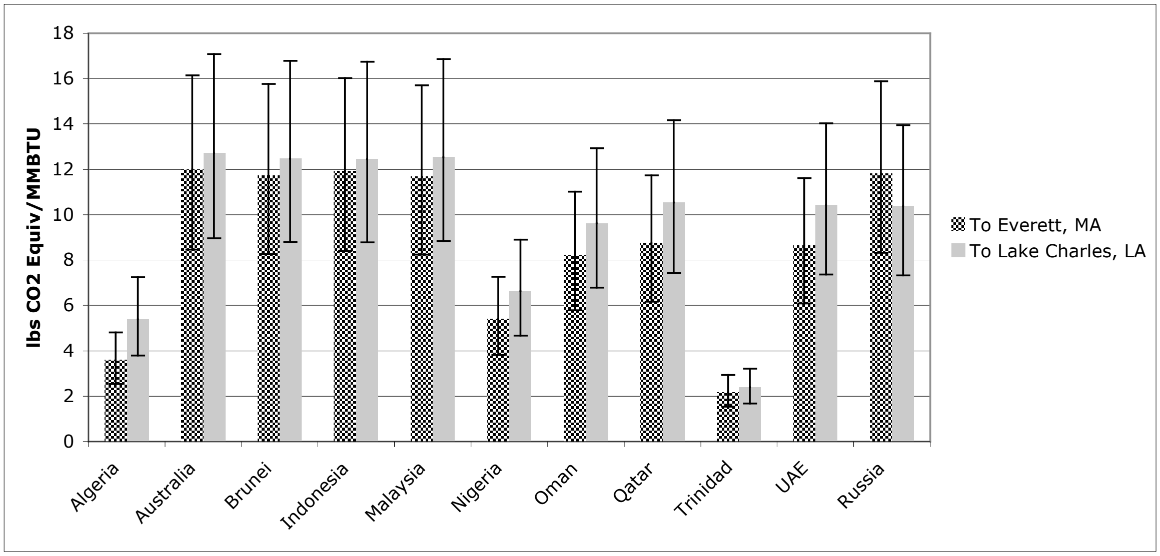

Figure 5S: Tanker Emission Factors from Each Country.

4. Calculating Emissions from the Coal Life-cycle

Table 5S presents fuel consumption data for coal mines in the U.S., and Table 6S presents carbon content, heat content of these fuels. These data was used to calculate GHG emissions factors for coal mines.

Table 5S: 1997 Fuel Consumption at Coal Mines (6)

Mine Type	Fuel Oil (1000 bbl)			Gas (10^9 ft^3)	Gasoline (10^6 gal)	Electricity (10^6 KWh)
	Total	Distillate	Residual			
Surface	8,280	7,524	756	0.7	30	42,474
Underground	801	656	145	0.5	4	7,123

Table 6S: Carbon Content, and Heat Content of Different Fuels (7).

Fuel Type	Carbon Content of Fuel lb/MMBtu Fuel	Heat Content of Fuel (MMBtu/bbl - MMBtu/MMcf)	Fraction Oxidized
Distillate	43.98	5.825	0.99
Residual	47.38	6.287	0.99
Gas	31.90	1,030	0.995
Gasoline	42.66	5.253	0.99

Table 7S: 1997 Coal Production Data (8).

Mine Type	Coal Produced (1000 tons)	Heat Content of Coal (BTU/lb)
Surface	669,273	9,626
Underground	420,657	11,944
Total	1,089,930	10,520

As described in the main document, EIO-LCA was used to estimate emission factors from coal transportation. Table 8S summarizes the emissions resulting from transporting one million ton-miles of coal via each transportation mode.

Table 8S: EIO-LCA GHG Emission Data for a Million Ton-Miles of Coal Transported (9).

Sector	Total GHG Emissions (tons CO_2 Equivalent)	Total SO_x Emissions (tons SO_x)	Total NO_x Emissions (tons NO_x)
Rail Transportation	43.6	0.02	0.40
Water Transportation	5.89	0.07	0.36
Truck Transportation	69.0	0.06	1.42

5. Calculating Emissions from the SNG Life-cycle

In order to calculate air emissions from the SNG life-cycle, the emissions from coal production, processing and transport were converted from pounds per MMBtu of coal used to pounds per MMBtu of SNG produced using the performance characteristics of two SNG plants given in Table 9S. The emissions from SNG transport, storage and use are the same as those from natural gas. The efficiency for the CCS case was obtained assuming an energy penalty of 16% as described for and IGCC plant by Rubin et al (10).

Table 9S: SNG Plant Performance Characteristics

	Case 1 (11)	Case 2 (12)
SNG Output (1. mcf/day and 2. MMBtu/hr)	250	1,739
Efficiency without CCS (HHV)	57%	60%
Efficiency with CCS (HHV)	50%	52%

6. Summary of Emissions from Fuel Life-cycles

Table 10S summarizes GHG emission factors for all fuels. The emission factors presented in this section are the average emission rate relative to units of fuel produced, without considering the efficiency of using these fuels. These emission factors can later be used to develop total inventories of GHG emissions from the annual consumption of each fuel. Allocation of these emissions for each life-cycle stage can be seen in Figure 6S through Figure 8S. Note that there are two different emission factors for SNG. In one case, no carbon capture and sequestration (CCS) is performed at the gasification-methanation stage. When CCS is performed at the gasification-methanation plant, an energy penalty is incurred. It was assumed that the energy penalty observed at IGCC plants with CCS (16%) is representative of the energy penalty at the SNG gasification-methanation plant (10). CCS could also be performed at power plants, as discussed in the main document.

It is also very important to note that the emission factors shown in Table 10**S** (and the emission factors given in Table 11S) are not comparable to each other, since one Btu of coal does not generate the same amount of electricity as one Btu of natural gas or SNG. These emission factors can be transformed to comparable units, namely lbs/MWh of electricity produced, by taking into consideration the efficiency of electricity generation.

Table 10S: Life-cycle GHG Emission Factors
(units: lbs/MMBtu of Fuel Produced)

Life-cycle Stages	North American NG		LNG		Coal		SNG (No CCS at Gasif./Methan. Plant)		SNG (CCS at Gasif./Methan. Plant)	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
Upstream	15.3	20.1	29.6	72.3	8.2	16.4	240	286	45.2	65.2
Combustion (no CCS)	120	120	120	120	205	205	120	120	120	120
Combustion (with CCS)	12	12	12	12	20.5	20.5	12	12	12	12

SO_x and NO_x emission factors for the upstream stages of electricity generation for the fuel life-cycles can be seen in Table 11S. SO_x and NO_x emissions from the combustion of fuel at power plants are very dependent on specific plant characteristics, so it was not possible to transform these power plant emissions (given in lbs/MWh) to the same units as the emissions from the upstream stages of the life-cycle (lbs/MMBtu) by simply using the efficiency of the power plants.

Table 11S: Upstream SO_x and NO_x Emission Factors (units: lbs/MMBtu of Fuel Produced)

Pollutant	North American Natural Gas		LNG		Coal		SNG (No CCS at Gasif./Methan. Plant)		SNG (CCS at Gasif./Methan. Plant)	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
SO_x	0.006	0.030	0.016	0.145	0.007	0.029	0.051	0.316	0.064	0.400
NO_x	0.009	0.342	0.022	0.831	0.030	0.535	0.090	0.234	0.104	0.253

7. GHG Emissions Allocated to Fuel Life-cycle Stages

Figure 6S through Figure 8S show how the GHG emissions reported in Table 10S are allocated among the different life-cycle stages.

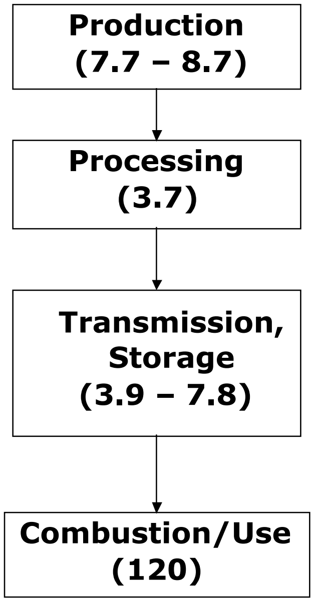

Figure 6S: North American Gas Life-cycle GHG Emission Factors (Units: lbs CO_2 Equivalent/MMBtu).

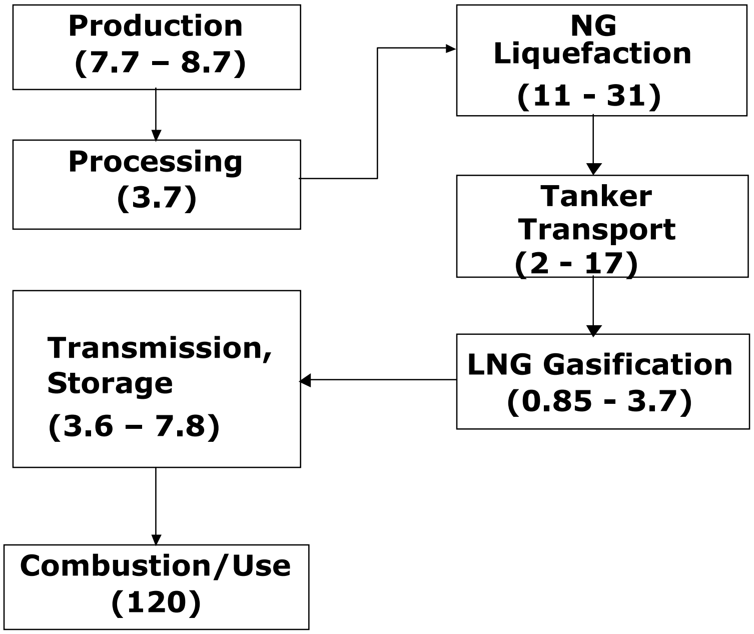

Figure 7S: LNG Life-cycle GHG Emission Factors (Units: lbs CO_2 Equivalent/MMBtu).

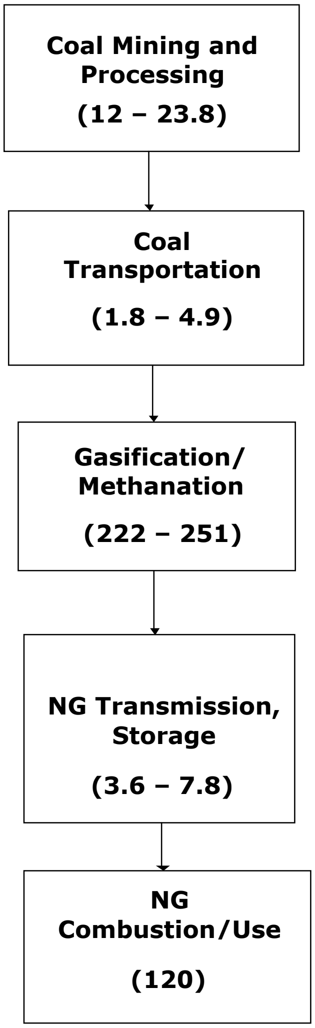

Figure 8S: SNG Life-cycle GHG Emission Factors (Units: lbs CO_2 Equivalent/MMBtu).

8. Efficiencies of Currently Operating Power Plants

Figure 9S shows the distribution of the efficiencies of currently operating power plants, obtained using the cumulative distribution function of EIA 2003 electricity generation data for all utility plants (13). As illustrated in Figure 9S, the median efficiency for natural gas plants is higher than the median efficiency for coal plants. These efficiencies were used to convert the emission factors previously presented (in lbs/ MMBtu of fuel) to lbs/MWh.

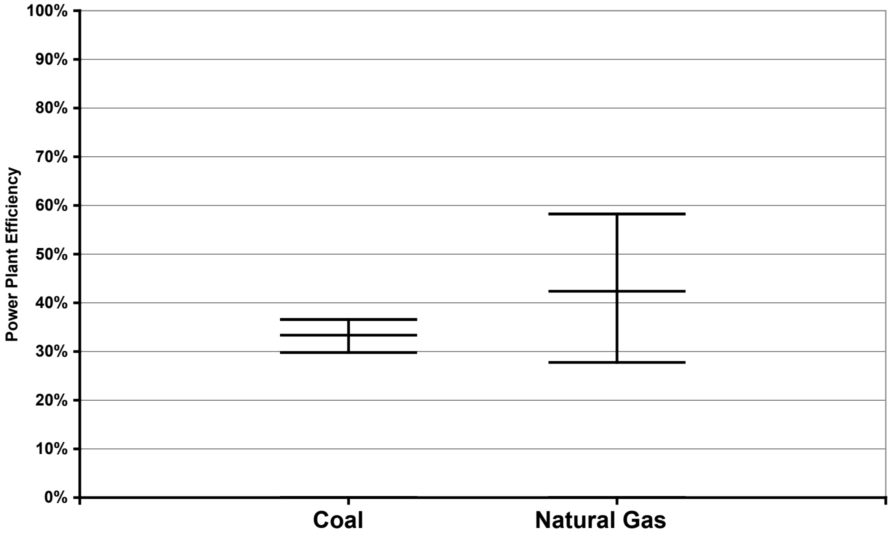

Figure 9S: Efficiencies of Natural Gas and Coal Plants (13).

9. Combustion Emissions from Advance Technologies

Table 12S reports combustion emissions from advanced power plant technologies. The emission factors from PC and IGCC plants were reported Bergerson (14) for PC and IGCC plants. Rubin et al reported the emissions for NGCC plants (10).

Table 12S: Combustion Emissions from Advanced Power Plants.

Fuel/Pollutant	SO_x (lbs/MWh)		NO_x (lbs/MWh)	
	Min	Max	Min	Max
PC w/o CCS	0.17	1.28	1.16	2.00
PC w/ CCS	0.00	0.01	1.56	3.00
IGCC w/o CCS	0.20	1.30	0.20	0.20
IGCC w/ CCS	0.24	1.52	0.20	0.20
NGCC w/o CCS	0.00	0.00	0.24	0.24
NGCC w/ CCS	0.00	0.00	0.29	0.29

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Comparative Life Cycle Carbon Emissions of LNG Versus Coal and Gas for Electricity Generation

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Introduction

Natural gas currently provides 24% of the energy used by homes and businesses in the US (1). It is also an important feedstock for the chemical and fertilizer industry. In the early 1990's the price of natural gas was low (around \$3/1000 ft^3) and as a result there was a surge in construction of natural gas plants (2). Today, the Henry Hub price of natural gas is around \$15/1000 ft^3 (3), and most of these plants are operating below capacity. However, natural gas consumption is expected to increase 41% by 2025 (to 30 trillion cubic feet), with demand from electricity generators growing the fastest (increasing 90% by 2025). At the same time natural gas production in North America is expected to remain fairly constant at around 24 trillion cubic feet, so that demand of imported liquefied natural gas (LNG) will increase to around 6 trillion cubic feet or 20% of the total supply by 2025 (3).

The natural gas system is the second largest source of greenhouse gas emissions in the US, generating around 132 million tons of CO_2 Equivalents (1). Several studies have performed emission inventories for the natural gas lifecycle from production to distribution. Usually these analyses have been performed for domestic natural gas, so that emissions from the LNG lifecycle stages have been ignored. If, as the DOE estimates suggest, larger percentages of the supply of natural gas will come from these imports, emissions from these steps in the lifecycle could influence the total natural gas lifecycle emissions. Thus, comparisons between coal and natural gas that concentrate only on the emissions at the utility plant may not be adequate. The objective of this study is to perform an analysis of the natural gas lifecycle greenhouse gas emissions taking the emissions from LNG into consideration. Different scenarios for the percentage of natural gas as LNG are analyzed. Moreover, a comparison with the coal fuel cycle greenhouse gas emissions will be presented, in order to have a better understanding of the advantages and disadvantages of using coal versus natural gas for electricity generation.

The Natural Gas Life Cycle

The natural gas life cycle starts with the production of natural gas and ends at the combustion plant. NaturalGas.org has a very detailed description of this life cycle. Readers are encouraged to visit this website if they need more information about the topic.

Geological surveys and seismic studies are used to determine the location of natural gas deposits. After these sites have been identified, wells are constructed. There are two types of well for the extraction of natural gas: oil wells and natural gas wells. Oil wells are drilled primarily to extract oil, but natural gas can also be obtained. Natural gas wells are specifically drilled to extract natural gas.

After natural gas is extracted through the wells, it has to be processed to meet the characteristics of the natural gas used by consumers. Consumer natural gas is composed primarily of methane. However, when natural gas is extracted, it exists with other hydrocarbons such as propane and ethane. In addition, the extracted natural gas contains impurities such as water vapor and carbon dioxide that must be removed. Natural gas processing plants are usually constructed in gas producing regions. The natural gas is transported from the extraction sites to these plants through a system of low-diameter, low-pressure pipelines. At the plant, water vapor is first removed from the gas by using absorption or adsorption methods. Glycol Dehydration is an example of absorption, in which glycol, which has a chemical affinity to water, is used to absorb the vapor. Solid-Desiccant Dehydration is an example of adsorption. In this process the natural gas passes through towers that contain activated alumina or other solid desiccants. As the gas is passed through these towers, the water particles are retained on the surface of the solids.

As previously mentioned, natural gas is extracted with other hydrocarbons that must be removed. The removal of these hydrocarbons, called Natural Gas Liquids (NGL), is done with the absorption method or the cryogenic expander process. The absorption method is similar to the water absorption method, but instead of glycol, absorbing oil is used. The cryogenic expansion method consists of dropping the temperatures of the gas causing the hydrocarbons to condense so that they can be separated from the natural gas. The absorption method is used to remove heavier hydrocarbons, while lighter hydrocarbons are removed using the cryogenic expansion process.

The final step in the processing of natural gas is the removal of sulfur and carbon dioxide. Often, natural gas from the wells contains high amounts of these two compounds, and it is called sour gas. Sulfur must be removed from the gas because it is a potentially lethal chemical if breathed. In addition, sour gas can be corrosive for the transmissions and distribution pipelines. The process of removing sulfur and carbon dioxide from the gas is similar to the absorption processes previously described.

After the natural gas is processed it enters the transmission system. In the US, this transmission system is the interstate natural gas pipeline network, which consists of thousands of miles of high-pressure pipelines that transport the gas from producing areas to high demand areas. In addition to the pipes, this pipeline system has compressor stations along the way, usually placed in 40 to 100 mile intervals. These compressor stations use a turbine or an engine to compress the natural gas and maintain the high pressure required in the pipeline. The turbines and engines generally run with a small amount of the gas from the pipeline. In addition to compressor stations, metering stations are also placed along the system to allow companies to better monitor and manage the natural gas in the pipes. Moreover valves can be found through the entire length of the pipelines to regulate flow.

Natural gas can be stored to meet seasonal demand increases or to meet sudden, short-term demand increases. Natural gas is usually stored in underground facilities. Such facilities could be built in reconditioned depleted gas reservoirs, aquifers or salt caverns. According to the Energy Information Administration (EIA), in 2003 the total storage capacity in the United States was 8.2 billion cubic feet. 82% of this capacity was in depleted gas fields, 15% in depleted aquifers, and 3% in salt caverns. Moreover during that year, withdrawals from storage added to 3.1 billion cubic feet while injections totaled 3.3 billion cubic feet (4). It is important to note that some gas injected into underground storage becomes physically unrecoverable gas. This gas is known as base gas.

Distribution is the final step before natural gas is delivered to consumers. Local Distribution Companies transport natural gas from delivery points along the transmission system to local consumers via a low-pressure, small-diameter pipeline system. Natural gas that arrives to a city gate through the transmission system is depressurized, and filtered to remove any moisture or particulate content. In addition, Mercaptan is added to the gas to create the distinctive smell that allows leaks to be detected. Small compressors are used in the distribution system to maintain the pressure required.

When Liquefied Natural Gas (LNG) is added to the mix of natural gas, three additional lifecycle stages are created: liquefaction, tanker transport, and regasification. Figure 1 shows the total life cycle of natural gas including the LNG stages.

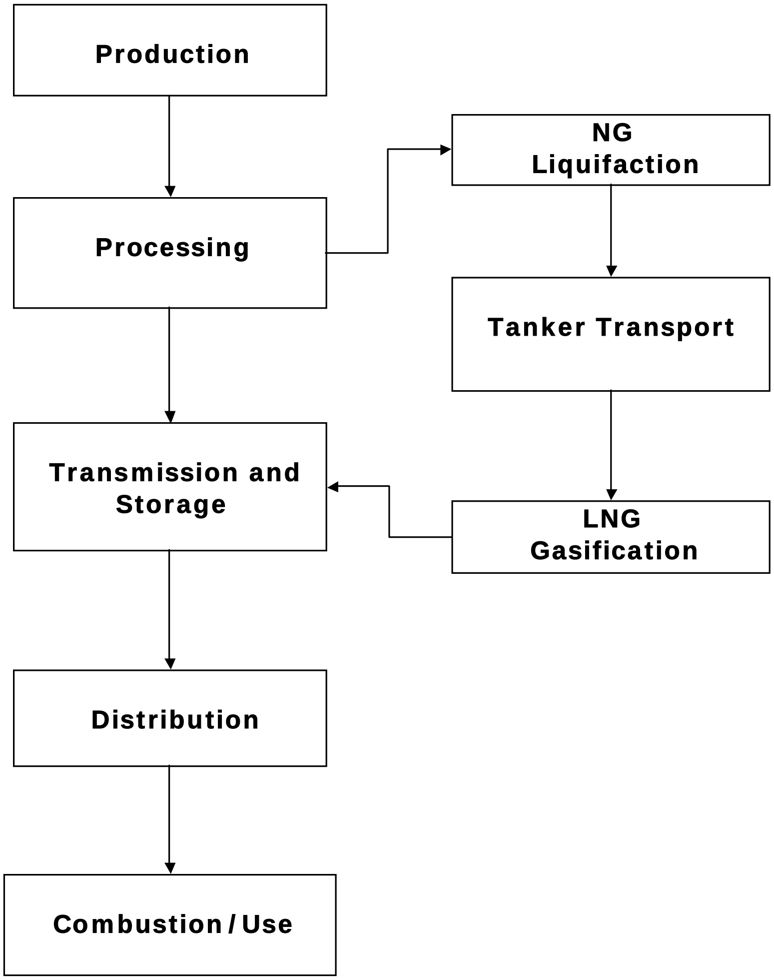

Figure 1: Natural Gas Life Cycle Including LNG.

In the liquefaction process, natural gas is cooled and pressurized to convert it to liquid form, reducing its volume by a factor of 610 (5). These liquefaction plants are generally located in coastal areas of LNG export countries. Currently 75% of the LNG imported to the US comes from Trinidad, but this percentage is expected to decrease as more imports come from Russia, the middle east, and southeast Asia (4). LNG tankers bring this gas to the US. According to EIA, there were 151 LNG tankers in operation worldwide as of October 2003. The majority of these tankers have the capacity to carry more than 120,000 cubic meters of liquefied natural gas (equivalent to 2.59 billion cubic feet of natural gas, enough gas to supply an average of 31,500 residences for a year (4)) and the total fleet capacity is 17.4 million cubic meters of liquid (equivalent to 366 billion cubic feet of natural gas). There are currently fifty-five ships under construction that will increase total fleet capacity to 25.1 million cubic meters of liquid (equivalent to 527 billion cubic feet of natural gas) in 2006 (6).

Regasification facilities are the last step LNG must pass through before going into the US pipeline system. Regasification facilities are LNG marine terminals where LNG tankers unload their gas. These facilities consist of storage tanks and vaporization equipment that warms the LNG to return it to the gaseous state. There are currently 5 LNG terminals in operation in the US: Lake Charles, Louisiana; Elba Island, Georgia; Cove Point, Maryland; Everett, Massachusetts; and a recently opened offshore terminal in the Gulf of Mexico. These terminals have a combined base load capacity of 3.05 billion cubic feet per day (about 1 trillion cubic feet per year). In addition to these there are over fifty proposed facilities for a total proposed capacity of 62 billion cubic feet per day (23 trillion cubic feet per year). Figure 2 shows the proposed location of these facilities (6).

As shown in Figure 1, natural gas combustion is the last stage in the natural gas lifecycle. In the US, natural gas is used for electricity generation, heating, and several industrial processes. Approximately 24% of the electricity generated comes from natural gas (1). Natural gas plants have heat rates that range from 5,800 BTU/kWh to 12,300 BTU/kWh (7).

US Natural Gas Industry in 2003

In 2003, the total supply of natural gas in the US was over 27 trillion cubic feet. Of this, 26.5 trillion cubic feet were produced in North America (US, Canada, and Mexico), and 0.5 trillion cubic feet were imported in the form of LNG. 75% of LNG came from Trinidad and Tobago. Other exporting countries included Algeria, Malaysia, Nigeria, Qatar, and Oman (4). Table 1 shows more detailed statistics about the state of the US natural gas industry in 2003. Numbers may not add up due to rounding.

Table 1: 2003 Natural Gas Industry Statistics (All units in million cubic feet) (4)

Gross Withdrawals	24,000,000
Total Dry Production	19,000,000
Total Supply	27,000,000
Total Consumption	22,500,000
Total Imports	4,000,000
Pipeline Imports	3,500,000
LNG Imports	505,000

Greenhouse gas emissions from Natural Gas produced in North America

During the late 1980's and early 1990's the US Environmental Protection Agency (EPA) conducted a study to determine methane emissions from the natural gas industry. This very comprehensive study developed hundreds of activity and emissions factors from all the areas of the natural industry. These factors were developed using data collected from the different sectors of the industry as well as from data collected in field measurements. Table 2 presents the percentage of produced natural gas that is emitted to the atmosphere during the lifecycle according to the results of the previously described study, as well as the source of these emissions.

Table 2: Methane Emissions from North American Gas Life Cycle as a Percentage of Natural Gas Produced (8).

Lifecycle Segment	Emission Sources	Emissions as a Percentage of Gas Produced
Production	Pneumatic Devices	0.38%
	Fugitive Emissions	
	Underground Pipeline Leaks	
	Blow and Purge	
	Compressor	
	Glycol Dehydrator	
Processing	Fugitive Emissions	0.16%
	Compressor	
	Blow and Purge	
Transmission and Storage	Fugitive Emissions	0.53%
	Blow and Purge	
	Pneumatic Devices	
	Compressor	
Distribution	Underground Pipeline Leaks	0.35%
	Meter and Pressure Stations	
	Costumer Meter	

Based on the statistics presented in Table 1, 26.5 billion cubic feet of natural gas were produced in North America in 2003. Using the percentages of natural gas emitted, an average heat content of 1,030 BTU/ft^3, and the assumption that 100% of the natural gas lost is methane (density 19.23 gr/ ft^3) which may result in a slight overestimate of emissions given that the real percentage of methane in natural gas varies between 94% and 98%; total methane emission were calculated to develop the emission factors shown in Figure 4.

In addition to methane, carbon dioxide emissions are produced from the combustion of natural gas used during the lifecycle stages previously described. The Energy Information Administration maintains records of the amount of natural gas used during the production, processing, transmission, storage, and distribution of natural gas. This data for 2003 can be seen in Table 3. Assuming that 100% of this gas is methane, total carbon dioxide emissions were found using thermodynamic calculations. These emissions were then added to methane emissions to obtain the total emission factors shown in Figure 3.

Table 3: Natural Gas Used During Natural Gas Life Cycle. (All units in million cubic feet) (4).

Flared Gas	98,000
Lease Fuel	760,000
Pipeline and Distribution Use	665,000
Plant Fuel	365,000

In 1993 the Natural Gas STAR program was established by the EPA to reduce methane emissions from the natural gas industry. The program is a voluntary partnership with the goal of encouraging industries to adopt practices that increase efficiency and reduce emissions. Since 1993, 338 billion cubic feet of methane have been eliminated. In 2003, 52,900 million cubic feet of methane emissions were eliminated, a 9% reduction over projected emissions for that year without improved practices (9). This data was used to develop a range of emission factors for the North American natural gas industry. Figure 2 shows the total range of emission factors for the North American natural gas lifecycle. It can be seen that total lifecycle emission for natural gas produced in North America are approximately 140 lbs CO_2/MMBTU, an amount dominated by combustion emissions for natural gas plants currently in operation in the US of an average 120 lbs CO_2/MMBTU (10)

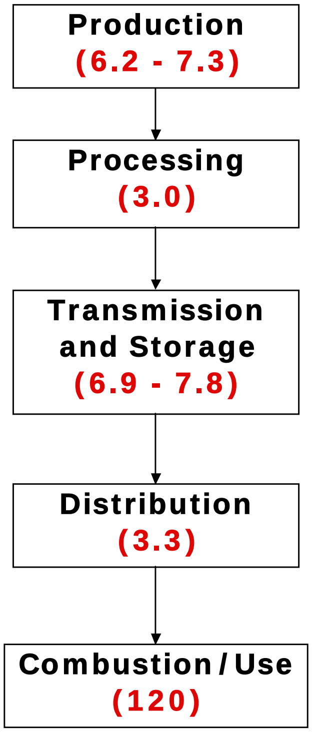

Figure 2: Carbon Dioxide Equivalent Emission Factors from North American Gas Lifecycle (All Units in lbs CO_2/MMBTU).

Greenhouse gas emissions from LNG lifecycle

As shown in Figure 1, the addition of liquefied natural gas (LNG) into the North American gas system introduces three additional stages into the lifecycle of natural gas: liquefaction, tanker transport, and regasification. It is assumed that natural gas produced in other countries and imported to the US in the form of LNG produces the same emissions in the production, processing, transmission, and distribution stages of the lifecycle as if the natural gas were produced in North America. Additional emission factors needed to be developed for the three additional lifecycle stages of LNG. Tamura et-al (11) has reported emission factors for the liquefaction stage in the range of 1.32 to 3,67 gr-C/MJ. Using these results, the emission factors for liquefaction were found in units of pounds of CO_2 per million BTUs, as shown in Table 4.

Table 4: Liquefaction Emission Factors.

Liquefaction	**Emission Factors (lb CO_2/MMBTU)**		
	Min	**Average**	**Max**
CO_2 from fuel combustion	11	12	13
CO_2 from flare combustion	0.00	0.77	1.5
CH_4 from vent	0.09	1.3	9.8
CO_2 in raw gas	0.09	4.0	6.6

Emissions from tanker transport of LNG were calculated using Equation 1.

$$EmissionFactor = \frac{(EF)\sum_{x}\left[\left(2 \times roundup\left(\frac{LNG_x}{TC}\right)\right) \times \frac{D_x}{TS} \times FC \times \frac{1}{24}\right]}{LNG_T}$$

Equation 1: Tanker Emission Factor.

Where EF is the tanker emission factor of 3,200 kg CO_2/ ton of fuel consumed; 2 is the number of trips each tanker does for every load (one bringing the LNG and one going back empty); LNG_x is the amount of natural gas (in cubic feet) brought from each country; TC is the tanker capacity in cubic feet of natural gas, assumed to be 120,000 cubic meters of LNG (1 m^3 LNG = 21,537 ft^3 NG); Dx is the distance from each country to US LNG facilities; TS is the tanker speed of 14 Knots; FC is a fuel consumption of 41 tons of fuel per day; and 24 is hours per day (12).

Exporting countries, their distances to the LNG facilities at Lake Charles, LA and Everett, MA, and the 2003 US imports can be seen in Table 5.

Table 5: LNG Exporting Countries in 2003 (4).

Exporting Country	Distance to Lake Charles Facility (nautical miles)	Distance to Everett, MA Facility (nautical miles)	2003 US Imports (million cubic feet NG)
Algeria	5,000	3,300	53,000
Australia	12,000	11,000	0
Brunei	12,000	11,000	0
Indonesia	12,000	11,000	0
Malaysia	12,000	11,000	2,700
Nigeria	6,100	5,000	50,000
Oman	8,900	7,500	8,600
Qatar	9,700	8,000	14,000
Trinidad	2,200	2,000	380,000
UAE	9,600	7,959	0
Russia	9,600	11,000	0

Emission factors for tanker transport from each country to both US facilities can be seen in Figure 3.

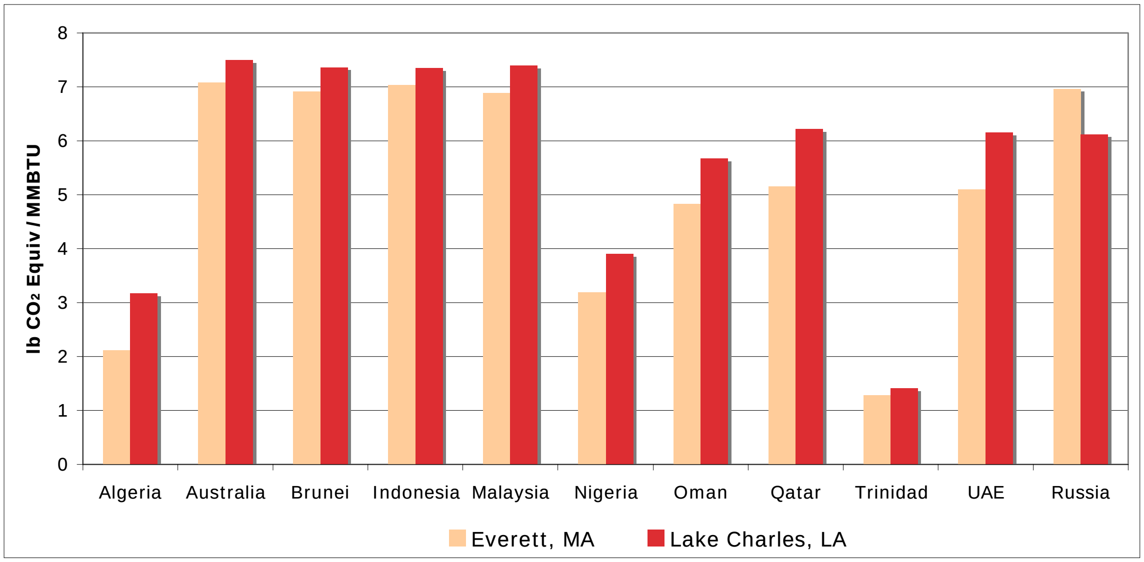

Figure 3: Tanker Emission Factors from Each Country

Since most of the LNG in 2003 was brought from Trinidad, the weighted average emission factor calculated for trips from each country to the Everett, MA facility is considered to be the a lower bound. An upper bound was obtained by assuming that all LNG was brought from Indonesia to the Lake Charles facility, and an average was obtained assuming all LNG was brought from Oman to the Lake Charles, LA facility. These resulting numbers can be seen in Table 6.

Table 6: Tanker Transport Emission Factors.

Emission Factors (lb CO_2/MMBTU)	
Min	1.8
Average	5.7
Max	7.3

Regasification emissions were reported by Tamura et-al to be 0.1 gr C/ MJ (0.85 lb CO_2/MMBTU) (11). Ruether et-al reports an emission factor of 1.6 gr CO_2/MJ (3.75 lb CO_2/MMBTU) for this stage of the LNG lifecycle by assuming that 3% of the gas is used to run the regasification equipment (13). These values were used as the lower and upper bounds of the range of emission from regasification of LNG. Total LNG lifecycle emissions are shown in Figure 4. They range between 154 and 184 lbs CO_2/MMBTU

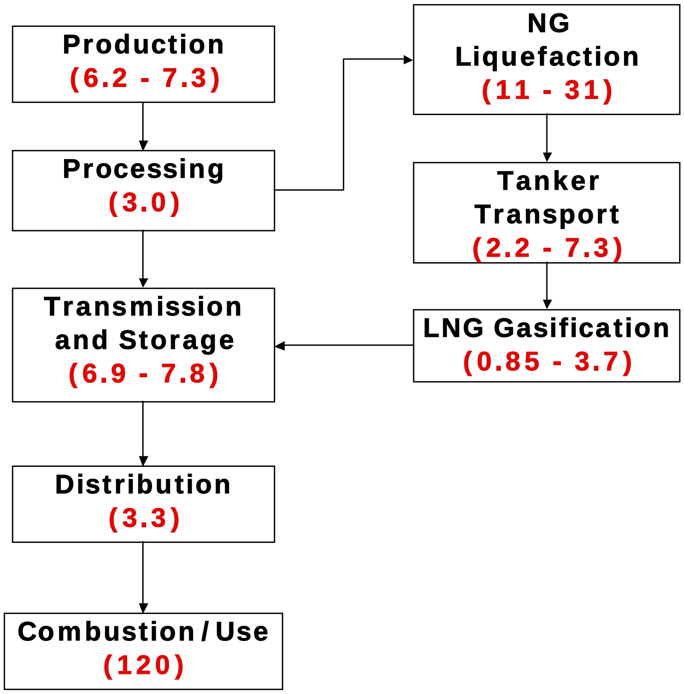

Figure 4: LNG Lifecycle Emission Factors (All Units in lbs CO_2/MMBTU).

Coal Lifecycle and its Greenhouse Gas Emissions for Electricity Generation

The coal lifecycle is conceptually simpler than the natural gas lifecycle, consisting of only three steps, as shown in Figure 5.

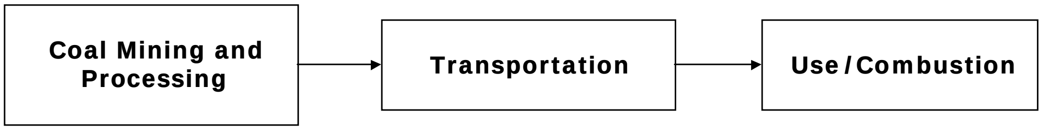

Figure 5: Coal Lifecycle.

In the US, 67% of the coal produced is mined in surface mines, while the remaining 33% is extracted from underground mines (1). Mined coal is then processed to remove impurities. Coal is then transported from the mines to the consumers via rail (84%), barge (11%), and trucks (5%) (14). Emissions from these lifecycle steps were calculated using the EIO-LCA tool developed at Carnegie Mellon University. In order to use this tool, economic values for each step of the lifecycle were necessary. In 1997, the year for which the EIO-LCA tool has data, the price of coal was $18.14/ton (15). Moreover, the cost for rail transport, barge, and truck transport was $11.06/ton, $3.2/ton, and $5.47/ton respectively (14). For a million tons of coal the following emission information was obtained using EIO-LCA.

Table 7: EIO-LCA Emission Data for Coal Lifecycle (16).

Sector	Total GHG Emissions (MT CO_2 Equiv)
Mining	75,000
Rail Transportation	36,000
Water Transportation	3,700
Truck Transportation	5,000

Using a weighted average US coal heat content of 10,266 BTU/lb (17) and the data previously discussed, it was found that the average emission factor for coal mining and transport is 11 lb CO_2/MMBTU.

In 1999, the National Renewable Energy Lab published a report on lifecycle emissions for power generation from coal (18). Upstream coal emissions (including transportation) from underground mines are reported to be 15 lbs CO_2/MMBTU, while upstream coal emissions from surface mines is 9.9 lbs CO_2/MMBTU. As previously mentioned, 67% of coal is currently mines in surface mines, while 33% is mined in underground mines (1). Using this information, the current coal upstream emissions average 12 lbs CO_2/MMBTU, which is very close to the emission factor obtained using EIO-LCA. In the future, the distribution of US mines could change, affecting the average emission factor. For this reason, the range of coal upstream emissions from underground and surface mines described above is used for this paper. Moreover, the average emission factors for coal combustion at utility plants used is 205 lb CO_2/MMBTU (10).

Comparing Natural Gas and Coal Lifecycle Emissions

Emissions factors for the natural gas lifecycle and the coal lifecycle were previously reported in pounds of CO_2 per MMBTU of fuel. Coal and natural gas power plants have different efficiencies; thus one million BTU of coal does not generate the same amount of electricity as one million BTU of natural gas. For this reason, emission factors must be converted to units of pounds of CO_2 per kWh of electricity generated. This conversion was done using the heat rates of natural gas and coal plants. Figure 6 shows the distribution of these heat rates, and Figure 7 shows the resulting emission factor distribution for coal and natural gas. These distributions were obtained using the cumulative distribution function of EIA electricity generation data for all utility plants in 2003 (7). The minimum value represents the heat rate at which 5% of the electricity generated with the specific fuel is seen. Similarly the mean and maximum values are the heat rates at which 50% and 95% of the electricity has been generated with each fuel. As seen in Figure 6, the average heat rate for natural gas plants is lower than the average heat rate for coal plants, however the upper range of heat rates for natural gas plants surpasses the heat rates for coal plants.

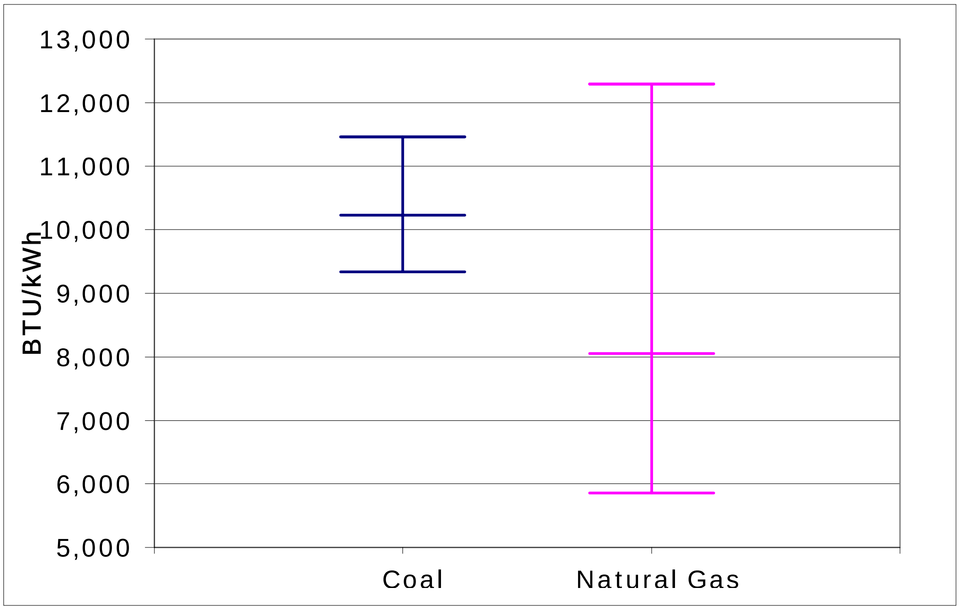

Figure 6: Natural Gas and Coal Plant Heat Rates (7).

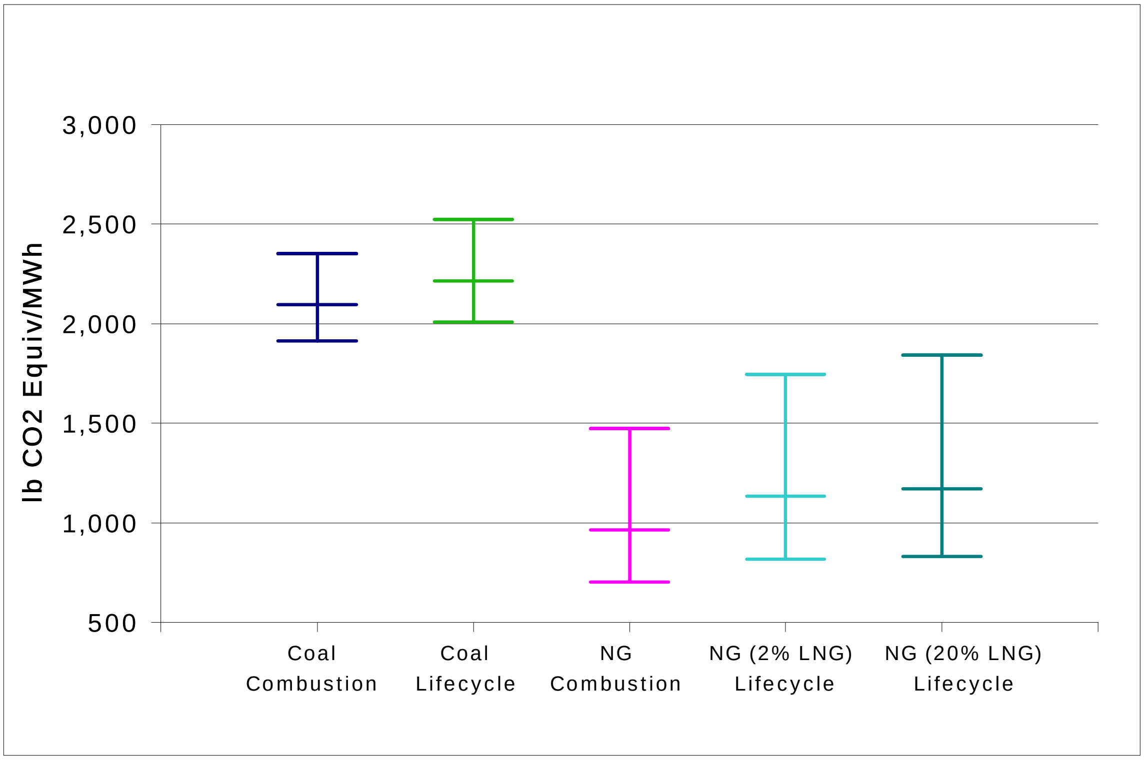

Figure 7: Emission Factors for Coal and Natural Gas Lifecycles.

Note that the average emission factor for coal combustion is higher than the emission factor for natural gas combustion. This does not change too much when the whole lifecycle is considered. More important seems to be the effect that including upstream emissions have in the range of emission factors for natural gas. While the average emission factor for the total coal lifecycle only increases by 5% compared to combustion emissions, the average emission factor for a natural gas mix with 20% LNG is 21% higher than the combustion emissions. Moreover, the maximum emission factor of the natural gas lifecycle gets closer to the minimum coal lifecycle emission factor. These results imply that if emissions at the combustion stage of the lifecycle could be controlled, natural gas would not be a much better alternative to coal in terms of greenhouse gas emissions.

New Generation Capacity

According to the DOE, by 2025 43 GW of inefficient gas and oil fired facilities will be retired, while 281 GW of new capacity will be installed (3). IGGC and NGCC power plants will probably be installed. These plants are generally more efficient than current technologies (average HHV Efficiencies are 37.5% and 50.2% respectively) (19) and thus have lower carbon emissions at the combustion stage. In addition, carbon capture and sequestration (CCS) can be performed more easily with these newer technologies. CCS is a process by which carbon emissions at the power plant are separated from other combustion products, captured and injected into underground geologic formations such as saline formations and depleted oil/gas fields. Experts believe that 90% CCS will be technologically and economically feasible in the future. Having CCS at IGCC and NGCC plants decreases the efficiency of the plants to average HHV efficiencies of 32.4% and 42.8% respectively (19) but overall lifecycle emissions would be greatly reduced and would be essentially the same for coal and natural gas (with 20% LNG). However, the major contributor for coal emissions would be at the combustion stage, while for natural gas the majority of the emissions would come from upstream processes. Figure 8, shows total emissions with CCS for IGCC and NGCC plants using average upstream emission factors of 11.6 lbs CO_2 Equiv/MMBTU and 25.6 lbs CO_2 Equiv/MMBTU for coal and natural gas respectively

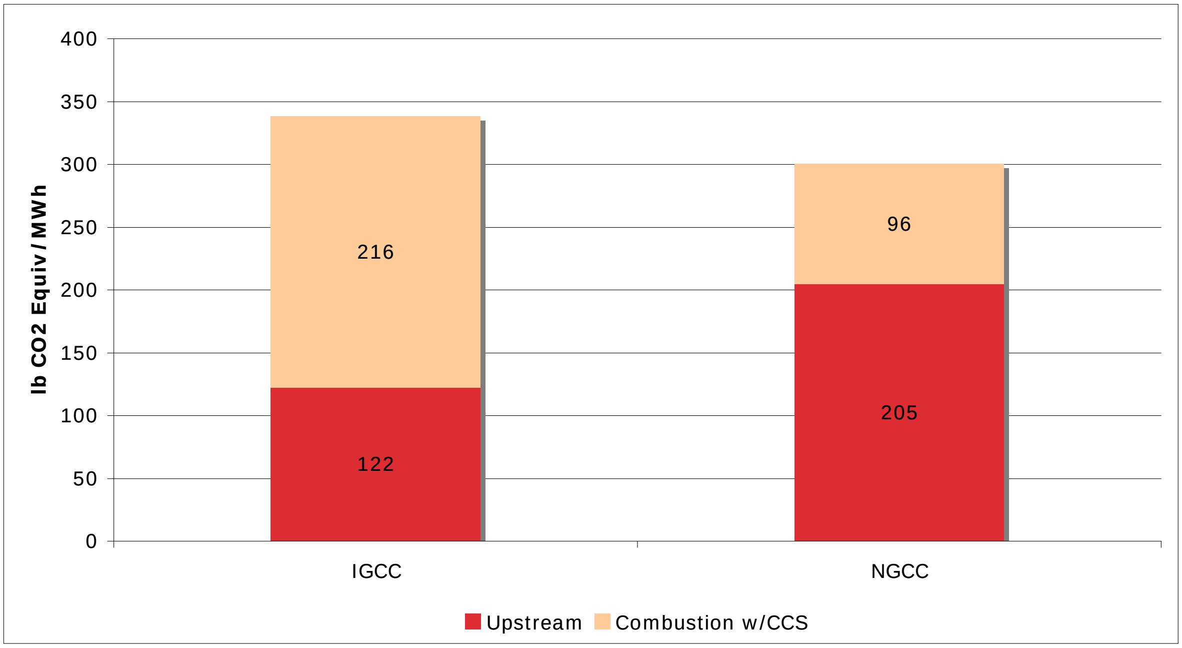

Figure 8: Lifecycle Emission Factors for IGCC and NGCC plants w/ CCS.

Discussion

It has been shown that there is high uncertainty about overall lifecycle carbon emissions for coal and LNG. In the future, as newer generation technologies and CCS are installed, overall emissions from electricity generated with coal and electricity generated with natural gas could be surprisingly similar. There is push right now from power generator to increase import of LNG. They seem to hope that the price of natural gas will decrease with these imports and they will be able to recover the investment they made in natural gas plants that are currently producing under capacity. These investments should be considered sunk costs and it is important to revaluate whether investing billions of dollars in LNG infrastructure will lead us into an energy path that cannot be easily changed as it will be harder to consider these investments as sunk costs once the expected environmental benefits are not achieved.

The analysis presented here only includes carbon emission, and no consideration was given to issues like energy security. Increasingly, LNG will come from areas of the world that are politically unstable. Policymakers should evaluate this increased dependence on foreign fuel before making decisions about future energy investments. In addition, the analysis presented only considers the use of natural gas for electricity generation. Natural gas is an indispensable fuel for many sectors of the US economy. As demand for natural gas from the electric utilities increases, these other sectors will probably be affected by higher natural gas prices. It is important to analyze whether these other sectors constitute a better use for natural gas than electricity generation, which has alternative fuels at its disposal.

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INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS:

1990 – 2009

APRIL 15, 2011

U.S. Environmental Protection Agency
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All data tables of this document are available for the full time series 1990 through 2009, inclusive, at the internet site mentioned above.

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For more information regarding climate change and greenhouse gas emissions, see the EPA web site at <http://www.epa.gov/climatechange>.

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Preface

The United States Environmental Protection Agency (EPA) prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks to comply with existing commitments under the United Nations Framework Convention on Climate Change (UNFCCC). Under decision 3/CP.5 of the UNFCCC Conference of the Parties, national inventories for UNFCCC Annex I parties should be provided to the UNFCCC Secretariat each year by April 15.

In an effort to engage the public and researchers across the country, the EPA has instituted an annual public review and comment process for this document. The availability of the draft document is announced via Federal Register Notice and is posted on the EPA web site. Copies are also mailed upon request. The public comment period is generally limited to 30 days; however, comments received after the closure of the public comment period are accepted and considered for the next edition of this annual report.

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Executive Summary

An emissions inventory that identifies and quantifies a country's primary anthropogenic[1] sources and sinks of greenhouse gases is essential for addressing climate change. This inventory adheres to both (1) a comprehensive and detailed set of methodologies for estimating sources and sinks of anthropogenic greenhouse gases, and (2) a common and consistent mechanism that enables Parties to the United Nations Framework Convention on Climate Change (UNFCCC) to compare the relative contribution of different emission sources and greenhouse gases to climate change.

In 1992, the United States signed and ratified the UNFCCC. As stated in Article 2 of the UNFCCC, "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."[2]

Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available…national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies…"[3] The United States views this report as an opportunity to fulfill these commitments.

This chapter summarizes the latest information on U.S. anthropogenic greenhouse gas emission trends from 1990 through 2009. To ensure that the U.S. emissions inventory is comparable to those of other UNFCCC Parties, the estimates presented here were calculated using methodologies consistent with those recommended in the Revised 1996 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000), and the IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003). Additionally, the U.S. emission inventory has continued to incorporate new methodologies and data from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The structure of this report is consistent with the UNFCCC guidelines for inventory reporting.[4] For most source categories, the IPCC methodologies were expanded, resulting in a more comprehensive and detailed estimate of emissions.

[BEGIN BOX]

Box ES-1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the IPCC.[5] Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[6] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports

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[1] The term "anthropogenic", in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC/UNEP/OECD/IEA 1997).

[2] Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <http://unfccc.int>.

[3] Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <http://unfccc.int>.

[4] See < http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

[5] See < http://www.ipcc-nggip.iges.or.jp/public/index.html>.

[6] See < http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>.

are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

[END BOX]

Background Information

Naturally occurring greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). As stratospheric ozone depleting substances, CFCs, HCFCs, and halons are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty. Consequently, Parties to the UNFCCC are not required to include these gases in their national greenhouse gas emission inventories.[7] Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas emission inventories.

There are also several gases that do not have a direct global warming effect but indirectly affect terrestrial and/or solar radiation absorption by influencing the formation or destruction of greenhouse gases, including tropospheric and stratospheric ozone. These gases include carbon monoxide (CO), oxides of nitrogen (NO_x), and non-CH_4 volatile organic compounds (NMVOCs). Aerosols, which are extremely small particles or liquid droplets, such as those produced by sulfur dioxide (SO_2) or elemental carbon emissions, can also affect the absorptive characteristics of the atmosphere.

Although the direct greenhouse gases CO_2, CH_4, and N_2O occur naturally in the atmosphere, human activities have changed their atmospheric concentrations. From the pre-industrial era (i.e., ending about 1750) to 2005, concentrations of these greenhouse gases have increased globally by 36, 148, and 18 percent, respectively (IPCC 2007).

Beginning in the 1950s, the use of CFCs and other stratospheric ozone depleting substances (ODS) increased by nearly 10 percent per year until the mid-1980s, when international concern about ozone depletion led to the entry into force of the Montreal Protocol. Since then, the production of ODS is being phased out. In recent years, use of ODS substitutes such as HFCs and PFCs has grown as they begin to be phased in as replacements for CFCs and HCFCs. Accordingly, atmospheric concentrations of these substitutes have been growing (IPCC 2007).

Global Warming Potentials

Gases in the atmosphere can contribute to the greenhouse effect both directly and indirectly. Direct effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations of the substance produce other greenhouse gases, when a gas influences the atmospheric lifetimes of other gases, and/or when a gas affects atmospheric processes that alter the radiative balance of the earth (e.g., affect cloud formation or albedo).[8] The IPCC developed the Global Warming Potential (GWP) concept to compare the ability of each greenhouse gas to trap heat in the atmosphere relative to another gas.

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[7] Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in the annexes of the Inventory report for informational purposes.

[8] Albedo is a measure of the Earth's reflectivity, and is defined as the fraction of the total solar radiation incident on a body that is reflected by it.

The GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2001). Direct radiative effects occur when the gas itself is a greenhouse gas. The reference gas used is CO_2, and therefore GWP-weighted emissions are measured in teragrams (or million metric tons) of CO_2 equivalent (Tg CO_2 Eq.).[9,10] All gases in this Executive Summary are presented in units of Tg CO_2 Eq.

The UNFCCC reporting guidelines for national inventories were updated in 2006,[11] but continue to require the use of GWPs from the IPCC Second Assessment Report (SAR) (IPCC 1996). This requirement ensures that current estimates of aggregate greenhouse gas emissions for 1990 to 2009 are consistent with estimates developed prior to the publication of the IPCC Third Assessment Report (TAR) (IPCC 2001) and the IPCC Fourth Assessment Report (AR4) (IPCC 2007). Therefore, to comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. All estimates are provided throughout the report in both CO_2 equivalents and unweighted units. A comparison of emission values using the SAR GWPs versus the TAR and AR4 GWPs can be found in Chapter 1 and, in more detail, in Annex 6.1 of this report. The GWP values used in this report are listed below in Table ES-1.

Table ES-1: Global Warming Potentials (100-Year Time Horizon) Used in this Report

Gas	GWP
CO_2	1
CH_4*	21
N_2O	310
HFC-23	11,700
HFC-32	650
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF_4	6,500
C_2F_6	9,200
C_4F_{10}	7,000
C_6F_{14}	7,400
SF_6	23,900

Source: IPCC (1996)

* The CH_4 GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Global warming potentials are not provided for CO, NO_x, NMVOCs, SO_2, and aerosols because there is no agreed-upon method to estimate the contribution of gases that are short-lived in the atmosphere, spatially variable, or have only indirect effects on radiative forcing (IPCC 1996).

Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2009, total U.S. greenhouse gas emissions were 6,633.2 Tg or million metric tons CO_2 Eq. While total U.S. emissions have increased by 7.3 percent from 1990 to 2009, emissions decreased from 2008 to 2009 by 6.1 percent (427.9 Tg CO_2 Eq.). This decrease was primarily due to (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; and (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly. Since 1990, U.S. emissions have increased at an average annual rate of 0.4 percent.

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[9] Carbon comprises 12/44^{ths} of carbon dioxide by weight.

[10] One teragram is equal to 10^{12} grams or one million metric tons.

[11] See <http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

Figure ES-1 through Figure ES-3 illustrate the overall trends in total U.S. emissions by gas, annual changes, and absolute change since 1990. Table ES-2 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2009.

Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg CO_2 Eq. or million metric tons CO_2 Eq.)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**5,099.7**	**5,975.0**	**6,113.8**	**6,021.1**	**6,120.0**	**5,921.4**	**5,505.2**
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Iron and Steel Production & Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Ammonia Production and Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Cropland Remaining Cropland	7.1	7.5	7.9	7.9	8.2	8.7	7.8
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Wetlands Remaining Wetlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
Land Use, Land-Use	*(861.5)*	*(576.6)*	*(1,056.5)*	*(1,064.3)*	*(1,060.9)*	*(1,040.5)*	*(1,015.1)*

Change, and Forestry (Sink)[a]							
Biomass - Wood[b]	*215.2*	*218.1*	*206.9*	*203.8*	*203.3*	*198.4*	*183.8*
International Bunker Fuels[c]	*111.8*	*98.5*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*
Biomass - Ethanol[b]	*4.2*	*9.4*	*23.0*	*31.0*	*38.9*	*54.8*	*61.2*
CH_4	**674.9**	**659.9**	**631.4**	**672.1**	**664.6**	**676.7**	**686.3**
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Forest Land Remaining Forest Land	3.2	14.3	9.8	21.6	20.0	11.9	7.8
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production & Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Field Burning of Agricultural Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[c]	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**315.2**	**341.0**	**322.9**	**326.4**	**325.1**	**310.8**	**295.6**
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Forest Land Remaining Forest Land	2.7	12.1	8.4	18.0	16.7	10.1	6.7
Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
N_2O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Settlements Remaining Settlements	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
HFCs	**36.9**	**103.2**	**120.2**	**123.5**	**129.5**	**129.4**	**125.7**
Substitution of Ozone Depleting Substances[d]	0.3	74.3	104.2	109.4	112.3	115.5	120.0

HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacture	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	**20.8**	**13.5**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**
Semiconductor Manufacture	2.2	4.9	3.2	3.5	3.7	4.0	4.0
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
SF_6	**34.4**	**20.1**	**19.0**	**17.9**	**16.7**	**16.1**	**14.8**
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Semiconductor Manufacture	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Total	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Parentheses indicate negative values or sequestration. The net CO_2 flux total includes both emissions and sequestration, and constitutes a net sink in the United States. Sinks are only included in net emissions total.

[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

[c] Emissions from International Bunker Fuels are not included in totals.

[d] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Figure ES-4 illustrates the relative contribution of the direct greenhouse gases to total U.S. emissions in 2009. The primary greenhouse gas emitted by human activities in the United States was CO_2, representing approximately 83.0 percent of total greenhouse gas emissions. The largest source of CO_2, and of overall greenhouse gas emissions, was fossil fuel combustion. CH_4 emissions, which have increased by 1.7 percent since 1990, resulted primarily from natural gas systems, enteric fermentation associated with domestic livestock, and decomposition of wastes in landfills. Agricultural soil management and mobile source fuel combustion were the major sources of N_2O emissions. Ozone depleting substance substitute emissions and emissions of HFC-23 during the production of HCFC-22 were the primary contributors to aggregate HFC emissions. PFC emissions resulted as a by-product of primary aluminum production and from semiconductor manufacturing, while electrical transmission and distribution systems accounted for most SF_6 emissions.

Figure ES-4: 2009 Greenhouse Gas Emissions by Gas (percents based on Tg CO_2 Eq.)

Overall, from 1990 to 2009, total emissions of CO_2 and CH_4 increased by 405.5 Tg CO_2 Eq. (8.0 percent) and 11.4 Tg CO_2 Eq. (1.7 percent), respectively. Conversely, N_2O emissions decreased by 19.6 Tg CO_2 Eq. (6.2 percent). During the same period, aggregate weighted emissions of HFCs, PFCs, and SF_6 rose by 54.1 Tg CO_2 Eq. (58.8 percent). From 1990 to 2009, HFCs increased by 88.8 Tg CO_2 Eq. (240.41 percent), PFCs decreased by 15.1 Tg CO_2 Eq. (73.0 percent), and SF_6 decreased by 19.5 Tg CO_2 Eq. (56.8 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, and SF_6 are significant because many of these gases have extremely high global warming potentials and, in the cases of PFCs and SF_6, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by carbon sequestration in forests, trees in urban areas, agricultural soils, and landfilled yard trimmings and food scraps, which, in aggregate, offset 15.3 percent of total emissions in 2009. The following sections describe each gas' contribution to total U.S. greenhouse gas emissions in more detail.

Carbon Dioxide Emissions

The global carbon cycle is made up of large carbon flows and reservoirs. Billions of tons of carbon in the form of CO_2 are absorbed by oceans and living biomass (i.e., sinks) and are emitted to the atmosphere annually through natural processes (i.e., sources). When in equilibrium, carbon fluxes among these various reservoirs are roughly balanced. Since the Industrial Revolution (i.e., about 1750), global atmospheric concentrations of CO_2 have risen about 36 percent (IPCC 2007), principally due to the combustion of fossil fuels. Within the United States, fossil fuel combustion accounted for 94.6 percent of CO_2 emissions in 2009. Globally, approximately 30,313 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[12] Changes in land use and forestry practices can also emit CO_2 (e.g., through conversion of forest land to agricultural or urban use) or can act as a sink for CO_2 (e.g., through net additions to forest biomass). In addition to fossil-fuel combustion, several other sources emit significant quantities of CO_2. These sources include, but are not limited to non-energy use of fuels, iron and steel production and cement production (Figure ES-5).

Figure ES-5: 2009 Sources of CO_2 Emissions

As the largest source of U.S. greenhouse gas emissions, CO_2 from fossil fuel combustion has accounted for approximately 78 percent of GWP-weighted emissions since 1990, growing slowly from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2009. Emissions of CO_2 from fossil fuel combustion increased at an average annual rate of 0.4 percent from 1990 to 2009. The fundamental factors influencing this trend include (1) a generally growing domestic economy over the last 20 years, and (2) overall growth in emissions from electricity generation and transportation activities. Between 1990 and 2009, CO_2 emissions from fossil fuel combustion increased from 4,738.4 Tg CO_2 Eq. to 5,209.0 Tg CO_2 Eq.—a 9.9 percent total increase over the twenty-year period. From 2008 to 2009, these emissions decreased by 356.9 Tg CO_2 Eq. (6.4 percent), the largest decrease in any year over the twenty-year period.

Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends. Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, and seasonal temperatures. In the short term, the overall consumption of fossil fuels in the United States fluctuates primarily in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants. In the long term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Figure ES-6: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Figure ES-7: 2009 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

The five major fuel consuming sectors contributing to CO_2 emissions from fossil fuel combustion are electricity generation, transportation, industrial, residential, and commercial. CO_2 emissions are produced by the electricity generation sector as they consume fossil fuel to provide electricity to one of the other four sectors, or “end-use” sectors. For the discussion below, electricity generation emissions have been distributed to each end-use sector on the basis of each sector’s share of aggregate electricity consumption. This method of distributing emissions assumes that each end-use sector consumes electricity that is generated from the national average mix of fuels according to their carbon intensity. Emissions from electricity generation are also addressed separately after the end-use sectors have been discussed.

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[12] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010a).

Note that emissions from U.S. territories are calculated separately due to a lack of specific consumption data for the individual end-use sectors.

Figure ES-6, Figure ES-7, and Table ES-3 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Table ES-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Consuming End-Use Sector (Tg or million metric tons CO_2 Eq.)

End-Use Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Transportation	**1,489.0**	**1,813.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.6**	**1,724.1**
Combustion	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Electricity	3.0	3.4	4.7	4.5	5.0	4.7	4.4
Industrial	**1,533.2**	**1,640.8**	**1,560.0**	**1,560.2**	**1,572.0**	**1,517.7**	**1,333.7**
Combustion	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Electricity	686.7	789.8	737.0	712.0	730.0	714.8	603.3
Residential	**931.4**	**1,133.1**	**1,214.7**	**1,152.4**	**1,198.5**	**1,182.2**	**1,123.8**
Combustion	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Electricity	593.0	762.4	856.7	830.8	856.1	834.0	784.6
Commercial	**757.0**	**972.1**	**1,027.2**	**1,007.6**	**1,041.1**	**1,031.6**	**985.7**
Combustion	219.0	230.8	223.5	208.6	219.4	224.2	224.0
Electricity	538.0	741.3	803.7	799.0	821.7	807.4	761.7
U.S. Territories[a]	**27.9**	**35.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**
Total	**4,738.4**	**5,594.8**	**5,753.2**	**5,653.1**	**5,756.7**	**5,565.9**	**5,209.0**
Electricity Generation	**1,820.8**	**2,296.9**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,154.0**

Note: Totals may not sum due to independent rounding. Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

[a] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report.

Transportation End-Use Sector. Transportation activities (excluding international bunker fuels) accounted for 33 percent of CO_2 emissions from fossil fuel combustion in 2009.[13] Virtually all of the energy consumed in this end-use sector came from petroleum products. Nearly 65 percent of the emissions resulted from gasoline consumption for personal vehicle use. The remaining emissions came from other transportation activities, including the combustion of diesel fuel in heavy-duty vehicles and jet fuel in aircraft. From 1990 to 2009, transportation emissions rose by 16 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 39 percent from 1990 to 2009, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

Industrial End-Use Sector. Industrial CO_2 emissions, resulting both directly from the combustion of fossil fuels and indirectly from the generation of electricity that is consumed by industry, accounted for 26 percent of CO_2 from fossil fuel combustion in 2009. Approximately 55 percent of these emissions resulted from direct fossil fuel combustion to produce steam and/or heat for industrial processes. The remaining emissions resulted from consuming electricity for motors, electric furnaces, ovens, lighting, and other applications. In contrast to the other end-use sectors, emissions from industry have steadily declined since 1990. This decline is due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements.

Residential and Commercial End-Use Sectors. The residential and commercial end-use sectors accounted for 22 and 19 percent, respectively, of CO_2 emissions from fossil fuel combustion in 2009. Both sectors relied heavily on electricity for meeting energy demands, with 70 and 77 percent, respectively, of their emissions attributable to electricity consumption for lighting, heating, cooling, and operating appliances. The remaining emissions were due to the consumption of natural gas and petroleum for heating and cooking. Emissions from these end-use sectors have increased 25 percent since 1990, due to increasing electricity consumption for lighting, heating, air

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[13] If emissions from international bunker fuels are included, the transportation end-use sector accounted for 35 percent of U.S. emissions from fossil fuel combustion in 2009.

conditioning, and operating appliances.

Electricity Generation. The United States relies on electricity to meet a significant portion of its energy demands. Electricity generators consumed 36 percent of U.S. energy from fossil fuels and emitted 41 percent of the CO_2 from fossil fuel combustion in 2009. The type of fuel combusted by electricity generators has a significant effect on their emissions. For example, some electricity is generated with low CO_2 emitting energy technologies, particularly non-fossil options such as nuclear, hydroelectric, or geothermal energy. However, electricity generators rely on coal for over half of their total energy requirements and accounted for 95 percent of all coal consumed for energy in the United States in 2009. Consequently, changes in electricity demand have a significant impact on coal consumption and associated CO_2 emissions.

Other significant CO_2 trends included the following:

- CO_2 emissions from non-energy use of fossil fuels have increased 4.7 Tg CO_2 Eq. (4.0 percent) from 1990 through 2009. Emissions from non-energy uses of fossil fuels were 123.4 Tg CO_2 Eq. in 2009, which constituted 2.2 percent of total national CO_2 emissions, approximately the same proportion as in 1990.
- CO_2 emissions from iron and steel production and metallurgical coke production decreased by 24.1 Tg CO_2 Eq. (36.6 percent) from 2008 to 2009, continuing a trend of decreasing emissions from 1990 through 2009 of 57.9 percent (57.7 Tg CO_2 Eq.). This decline is due to the restructuring of the industry, technological improvements, and increased scrap utilization.
- In 2009, CO_2 emissions from cement production decreased by 11.5 Tg CO_2 Eq. (28.4 percent) from 2008. After decreasing in 1991 by two percent from 1990 levels, cement production emissions grew every year through 2006; emissions decreased in the last three years. Overall, from 1990 to 2009, emissions from cement production decreased by 12.8 percent, a decrease of 4.3 Tg CO_2 Eq.
- Net CO_2 uptake from Land Use, Land-Use Change, and Forestry increased by 153.5 Tg CO_2 Eq. (17.8 percent) from 1990 through 2009. This increase was primarily due to an increase in the rate of net carbon accumulation in forest carbon stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual carbon accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of carbon accumulation in urban trees increased.

Methane Emissions

Methane (CH_4) is more than 20 times as effective as CO_2 at trapping heat in the atmosphere (IPCC 1996). Over the last two hundred and fifty years, the concentration of CH_4 in the atmosphere increased by 148 percent (IPCC 2007). Anthropogenic sources of CH_4 include natural gas and petroleum systems, , agricultural activities, landfills, coal mining, wastewater treatment, stationary and mobile combustion, and certain industrial processes (see Figure ES-8).

Figure ES-8: 2009 Sources of CH_4 Emissions

Some significant trends in U.S. emissions of CH_4 include the following:

- In 2009, CH_4 emissions from coal mining were 71.0 Tg CO_2 Eq., a 3.9 Tg CO_2 Eq. (5.8 percent) increase over 2008 emission levels. The overall decline of 13.0 Tg CO_2 Eq. (15.5 percent) from 1990 results from the mining of less gassy coal from underground mines and the increased use of CH_4 collected from degasification systems.
- Natural gas systems were the largest anthropogenic source category of CH_4 emissions in the United States in 2009 with 221.2 Tg CO_2 Eq. of CH_4 emitted into the atmosphere. Those emissions have increased by 31.4 Tg CO_2 Eq. (16.6 percent) since 1990. Methane emissions from this source increased 4 percent from 2008 to 2009 due to an increase in production and production wells.
- Enteric Fermentation is the second largest anthropogenic source of CH_4 emissions in the United States. In 2009, enteric fermentation CH_4 emissions were 139.8 Tg CO_2 Eq. (20 percent of total CH_4 emissions), which represents an increase of 7.7 Tg CO_2 Eq. (5.8 percent) since 1990.

- Methane emissions from manure management increased by 55.9 percent since 1990, from 31.7 Tg CO_2 Eq. in 1990 to 49.5 Tg CO_2 Eq. in 2009. The majority of this increase was from swine and dairy cow manure, since the general trend in manure management is one of increasing use of liquid systems, which tends to produce greater CH_4 emissions. The increase in liquid systems is the combined result of a shift to larger facilities, and to facilities in the West and Southwest, all of which tend to use liquid systems. Also, new regulations limiting the application of manure nutrients have shifted manure management practices at smaller dairies from daily spread to manure managed and stored on site.
- Landfills are the third largest anthropogenic source of CH_4 emissions in the United States, accounting for 17 percent of total CH_4 emissions (117.5 Tg CO_2 Eq.) in 2009. From 1990 to 2009, CH_4 emissions from landfills decreased by 29.9 Tg CO_2 Eq. (20 percent), with small increases occurring in some interim years. This downward trend in overall emissions is the result of increases in the amount of landfill gas collected and combusted,[14] which has more than offset the additional CH_4 emissions resulting from an increase in the amount of municipal solid waste landfilled.

Nitrous Oxide Emissions

N_2O is produced by biological processes that occur in soil and water and by a variety of anthropogenic activities in the agricultural, energy-related, industrial, and waste management fields. While total N_2O emissions are much lower than CO_2 emissions, N_2O is approximately 300 times more powerful than CO_2 at trapping heat in the atmosphere (IPCC 1996). Since 1750, the global atmospheric concentration of N_2O has risen by approximately 18 percent (IPCC 2007). The main anthropogenic activities producing N_2O in the United States are agricultural soil management, fuel combustion in motor vehicles, manure management, nitric acid production and stationary fuel combustion, (see Figure ES-9).

Figure ES-9: 2009 Sources of N_2O Emissions

Some significant trends in U.S. emissions of N_2O include the following:

- In 2009, N_2O emissions from mobile combustion were 23.9 Tg CO_2 Eq. (approximately 8.1 percent of U.S. N_2O emissions). From 1990 to 2009, N_2O emissions from mobile combustion decreased by 45.6 percent. However, from 1990 to 1998 emissions increased by 25.6 percent, due to control technologies that reduced NO_x emissions while increasing N_2O emissions. Since 1998, newer control technologies have led to an overall decline in N_2O from this source.
- N_2O emissions from adipic acid production were 1.9 Tg CO_2 Eq. in 2009, and have decreased significantly since 1996 from the widespread installation of pollution control measures. Emissions from adipic acid production have decreased by 87.7 percent since 1990, and emissions from adipic acid production have remained consistently lower than pre-1996 levels since 1998.
- Agricultural soils accounted for approximately 69.2 percent of N_2O emissions in the United States in 2009. Estimated emissions from this source in 2009 were 204.6 Tg CO_2 Eq. Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2009, although overall emissions were 3.4 percent higher in 2009 than in 1990.

HFC, PFC, and SF_6 Emissions

HFCs and PFCs are families of synthetic chemicals that are used as alternatives to ODS, which are being phased out under the Montreal Protocol and Clean Air Act Amendments of 1990. HFCs and PFCs do not deplete the stratospheric ozone layer, and are therefore acceptable alternatives under the Montreal Protocol.

These compounds, however, along with SF_6, are potent greenhouse gases. In addition to having high global warming potentials, SF_6 and PFCs have extremely long atmospheric lifetimes, resulting in their essentially irreversible accumulation in the atmosphere once emitted. Sulfur hexafluoride is the most potent greenhouse gas the

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[14] The CO_2 produced from combusted landfill CH_4 at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

IPCC has evaluated (IPCC 1996).

Other emissive sources of these gases include electrical transmission and distribution systems, HCFC-22 production, semiconductor manufacturing, aluminum production, and magnesium production and processing (see Figure ES-10).

Figure ES-10: 2009 Sources of HFCs, PFCs, and SF_6 Emissions

Some significant trends in U.S. HFC, PFC, and SF_6 emissions include the following:

- Emissions resulting from the substitution of ODS (e.g., CFCs) have been consistently increasing, from small amounts in 1990 to 120.0 Tg CO_2 Eq. in 2009. Emissions from ODS substitutes are both the largest and the fastest growing source of HFC, PFC, and SF_6 emissions. These emissions have been increasing as phase-outs required under the Montreal Protocol come into effect, especially after 1994, when full market penetration was made for the first generation of new technologies featuring ODS substitutes.
- HFC emissions from the production of HCFC-22 decreased by 85.2 percent (31.0 Tg CO_2 Eq.) from 1990 through 2009, due to a steady decline in the emission rate of HFC-23 (i.e., the amount of HFC-23 emitted per kilogram of HCFC-22 manufactured) and the use of thermal oxidation at some plants to reduce HFC-23 emissions.
- SF_6 emissions from electric power transmission and distribution systems decreased by 54.8 percent (15.6 Tg CO_2 Eq.) from 1990 to 2009, primarily because of higher purchase prices for SF_6 and efforts by industry to reduce emissions.
- PFC emissions from aluminum production decreased by 91.5 percent (17.0 Tg CO_2 Eq.) from 1990 to 2009, due to both industry emission reduction efforts and lower domestic aluminum production.

Overview of Sector Emissions and Trends

In accordance with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), and the 2003 UNFCCC Guidelines on Reporting and Review (UNFCCC 2003), Figure ES-11 and Table ES-4 aggregate emissions and sinks by these chapters. Emissions of all gases can be summed from each source category from IPCC guidance. Over the twenty-year period of 1990 to 2009, total emissions in the Energy and Agriculture sectors grew by 463.3 Tg CO_2 Eq. (9 percent), and 35.7 Tg CO_2 Eq. (9 percent), respectively. Emissions decreased in the Industrial Processes, Waste, and Solvent and Other Product Use sectors by 32.9 Tg CO_2 Eq. (10 percent), 24.7 Tg CO_2 Eq. (14 percent) and less than 0.1 Tg CO_2 Eq. (0.4 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry sector (magnitude of emissions plus CO_2 flux from all LULUCF source categories) increased by 143.5 Tg CO_2 Eq. (17 percent).

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

Table ES-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg or million metric tons CO_2 Eq.)

Chapter/IPCC Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Energy	5,287.8	6,168.0	6,282.8	6,210.2	6,290.7	6,116.6	5,751.1
Industrial Processes	315.8	348.8	334.1	339.4	350.9	331.7	282.9
Solvent and Other Product Use	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Agriculture	383.6	410.6	418.8	418.8	425.8	426.3	419.3
Land Use, Land-Use Change, and Forestry (Emissions)	15.0	36.3	28.6	49.8	47.5	33.2	25.0
Waste	175.2	143.9	144.9	144.4	144.1	149.0	150.5
Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net CO_2 Flux from Land Use, Land-	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)

Use Change, and Forestry (Sinks)*							
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

* The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total.

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Energy

The Energy chapter contains emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions. Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO_2 emissions for the period of 1990 through 2009. In 2009, approximately 83 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 17 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure ES-12). Energy-related activities are also responsible for CH_4 and N_2O emissions (49 percent and 13 percent of total U.S. emissions of each gas, respectively). Overall, emission sources in the Energy chapter account for a combined 87 percent of total U.S. greenhouse gas emissions in 2009.

Figure ES-12: 2009 U.S. Energy Consumption by Energy Source

Industrial Processes

The Industrial Processes chapter contains by-product or fugitive emissions of greenhouse gases from industrial processes not directly related to energy activities such as fossil fuel combustion. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO_2, CH_4, and N_2O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production and urea consumption, lime production, limestone and dolomite use (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO_2 consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, and zinc production. Additionally, emissions from industrial processes release HFCs, PFCs, and SF_6. Overall, emission sources in the Industrial Process chapter account for 4 percent of U.S. greenhouse gas emissions in 2009.

Solvent and Other Product Use

The Solvent and Other Product Use chapter contains greenhouse gas emissions that are produced as a by-product of various solvent and other product uses. In the United States, emissions from N_2O from product uses, the only source of greenhouse gas emissions from this sector, accounted for about 0.1 percent of total U.S. anthropogenic greenhouse gas emissions on a carbon equivalent basis in 2009.

Agriculture

The Agricultural chapter contains anthropogenic emissions from agricultural activities (except fuel combustion, which is addressed in the Energy chapter, and agricultural CO_2 fluxes, which are addressed in the Land Use, Land-Use Change, and Forestry Chapter). Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues. CH_4 and N_2O were the primary greenhouse gases emitted by agricultural activities. CH_4 emissions from enteric fermentation and manure management represented 20 percent and 7 percent of total CH_4 emissions from anthropogenic activities, respectively, in 2009. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N_2O emissions in 2009, accounting for 69 percent. In 2009, emission sources accounted for in the Agricultural chapters were responsible for 6.3 percent of total U.S. greenhouse gas emissions.

Land Use, Land-Use Change, and Forestry

The Land Use, Land-Use Change, and Forestry chapter contains emissions of CH_4 and N_2O, and emissions and removals of CO_2 from forest management, other land-use activities, and land-use change. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps resulted in a net uptake (sequestration) of C in the United States. Forests (including vegetation, soils, and harvested wood) accounted for 85 percent of total 2009 net CO_2 flux, urban trees accounted for 9 percent, mineral and organic soil carbon stock changes accounted for 4 percent, and landfilled yard trimmings and food scraps accounted for 1 percent of the total net flux in 2009. The net forest sequestration is a result of net forest growth and increasing forest area, as well as a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth in these areas. In agricultural soils, mineral and organic soils sequester approximately 5.5 times as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to permanent pastures and hay production, a reduction in summer fallow areas in semi-arid areas, an increase in the adoption of conservation tillage practices, and an increase in the amounts of organic fertilizers (i.e., manure and sewage sludge) applied to agriculture lands. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming carbon and food scraps in landfills.

Land use, land-use change, and forestry activities in 2009 resulted in a net C sequestration of 1,015.1 Tg CO_2 Eq. (Table ES-5). This represents an offset of 18 percent of total U.S. CO_2 emissions, or 15 percent of total greenhouse gas emissions in 2009. Between 1990 and 2009, total land use, land-use change, and forestry net C flux resulted in a 17.8 percent increase in CO_2 sequestration, primarily due to an increase in the rate of net C accumulation in forest C stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual C accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of annual C accumulation increased in urban trees.

Table ES-5: Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Sink Category	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Forest Land Remaining Forest Land[1]	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)
Cropland Remaining Cropland	(29.4)	(30.2)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)
Land Converted to Cropland	2.2	2.4	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)	(52.6)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)
Land Converted to Grassland	(19.8)	(27.2)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)
Settlements Remaining Settlements[2]	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)
Total	**(861.5)**	**(576.6)**	**(1,056.5)**	**(1,064.3)**	**(1,060.9)**	**(1,040.5)**	**(1,015.1)**

Note: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Emissions from Land Use, Land-Use Change, and Forestry are shown in Table ES-6. The application of crushed limestone and dolomite to managed land (i.e., liming of agricultural soils) and urea fertilization resulted in CO_2 emissions of 7.8 Tg CO_2 Eq. in 2009, an increase of 11 percent relative to 1990. The application of synthetic fertilizers to forest and settlement soils in 2009 resulted in direct N_2O emissions of 1.9 Tg CO_2 Eq. Direct N_2O emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, direct N_2O emissions from fertilizer application to settlement soils increased by 55 percent since 1990. Forest fires resulted in CH_4 emissions of 7.8 Tg CO_2 Eq., and in N_2O emissions of 6.4 Tg CO_2 Eq. in 2009. CO_2 and N_2O emissions from peatlands totaled 1.1 Tg CO_2 Eq. and less than 0.01 Tg CO_2 Eq. in 2009, respectively.

Table ES-6: Emissions from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Source Category	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**8.1**	**8.8**	**8.9**	**8.8**	**9.2**	**9.6**	**8.9**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2
Cropland Remaining Cropland: Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6

Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
CH_4	**3.2**	**14.3**	**9.8**	**21.6**	**20.0**	**11.9**	**7.8**
Forest Land Remaining Forest Land: Forest Fires	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N_2O	**3.7**	**13.2**	**9.8**	**19.5**	**18.3**	**11.6**	**8.3**
Forest Land Remaining Forest Land: Forest Fires	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Forest Land Remaining Forest Land: Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**15.0**	**36.3**	**28.6**	**49.8**	**47.5**	**33.2**	**25.0**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Waste

The Waste chapter contains emissions from waste management activities (except incineration of waste, which is addressed in the Energy chapter). Landfills were the largest source of anthropogenic greenhouse gas emissions in the Waste chapter, accounting for just over 78 percent of this chapter's emissions, and 17 percent of total U.S. CH_4 emissions.[15] Additionally, wastewater treatment accounts for 20 percent of Waste emissions, 4 percent of U.S. CH_4 emissions, and 2 percent of U.S. N_2O emissions. Emissions of CH_4 and N_2O from composting are also accounted for in this chapter; generating emissions of 1.7 Tg CO_2 Eq. and 1.8 Tg CO_2 Eq., respectively. Overall, emission sources accounted for in the Waste chapter generated 2.3 percent of total U.S. greenhouse gas emissions in 2009.

Other Information

Emissions by Economic Sector

Throughout the Inventory of U.S. Greenhouse Gas Emissions and Sinks report, emission estimates are grouped into six sectors (i.e., chapters) defined by the IPCC: Energy; Industrial Processes; Solvent Use; Agriculture; Land Use, Land-Use Change, and Forestry; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following economic sectors: Residential, Commercial, Industry, Transportation, Electricity Generation, Agriculture, and U.S. Territories.

Table ES-7 summarizes emissions from each of these sectors, and Figure ES-13 shows the trend in emissions by sector from 1990 to 2009.

Figure ES-13: Emissions Allocated to Economic Sectors

Table ES-7: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg or million metric tons CO_2 Eq.)

Implied Sectors	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Electric Power Industry	1,868.9	2,337.6	2,444.6	2,388.2	2,454.0	2,400.7	2,193.0
Transportation	1,545.2	1,932.3	2,017.4	1,994.4	2,003.8	1,890.7	1,812.4
Industry	1,564.4	1,544.0	1,441.9	1,497.3	1,483.0	1,446.9	1,322.7
Agriculture	429.0	485.1	493.2	516.7	520.7	503.9	490.0
Commercial	395.5	381.4	387.2	375.2	389.6	403.5	409.5
Residential	345.1	386.2	371.0	335.8	358.9	367.1	360.1
U.S. Territories	33.7	46.0	58.2	59.3	53.5	48.4	45.5

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[15] Landfills also store carbon, due to incomplete degradation of organic materials such as wood products and yard trimmings, as described in the Land-Use, Land-Use Change, and Forestry chapter of the Inventory report.

Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Land Use, Land-Use Change, and Forestry (Sinks)	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

Note: Totals may not sum due to independent rounding. Emissions include CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6.
See Table 2-12 for more detailed data.

Using this categorization, emissions from electricity generation accounted for the largest portion (33 percent) of U.S. greenhouse gas emissions in 2009. Transportation activities, in aggregate, accounted for the second largest portion (27 percent), while emissions from industry accounted for the third largest portion (20 percent) of U.S. greenhouse gas emissions in 2009. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and energy efficiency improvements. The remaining 20 percent of U.S. greenhouse gas emissions were contributed by, in order of importance, the agriculture, commercial, and residential sectors, plus emissions from U.S. territories. Activities related to agriculture accounted for 7 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N_2O emissions from agricultural soil management and CH_4 emissions from enteric fermentation. The commercial sector accounted for 6 percent of emissions while the residential sector accounted for 5 percent of emissions and U.S. territories accounted for 1 percent of emissions; emissions from these sectors primarily consisted of CO_2 emissions from fossil fuel combustion.

CO_2 was also emitted and sequestered by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Electricity is ultimately consumed in the economic sectors described above. Table ES-8 presents greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). To distribute electricity emissions among end-use sectors, emissions from the source categories assigned to electricity generation were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity.[16] These source categories include CO_2 from fossil fuel combustion and the use of limestone and dolomite for flue gas desulfurization, CO_2 and N_2O from incineration of waste, CH_4 and N_2O from stationary sources, and SF_6 from electrical transmission and distribution systems.

When emissions from electricity are distributed among these sectors, Industrial activities account for the largest share of U.S. greenhouse gas emissions (29 percent) in 2009. Transportation is the second largest contributor to total U.S. emissions (28 percent). The commercial and residential sectors contributed the next largest shares of total U.S. greenhouse gas emissions in 2009. Emissions from these sectors increase substantially when emissions from electricity are included, due to their relatively large share of electricity consumption (e.g., lighting, appliances, etc.). In all sectors except agriculture, CO_2 accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels. Figure ES-14 shows the trend in these emissions by sector from 1990 to 2009.

Table ES-8: U.S Greenhouse Gas Emissions by Economic Sector with Electricity-Related Emissions Distributed (Tg or million metric tons CO_2 Eq.)

Implied Sectors	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Industry	2,238.3	2,314.4	2,162.5	2,194.6	2,192.9	2,146.5	1,910.9
Transportation	1,548.3	1,935.8	2,022.2	1,999.0	2,008.9	1,895.5	1,816.9
Commercial	947.7	1,135.8	1,205.1	1,188.5	1,225.3	1,224.5	1,184.9
Residential	953.8	1,162.2	1,242.9	1,181.5	1,229.6	1,215.1	1,158.9
Agriculture	460.0	518.4	522.7	544.1	553.2	531.1	516.0
U.S. Territories	33.7	46.0	58.2	59.3	53.5	48.4	45.5
Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Land Use, Land-Use Change,	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)

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[16] Emissions were not distributed to U.S. territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

and Forestry (Sinks)							
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

See Table 2-14 for more detailed data.

Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

[BEGIN BOX]

Box ES-2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and nonutilities combined—was the largest source of U.S. greenhouse gas emissions in 2009; (4) emissions per unit of total gross domestic product as a measure of national economic activity; and (5) emissions per capita.

Table ES-9 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.4 percent since 1990. This rate is slightly slower than that for total energy and for fossil fuel consumption, and much slower than that for electricity consumption, overall gross domestic product and national population (see Figure ES-15).

Table ES-9: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**	**Growth Rate**[a]
GDP[b]	100	140	157	162	165	165	160	2.5%
Electricity Consumption[c]	100	127	134	135	138	138	132	1.5%
Fossil Fuel Consumption[c]	100	117	119	117	119	116	108	0.5%
Energy Consumption[c]	100	116	118	118	120	118	112	0.6%
Population[d]	100	113	118	120	121	122	123	1.1%
Greenhouse Gas Emissions[e]	100	115	117	116	117	114	107	0.4%

[a] Average annual growth rate

[b] Gross Domestic Product in chained 2005 dollars (BEA 2010)

[c] Energy content-weighted values (EIA 2010b)

[d] U.S. Census Bureau (2010)

[e] GWP-weighted values

Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

Source: BEA (2010), U.S. Census Bureau (2010), and emission estimates in this report.

[END BOX]

Indirect Greenhouse Gases (CO, NO_x, NMVOCs, and SO_2)

The reporting requirements of the UNFCCC[17] request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO_2. These gases do not have a direct global warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO_2, by affecting the absorptive characteristics of the atmosphere. Additionally, some of these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases.

Since 1970, the United States has published estimates of annual emissions of CO, NO_x, NMVOCs, and SO_2 (EPA 2010, EPA 2009),[18] which are regulated under the Clean Air Act. Table ES- 10 shows that fuel combustion accounts for the majority of emissions of these indirect greenhouse gases. Industrial processes—such as the manufacture of chemical and allied products, metals processing, and industrial uses of solvents—are also significant sources of CO, NO_x, and NMVOCs.

Table ES- 10: Emissions of NO_x, CO, NMVOCs, and SO_2 (Gg)

Gas/Activity	1990	2000	2005	2006	2007	2008	2009
NO_x	**21,707**	**19,116**	**15,900**	**15,039**	**14,380**	**13,547**	**11,468**
Mobile Fossil Fuel Combustion	10,862	10,199	9,012	8,488	7,965	7,441	6,206
Stationary Fossil Fuel Combustion	10,023	8,053	5,858	5,545	5,432	5,148	4,159
Industrial Processes	591	626	569	553	537	520	568
Oil and Gas Activities	139	111	321	319	318	318	393
Incineration of Waste	82	114	129	121	114	106	128
Agricultural Burning	8	8	6	7	8	8	8
Solvent Use	1	3	3	4	4	4	3
Waste	0	2	2	2	2	2	2
CO	**130,038**	**92,243**	**70,809**	**67,238**	**63,625**	**60,039**	**51,452**
Mobile Fossil Fuel Combustion	119,360	83,559	62,692	58,972	55,253	51,533	43,355
Stationary Fossil Fuel Combustion	5,000	4,340	4,649	4,695	4,744	4,792	4,543
Industrial Processes	4,125	2,216	1,555	1,597	1,640	1,682	1,549
Incineration of Waste	978	1,670	1,403	1,412	1,421	1,430	1,403
Agricultural Burning	268	259	184	233	237	270	247
Oil and Gas Activities	302	146	318	319	320	322	345
Waste	1	8	7	7	7	7	7
Solvent Use	5	45	2	2	2	2	2
NMVOCs	**20,930**	**15,227**	**13,761**	**13,594**	**13,423**	**13,254**	**9,313**
Mobile Fossil Fuel Combustion	10,932	7,229	6,330	6,037	5,742	5,447	4,151
Solvent Use	5,216	4,384	3,851	3,846	3,839	3,834	2,583
Industrial Processes	2,422	1,773	1,997	1,933	1,869	1,804	1,322
Stationary Fossil Fuel Combustion	912	1,077	716	918	1,120	1,321	424
Oil and Gas Activities	554	388	510	510	509	509	599
Incineration of Waste	222	257	241	238	234	230	159
Waste	673	119	114	113	111	109	76
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO_2	**20,935**	**14,830**	**13,466**	**12,388**	**11,799**	**10,368**	**8,599**
Stationary Fossil Fuel Combustion	18,407	12,849	11,541	10,612	10,172	8,891	7,167
Industrial Processes	1,307	1,031	831	818	807	795	798
Mobile Fossil Fuel Combustion	793	632	889	750	611	472	455
Oil and Gas Activities	390	287	181	182	184	187	154
Incineration of Waste	38	29	24	24	24	23	24
Waste	0	1	1	1	1	1	1
Solvent Use	0	1	0	0	0	0	0

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[17] See <http://unfccc.int/resource/docs/cop8/08.pdf>.

[18] NO_x and CO emission estimates from field burning of agricultural residues were estimated separately, and therefore not taken from EPA (2008).

Agricultural Burning	NA	NA	NA	NA	NA	NA	NA

Source: (EPA 2010, EPA 2009) except for estimates from field burning of agricultural residues.
NA (Not Available)
Note: Totals may not sum due to independent rounding.

Key Categories

The 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) defines a key category as a "[source or sink category] that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both."[19] By definition, key categories are sources or sinks that have the greatest contribution to the absolute overall level of national emissions in any of the years covered by the time series. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key categories must also account for the influence of trends of individual source and sink categories. Finally, a qualitative evaluation of key categories should be performed, in order to capture any key categories that were not identified in either of the quantitative analyses.

Figure ES-16 presents 2009 emission estimates for the key categories as defined by a level analysis (i.e., the contribution of each source or sink category to the total inventory level). The UNFCCC reporting guidelines request that key category analyses be reported at an appropriate level of disaggregation, which may lead to source and sink category names which differ from those used elsewhere in the inventory report. For more information regarding key categories, see section 1.5 and Annex 1.

Figure ES-16: 2009 Key Categories

Quality Assurance and Quality Control (QA/QC)

The United States seeks to continually improve the quality, transparency, and credibility of the Inventory of U.S. Greenhouse Gas Emissions and Sinks. To assist in these efforts, the United States implemented a systematic approach to QA/QC. While QA/QC has always been an integral part of the U.S. national system for inventory development, the procedures followed for the current inventory have been formalized in accordance with the QA/QC plan and the UNFCCC reporting guidelines.

Uncertainty Analysis of Emission Estimates

While the current U.S. emissions inventory provides a solid foundation for the development of a more detailed and comprehensive national inventory, there are uncertainties associated with the emission estimates. Some of the current estimates, such as those for CO_2 emissions from energy-related activities and cement processing, are considered to have low uncertainties. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty associated with the estimates presented. Acquiring a better understanding of the uncertainty associated with inventory estimates is an important step in helping to prioritize future work and improve the overall quality of the Inventory. Recognizing the benefit of conducting an uncertainty analysis, the UNFCCC reporting guidelines follow the recommendations of the IPCC Good Practice Guidance (IPCC 2000) and require that countries provide single estimates of uncertainty for source and sink categories.

Currently, a qualitative discussion of uncertainty is presented for all source and sink categories. Within the discussion of each emission source, specific factors affecting the uncertainty surrounding the estimates are discussed. Most sources also contain a quantitative uncertainty assessment, in accordance with UNFCCC reporting guidelines.

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[19] See Chapter 7 "Methodological Choice and Recalculation" in IPCC (2000). <http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>

[BEGIN BOX]

Box ES-3: Recalculations of Inventory Estimates

Each year, emission and sink estimates are recalculated and revised for all years in the Inventory of U.S. Greenhouse Gas Emissions and Sinks, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In this effort, the United States follows the 2006 IPCC Guidelines (IPCC 2006), which states, “Both methodological changes and refinements over time are an essential part of improving inventory quality. It is good practice to change or refine methods” when: available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors.” In general, recalculations are made to the U.S. greenhouse gas emission estimates either to incorporate new methodologies or, most commonly, to update recent historical data.

In each Inventory report, the results of all methodology changes and historical data updates are presented in the "Recalculations and Improvements" chapter; detailed descriptions of each recalculation are contained within each source's description contained in the report, if applicable. In general, when methodological changes have been implemented, the entire time series (in the case of the most recent inventory report, 1990 through 2009) has been recalculated to reflect the change, per the 2006 IPCC Guidelines (IPCC 2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies. References for the data are provided for additional information.

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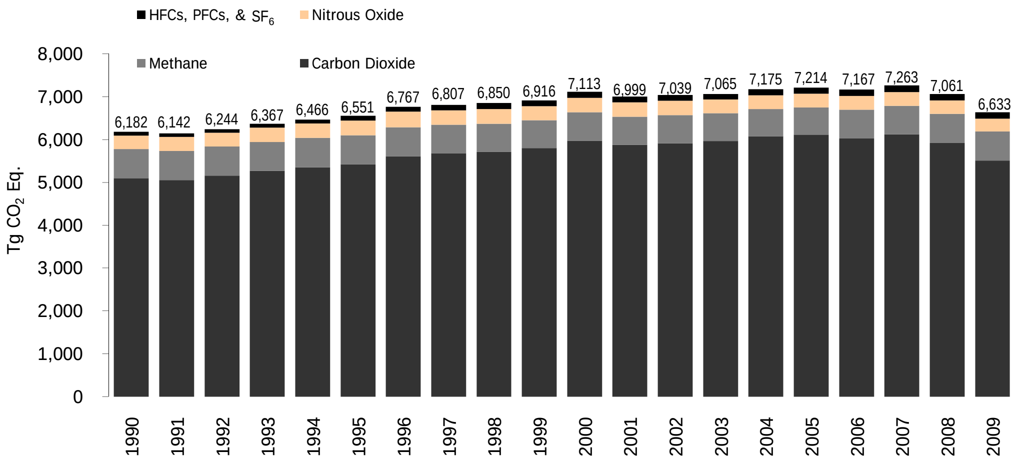


Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

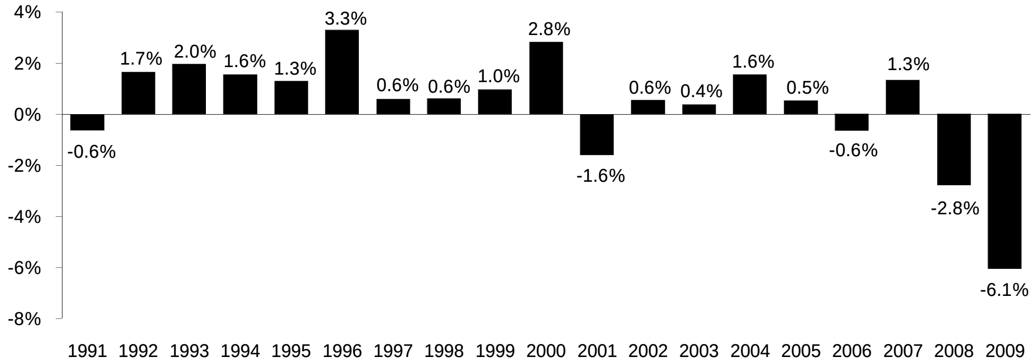


Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

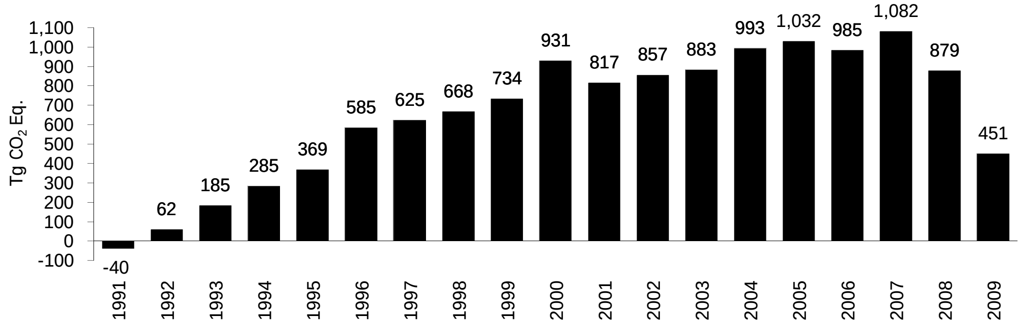


Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

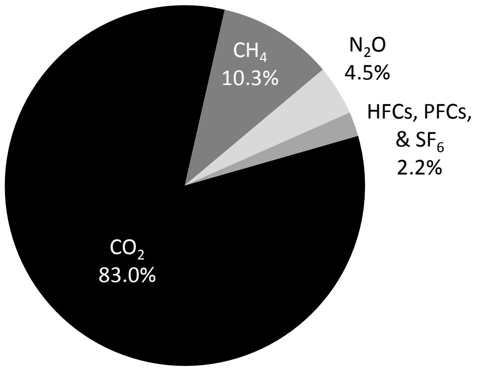


Figure ES-4: 2009 Greenhouse Gas Emissions by Gas (percents based on Tg CO_2 Eq.)

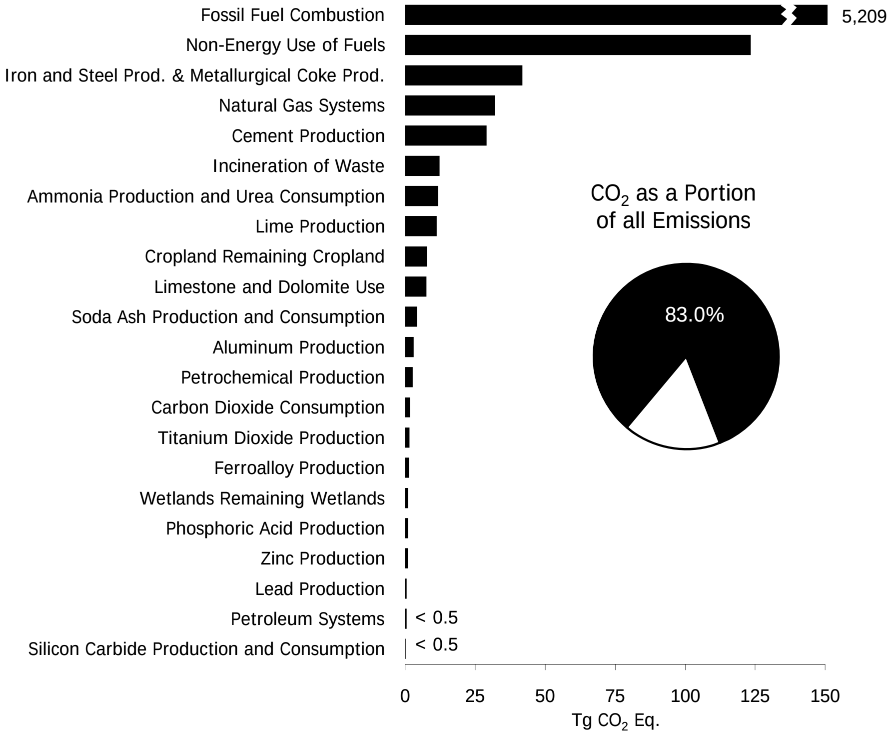


Figure ES-5: 2009 Sources of CO_2 Emissions

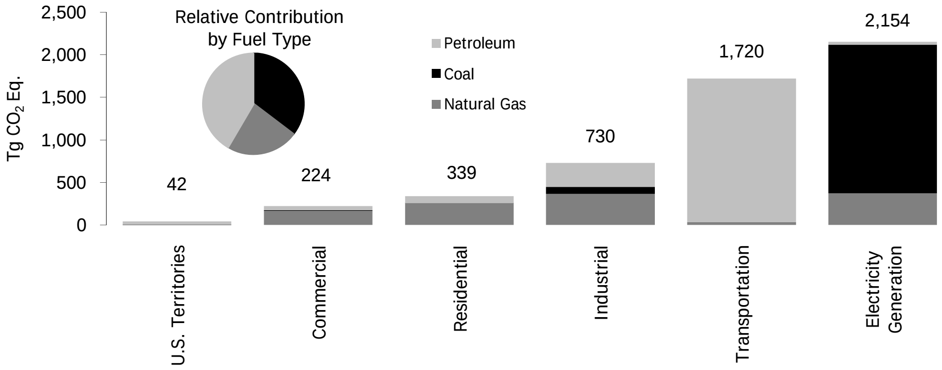


Figure ES-6: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: Electricity generation also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

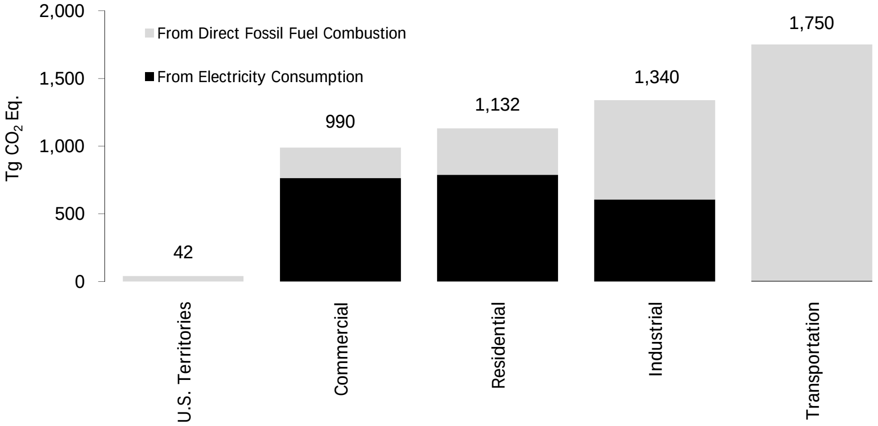


Figure ES-7: 2009 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

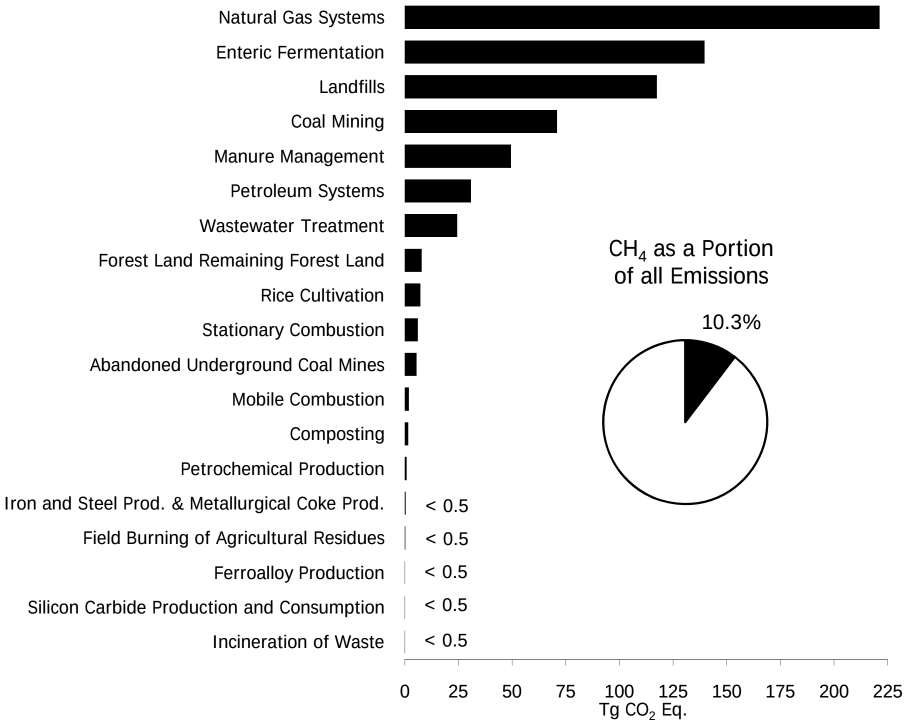


Figure ES-8: 2009 Sources of CH_4 Emissions

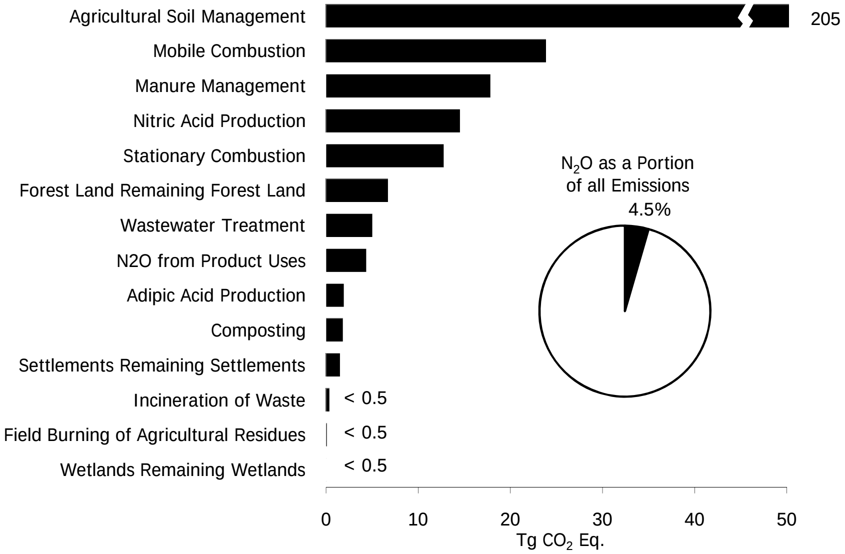


Figure ES-9: 2009 Sources of N_2O Emissions

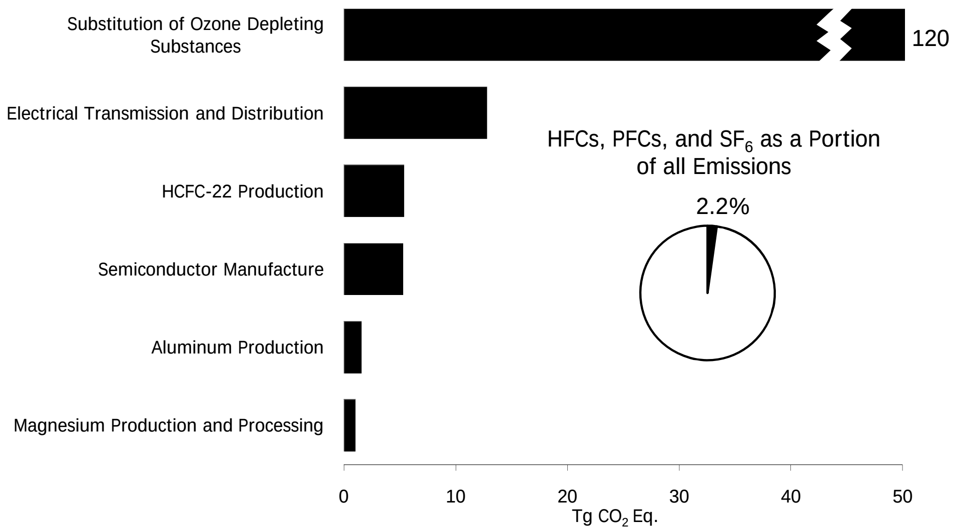
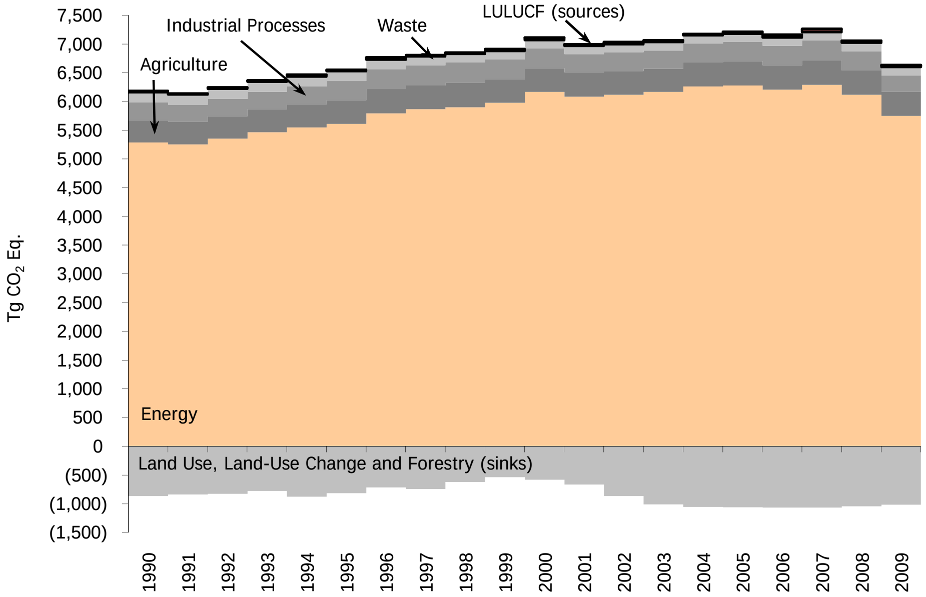


Figure ES-10: 2009 Sources of HFCs, PFCs, and SF_6 Emissions



Note: Relatively smaller amounts of GWP-weighted emissions are also emitted from the Solvent and Other Product Use sectors

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

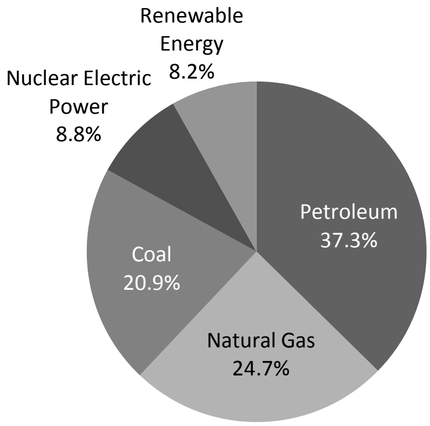


Figure ES-12: 2009 U.S. Energy Consumption by Energy Source

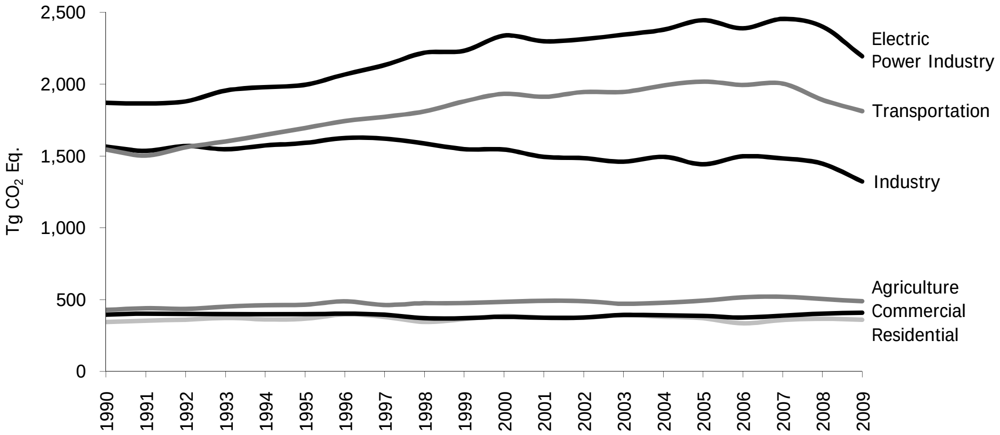


Figure ES-13: Emissions Allocated to Economic Sectors
Note: Does not include U.S. Territories.

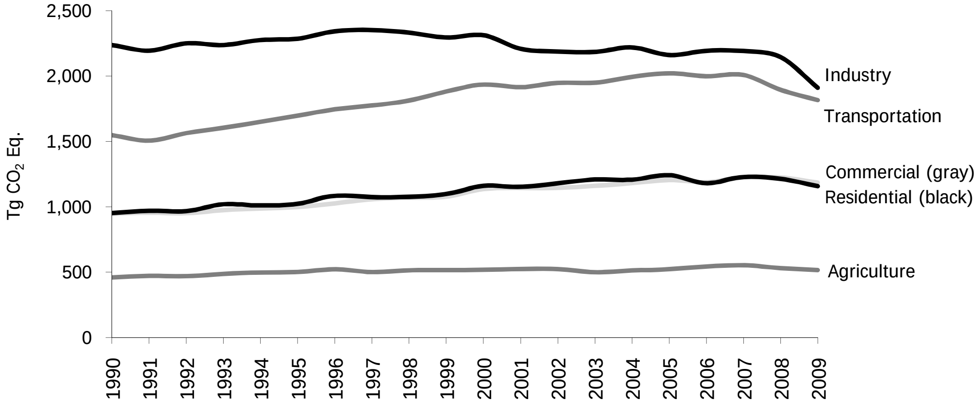


Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

Note: Does not include U.S. Territories.

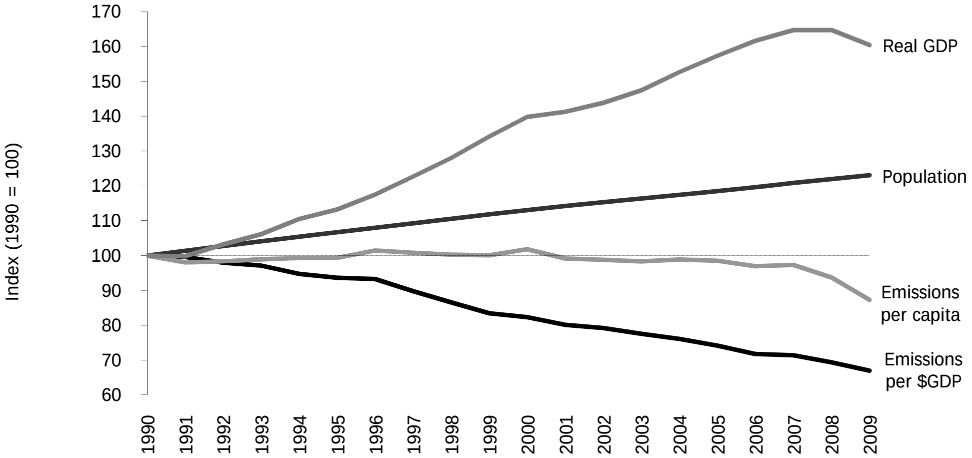


Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

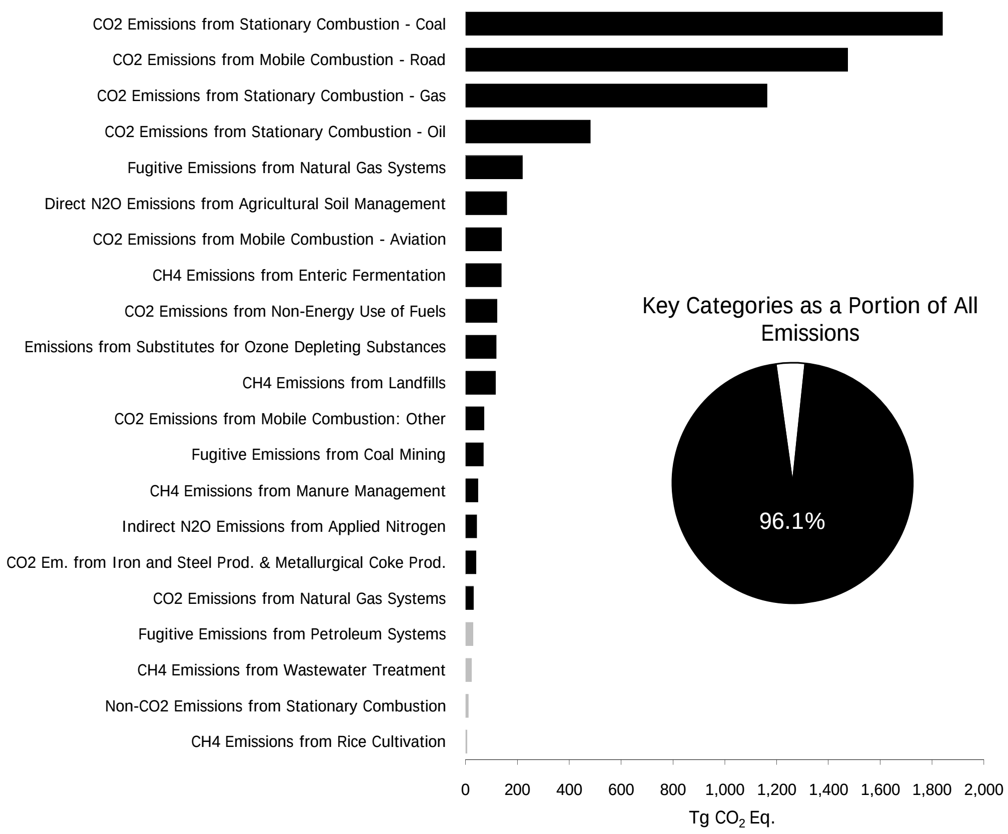


Figure ES-16: 2009 Key Categories

Notes: For a complete discussion of the key category analysis, see Annex 1.
Black bars indicate a Tier 1 level assessment key category.
Gray bars indicate a Tier 2 level assessment key category.

1. Introduction

This report presents estimates by the United States government of U.S. anthropogenic greenhouse gas emissions and sinks for the years 1990 through 2009. A summary of these estimates is provided in Table 2.1 and Table 2.2 by gas and source category in the Trends in Greenhouse Gas Emissions chapter. The emission estimates in these tables are presented on both a full molecular mass basis and on a Global Warming Potential (GWP) weighted basis in order to show the relative contribution of each gas to global average radiative forcing.[20] This report also discusses the methods and data used to calculate these emission estimates.

In 1992, the United States signed and ratified the United Nations Framework Convention on Climate Change (UNFCCC). As stated in Article 2 of the UNFCCC, "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."[21,22]

Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available…national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies…"[23] The United States views this report as an opportunity to fulfill these commitments under the UNFCCC.

In 1988, preceding the creation of the UNFCCC, the World Meteorological Organization (WMO) and the United Nations Environment Programme (UNEP) jointly established the Intergovernmental Panel on Climate Change (IPCC). The role of the IPCC is to assess on a comprehensive, objective, open and transparent basis the scientific, technical and socio-economic information relevant to understanding the scientific basis of risk of human-induced climate change, its potential impacts and options for adaptation and mitigation (IPCC 2003). Under Working Group 1 of the IPCC, nearly 140 scientists and national experts from more than thirty countries collaborated in the creation of the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997) to ensure that the emission inventories submitted to the UNFCCC are consistent and comparable between nations. The IPCC accepted the Revised 1996 IPCC Guidelines at its Twelfth Session (Mexico City, September 11-13, 1996). This report presents information in accordance with these guidelines. In addition, this Inventory is in accordance with the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories and the Good Practice Guidance for Land Use, Land-Use Change, and Forestry, which further expanded upon the methodologies in the Revised 1996 IPCC Guidelines. The IPCC has also accepted the 2006 Guidelines for National Greenhouse Gas Inventories (IPCC 2006) at its Twenty-Fifth Session (Mauritius, April 2006). The 2006 IPCC Guidelines build on the previous bodies of work and includes new sources and gases "…as well as updates to the previously published methods whenever scientific and technical knowledge have improved since the previous guidelines were issued." Many of the methodological improvements presented in the 2006 Guidelines have been adopted in this Inventory.

Overall, this inventory of anthropogenic greenhouse gas emissions provides a common and consistent mechanism through which Parties to the UNFCCC can estimate emissions and compare the relative contribution of individual sources, gases, and nations to climate change. The inventory provides a national estimate of sources and sinks for the United States, including all states and U.S. territories[24] . The structure of this report is consistent with the current

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[20] See the section below entitled *Global Warming Potentials* for an explanation of GWP values.

[21] The term "anthropogenic", in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC/UNEP/OECD/IEA 1997).

[22] Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <http://unfccc.int>. (UNEP/WMO 2000)

[23] Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <http://unfccc.int>.

[24] U.S. Territories include American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands.

UNFCCC Guidelines on Annual Inventories (UNFCCC 2006).

[BEGIN BOX]

Box 1-1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the Intergovernmental Panel on Climate Change (IPCC).[25] Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[26] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

[END BOX]

1.1. Background Information

Science

For over the past 200 years, the burning of fossil fuels such as coal and oil, deforestation, and other sources have caused the concentrations of heat-trapping "greenhouse gases" to increase significantly in our atmosphere. These gases absorb some of the energy being radiated from the surface of the earth and trap it in the atmosphere, essentially acting like a blanket that makes the earth's surface warmer than it would be otherwise.

Greenhouse gases are necessary to life as we know it, because without them the planet's surface would be about 60 ºF cooler than present. But, as the concentrations of these gases continue to increase in the atmosphere, the Earth's temperature is climbing above past levels. According to NOAA and NASA data, the Earth's average surface temperature has increased by about 1.2 to 1.4 ºF since 1900. The ten warmest years on record (since 1850) have all occurred in the past 13 years (EPA 2009). Most of the warming in recent decades is very likely the result of human activities. Other aspects of the climate are also changing such as rainfall patterns, snow and ice cover, and sea level.

If greenhouse gases continue to increase, climate models predict that the average temperature at the Earth's surface could increase from 2.0 to 11.5 ºF above 1990 levels by the end of this century (IPCC 2007). Scientists are certain that human activities are changing the composition of the atmosphere, and that increasing the concentration of greenhouse gases will change the planet's climate. But they are not sure by how much it will change, at what rate it will change, or what the exact effects will be.[27]

Greenhouse Gases

Although the Earth's atmosphere consists mainly of oxygen and nitrogen, neither plays a significant role in enhancing the greenhouse effect because both are essentially transparent to terrestrial radiation. The greenhouse effect is primarily a function of the concentration of water vapor, carbon dioxide (CO_2), and other trace gases in the

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[25] See <http://www.ipcc-nggip.iges.or.jp/public/index.html>.

[26] See <http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>

[27] For more information see <http://www.epa.gov/climatechange/science>

atmosphere that absorb the terrestrial radiation leaving the surface of the Earth (IPCC 2001). Changes in the atmospheric concentrations of these greenhouse gases can alter the balance of energy transfers between the atmosphere, space, land, and the oceans.[28] A gauge of these changes is called radiative forcing, which is a measure of the influence a factor has in altering the balance of incoming and outgoing energy in the Earth-atmosphere system (IPCC 2001). Holding everything else constant, increases in greenhouse gas concentrations in the atmosphere will produce positive radiative forcing (i.e., a net increase in the absorption of energy by the Earth).

> *Climate change can be driven by changes in the atmospheric concentrations of a number of radiatively active gases and aerosols. We have clear evidence that human activities have affected concentrations, distributions and life cycles of these gases (IPCC 1996).*

Naturally occurring greenhouse gases include water vapor, CO_2, methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). As stratospheric ozone depleting substances, CFCs, HCFCs, and halons are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty. Consequently, Parties to the UNFCCC are not required to include these gases in national greenhouse gas inventories.[29] Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas inventories.

There are also several gases that, although they do not have a commonly agreed upon direct radiative forcing effect, do influence the global radiation budget. These tropospheric gases include carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and tropospheric (ground level) ozone O_3. Tropospheric ozone is formed by two precursor pollutants, volatile organic compounds (VOCs) and nitrogen oxides (NO_x) in the presence of ultraviolet light (sunlight). Aerosols are extremely small particles or liquid droplets that are often composed of sulfur compounds, carbonaceous combustion products, crustal materials and other human induced pollutants. They can affect the absorptive characteristics of the atmosphere. Comparatively, however, the level of scientific understanding of aerosols is still very low (IPCC 2001).

CO_2, CH_4, and N_2O are continuously emitted to and removed from the atmosphere by natural processes on Earth. Anthropogenic activities, however, can cause additional quantities of these and other greenhouse gases to be emitted or sequestered, thereby changing their global average atmospheric concentrations. Natural activities such as respiration by plants or animals and seasonal cycles of plant growth and decay are examples of processes that only cycle carbon or nitrogen between the atmosphere and organic biomass. Such processes, except when directly or indirectly perturbed out of equilibrium by anthropogenic activities, generally do not alter average atmospheric greenhouse gas concentrations over decadal timeframes. Climatic changes resulting from anthropogenic activities, however, could have positive or negative feedback effects on these natural systems. Atmospheric concentrations of these gases, along with their rates of growth and atmospheric lifetimes, are presented in Table 1-1.

Table 1-1: Global Atmospheric Concentration, Rate of Concentration Change, and Atmospheric Lifetime (years) of Selected Greenhouse Gases

Atmospheric Variable	**CO_2**	**CH_4**	**N_2O**	**SF_6**	**CF_4**
Pre-industrial atmospheric concentration	278 ppm	0.715 ppm	0.270 ppm	0 ppt	40 ppt
Atmospheric concentration	385 ppm	1.741-1.865 ppm[a]	0.321-0.322 ppm[a]	5.6 ppt	74 ppt
Rate of concentration change	1.4 ppm/yr	0.005 ppm/yr[b]	0.26%/yr	Linear[c]	Linear[c]
Atmospheric lifetime (years)	50-200[d]	12[e]	114[e]	3,200	>50,000

Source: Pre-industrial atmospheric concentrations and rate of concentration changes for all gases are from IPCC (2007). The current atmospheric concentration for CO_2 is from NOAA/ESRL (2009).

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[28] For more on the science of climate change, see NRC (2001).

[29] Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in this document for informational purposes.

[a] The range is the annual arithmetic averages from a mid-latitude Northern-Hemisphere site and a mid-latitude Southern-Hemisphere site for October 2006 through September 2007 (CDIAC 2009).
[b] The growth rate for atmospheric CH_4 has been decreasing from 1.4 ppb/yr in 1984 to less than 0 ppb/yr in 2001, 2004, and 2005.
[c] IPCC (2007) identifies the rate of concentration change for SF_6 and CF_4 as linear.
[d] No single lifetime can be defined for CO_2 because of the different rates of uptake by different removal processes.
[e] This lifetime has been defined as an "adjustment time" that takes into account the indirect effect of the gas on its own residence time.

A brief description of each greenhouse gas, its sources, and its role in the atmosphere is given below. The following section then explains the concept of GWPs, which are assigned to individual gases as a measure of their relative average global radiative forcing effect.

Water Vapor (H_2O). Overall, the most abundant and dominant greenhouse gas in the atmosphere is water vapor. Water vapor is neither long-lived nor well mixed in the atmosphere, varying spatially from 0 to 2 percent (IPCC 1996). In addition, atmospheric water can exist in several physical states including gaseous, liquid, and solid. Human activities are not believed to affect directly the average global concentration of water vapor, but, the radiative forcing produced by the increased concentrations of other greenhouse gases may indirectly affect the hydrologic cycle. While a warmer atmosphere has an increased water holding capacity, increased concentrations of water vapor affects the formation of clouds, which can both absorb and reflect solar and terrestrial radiation. Aircraft contrails, which consist of water vapor and other aircraft emittants, are similar to clouds in their radiative forcing effects (IPCC 1999).

Carbon Dioxide. In nature, carbon is cycled between various atmospheric, oceanic, land biotic, marine biotic, and mineral reservoirs. The largest fluxes occur between the atmosphere and terrestrial biota, and between the atmosphere and surface water of the oceans. In the atmosphere, carbon predominantly exists in its oxidized form as CO_2. Atmospheric CO_2 is part of this global carbon cycle, and therefore its fate is a complex function of geochemical and biological processes. CO_2 concentrations in the atmosphere increased from approximately 280 parts per million by volume (ppmv) in pre-industrial times to 385 ppmv in 2008, a 37.5 percent increase (IPCC 2007 and NOAA/ESRL 2009) .[30,31] The IPCC definitively states that "the present atmospheric CO_2 increase is caused by anthropogenic emissions of CO_2" (IPCC 2001). The predominant source of anthropogenic CO_2 emissions is the combustion of fossil fuels. Forest clearing, other biomass burning, and some non-energy production processes (e.g., cement production) also emit notable quantities of CO_2. In it's fourth assessment, the IPCC stated "most of the observed increase in global average temperatures since the mid-20th century is very likely due to the observed increased in anthropogenic greenhouse gas concentrations," of which CO_2 is the most important (IPCC 2007)

Methane. CH_4 is primarily produced through anaerobic decomposition of organic matter in biological systems. Agricultural processes such as wetland rice cultivation, enteric fermentation in animals, and the decomposition of animal wastes emit CH_4, as does the decomposition of municipal solid wastes. CH_4 is also emitted during the production and distribution of natural gas and petroleum, and is released as a by-product of coal mining and incomplete fossil fuel combustion. Atmospheric concentrations of CH_4 have increased by about 143 percent since 1750, from a pre-industrial value of about 722 ppb to 1,741-1,865 ppb in 2007[32], although the rate of increase has been declining. The IPCC has estimated that slightly more than half of the current CH_4 flux to the atmosphere is anthropogenic, from human activities such as agriculture, fossil fuel use, and waste disposal (IPCC 2007).

CH_4 is removed from the atmosphere through a reaction with the hydroxyl radical (OH) and is ultimately converted to CO_2. Minor removal processes also include reaction with chlorine in the marine boundary layer, a soil sink, and stratospheric reactions. Increasing emissions of CH_4 reduce the concentration of OH, a feedback that may increase the atmospheric lifetime of CH_4 (IPCC 2001).

Nitrous Oxide. Anthropogenic sources of N_2O emissions include agricultural soils, especially production of

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[30] The pre-industrial period is considered as the time preceding the year 1750 (IPCC 2001).

[31] Carbon dioxide concentrations during the last 1,000 years of the pre-industrial period (i.e., 750-1750), a time of relative climate stability, fluctuated by about ±10 ppmv around 280 ppmv (IPCC 2001).

[32] The range is the annual arithmetic averages from a mid-latitude Northern-Hemisphere site and a mid-latitude Southern-Hemisphere site for October 2006 through September 2007 (CDIAC 2009)

nitrogen-fixing crops and forages, the use of synthetic and manure fertilizers, and manure deposition by livestock; fossil fuel combustion, especially from mobile combustion; adipic (nylon) and nitric acid production; wastewater treatment and waste incineration; and biomass burning. The atmospheric concentration of N_2O has increased by 18 percent since 1750, from a pre-industrial value of about 270 ppb to 321-322 ppb in 2007[33], a concentration that has not been exceeded during the last thousand years. N_2O is primarily removed from the atmosphere by the photolytic action of sunlight in the stratosphere (IPCC 2007).

Ozone. Ozone is present in both the upper stratosphere,[34] where it shields the Earth from harmful levels of ultraviolet radiation, and at lower concentrations in the troposphere,[35] where it is the main component of anthropogenic photochemical “smog.” During the last two decades, emissions of anthropogenic chlorine and bromine-containing halocarbons, such as CFCs, have depleted stratospheric ozone concentrations. This loss of ozone in the stratosphere has resulted in negative radiative forcing, representing an indirect effect of anthropogenic emissions of chlorine and bromine compounds (IPCC 1996). The depletion of stratospheric ozone and its radiative forcing was expected to reach a maximum in about 2000 before starting to recover. As of IPCC’s fourth assessment,”whether or not recently observed changes in ozone trends are already indicative of recovery of the global ozone layer is not yet clear.” (IPCC 2007)

The past increase in tropospheric ozone, which is also a greenhouse gas, is estimated to provide the third largest increase in direct radiative forcing since the pre-industrial era, behind CO_2 and CH_4. Tropospheric ozone is produced from complex chemical reactions of volatile organic compounds mixing with NO_x in the presence of sunlight. The tropospheric concentrations of ozone and these other pollutants are short-lived and, therefore, spatially variable. (IPCC 2001)

Halocarbons, Perfluorocarbons, and Sulfur Hexafluoride. Halocarbons are, for the most part, man-made chemicals that have both direct and indirect radiative forcing effects. Halocarbons that contain chlorine (CFCs, HCFCs, methyl chloroform, and carbon tetrachloride) and bromine (halons, methyl bromide, and hydrobromofluorocarbons [HFCs]) result in stratospheric ozone depletion and are therefore controlled under the Montreal Protocol on Substances that Deplete the Ozone Layer. Although CFCs and HCFCs include potent global warming gases, their net radiative forcing effect on the atmosphere is reduced because they cause stratospheric ozone depletion, which itself is an important greenhouse gas in addition to shielding the Earth from harmful levels of ultraviolet radiation. Under the Montreal Protocol, the United States phased out the production and importation of halons by 1994 and of CFCs by 1996. Under the Copenhagen Amendments to the Protocol, a cap was placed on the production and importation of HCFCs by non-Article 5[36] countries beginning in 1996, and then followed by a complete phase-out by the year 2030. While ozone depleting gases covered under the Montreal Protocol and its Amendments are not covered by the UNFCCC; they are reported in this inventory under Annex 6.2 of this report for informational purposes.

HFCs, PFCs, and SF_6 are not ozone depleting substances, and therefore are not covered under the Montreal Protocol. They are, however, powerful greenhouse gases. HFCs are primarily used as replacements for ozone depleting substances but also emitted as a by-product of the HCFC-22 manufacturing process. Currently, they have a small aggregate radiative forcing impact, but it is anticipated that their contribution to overall radiative forcing will increase (IPCC 2001). PFCs and SF_6 are predominantly emitted from various industrial processes including aluminum smelting, semiconductor manufacturing, electric power transmission and distribution, and magnesium

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[33] The range is the annual arithmetic averages from a mid-latitude Northern-Hemisphere site and a mid-latitude Southern-Hemisphere site for October 2006 through September 2007 (CDIAC 2009).

[34] The stratosphere is the layer from the troposphere up to roughly 50 kilometers. In the lower regions the temperature is nearly constant but in the upper layer the temperature increases rapidly because of sunlight absorption by the ozone layer. The ozone-layer is the part of the stratosphere from 19 kilometers up to 48 kilometers where the concentration of ozone reaches up to 10 parts per million.

[35] The troposphere is the layer from the ground up to 11 kilometers near the poles and up to 16 kilometers in equatorial regions (i.e., the lowest layer of the atmosphere where people live). It contains roughly 80 percent of the mass of all gases in the atmosphere and is the site for most weather processes, including most of the water vapor and clouds.

[36] Article 5 of the Montreal Protocol covers several groups of countries, especially developing countries, with low consumption rates of ozone depleting substances. Developing countries with per capita consumption of less than 0.3 kg of certain ozone depleting substances (weighted by their ozone depleting potential) receive financial assistance and a grace period of ten additional years in the phase-out of ozone depleting substances.

casting. Currently, the radiative forcing impact of PFCs and SF_6 is also small, but they have a significant growth rate, extremely long atmospheric lifetimes, and are strong absorbers of infrared radiation, and therefore have the potential to influence climate far into the future (IPCC 2001).

Carbon Monoxide. Carbon monoxide has an indirect radiative forcing effect by elevating concentrations of CH_4 and tropospheric ozone through chemical reactions with other atmospheric constituents (e.g., the hydroxyl radical, OH) that would otherwise assist in destroying CH_4 and tropospheric ozone. Carbon monoxide is created when carbon-containing fuels are burned incompletely. Through natural processes in the atmosphere, it is eventually oxidized to CO_2. Carbon monoxide concentrations are both short-lived in the atmosphere and spatially variable.

Nitrogen Oxides. The primary climate change effects of nitrogen oxides (i.e., NO and NO_2) are indirect and result from their role in promoting the formation of ozone in the troposphere and, to a lesser degree, lower stratosphere, where it has positive radiative forcing effects.[37] Additionally, NO_x emissions from aircraft are also likely to decrease CH_4 concentrations, thus having a negative radiative forcing effect (IPCC 1999). Nitrogen oxides are created from lightning, soil microbial activity, biomass burning (both natural and anthropogenic fires) fuel combustion, and, in the stratosphere, from the photo-degradation of N_2O. Concentrations of NO_x are both relatively short-lived in the atmosphere and spatially variable.

Nonmethane Volatile Organic Compounds (NMVOCs). Non-CH_4 volatile organic compounds include substances such as propane, butane, and ethane. These compounds participate, along with NO_x, in the formation of tropospheric ozone and other photochemical oxidants. NMVOCs are emitted primarily from transportation and industrial processes, as well as biomass burning and non-industrial consumption of organic solvents. Concentrations of NMVOCs tend to be both short-lived in the atmosphere and spatially variable.

Aerosols. Aerosols are extremely small particles or liquid droplets found in the atmosphere. They can be produced by natural events such as dust storms and volcanic activity, or by anthropogenic processes such as fuel combustion and biomass burning. Aerosols affect radiative forcing differently than greenhouse gases, and their radiative effects occur through direct and indirect mechanisms: directly by scattering and absorbing solar radiation; and indirectly by increasing droplet counts that modify the formation, precipitation efficiency, and radiative properties of clouds. Aerosols are removed from the atmosphere relatively rapidly by precipitation. Because aerosols generally have short atmospheric lifetimes, and have concentrations and compositions that vary regionally, spatially, and temporally, their contributions to radiative forcing are difficult to quantify (IPCC 2001).

The indirect radiative forcing from aerosols is typically divided into two effects. The first effect involves decreased droplet size and increased droplet concentration resulting from an increase in airborne aerosols. The second effect involves an increase in the water content and lifetime of clouds due to the effect of reduced droplet size on precipitation efficiency (IPCC 2001). Recent research has placed a greater focus on the second indirect radiative forcing effect of aerosols.

Various categories of aerosols exist, including naturally produced aerosols such as soil dust, sea salt, biogenic aerosols, sulfates, and volcanic aerosols, and anthropogenically manufactured aerosols such as industrial dust and carbonaceous[38] aerosols (e.g., black carbon, organic carbon) from transportation, coal combustion, cement manufacturing, waste incineration, and biomass burning.

The net effect of aerosols on radiative forcing is believed to be negative (i.e., net cooling effect on the climate), although because they remain in the atmosphere for only days to weeks, their concentrations respond rapidly to changes in emissions.[39] Locally, the negative radiative forcing effects of aerosols can offset the positive forcing of greenhouse gases (IPCC 1996). "However, the aerosol effects do not cancel the global-scale effects of the much longer-lived greenhouse gases, and significant climate changes can still result" (IPCC 1996).

The IPCC's Third Assessment Report notes that "the indirect radiative effect of aerosols is now understood to also

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[37] NO_x emissions injected higher in the stratosphere, primarily from fuel combustion emissions from high altitude supersonic aircraft, can lead to stratospheric ozone depletion.

[38] Carbonaceous aerosols are aerosols that are comprised mainly of organic substances and forms of black carbon (or soot) (IPCC 2001).

[39] Volcanic activity can inject significant quantities of aerosol producing sulfur dioxide and other sulfur compounds into the stratosphere, which can result in a longer negative forcing effect (i.e., a few years) (IPCC 1996).

encompass effects on ice and mixed-phase clouds, but the magnitude of any such indirect effect is not known, although it is likely to be positive" (IPCC 2001). Additionally, current research suggests that another constituent of aerosols, black carbon, has a positive radiative forcing, and that its presence "in the atmosphere above highly reflective surfaces such as snow and ice, or clouds, may cause a significant positive radiative forcing (IPCC 2007). The primary anthropogenic emission sources of black carbon include diesel exhaust and open biomass burning.

Global Warming Potentials

A global warming potential is a quantified measure of the globally averaged relative radiative forcing impacts of a particular greenhouse gas (see Table 1-2). It is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2001). Direct radiative effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations involving the original gas produce a gas or gases that are greenhouse gases, or when a gas influences other radiatively important processes such as the atmospheric lifetimes of other gases. The reference gas used is CO_2, and therefore GWP weighted emissions are measured in teragrams of CO_2 equivalent (Tg CO_2 Eq.)[40] The relationship between gigagrams (Gg) of a gas and Tg CO_2 Eq. can be expressed as follows:

$$\text{Tg CO}_2\ \text{Eq} = (\text{Gg of gas}) \times (\text{GWP}) \times \left(\frac{\text{Tg}}{1{,}000\,\text{Gg}} \right)$$

where,

Tg CO_2 Eq. = Teragrams of CO_2 Equivalents

Gg = Gigagrams (equivalent to a thousand metric tons)

GWP = Global Warming Potential

Tg = Teragrams

GWP values allow for a comparison of the impacts of emissions and reductions of different gases. According to the IPCC, GWPs typically have an uncertainty of ±35 percent. The parties to the UNFCCC have also agreed to use GWPs based upon a 100-year time horizon although other time horizon values are available.

> *Greenhouse gas emissions and removals should be presented on a gas-by-gas basis in units of mass... In addition, consistent with decision 2/CP.3, Parties should report aggregate emissions and removals of greenhouse gases, expressed in CO_2 equivalent terms at summary inventory level, using GWP values provided by the IPCC in its Second Assessment Report... based on the effects of greenhouse gases over a 100-year time horizon.*[41]

Greenhouse gases with relatively long atmospheric lifetimes (e.g., CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6) tend to be evenly distributed throughout the atmosphere, and consequently global average concentrations can be determined. The short-lived gases such as water vapor, carbon monoxide, tropospheric ozone, ozone precursors (e.g., NO_x, and NMVOCs), and tropospheric aerosols (e.g., SO_2 products and carbonaceous particles), however, vary regionally, and consequently it is difficult to quantify their global radiative forcing impacts. No GWP values are attributed to these gases that are short-lived and spatially inhomogeneous in the atmosphere.

Table 1-2: Global Warming Potentials and Atmospheric Lifetimes (Years) Used in this Report

Gas	Atmospheric Lifetime	GWP[a]
CO_2	50-200	1

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[40] Carbon comprises 12/44ths of carbon dioxide by weight.

[41] Framework Convention on Climate Change; <http://unfccc.int/resource/docs/cop8/08.pdf>; 1 November 2002; Report of the Conference of the Parties at its eighth session; held at New Delhi from 23 October to 1 November 2002; Addendum; Part One: Action taken by the Conference of the Parties at its eighth session; Decision -/CP.8; Communications from Parties included in Annex I to the Convention: Guidelines for the Preparation of National Communications by Parties Included in Annex I to the Convention, Part 1: UNFCCC reporting guidelines on annual inventories; p. 7. (UNFCCC 2003)

CH4[b]	12±3	21
N_2O	120	310
HFC-23	264	11,700
HFC-32	5.6	650
HFC-125	32.6	2,800
HFC-134a	14.6	1,300
HFC-143a	48.3	3,800
HFC-152a	1.5	140
HFC-227ea	36.5	2,900
HFC-236fa	209	6,300
HFC-4310mee	17.1	1,300
CF_4	50,000	6,500
C_2F_6	10,000	9,200
C_4F_{10}	2,600	7,000
C_6F_{14}	3,200	7,400
SF_6	3,200	23,900

Source: (IPCC 1996)

[a] 100-year time horizon

[b] The GWP of CH_4 includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

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Box 1-2: The IPCC Fourth Assessment Report and Global Warming Potentials

In 2007, the IPCC published its Fourth Assessment Report (AR4), which provided an updated and more comprehensive scientific assessment of climate change. Within this report, the GWPs of several gases were revised relative to the SAR and the IPCC's Third Assessment Report (TAR) (IPCC 2001). Thus the GWPs used in this report have been updated twice by the IPCC; although the SAR GWPs are used throughout this report, it is interesting to review the changes to the GWPs and the impact such improved understanding has on the total GWP-weighted emissions of the United States. Since the SAR and TAR, the IPCC has applied an improved calculation of CO_2 radiative forcing and an improved CO_2 response function. The GWPs are drawn from IPCC/TEAP (2005) and the TAR, with updates for those cases where new laboratory or radiative transfer results have been published. Additionally, the atmospheric lifetimes of some gases have been recalculated. In addition, the values for radiative forcing and lifetimes have been recalculated for a variety of halocarbons, which were not presented in the SAR. Table 1-3 presents the new GWPs, relative to those presented in the SAR.

Table 1-3: Comparison of 100-Year GWPs

Gas	**SAR**	**TAR**	**AR4**	**Change from SAR**	
				TAR	**AR4**
CO_2	1	1	1	NC	0
CH_4*	21	23	25	2	4
N_2O	310	296	298	(14)	(12)
HFC-23	11,700	12,000	14,800	300	3,100
HFC-32	650	550	675	(100)	25
HFC-125	2,800	3,400	3,500	600	700
HFC-134a	1,300	1,300	1,430	NC	130
HFC-143a	3,800	4,300	4,470	500	670
HFC-152a	140	120	124	(20)	(16)
HFC-227ea	2,900	3,500	3,220	600	320
HFC-236fa	6,300	9,400	9,810	3,100	3,510
HFC-4310mee	1,300	1,500	1,640	200	340
CF_4	6,500	5,700	7,390	(800)	890
C_2F_6	9,200	11,900	12,200	2,700	3,000

$C_4F_1$0	7,000	8,600	8,860	1,600	1,860
C6F14	7,400	9,000	9,300	1,600	1,900
SF_6	23,900	22,200	22,800	(1,700)	(1,100)

Source: (IPCC 2007, IPCC 2001)
NC (No Change)
Note: Parentheses indicate negative values.
* The GWP of CH_4 includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

To comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. The UNFCCC reporting guidelines for national inventories[42] were updated in 2002 but continue to require the use of GWPs from the SAR so that current estimates of aggregate greenhouse gas emissions for 1990 through 2009 are consistent and comparable with estimates developed prior to the publication of the TAR and AR4. For informational purposes, emission estimates that use the updated GWPs are presented in detail in Annex 6.1 of this report. All estimates provided throughout this report are also presented in unweighted units.

[END BOX]

1.2. Institutional Arrangements

The U.S. Environmental Protection Agency (EPA), in cooperation with other U.S. government agencies, prepares the Inventory of U.S. Greenhouse Gas Emissions and Sinks. A wide range of agencies and individuals are involved in supplying data to, reviewing, or preparing portions of the U.S. Inventory—including federal and state government authorities, research and academic institutions, industry associations, and private consultants.

Within EPA, the Office of Atmospheric Programs (OAP) is the lead office responsible for the emission calculations provided in the Inventory, as well as the completion of the National Inventory Report and the Common Reporting Format tables. The Office of Transportation and Air Quality (OTAQ) is also involved in calculating emissions for the Inventory. While the U.S. Department of State officially submits the annual Inventory to the UNFCCC, EPA's OAP serves as the focal point for technical questions and comments on the U.S. Inventory. The staff of OAP and OTAQ coordinates the annual methodological choice, activity data collection, and emission calculations at the individual source category level. Within OAP, an inventory coordinator compiles the entire Inventory into the proper reporting format for submission to the UNFCCC, and is responsible for the collection and consistency of cross-cutting issues in the Inventory.

Several other government agencies contribute to the collection and analysis of the underlying activity data used in the Inventory calculations. Formal relationships exist between EPA and other U.S. agencies that provide official data for use in the Inventory. The U.S. Department of Energy's Energy Information Administration provides national fuel consumption data and the U.S. Department of Defense provides military fuel consumption and bunker fuels. Informal relationships also exist with other U.S. agencies to provide activity data for use in EPA's emission calculations. These include: the U.S. Department of Agriculture, the U.S. Geological Survey, the Federal Highway Administration, the Department of Transportation, the Bureau of Transportation Statistics, the Department of Commerce, the National Agricultural Statistics Service, and the Federal Aviation Administration. Academic and research centers also provide activity data and calculations to EPA, as well as individual companies participating in voluntary outreach efforts with EPA. Finally, the U.S. Department of State officially submits the Inventory to the UNFCCC each April.

1.3. Inventory Process

EPA has a decentralized approach to preparing the annual U.S. Inventory, which consists of a National Inventory Report (NIR) and Common Reporting Format (CRF) tables. The Inventory coordinator at EPA is responsible for

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[42] See <http://unfccc.int/resource/docs/cop8/08.pdf>.

compiling all emission estimates, and ensuring consistency and quality throughout the NIR and CRF tables. Emission calculations for individual sources are the responsibility of individual source leads, who are most familiar with each source category and the unique characteristics of its emissions profile. The individual source leads determine the most appropriate methodology and collect the best activity data to use in the emission calculations, based upon their expertise in the source category, as well as coordinating with researchers and contractors familiar with the sources. A multi-stage process for collecting information from the individual source leads and producing the Inventory is undertaken annually to compile all information and data.

Methodology Development, Data Collection, and Emissions and Sink Estimation

Source leads at EPA collect input data and, as necessary, evaluate or develop the estimation methodology for the individual source categories. For most source categories, the methodology for the previous year is applied to the new "current" year of the Inventory, and inventory analysts collect any new data or update data that have changed from the previous year. If estimates for a new source category are being developed for the first time, or if the methodology is changing for an existing source category (e.g., the United States is implementing a higher Tiered approach for that source category), then the source category lead will develop a new methodology, gather the most appropriate activity data and emission factors (or in some cases direct emission measurements) for the entire time series, and conduct a special source-specific peer review process involving relevant experts from industry, government, and universities.

Once the methodology is in place and the data are collected, the individual source leads calculate emissions and sink estimates. The source leads then update or create the relevant text and accompanying annexes for the Inventory. Source leads are also responsible for completing the relevant sectoral background tables of the Common Reporting Format, conducting quality assurance and quality control (QA/QC) checks, and uncertainty analyses.

Summary Spreadsheet Compilation and Data Storage

The inventory coordinator at EPA collects the source categories' descriptive text and Annexes, and also aggregates the emission estimates into a summary spreadsheet that links the individual source category spreadsheets together. This summary sheet contains all of the essential data in one central location, in formats commonly used in the Inventory document. In addition to the data from each source category, national trend and related data are also gathered in the summary sheet for use in the Executive Summary, Introduction, and Recent Trends sections of the Inventory report. Electronic copies of each year's summary spreadsheet, which contains all the emission and sink estimates for the United States, are kept on a central server at EPA under the jurisdiction of the Inventory coordinator.

National Inventory Report Preparation

The NIR is compiled from the sections developed by each individual source lead. In addition, the inventory coordinator prepares a brief overview of each chapter that summarizes the emissions from all sources discussed in the chapters. The inventory coordinator then carries out a key category analysis for the Inventory, consistent with the IPCC Good Practice Guidance, IPCC Good Practice Guidance for Land Use, Land Use Change and Forestry, and in accordance with the reporting requirements of the UNFCCC. Also at this time, the Introduction, Executive Summary, and Recent Trends sections are drafted, to reflect the trends for the most recent year of the current Inventory. The analysis of trends necessitates gathering supplemental data, including weather and temperature conditions, economic activity and gross domestic product, population, atmospheric conditions, and the annual consumption of electricity, energy, and fossil fuels. Changes in these data are used to explain the trends observed in greenhouse gas emissions in the United States. Furthermore, specific factors that affect individual sectors are researched and discussed. Many of the factors that affect emissions are included in the Inventory document as separate analyses or side discussions in boxes within the text. Text boxes are also created to examine the data aggregated in different ways than in the remainder of the document, such as a focus on transportation activities or emissions from electricity generation. The document is prepared to match the specification of the UNFCCC reporting guidelines for National Inventory Reports.

Common Reporting Format Table Compilation

The CRF tables are compiled from individual tables completed by each individual source lead, which contain source emissions and activity data. The inventory coordinator integrates the source data into the UNFCCC's "CRF Reporter" for the United States, assuring consistency across all sectoral tables. The summary reports for emissions, methods, and emission factors used, the overview tables for completeness and quality of estimates, the recalculation tables, the notation key completion tables, and the emission trends tables are then completed by the inventory coordinator. Internal automated quality checks on the CRF Reporter, as well as reviews by the source leads, are completed for the entire time series of CRF tables before submission.

QA/QC and Uncertainty

QA/QC and uncertainty analyses are supervised by the QA/QC and Uncertainty coordinators, who have general oversight over the implementation of the QA/QC plan and the overall uncertainty analysis for the Inventory (see sections on QA/QC and Uncertainty, below). These coordinators work closely with the source leads to ensure that a consistent QA/QC plan and uncertainty analysis is implemented across all inventory sources. The inventory QA/QC plan, detailed in a following section, is consistent with the quality assurance procedures outlined by EPA and IPCC.

Expert and Public Review Periods

During the Expert Review period, a first draft of the document is sent to a select list of technical experts outside of EPA. The purpose of the Expert Review is to encourage feedback on the methodological and data sources used in the current Inventory, especially for sources which have experienced any changes since the previous Inventory.

Once comments are received and addressed, a second draft of the document is released for public review by publishing a notice in the U.S. Federal Register and posting the document on the EPA Web site. The Public Review period allows for a 30 day comment period and is open to the entire U.S. public.

Final Submittal to UNFCCC and Document Printing

After the final revisions to incorporate any comments from the Expert Review and Public Review periods, EPA prepares the final National Inventory Report and the accompanying Common Reporting Format Reporter database. The U.S. Department of State sends the official submission of the U.S. Inventory to the UNFCCC. The document is then formatted for printing, posted online, printed by the U.S. Government Printing Office, and made available for the public.

1.4. Methodology and Data Sources

Emissions of greenhouse gases from various source and sink categories have been estimated using methodologies that are consistent with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997). In addition, the United States references the additional guidance provided in the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000), the IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003), and the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). To the extent possible, the present report relies on published activity and emission factor data. Depending on the emission source category, activity data can include fuel consumption or deliveries, vehicle-miles traveled, raw material processed, etc. Emission factors are factors that relate quantities of emissions to an activity.

The IPCC methodologies provided in the Revised 1996 IPCC Guidelines represent baseline methodologies for a variety of source categories, and many of these methodologies continue to be improved and refined as new research and data become available. This report uses the IPCC methodologies when applicable, and supplements them with other available methodologies and data where possible. Choices made regarding the methodologies and data sources used are provided in conjunction with the discussion of each source category in the main body of the report. Complete documentation is provided in the annexes on the detailed methodologies and data sources utilized in the calculation of each source category.

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Box 1-3: IPCC Reference Approach

The UNFCCC reporting guidelines require countries to complete a "top-down" reference approach for estimating CO_2 emissions from fossil fuel combustion in addition to their “bottom-up” sectoral methodology. This estimation method uses alternative methodologies and different data sources than those contained in that section of the Energy chapter. The reference approach estimates fossil fuel consumption by adjusting national aggregate fuel production data for imports, exports, and stock changes rather than relying on end-user consumption surveys (see Annex 4 of this report). The reference approach assumes that once carbon-based fuels are brought into a national economy, they are either saved in some way (e.g., stored in products, kept in fuel stocks, or left unoxidized in ash) or combusted, and therefore the carbon in them is oxidized and released into the atmosphere. Accounting for actual consumption of fuels at the sectoral or sub-national level is not required.

[END BOX]

1.5. Key Categories

The IPCC’s Good Practice Guidance (IPCC 2000) defines a key category as a “[source or sink category] that is prioritized within the national inventory system because its estimate has a significant influence on a country’s total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both.”[43] By definition, key categories include those sources that have the greatest contribution to the absolute level of national emissions. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key categories must also account for the influence of trends and uncertainties of individual source and sink categories. This analysis culls out source and sink categories that diverge from the overall trend in national emissions. Finally, a qualitative evaluation of key categories is performed to capture any categories that were not identified in any of the quantitative analyses.

A Tier 1 approach, as defined in the IPCC’s Good Practice Guidance (IPCC 2000), was implemented to identify the key categories for the United States. This analysis was performed twice; one analysis included sources and sinks from the Land Use, Land-Use Change, and Forestry (LULUCF) sector, the other analysis did not include the LULUCF categories. Following the Tier 1 approach, a Tier 2 approach, as defined in the IPCC’s Good Practice Guidance (IPCC 2000), was then implemented to identify any additional key categories not already identified in the Tier 1 assessment. This analysis, which includes each source categories’ uncertainty assessments (or proxies) in its calculations, was also performed twice to include or exclude LULUCF categories.

In addition to conducting Tier 1 and 2 level and trend assessments, a qualitative assessment of the source categories, as described in the IPCC’s Good Practice Guidance (IPCC 2000), was conducted to capture any key categories that were not identified by either quantitative method. One additional key category, international bunker fuels, was identified using this qualitative assessment. International bunker fuels are fuels consumed for aviation or marine international transport activities, and emissions from these fuels are reported separately from totals in accordance with IPCC guidelines. If these emissions were included in the totals, bunker fuels would qualify as a key category according to the Tier 1 approach. The amount of uncertainty associated with estimation of emissions from international bunker fuels also supports the qualification of this source category as key, because it would qualify bunker fuels as a key category according to the Tier 2 approach. Table 1-4 presents the key categories for the United States (including and excluding LULUCF categories) using emissions and uncertainty data in this report, and ranked according to their sector and global warming potential-weighted emissions in 2009. The table also indicates the criteria used in identifying these categories (i.e., level, trend, Tier 1, Tier 2, and/or qualitative assessments). Annex 1 of this report provides additional information regarding the key categories in the United States and the methodologies used to identify them.

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[43] See Chapter 7 “Methodological Choice and Recalculation” in IPCC (2000). <http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>

Table 1-4: Key Categories for the United States (1990-2009)

		Tier 1				Tier 2					
IPCC Source Categories	**Gas**	**Level Without LULUCF**	**Trend Without LULUCF**	**Level With LULUCF**	**Trend With LULUCF**	**Level Without LULUCF**	**Trend Without LULUCF**	**Level With LULUCF**	**Trend With LULUCF**	**Qual**[a]	**2009 Emissions (Tg CO_2 Eq.)**
Energy											
CO_2 Emissions from Stationary Combustion - Coal	CO_2	•		•	•	•		•	•		1,841.0
CO_2 Emissions from Mobile Combustion: Road	CO_2	•	•	•	•	•	•	•	•		1,475.6
CO_2 Emissions from Stationary Combustion - Gas	CO_2	•	•	•	•	•	•	•	•		1,164.6
CO_2 Emissions from Stationary Combustion - Oil	CO_2	•	•	•	•	•	•	•	•		483.3
CO_2 Emissions from Mobile Combustion: Aviation	CO_2	•	•	•	•	•	•	•	•		140.7
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	•		•	•	•		•			123.4
CO_2 Emissions from Mobile Combustion: Other	CO_2	•	•	•	•						73.5
CO_2 Emissions from Natural Gas Systems	CO_2	•	•	•	•	•	•	•	•		32.2
CO_2 Emissions from Mobile Combustion: Marine	CO_2	•	•	•	•						30.0
Fugitive Emissions from Natural Gas Systems	CH_4	•	•	•	•	•	•	•	•		221.2
Fugitive Emissions from Coal Mining	CH_4	•	•	•	•	•	•	•	•		71.0
Fugitive Emissions from Petroleum Systems	CH_4	•	•	•	•	•	•	•	•		30.9
Non-CO_2 Emissions from Stationary Combustion	CH_4						•		•		6.2
N_2O Emissions from Mobile Combustion: Road	N_2O	•	•	•	•		•		•		20.3
Non-CO_2 Emissions from Stationary Combustion	N_2O					•		•			12.8
International Bunker Fuels[b]	Several									•	124.4
Industrial Processes											
CO_2 Emissions from Iron and Steel Production & Metallurgical Coke Production	CO_2	•	•	•	•	•	•	•	•		41.9
CO_2 Emissions from Cement Production	CO_2		•	•	•						29.0
CO_2 Emissions from Ammonia Production and Urea Consumption	CO_2		•		•						11.8
CO_2 Emissions from Aluminum Production	CO_2										3.0
N_2O Emissions from Nitric Acid Production	N_2O				•		•				14.6
N_2O Emissions from Adipic Acid Production	N_2O		•		•		•		•		1.9
Emissions from Substitutes for Ozone Depleting Substances	HiGWP	•	•	•	•		•	•	•		120.0
SF_6 Emissions from Electrical Transmission and Distribution	HiGWP		•		•		•		•		12.8
HFC-23 Emissions from HCFC-22 Production	HiGWP	•	•	•	•		•		•		5.4

IPCC Source Categories	Gas	Tier 1				Tier 2				Qual[a]	2009 Emissions (Tg CO_2 Eq.)
		Level Without LULUCF	Trend Without LULUCF	Level With LULUCF	Trend With LULUCF	Level Without LULUCF	Trend Without LULUCF	Level With LULUCF	Trend With LULUCF		
PFC Emissions from Aluminum Production	HiGWP		•		•		•				1.6
SF_6 Emissions from Magnesium Production and Processing	HiGWP		•		•						1.1
Agriculture											
CH_4 Emissions from Enteric Fermentation	CH_4	•		•		•		•			139.8
CH_4 Emissions from Manure Management	CH_4	•	•	•	•		•		•		49.5
CH_4 Emissions from Rice Cultivation	CH_4					•		•			7.3
Direct N_2O Emissions from Agricultural Soil Management	N_2O	•	•	•	•	•	•	•	•		160.2
Indirect N_2O Emissions from Applied Nitrogen	N_2O	•		•		•	•	•	•		44.4
Waste											
CH_4 Emissions from Landfills	CH_4	•	•	•	•	•	•	•	•		117.5
CH_4 Emissions from Wastewater Treatment	CH_4					•		•			24.5
Land Use, Land Use Change, and Forestry											
CO_2 Emissions from Changes in Forest Carbon Stocks	CO_2			•	•			•	•		(863.1)
CO_2 Emissions from Urban Trees	CO_2			•	•			•	•		(95.9)
CO_2 Emissions from Cropland Remaining Cropland	CO_2				•			•	•		(17.4)
CO_2 Emissions from Landfilled Yard Trimmings and Food Scraps	CO_2				•			•	•		(12.6)
CO_2 Emissions from Grassland Remaining Grassland	CO_2			•	•			•	•		(8.3)
CH_4 Emissions from Forest Fires	CH_4							•	•		7.8
N_2O Emissions from Forest Fires	N_2O								•		6.4
Subtotal Without LULUCF											**6,512.7**
Total Emissions Without LULUCF											**6,608.2**
Percent of Total Without LULUCF											**99%**
Subtotal With LULUCF											**5,529.5**
Total Emissions With LULUCF											**5,618.2**
Percent of Total With LULUCF											**98%**

[a] Qualitative criteria.

[b] Emissions from this source not included in totals.

Note: Parentheses indicate negative values (or sequestration).

1.6. Quality Assurance and Quality Control (QA/QC)

As part of efforts to achieve its stated goals for inventory quality, transparency, and credibility, the United States has developed a quality assurance and quality control plan designed to check, document and improve the quality of its inventory over time. QA/QC activities on the Inventory are undertaken within the framework of the U.S. QA/QC plan, Quality Assurance/Quality Control and Uncertainty Management Plan for the U.S. Greenhouse Gas Inventory: Procedures Manual for QA/QC and Uncertainty Analysis.

Key attributes of the QA/QC plan are summarized in Figure 1-1. These attributes include:

- specific detailed procedures and forms that serve to standardize the process of documenting and archiving information, as well as to guide the implementation of QA/QC and the analysis of the uncertainty of the inventory estimates;
- expert review as well as QC—for both the inventory estimates and the Inventory (which is the primary vehicle for disseminating the results of the inventory development process). In addition, the plan provides for public review of the Inventory;
- both Tier 1 (general) and Tier 2 (source-specific) quality controls and checks, as recommended by IPCC Good Practice Guidance;
- consideration of secondary data quality and source-specific quality checks (Tier 2 QC) in parallel and coordination with the uncertainty assessment; the development of protocols and templates provides for more structured communication and integration with the suppliers of secondary information;
- record-keeping provisions to track which procedures have been followed, and the results of the QA/QC and uncertainty analysis, and contains feedback mechanisms for corrective action based on the results of the investigations, thereby providing for continual data quality improvement and guided research efforts;
- implementation of QA/QC procedures throughout the whole inventory development process—from initial data collection, through preparation of the emission estimates, to publication of the Inventory;
- a schedule for multi-year implementation; and
- promotion of coordination and interaction within the EPA, across Federal agencies and departments, state government programs, and research institutions and consulting firms involved in supplying data or preparing estimates for the inventory. The QA/QC plan itself is intended to be revised and reflect new information that becomes available as the program develops, methods are improved, or additional supporting documents become necessary.

In addition, based on the national QA/QC plan for the Inventory, source-specific QA/QC plans have been developed for a number of sources. These plans follow the procedures outlined in the national QA/QC plan, tailoring the procedures to the specific text and spreadsheets of the individual sources. For each greenhouse gas emissions source or sink included in this Inventory, a minimum of a Tier 1 QA/QC analysis has been undertaken. Where QA/QC activities for a particular source go beyond the minimum Tier 1 level, further explanation is provided within the respective source category text.

The quality control activities described in the U.S. QA/QC plan occur throughout the inventory process; QA/QC is not separate from, but is an integral part of, preparing the inventory. Quality control—in the form of both good practices (such as documentation procedures) and checks on whether good practices and procedures are being followed—is applied at every stage of inventory development and document preparation. In addition, quality assurance occurs at two stages—an expert review and a public review. While both phases can significantly contribute to inventory quality, the public review phase is also essential for promoting the openness of the inventory development process and the transparency of the inventory data and methods.

The QA/QC plan guides the process of ensuring inventory quality by describing data and methodology checks, developing processes governing peer review and public comments, and developing guidance on conducting an analysis of the uncertainty surrounding the emission estimates. The QA/QC procedures also include feedback loops and provide for corrective actions that are designed to improve the inventory estimates over time.

Figure 1-1: U.S. QA/QC Plan Summary

1.7. Uncertainty Analysis of Emission Estimates

Uncertainty estimates are an essential element of a complete and transparent emissions inventory. Uncertainty information is not intended to dispute the validity of the inventory estimates, but to help prioritize efforts to improve the accuracy of future inventories and guide future decisions on methodological choice. While the U.S. Inventory calculates its emission estimates with the highest possible accuracy, uncertainties are associated to a varying degree with the development of emission estimates for any inventory. Some of the current estimates, such as those for CO_2 emissions from energy-related activities, are considered to have minimal uncertainty associated with them. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty surrounding the estimates presented. Despite these uncertainties, the UNFCCC reporting guidelines follow the recommendation in the 1996 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1997) and require that countries provide single point estimates for each gas and emission or removal source category. Within the discussion of each emission source, specific factors affecting the uncertainty associated with the estimates are discussed.

Additional research in the following areas could help reduce uncertainty in the U.S. Inventory:

- *Incorporating excluded emission sources.* Quantitative estimates for some of the sources and sinks of greenhouse gas emissions are not available at this time. In particular, emissions from some land-use activities and industrial processes are not included in the inventory either because data are incomplete or because methodologies do not exist for estimating emissions from these source categories. See Annex 5 of this report for a discussion of the sources of greenhouse gas emissions and sinks excluded from this report.
- *Improving the accuracy of emission factors.* Further research is needed in some cases to improve the accuracy of emission factors used to calculate emissions from a variety of sources. For example, the accuracy of current emission factors applied to CH_4 and N_2O emissions from stationary and mobile combustion is highly uncertain.
- *Collecting detailed activity data.* Although methodologies exist for estimating emissions for some sources, problems arise in obtaining activity data at a level of detail in which aggregate emission factors can be applied. For example, the ability to estimate emissions of SF_6 from electrical transmission and distribution is limited due to a lack of activity data regarding national SF_6 consumption or average equipment leak rates.

The overall uncertainty estimate for the U.S. greenhouse gas emissions inventory was developed using the IPCC Tier 2 uncertainty estimation methodology. Estimates of quantitative uncertainty for the overall greenhouse gas emissions inventory are shown below, in Table 1-5.

The IPCC provides good practice guidance on two approaches—Tier 1 and Tier 2—to estimating uncertainty for individual source categories. Tier 2 uncertainty analysis, employing the Monte Carlo Stochastic Simulation technique, was applied wherever data and resources permitted; further explanation is provided within the respective source category text and in Annex 7. Consistent with the IPCC Good Practice Guidance (IPCC 2000), over a multi-year timeframe, the United States expects to continue to improve the uncertainty estimates presented in this report.

Table 1-5. Estimated Overall Inventory Quantitative Uncertainty (Tg CO_2 Eq. and Percent)

Gas	**2009 Emission Estimate[a] (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[b] (Tg CO_2 Eq.)**		**(%)**		**Mean[c] (Tg CO_2 Eq.)**	**Standard Deviation[c] (Tg CO_2 Eq.)**
		Lower Bound[d]	**Upper Bound[d]**	**Lower Bound**	**Upper Bound**		
CO_2	5,504.8	5,436.6	5,813.8	-1%	6%	5,622.5	97.5
CH_4[e]	686.3	623.9	805.4	-9%	17%	702.8	45.3
N_2O[e]	295.6	261.7	425.3	-11%	44%	334.2	42.1
PFC, HFC & SF_6[e]	143.3	134.5	153.4	-6%	7%	143.7	4.8
Total	**6,630.0**	**6,584.2**	**7,033.6**	**-1%**	**6%**	**6,803.2**	**115.0**
Net Emissions (Sources and Sinks)	**5,614.9**	**5,512.3**	**6,055.1**	**-2%**	**8%**	**5,785.4**	**139.1**

Notes:

[a] Emission estimates reported in this table correspond to emissions from only those source categories for which quantitative uncertainty was performed this year. Thus the totals reported in this table exclude approximately 3.1 Tg CO_2 Eq. of emissions for

which quantitative uncertainty was not assessed. Hence, these emission estimates do not match the final total U.S. greenhouse gas emission estimates presented in this Inventory.

[b] The lower and upper bounds for emission estimates correspond to a 95 percent confidence interval, with the lower bound corresponding to 2.5th percentile and the upper bound corresponding to 97.5th percentile.

[c] Mean value indicates the arithmetic average of the simulated emission estimates; standard deviation indicates the extent of deviation of the simulated values from the mean.

[d] The lower and upper bound emission estimates for the sub-source categories do not sum to total emissions because the low and high estimates for total emissions were calculated separately through simulations.

[e] The overall uncertainty estimates did not take into account the uncertainty in the GWP values for CH_4, N_2O and high GWP gases used in the inventory emission calculations for 2009.

Emissions calculated for the U.S. Inventory reflect current best estimates; in some cases, however, estimates are based on approximate methodologies, assumptions, and incomplete data. As new information becomes available in the future, the United States will continue to improve and revise its emission estimates. See Annex 7 of this report for further details on the U.S. process for estimating uncertainty associated with the emission estimates and for a more detailed discussion of the limitations of the current analysis and plans for improvement. Annex 7 also includes details on the uncertainty analysis performed for selected source categories.

1.8. Completeness

This report, along with its accompanying CRF reporter, serves as a thorough assessment of the anthropogenic sources and sinks of greenhouse gas emissions for the United States for the time series 1990 through 2009. Although this report is intended to be comprehensive, certain sources have been identified yet excluded from the estimates presented for various reasons. Generally speaking, sources not accounted for in this inventory are excluded due to data limitations or a lack of thorough understanding of the emission process. The United States is continually working to improve upon the understanding of such sources and seeking to find the data required to estimate related emissions. As such improvements are implemented, new emission sources are quantified and included in the Inventory. For a complete list of sources not included, see Annex 5 of this report.

1.9. Organization of Report

In accordance with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), and the 2006 UNFCCC Guidelines on Reporting and Review (UNFCCC 2006), this Inventory of U.S. Greenhouse Gas Emissions and Sinks is segregated into six sector-specific chapters, listed below in Table 1-6. In addition, chapters on Trends in Greenhouse Gas Emissions and Other information to be considered as part of the U.S. Inventory submission are included.

Table 1-6: IPCC Sector Descriptions

Chapter/IPCC Sector	Activities Included
Energy	Emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions.
Industrial Processes	By-product or fugitive emissions of greenhouse gases from industrial processes not directly related to energy activities such as fossil fuel combustion.
Solvent and Other Product Use	Emissions, of primarily NMVOCs, resulting from the use of solvents and N_2O from product uses.
Agriculture	Anthropogenic emissions from agricultural activities except fuel combustion, which is addressed under Energy.
Land Use, Land-Use Change, and Forestry	Emissions and removals of CO_2, CH_4, and N_2O from forest management, other land-use activities, and land-use change.
Waste	Emissions from waste management activities.

Source: (IPCC/UNEP/OECD/IEA 1997)

Within each chapter, emissions are identified by the anthropogenic activity that is the source or sink of the greenhouse gas emissions being estimated (e.g., coal mining). Overall, the following organizational structure is consistently applied throughout this report:

Chapter/IPCC Sector: Overview of emission trends for each IPCC defined sector

Source category: Description of source pathway and emission trends.

Methodology: Description of analytical methods employed to produce emission estimates and identification of data references, primarily for activity data and emission factors.

Uncertainty: A discussion and quantification of the uncertainty in emission estimates and a discussion of time-series consistency.

QA/QC and Verification: A discussion on steps taken to QA/QC and verify the emission estimates, where beyond the overall U.S. QA/QC plan, and any key findings.

Recalculations: A discussion of any data or methodological changes that necessitate a recalculation of previous years' emission estimates, and the impact of the recalculation on the emission estimates, if applicable.

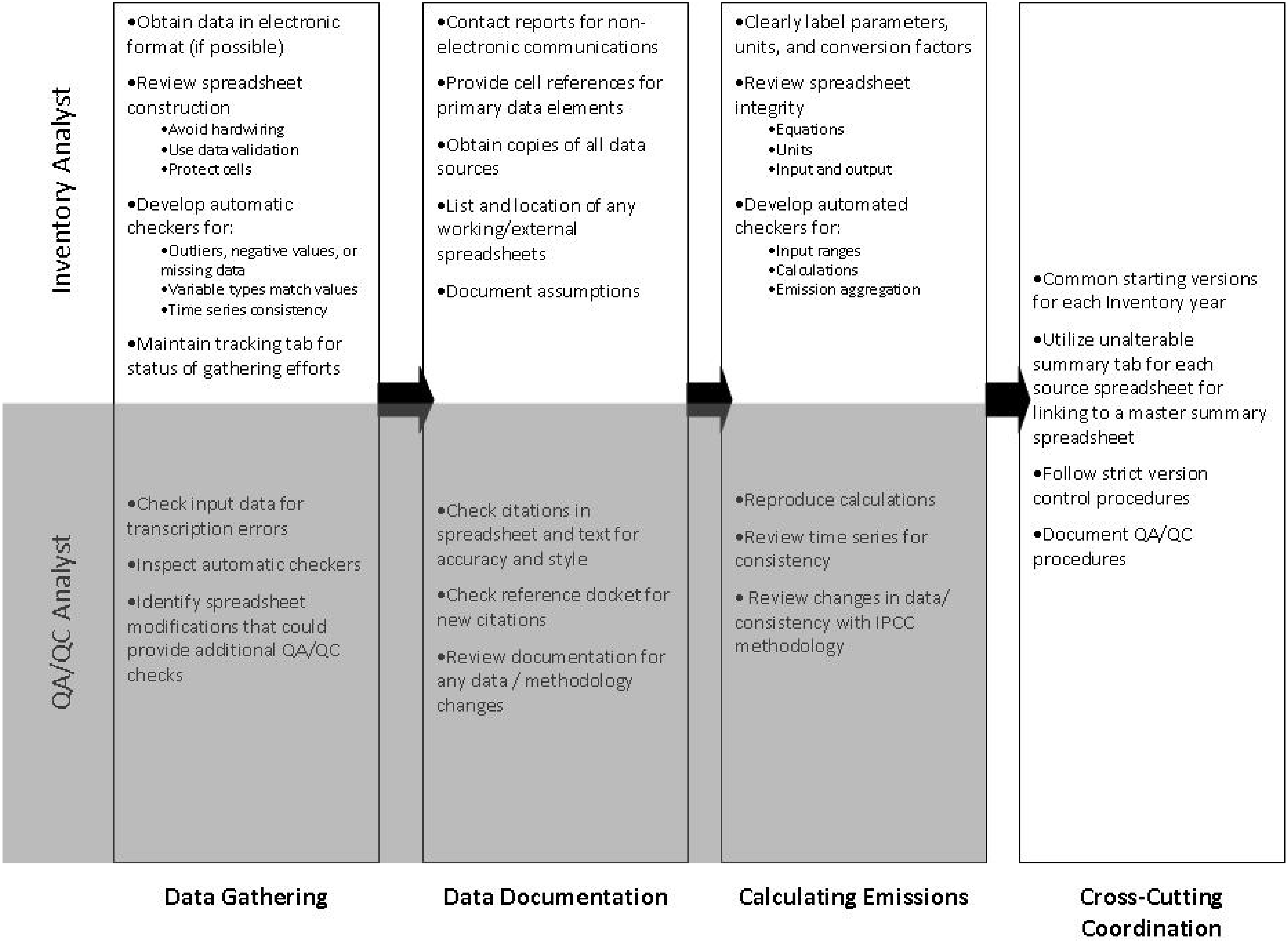
Planned Improvements: A discussion on any source-specific planned improvements, if applicable.

Special attention is given to CO_2 from fossil fuel combustion relative to other sources because of its share of emissions and its dominant influence on emission trends. For example, each energy consuming end-use sector (i.e., residential, commercial, industrial, and transportation), as well as the electricity generation sector, is described individually. Additional information for certain source categories and other topics is also provided in several Annexes listed in Table 1-7.

Table 1-7: List of Annexes

ANNEX 1 Key Category Analysis
ANNEX 2 Methodology and Data for Estimating CO_2 Emissions from Fossil Fuel Combustion
2.1. Methodology for Estimating Emissions of CO_2 from Fossil Fuel Combustion
2.2. Methodology for Estimating the Carbon Content of Fossil Fuels
2.3. Methodology for Estimating Carbon Emitted from Non-Energy Uses of Fossil Fuels
ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories
3.1. Methodology for Estimating Emissions of CH_4, N_2O, and Indirect Greenhouse Gases from Stationary Combustion
3.2. Methodology for Estimating Emissions of CH_4, N_2O, and Indirect Greenhouse Gases from Mobile Combustion and Methodology for and Supplemental Information on Transportation-Related Greenhouse Gas Emissions
3.3. Methodology for Estimating CH_4 Emissions from Coal Mining
3.4. Methodology for Estimating CH_4 Emissions from Natural Gas Systems
3.5. Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems
3.6. Methodology for Estimating CO_2 and N_2O Emissions from Incineration of Waste
3.7. Methodology for Estimating Emissions from International Bunker Fuels used by the U.S. Military
3.8. Methodology for Estimating HFC and PFC Emissions from Substitution of Ozone Depleting Substances
3.9. Methodology for Estimating CH_4 Emissions from Enteric Fermentation
3.10. Methodology for Estimating CH_4 and N_2O Emissions from Manure Management
3.11. Methodology for Estimating N_2O Emissions from Agricultural Soil Management
3.12. Methodology for Estimating Net Carbon Stock Changes in Forest Lands Remaining Forest Lands
3.13. Methodology for Estimating Net Changes in Carbon Stocks in Mineral and Organic Soils on Croplands and Grasslands
3.14. Methodology for Estimating CH_4 Emissions from Landfills
ANNEX 4 IPCC Reference Approach for Estimating CO_2 Emissions from Fossil Fuel Combustion
ANNEX 5 Assessment of the Sources and Sinks of Greenhouse Gas Emissions Not Included
ANNEX 6 Additional Information
6.1. Global Warming Potential Values
6.2. Ozone Depleting Substance Emissions
6.3. Sulfur Dioxide Emissions
6.4. Complete List of Source Categories
6.5. Constants, Units, and Conversions
6.6. Abbreviations

Figure 1: U.S. QA/QC Plan Summary



	Data Gathering	Data Documentation	Calculating Emissions	Cross-Cutting Coordination
Inventory Analyst	•Obtain data in electronic format (if possible) •Review spreadsheet construction •Avoid hardwiring •Use data validation •Protect cells •Develop automatic checkers for: •Outliers, negative values, or missing data •Variable types match values •Time series consistency •Maintain tracking tab for status of gathering efforts	•Contact reports for non-electronic communications •Provide cell references for primary data elements •Obtain copies of all data sources •List and location of any working/external spreadsheets •Document assumptions	•Clearly label parameters, units, and conversion factors •Review spreadsheet integrity •Equations •Units •Input and output •Develop automated checkers for: •Input ranges •Calculations •Emission aggregation	•Common starting versions for each Inventory year •Utilize unalterable summary tab for each source spreadsheet for linking to a master summary spreadsheet •Follow strict version control procedures •Document QA/QC procedures
QA/QC Analyst	•Check input data for transcription errors •Inspect automatic checkers •Identify spreadsheet modifications that could provide additional QA/QC checks	•Check citations in spreadsheet and text for accuracy and style •Check reference docket for new citations •Review documentation for any data / methodology changes	•Reproduce calculations •Review time series for consistency • Review changes in data/ consistency with IPCC methodology	

2. Trends in Greenhouse Gas Emissions

2.1. *Recent Trends in U.S. Greenhouse Gas Emissions and Sinks*

In 2009, total U.S. greenhouse gas emissions were 6,633.2 teragrams of carbon dioxide equivalents (Tg CO_2 Eq.); net emissions were 5,618.2 Tg CO_2 Eq. reflecting the influence of sinks (net CO_2 flux from Land Use, Land Use Change, and Forestry).[44] While total U.S. emissions have increased by 7.3 percent from 1990 to 2009, emissions decreased from 2008 to 2009 by 6.1 percent (427.9 Tg CO_2 Eq.). The following factors were primary contributors to this decrease: (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; and (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly.

Figure 2-1: U.S. Greenhouse Gas Emissions by Gas

Figure 2-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

Figure 2-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

As the largest contributor to U.S. greenhouse gas emissions, carbon dioxide (CO_2) from fossil fuel combustion has accounted for approximately 79 percent of global warming potential (GWP) weighted emissions since 1990, from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2009. Emissions from this source category grew by 9.9 percent (470.6 Tg CO_2 Eq.) from 1990 to 2009 and were responsible for most of the increase in national emissions during this period. From 2008 to 2009, these emissions decreased by 6.4 percent (356.9 Tg CO_2 Eq.). Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends.

Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, and seasonal temperatures. On an annual basis, the overall consumption of fossil fuels in the United States fluctuates primarily in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than in a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

In the longer-term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Energy-related CO_2 emissions also depend on the type of fuel or energy consumed and its carbon (C) intensity. Producing a unit of heat or electricity using natural gas instead of coal, for example, can reduce the CO_2 emissions because of the lower C content of natural gas.

A brief discussion of the year to year variability in fuel combustion emissions is provided below, beginning with 2005.

From 2005 to 2006, emissions from fuel combustion decreased for the first time since 2000 to 2001. This decrease occurred across all sectors, with the exception of the industrial sector and the U.S. Territories sector, due to a

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[44] Estimates are presented in units of teragrams of carbon dioxide equivalent (Tg CO_2 Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

number of factors. The decrease in emissions from electricity generation is a result of a smaller share of electricity generated by coal and a greater share generated by natural gas. Coal consumption for electricity generation decreased by 1.3 percent while natural gas consumption for electricity generation increased by 6.0 percent in 2006 and nuclear power generation increased by less than 1 percent. The decrease in consumption of transportation fuels is primarily a result of the restraint on fuel consumption caused by rising fuel prices, which directly resulted in a decrease of petroleum consumption within this sector of about 1.1 percent in 2006. The significant decrease in emissions from the residential sector is primarily a result of decreased electricity consumption due to increases in the price of electricity, and warmer winter weather conditions compared to 2005. A moderate increase in industrial sector emissions is the result of growth in industrial output and growth in the U.S. economy. Renewable fuels used to generate electricity increased in 2006, with the greatest growth occurring in generation from wind by 48 percent.

After experiencing a decrease from 2005 to 2006, emissions from fuel combustion grew from 2006 to 2007 at a rate somewhat higher than the average growth rate since 1990. There were a number of factors contributing to this increase. More energy-intensive weather conditions in both the winter and summer resulted in an increase in consumption of heating fuels, as well as an increase in the demand for electricity. This demand for electricity was met with an increase in coal consumption of 1.7 percent, and with an increase in natural gas consumption of 9.9 percent. This increase in fossil fuel consumption, combined with a 14.7 percent decrease in hydropower generation from 2006 to 2007, resulted in an increase in emissions in 2007. The increase in emissions from the residential and commercial sectors is a result of increased electricity consumption due to warmer summer conditions and cooler winter conditions compared to 2006. In addition to these more energy-intensive weather conditions, electricity prices remained relatively stable compared to 2006, and natural gas prices decreased slightly. Emissions from the industrial sector decreased compared to 2006 as a result of a decrease in industrial production and fossil fuels used for electricity generation. Despite an overall decrease in electricity generation from renewable energy in 2007 driven by decreases in hydropower generation, wind and solar generation increased significantly.

Emissions from fossil fuel combustion decreased from 2007 to 2008. Several factors contributed to this decrease in emissions. An increase in energy prices coupled with the economic downturn led to a decrease in energy demand and a resulting decrease in emissions from 2007 to 2008. In 2008, the price of coal, natural gas, and petroleum used to generate electricity, as well as the price of fuels used for transportation, increased significantly. As a result of this price increase, coal, natural gas, and petroleum consumption used for electricity generation decreased by 1.4 percent, 2.5 percent, and 28.8 percent, respectively. The increase in the cost of fuels to generate electricity translated into an increase in the price of electricity, leading to a decrease in electricity consumption across all sectors except the commercial sector. The increase in transportation fuel prices led to a decrease in vehicle miles traveled (VMT) and a 5.5 percent decrease in transportation fossil fuel combustion emissions from 2007 to 2008. Cooler weather conditions in the summer led to a decrease in cooling degree days by 8.7 percent and a decrease in electricity demand compared to 2007, whereas cooler winter conditions led to a 5.6 percent increase in heating degree days compared to 2007 and a resulting increase in demand for heating fuels. The increased emissions from winter heating energy demand was offset by a decrease in emissions from summer cooling related electricity demand. Lastly, renewable energy[45] consumption for electricity generation increased by 9.6 percent from 2007 to 2008, driven by a significant increase in solar and wind energy consumption (of 19.4 percent and 60.2 percent, respectively). This increase in renewable energy generation contributed to a decrease in the carbon intensity of electricity generation.

From 2008 to 2009, CO_2 from fossil fuel combustion emissions experienced a decrease of 6.4 percent, the greatest decrease of any year over the course of the twenty-year period. Various factors contributed to this decrease in emissions. The continued economic downturn resulted in a 2.6 percent decrease in GDP, and a decrease in energy consumption across all sectors. The economic downturn also impacted total industrial production and manufacturing output, which decreased by 9.3 and 10.9 percent, respectively. In 2009, the price of coal used to generate electricity increased, while the price of natural gas used to generate electricity decreased significantly. As a result, natural gas was used for a greater share of electricity generation in 2009 than 2008, and coal was used for a smaller share. The fuel switching from coal to natural gas and additional electricity generation from other energy sources in 2009, which included a 6.8 percent increase in hydropower generation from the previous year, resulted in a decrease in carbon intensity, and in turn, a decrease in emissions from electricity generation. From 2008 to 2009, industrial sector emissions decreased significantly as a result of a decrease in output from energy-intensive industries of 16.6

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[45] Renewable energy, as defined in EIA’s energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biofuels, solar energy, and wind energy.

percent in nonmetallic mineral and 31.6 percent in primary metal industries. The residential and commercial sectors only experienced minor decreases in emissions as summer and winter weather conditions were less energy-intensive from 2008 to 2009, and the price of electricity only increased slightly. Heating degree days decreased slightly and cooling degree days decreased by 3.8 percent from 2008 to 2009.

Overall, from 1990 to 2009, total emissions of CO_2 and CH_4 increased by 405.5 Tg CO_2 Eq. (8.0 percent) and 11.4 Tg CO_2 Eq. (1.7 percent), respectively, while N_2O emissions decreased by 19.6 Tg CO_2 Eq. (6.2 percent). During the same period, aggregate weighted emissions of HFCs, PFCs, and SF_6 rose by 54.1 Tg CO_2 Eq. (58.8 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, and SF_6 are significant because many of them have extremely high GWPs and, in the cases of PFCs and SF_6, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by C sequestration in managed forests, trees in urban areas, agricultural soils, and landfilled yard trimmings. These were estimated to offset 15.3 percent of total emissions in 2009.

Table 2-1 summarizes emissions and sinks from all U.S. anthropogenic sources in weighted units of Tg CO_2 Eq., while unweighted gas emissions and sinks in gigagrams (Gg) are provided in Table 2-2.

Table 2-1: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg CO_2 Eq.)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**5,099.7**	**5,975.0**	**6,113.8**	**6,021.1**	**6,120.0**	**5,921.4**	**5,505.2**
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	*1,820.8*	*2,296.9*	*2,402.1*	*2,346.4*	*2,412.8*	*2,360.9*	*2,154.0*
Transportation	*1,485.9*	*1,809.5*	*1,896.6*	*1,878.1*	*1,894.0*	*1,789.9*	*1,719.7*
Industrial	*846.5*	*851.1*	*823.1*	*848.2*	*842.0*	*802.9*	*730.4*
Residential	*338.3*	*370.7*	*357.9*	*321.5*	*342.4*	*348.2*	*339.2*
Commercial	*219.0*	*230.8*	*223.5*	*208.6*	*219.4*	*224.2*	*224.0*
U.S. Territories	*27.9*	*35.9*	*50.0*	*50.3*	*46.1*	*39.8*	*41.7*
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Iron and Steel Production & Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Ammonia Production and Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Cropland Remaining Cropland	7.1	7.5	7.9	7.9	8.2	8.7	7.8
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Wetlands Remaining Wetlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
Land Use, Land-Use Change, and Forestry (Sink)[a]	*(861.5)*	*(576.6)*	*(1,056.5)*	*(1,064.3)*	*(1,060.9)*	*(1,040.5)*	*(1,015.1)*
Biomass—Wood[b]	215.2	218.1	206.9	203.8	203.3	198.4	183.8
International Bunker Fuels[c]	*111.8*	*98.5*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*

Biomass—Ethanol[b]	4.2	9.4	23.0	31.0	38.9	54.8	61.2
CH_4	**674.9**	**659.9**	**631.4**	**672.1**	**664.6**	**676.7**	**686.3**
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Forest Land Remaining Forest Land	3.2	14.3	9.8	21.6	20.0	11.9	7.8
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production & Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Field Burning of Agriculture Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[c]	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**315.2**	**341.0**	**322.9**	**326.4**	**325.1**	**310.8**	**295.6**
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Forest Land Remaining Forest Land	2.7	12.1	8.4	18.0	16.7	10.1	6.7
Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
N_2O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Settlements Remaining Settlements	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
HFCs	**36.9**	**103.2**	**120.2**	**123.5**	**129.5**	**129.4**	**125.7**
Substitution of Ozone Depleting Substances[d]	0.3	74.3	104.2	109.4	112.3	115.5	120.0
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacture	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	**20.8**	**13.5**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**
Semiconductor Manufacture	2.2	4.9	3.2	3.5	3.7	4.0	4.0
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
SF_6	**34.4**	**20.1**	**19.0**	**17.9**	**16.7**	**16.1**	**14.8**

Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Semiconductor Manufacture	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Total	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total. Parentheses indicate negative values or sequestration.

[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

[c] Emissions from International Bunker Fuels are not included in totals.

[d] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Table 2-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**5,099,719**	**5,974,991**	**6,113,751**	**6,021,089**	**6,120,009**	**5,921,443**	**5,505,204**
Fossil Fuel Combustion	4,738,422	5,594,848	5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
Electricity Generation	*1,820,818*	*2,296,894*	*2,402,142*	*2,346,406*	*2,412,827*	*2,360,919*	*2,154,025*
Transportation	*1,485,937*	*1,809,514*	*1,896,606*	*1,878,125*	*1,893,994*	*1,789,918*	*1,719,685*
Industrial	*846,475*	*851,094*	*823,069*	*848,206*	*842,048*	*802,856*	*730,422*
Residential	*338,347*	*370,666*	*357,903*	*321,513*	*342,397*	*348,221*	*339,203*
Commercial	*218,964*	*230,828*	*223,512*	*208,582*	*219,356*	*224,167*	*223,993*
U.S. Territories	*27,882*	*35,853*	*49,968*	*50,284*	*46,123*	*39,845*	*41,652*
Non-Energy Use of Fuels	118,630	144,933	143,392	145,574	137,233	140,952	123,356
Iron and Steel Production & Metallurgical Coke Production	99,528	85,935	65,925	68,772	71,045	66,015	41,871
Natural Gas Systems	37,574	29,877	29,902	30,755	31,050	32,828	32,171
Cement Production	33,278	40,405	45,197	45,792	44,538	40,531	29,018
Incineration of Waste	7,989	11,112	12,450	12,531	12,700	12,169	12,300
Ammonia Production and Urea Consumption	16,831	16,402	12,849	12,300	14,038	11,949	11,797
Lime Production	11,533	14,088	14,379	15,100	14,595	14,330	11,223
Cropland Remaining Cropland	7,084	7,541	7,854	7,875	8,202	8,654	7,832
Limestone and Dolomite Use	5,127	5,056	6,768	8,035	7,702	6,276	7,649
Soda Ash Production and Consumption	4,141	4,181	4,228	4,162	4,140	4,111	4,265
Aluminum Production	6,831	6,086	4,142	3,801	4,251	4,477	3,009
Petrochemical Production	3,311	4,479	4,181	3,837	3,931	3,449	2,735
Carbon Dioxide Consumption	1,416	1,421	1,321	1,709	1,867	1,780	1,763
Titanium Dioxide Production	1,195	1,752	1,755	1,836	1,930	1,809	1,541
Ferroalloy Production	2,152	1,893	1,392	1,505	1,552	1,599	1,469
Wetlands Remaining Wetlands	1,033	1,227	1,079	879	1,012	992	1,090
Phosphoric Acid Production	1,529	1,382	1,386	1,167	1,166	1,187	1,035
Zinc Production	667	997	1,088	1,088	1,081	1,230	966

Lead Production	516	594	553	560	562	551	525
Petroleum Systems	555	534	490	488	474	453	463
Silicon Carbide Production and Consumption	375	248	219	207	196	175	145
Land Use, Land-Use Change, and Forestry (Sink)[a]	*(861,535)*	*(576,588)*	*(1,056,459)*	*(1,064,330)*	*(1,060,882)*	*(1,040,461)*	*(1,015,074)*
Biomass - Wood[b]	*215,186*	*218,088*	*206,865*	*203,846*	*203,316*	*198,361*	*183,777*
International Bunker Fuels[c]	*111,828*	*98,482*	*109,750*	*128,384*	*127,618*	*133,704*	*123,127*
Biomass - Ethanol[b]	*4,229*	*9,352*	*22,956*	*31,002*	*38,946*	*54,770*	*61,231*
CH_4	**32,136**	**31,423**	**30,069**	**32,004**	**31,647**	**32,225**	**32,680**
Natural Gas Systems	9,038	9,968	9,069	10,364	9,771	10,087	10,535
Enteric Fermentation	6,290	6,502	6,500	6,611	6,715	6,696	6,655
Landfills	7,018	5,317	5,358	5,321	5,299	5,520	5,593
Coal Mining	4,003	2,877	2,710	2,774	2,756	3,196	3,382
Manure Management	1,511	2,019	2,217	2,226	2,416	2,353	2,356
Petroleum Systems	1,685	1,501	1,398	1,398	1,427	1,439	1,473
Wastewater Treatment	1,118	1,199	1,159	1,167	1,163	1,168	1,167
Forest Land Remaining Forest Land	152	682	467	1,027	953	569	372
Rice Cultivation	339	357	326	282	295	343	349
Stationary Combustion	354	315	312	293	308	310	293
Abandoned Underground Coal Mines	288	350	264	261	267	279	262
Mobile Combustion	223	160	119	112	105	97	93
Composting	15	60	75	75	79	80	79
Petrochemical Production	41	59	51	48	48	43	40
Iron and Steel Production & Metallurgical Coke Production	46	44	34	35	33	31	17
Field Burning of Agricultural Residues	13	12	9	11	11	13	12
Ferroalloy Production	1	1	+	+	+	+	+
Silicon Carbide Production and Consumption	1	1	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[c]	*8*	*6*	*7*	*8*	*8*	*8*	*7*
N_2O	**1,017**	**1,100**	**1,042**	**1,053**	**1,049**	**1,002**	**954**
Agricultural Soil Management	638	667	682	674	675	680	660
Mobile Combustion	142	172	119	108	98	84	77
Manure Management	47	55	56	58	58	58	58
Nitric Acid Production	57	63	53	52	62	53	47
Stationary Combustion	41	47	47	47	47	46	41
Forest Land Remaining Forest Land	9	39	27	58	54	33	22
Wastewater Treatment	12	14	15	16	16	16	16
N_2O from Product Uses	14	16	14	14	14	14	14
Adipic Acid Production	51	18	16	14	12	7	6
Composting	1	4	6	6	6	6	6
Settlements Remaining Settlements	3	4	5	5	5	5	5

Incineration of Waste	2	1	1	1	1	1	1
Field Burning of Agricultural Residues	+	+	+	+	+	+	+
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*3*	*3*	*3*	*4*	*4*	*4*	*4*
HFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Substitution of Ozone Depleting Substances[d]	M	M	M	M	M	M	M
HCFC-22 Production	3	2	1	1	1	1	+
Semiconductor Manufacture	+	+	+	+	+	+	+
PFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Semiconductor Manufacture	M	M	M	M	M	M	M
Aluminum Production	M	M	M	M	M	M	M
SF_6	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Electrical Transmission and Distribution	1	1	1	1	1	1	1
Magnesium Production and Processing	+	+	+	+	+	+	+
Semiconductor Manufacture	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg.

M Mixture of multiple gases

[a] The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total. Parentheses indicate negative values or sequestration.

[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry

[c] Emissions from International Bunker Fuels are not included in totals.

[d] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Emissions of all gases can be summed from each source category from Intergovernmental Panel on Climate Change (IPCC) guidance. Over the twenty-year period of 1990 to 2009, total emissions in the Energy and Agriculture sectors grew by 463.3 Tg CO_2 Eq. (8.8 percent) and 35.7 Tg CO_2 Eq. (9.3 percent), respectively. Emissions decreased in the Industrial Processes, Waste, and Solvent and Other Product Use sectors by 32.9 Tg CO_2 Eq. (10.4 percent), 24.7 Tg CO_2 Eq. (14.1 percent) and less than 0.1 Tg CO_2 Eq. (less than 0.4 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry sector increased by 153.5 Tg CO_2 Eq. (17.8 percent).

Figure 2-4: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

Table 2-3: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg CO_2 Eq.)

Chapter/IPCC Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Energy	5,287.8	6,168.0	6,282.8	6,210.2	6,290.7	6,116.6	5,751.1
Industrial Processes	315.8	348.8	334.1	339.4	350.9	331.7	282.9
Solvent and Other Product Use	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Agriculture	383.6	410.6	418.8	418.8	425.8	426.3	419.3
Land Use, Land-Use Change, and Forestry (Emissions)	15.0	36.3	28.6	49.8	47.5	33.2	25.0
Waste	175.2	143.9	144.9	144.4	144.1	149.0	150.5

Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Sinks)[*]	(861.5)	(576.6)	(1056.5)	(1064.3)	(1060.9)	(1040.5)	(1015.1)
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

[*] The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total. Please refer to Table 2-9 for a breakout by source.

Note: Totals may not sum due to independent rounding.

Note: Parentheses indicate negative values or sequestration.

Energy

Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO_2 emissions for the period of 1990 through 2009. In 2009, approximately 83 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 17 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure 2-5 and Figure 2-6). A discussion of specific trends related to CO_2 as well as other greenhouse gas emissions from energy consumption is presented in the Energy chapter. Energy-related activities are also responsible for CH_4 and N_2O emissions (49 percent and 13 percent of total U.S. emissions of each gas, respectively). Table 2-4 presents greenhouse gas emissions from the Energy chapter, by source and gas.

Figure 2-5: 2009 Energy Chapter Greenhouse Gas Sources

Figure 2-6: 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

Table 2-4: Emissions from Energy (Tg CO_2 Eq.)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**4,903.2**	**5,781.3**	**5,939.4**	**5,842.5**	**5,938.2**	**5,752.3**	**5,377.3**
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Biomass - Wood[a]	*215.2*	*218.1*	*206.9*	*203.8*	*203.3*	*198.4*	*183.8*
International Bunker Fuels[b]	*111.8*	*98.5*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*
Biomass - Ethanol[a]	*4.2*	*9.4*	*23.0*	*31.0*	*38.9*	*54.8*	*61.2*
CH_4	**327.4**	**318.6**	**291.3**	**319.2**	**307.3**	**323.6**	**336.8**
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Incineration of Waste	+	+	+	+	+	+	+

International Bunker Fuels[b]	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**57.2**	**68.1**	**52.1**	**48.5**	**45.2**	**40.7**	**37.0**
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
International Bunker Fuels[b]	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
Total	**5,287.8**	**6,168.0**	**6,282.8**	**6,210.2**	**6,290.7**	**6,116.6**	**5,751.1**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry

[b] Emissions from International Bunker Fuels are not included in totals.

Note: Totals may not sum due to independent rounding.

Carbon dioxide emissions from fossil fuel combustion are presented in Table 2-5 based on the underlying U.S. energy consumer data collected by EIA. Estimates of CO_2 emissions from fossil fuel combustion are calculated from these EIA "end-use sectors" based on total consumption and appropriate fuel properties (any additional analysis and refinement of the EIA data is further explained in the Energy chapter of this report). EIA's fuel consumption data for the electric power sector comprises electricity-only and combined-heat-and-power (CHP) plants within the NAICS 22 category whose primary business is to sell electricity, or electricity and heat, to the public (nonutility power producers can be included in this sector as long as they meet they electric power sector definition). EIA statistics for the industrial sector include fossil fuel consumption that occurs in the fields of manufacturing, agriculture, mining, and construction. EIA's fuel consumption data for the transportation sector consists of all vehicles whose primary purpose is transporting people and/or goods from one physical location to another. EIA's fuel consumption data for the industrial sector consists of all facilities and equipment used for producing, processing, or assembling goods (EIA includes generators that produce electricity and/or useful thermal output primarily to support on-site industrial activities in this sector). EIA's fuel consumption data for the residential sector consists of living quarters for private households. EIA's fuel consumption data for the commercial sector consists of service-providing facilities and equipment from private and public organizations and businesses (EIA includes generators that produce electricity and/or useful thermal output primarily to support the activities at commercial establishments in this sector). Table 2-5, Figure 2-7, and Figure 2-8 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Table 2-5: CO_2 Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Transportation	**1,489.0**	**1,813.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.6**	**1,724.1**
Combustion	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Electricity	3.0	3.4	4.7	4.5	5.0	4.7	4.4
Industrial	**1,533.2**	**1,640.8**	**1,560.0**	**1,560.2**	**1,572.0**	**1,517.7**	**1,333.7**
Combustion	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Electricity	686.7	789.8	737.0	712.0	730.0	714.8	603.3
Residential	**931.4**	**1,133.1**	**1,214.7**	**1,152.4**	**1,198.5**	**1,182.2**	**1,123.8**
Combustion	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Electricity	593.0	762.4	856.7	830.8	856.1	834.0	784.6
Commercial	**757.0**	**972.1**	**1,027.2**	**1,007.6**	**1,041.1**	**1,031.6**	**985.7**
Combustion	219.0	230.8	223.5	208.6	219.4	224.2	224.0
Electricity	538.0	741.3	803.7	799.0	821.7	807.4	761.7
U.S. Territories	**27.9**	**35.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**
Total	**4,738.4**	**5,594.8**	**5,753.2**	**5,653.1**	**5,756.7**	**5,565.9**	**5,209.0**
Electricity Generation	**1,820.8**	**2,296.9**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,154.0**

Note: Totals may not sum due to independent rounding. Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

Figure 2-7: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Figure 2-8: 2009 End-Use Sector Emissions from Fossil Fuel Combustion

The main driver of emissions in the Energy sector is CO_2 from fossil fuel combustion. The transportation end-use sector accounted for 1,724.1 Tg CO_2 Eq. in 2009 or approximately 33 percent of total CO_2 emissions from fossil fuel combustion, the largest share of any end-use sector.[46] The industrial end-use sector accounted for 26 percent of CO_2 emissions from fossil fuel combustion. The residential and commercial end-use sectors accounted for an average 22 and 19 percent, respectively, of CO_2 emissions from fossil fuel combustion. Both end-use sectors were heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances contributing 70 and 77 percent of emissions from the residential and commercial end-use sectors, respectively. Significant trends in emissions from energy source categories over the twenty-year period from 1990 through 2009 included the following:

- Total CO_2 emissions from fossil fuel combustion increased from 4,738.4 Tg CO_2 Eq. to 5,209.0 Tg CO_2 Eq.—a 9.9 percent total increase over the twenty-year period. From 2008 to 2009, these emissions decreased by 356.9 Tg CO_2 Eq. (6.4 percent), the largest decrease of any year over the twenty-year period.
- CO_2 emissions from non-energy use of fossil fuels increased 4.7 Tg CO_2 Eq. (4.0 percent) from 1990 through 2009. Emissions from non-energy uses of fossil fuels were 123.4 Tg CO_2 Eq. in 2009, which constituted 2.2 percent of total national CO_2 emissions.
- CO_2 emissions from incineration of waste (12.3 Tg CO_2 Eq. in 2009) increased by 4.3 Tg CO_2 Eq. (54 percent) from 1990 through 2009, as the volume of plastics and other fossil carbon-containing materials in municipal solid waste grew.
- CH_4 emissions from coal mining were 71.0 Tg CO_2 Eq. in 2009, a decline in emissions of 13.0 Tg CO_2 Eq. (15.5 percent) from 1990. This occurred as a result of the mining of less gassy coal from underground mines and the increased use of CH_4 collected from degasification systems.
- CH_4 emissions from natural gas systems were 221.2 Tg CO_2 Eq. in 2009; emissions have increased by 31.4 Tg CO_2 Eq. (16.6 percent) since 1990.
- In 2009, N_2O emissions from mobile combustion were 23.9 Tg CO_2 Eq. (approximately 8.1 percent of U.S. N_2O emissions). From 1990 to 2009, N_2O emissions from mobile combustion decreased by 45.6 percent. However, from 1990 to 1998 emissions increased by 26 percent, due to control technologies that reduced NO_x emissions while increasing N_2O emissions. Since 1998, newer control technologies have led to a steady decline in N_2O from this source.

Industrial Processes

Greenhouse gas emissions are produced as the by-products of many non-energy-related industrial activities. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO_2, CH_4, and N_2O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production and urea consumption, lime production, limestone and dolomite use (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO_2 consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, and zinc production (see Figure 2-9). Industrial processes also release HFCs, PFCs and SF_6. In addition to their use as ODS substitutes, HFCs, PFCs, SF_6, and other fluorinated compounds are employed and emitted by a number of other industrial sources in the United States. These industries include aluminum production, HCFC-22 production, semiconductor manufacture, electric power transmission and distribution, and magnesium metal production and processing. Table 2-6 presents greenhouse gas emissions from industrial processes by source category.

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[46] Note that electricity generation is the largest emitter of CO_2 when electricity is not distributed among end-use sectors.

Figure 2-9: 2009 Industrial Processes Chapter Greenhouse Gas Sources

Table 2-6: Emissions from Industrial Processes (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**188.4**	**184.9**	**165.4**	**169.9**	**172.6**	**159.5**	**119.0**
Iron and Steel Production & Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Iron and Steel Production	*97.1*	*83.7*	*63.9*	*66.9*	*69.0*	*63.7*	*40.9*
Metallurgical Coke Production	*2.5*	*2.2*	*2.0*	*1.9*	*2.1*	*2.3*	*1.0*
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Ammonia Production & Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
CH_4	**1.9**	**2.2**	**1.8**	**1.7**	**1.7**	**1.6**	**1.2**
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production & Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Iron and Steel Production	*1.0*	*0.9*	*0.7*	*0.7*	*0.7*	*0.6*	*0.4*
Metallurgical Coke Production	+	+	+	+	+	+	+
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
N_2O	**33.5**	**24.9**	**21.5**	**20.5**	**22.9**	**18.5**	**16.5**
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
HFCs	**36.9**	**103.2**	**120.2**	**123.4**	**129.5**	**129.4**	**125.7**
Substitution of Ozone Depleting Substances[a]	0.3	74.3	104.2	109.4	112.3	115.5	120.0
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacture	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	**20.8**	**13.5**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**
Semiconductor Manufacture	2.2	4.9	3.2	3.5	3.7	4.0	4.0
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
SF_6	**34.4**	**20.1**	**19.0**	**17.9**	**16.7**	**16.1**	**14.8**
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Semiconductor Manufacture	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Total	**315.8**	**348.8**	**334.1**	**339.4**	**350.9**	**331.7**	**282.9**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Overall, emissions from industrial processes decreased by 10.4 percent from 1990 to 2009 due to decreases in emissions from several industrial processes, such as iron and steel production and metallurgical coke production, HCFC-22 production, aluminum production, adipic acid production, and electrical transmission and distribution. Significant trends in emissions from industrial processes source categories over the twenty-year period from 1990 through 2009 included the following:

- Combined CO_2 and CH_4 emissions from iron and steel production and metallurgical coke production decreased by 36.6 percent to 42.2 Tg CO_2 Eq. from 2008 to 2009, and have declined overall by 58.2 Tg CO_2 Eq. (58.0 percent) from 1990 through 2009, due to restructuring of the industry, technological improvements, and increased scrap utilization.
- CO_2 emissions from ammonia production and urea consumption (11.8 Tg CO_2 Eq. in 2009) have decreased by 5.0 Tg CO_2 Eq. (29.9 percent) since 1990, due to a decrease in domestic ammonia production. This decrease in ammonia production is primarily attributed to market fluctuations.
- N_2O emissions from adipic acid production were 1.9 Tg CO_2 Eq. in 2009, and have decreased significantly in recent years from the widespread installation of pollution control measures. Emissions from adipic acid production have decreased by 87.7 percent since 1990 and by 89.0 percent since a peak in 1995.
- HFC emissions from ODS substitutes have been increasing from small amounts in 1990 to 120.0 Tg CO_2 Eq. in 2009. This increase results from efforts to phase out CFCs and other ODSs in the United States. In the short term, this trend is expected to continue, and will likely accelerate over the next decade as HCFCs—which are interim substitutes in many applications—are phased out under the provisions of the Copenhagen Amendments to the Montreal Protocol.
- PFC emissions from aluminum production decreased by about 91.5 percent (17.0 Tg CO_2 Eq.) from 1990 to 2009, due to both industry emission reduction efforts and lower domestic aluminum production.

Solvent and Other Product Use

Greenhouse gas emissions are produced as a by-product of various solvent and other product uses. In the United States, N_2O Emissions from Product Uses, the only source of greenhouse gas emissions from this sector, accounted for 4.4 Tg CO_2 Eq., or less than 0.1 percent of total U.S. emissions in 2009 (see Table 2-7).

Table 2-7: N_2O Emissions from Solvent and Other Product Use (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
N_2O	**4.4**	**4.9**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**
N_2O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Total	**4.4**	**4.9**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**

In 2009, N_2O emissions from product uses constituted 1.5 percent of U.S. N_2O emissions. From 1990 to 2009, emissions from this source category decreased by just under 0.4 percent, though slight increases occurred in intermediate years.

Agriculture

Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues.

In 2009, agricultural activities were responsible for emissions of 419.3 Tg CO_2 Eq., or 6.3 percent of total U.S. greenhouse gas emissions. CH_4 and N_2O were the primary greenhouse gases emitted by agricultural activities. CH_4 emissions from enteric fermentation and manure management represented about 20.4 percent and 7.2 percent of total CH_4 emissions from anthropogenic activities, respectively, in 2009. Agricultural soil management activities, such as fertilizer application and other cropping practices, were the largest source of U.S. N_2O emissions in 2009, accounting for 69.2 percent.

Figure 2-10: 2009 Agriculture Chapter Greenhouse Gas Sources

Table 2-8: Emissions from Agriculture (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH_4	**171.2**	**186.7**	**190.1**	**191.7**	**198.2**	**197.5**	**196.8**
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Field Burning of Agricultural Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
N_2O	**212.4**	**224.0**	**228.7**	**227.1**	**227.6**	**228.8**	**222.5**
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**383.6**	**410.6**	**418.8**	**418.8**	**425.8**	**426.3**	**419.3**

Note: Totals may not sum due to independent rounding.

Some significant trends in U.S. emissions from Agriculture include the following:

- Agricultural soils produced approximately 69 percent of N_2O emissions in the United States in 2009. Estimated emissions from this source in 2009 were 204.6 Tg CO_2 Eq. Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2009, although overall emissions were 3.4 percent higher in 2009 than in 1990. Nitrous oxide emissions from this source have not shown any significant long-term trend, as their estimation is highly sensitive to the amount of N applied to soils, which has not changed significantly over the time-period, and to weather patterns and crop type.
- Enteric fermentation was the largest source of CH_4 emissions in 2009, at 139.8 Tg CO_2 Eq. Generally, emissions decreased from 1996 to 2003, though with a slight increase in 2002. This trend was mainly due to decreasing populations of both beef and dairy cattle and increased digestibility of feed for feedlot cattle. Emissions increased from 2004 through 2007, as both dairy and beef populations increased and the literature for dairy cow diets indicated a trend toward a decrease in feed digestibility for those years. Emissions decreased again in 2008 and 2009 as beef cattle populations decreased again. During the timeframe of this analysis, populations of sheep have decreased 49 percent since 1990 while horse populations have increased over 87 percent, mostly since 1999. Goat and swine populations have increased 25 percent and 23 percent, respectively, during this timeframe.
- Overall, emissions from manure management increased 46 percent between 1990 and 2009. This encompassed an increase of 56 percent for CH_4, from 31.7 Tg CO_2 Eq. in 1990 to 49.5 Tg CO_2 Eq. in 2009; and an increase of 23 percent for N_2O, from 14.5 Tg CO_2 Eq. in 1990 to 17.9 Tg CO_2 Eq. in 2009. The majority of this increase was from swine and dairy cow manure, since the general trend in manure management is one of increasing use of liquid systems, which tends to produce greater CH_4 emissions.

Land Use, Land-Use Change, and Forestry

When humans alter the terrestrial biosphere through land use, changes in land use, and land management practices, they also alter the background carbon fluxes between biomass, soils, and the atmosphere. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps have resulted in an uptake (sequestration) of carbon in the United States, which offset about 15 percent of total U.S. greenhouse gas emissions in 2009. Forests (including vegetation, soils, and harvested wood) accounted for approximately 85 percent of total 2009 net CO_2 flux, urban trees accounted for 9 percent, mineral and organic soil carbon stock changes accounted for 4 percent, and landfilled yard trimmings and food scraps accounted for 1 percent of the total net flux in 2009. The net forest sequestration is a result of net forest growth, increasing forest area, and a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth and increased urban forest size. In agricultural soils, mineral and organic soils sequester approximately 5.5 times as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to hay production fields, the limited use of bare-summer fallow areas in semi-arid areas, and an increase in the adoption of conservation tillage practices. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming carbon and food scraps in landfills.

Land use, land-use change, and forestry activities in 2009 resulted in a net C sequestration of 1,015.1 Tg CO_2 Eq. (276.8 Tg C) (Table 2-9). This represents an offset of approximately 18 percent of total U.S. CO_2 emissions, or 15 percent of total greenhouse gas emissions in 2009. Between 1990 and 2009, total land use, land-use change, and forestry net C flux resulted in a 17.8 percent increase in CO_2 sequestration.

Table 2-9: Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Tg CO_2 Eq.)

Sink Category	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Forest Land Remaining Forest Land	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)
Cropland Remaining Cropland	(29.4)	(30.2)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)
Land Converted to Cropland	2.2	2.4	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)	(52.6)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)
Land Converted to Grassland	(19.8)	(27.2)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)
Settlements Remaining Settlements	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)
Total	**(861.5)**	**(576.6)**	**(1,056.5)**	**(1,064.3)**	**(1,060.9)**	**(1,040.5)**	**(1,015.1)**

Note: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Land use, land-use change, and forestry source categories also resulted in emissions of CO_2, CH_4, and N_2O that are not included in the net CO_2 flux estimates presented in Table 2-9. The application of crushed limestone and dolomite to managed land (i.e., soil liming) and urea fertilization resulted in CO_2 emissions of 7.8 Tg CO_2 Eq. in 2009, an increase of about 10.6 percent relative to 1990. Lands undergoing peat extraction resulted in CO_2 emissions of 1.1 Tg CO_2 Eq. (1,090 Gg), and N_2O emissions of less than 0.01 Tg CO_2 Eq. N_2O emissions from the application of synthetic fertilizers to forest soils have increased from 0.1 Tg CO_2 Eq. in 1990 to 0.4 Tg CO_2 Eq. in 2009. Settlement soils in 2009 resulted in direct N_2O emissions of 1.5 Tg CO_2 Eq., a 55 percent increase relative to 1990. Emissions from forest fires in 2009 resulted in CH_4 emissions of 7.8 Tg CO_2 Eq., and in N_2O emissions of 6.4 Tg CO_2 Eq. (Table 2-10).

Table 2-10: Emissions from Land Use, Land-Use Change, and Forestry (Tg CO_2 Eq.)

Source Category	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**8.1**	**8.8**	**8.9**	**8.8**	**9.2**	**9.6**	**8.9**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2
Cropland Remaining Cropland: Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
CH_4	**3.2**	**14.3**	**9.8**	**21.6**	**20.0**	**11.9**	**7.8**
Forest Land Remaining Forest Land: Forest Fires	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N_2O	**3.7**	**13.2**	**9.8**	**19.5**	**18.3**	**11.6**	**8.3**
Forest Land Remaining Forest Land: Forest Fires	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Forest Land Remaining Forest Land: Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**15.0**	**36.3**	**28.6**	**49.8**	**47.5**	**33.2**	**25.0**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Other significant trends from 1990 to 2009 in land use, land-use change, and forestry emissions include:

- Net C sequestration by forest land has increased by almost 27 percent. This is primarily due to increased forest management and the effects of previous reforestation. The increase in intensive forest management resulted in higher growth rates and higher biomass density. The tree planting and conservation efforts of the 1970s and 1980s continue to have a significant impact on sequestration rates. Finally, the forested area in the United States increased over the past 20 years, although only at an average rate of 0.21 percent per year.
- Net sequestration of C by urban trees has increased by 68 percent over the period from 1990 to 2009. This is primarily due to an increase in urbanized land area in the United States.
- Annual C sequestration in landfilled yard trimmings and food scraps has decreased by 48 percent since 1990. This is due in part to a decrease in the amount of yard trimmings and food scraps generated. In addition, the proportion of yard trimmings and food scraps landfilled has decreased, as there has been a significant rise in the number of municipal composting facilities in the United States.

Waste

Waste management and treatment activities are sources of greenhouse gas emissions (see Figure 2-11). In 2009, landfills were the third largest source of anthropogenic CH_4 emissions, accounting for 17 percent of total U.S. CH_4 emissions.[47] Additionally, wastewater treatment accounts for 4 percent of U.S. CH_4 emissions, and 2 percent of N_2O emissions. Emissions of CH_4 and N_2O from composting grew from 1990 to 2009, and resulted in emissions of 3.5 Tg CO_2 Eq. in 2009. A summary of greenhouse gas emissions from the Waste chapter is presented in Table 2-11.

Figure 2-11: 2009 Waste Chapter Greenhouse Gas Sources

Overall, in 2009, waste activities generated emissions of 150.5 Tg CO_2 Eq., or 2.3 percent of total U.S. greenhouse gas emissions.

Table 2-11: Emissions from Waste (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH_4	**171.2**	**138.1**	**138.4**	**137.8**	**137.4**	**142.1**	**143.6**
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
N_2O	**4.0**	**5.9**	**6.5**	**6.6**	**6.7**	**6.8**	**6.9**
Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Total	**175.2**	**143.9**	**144.9**	**144.4**	**144.1**	**149.0**	**150.5**

Note: Totals may not sum due to independent rounding.

Some significant trends in U.S. emissions from Waste include the following:

- Combined CO_2 and CH_4 emissions from composting have generally increased since 1990, from 0.7 Tg CO_2 Eq. to 3.5 Tg CO_2 Eq. in 2009, an over four-fold increase over the time series.
- From 1990 to 2009, net CH_4 emissions from landfills decreased by 29.9 Tg CO_2 Eq. (20 percent), with small increases occurring in interim years. This downward trend in overall emissions is the result of increases in the amount of landfill gas collected and combusted,[48] which has more than offset the

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[47] Landfills also store carbon, due to incomplete degradation of organic materials such as wood products and yard trimmings, as described in the Land Use, Land-Use Change, and Forestry chapter.

[48] The CO_2 produced from combusted landfill CH_4 at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

additional CH_4 emissions resulting from an increase in the amount of municipal solid waste landfilled.

- From 1990 to 2009, CH_4 and N_2O emissions from wastewater treatment increased by 1.0 Tg CO_2 Eq. (4.4 percent) and 1.3 Tg CO_2 Eq. (36 percent), respectively.

2.2. Emissions by Economic Sector

Throughout this report, emission estimates are grouped into six sectors (i.e., chapters) defined by the IPCC and detailed above: Energy; Industrial Processes; Solvent and Other Product Use; Agriculture; Land Use, Land-Use Change, and Forestry; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following U.S. economic sectors: residential, commercial, industry, transportation, electricity generation, and agriculture, as well as U.S. territories.

Using this categorization, emissions from electricity generation accounted for the largest portion (33 percent) of U.S. greenhouse gas emissions in 2009. Transportation activities, in aggregate, accounted for the second largest portion (27 percent). Emissions from industry accounted for about 20 percent of U.S. greenhouse gas emissions in 2009. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements. The remaining 20 percent of U.S. greenhouse gas emissions were contributed by the residential, agriculture, and commercial sectors, plus emissions from U.S. territories. The residential sector accounted for 5 percent, and primarily consisted of CO_2 emissions from fossil fuel combustion. Activities related to agriculture accounted for roughly 7 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N_2O emissions from agricultural soil management and CH_4 emissions from enteric fermentation, rather than CO_2 from fossil fuel combustion. The commercial sector accounted for roughly 6 percent of emissions, while U.S. territories accounted for less than 1 percent.

CO_2 was also emitted and sequestered (in the form of C) by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Table 2-12 presents a detailed breakdown of emissions from each of these economic sectors by source category, as they are defined in this report. Figure 2-12 shows the trend in emissions by sector from 1990 to 2009.

Figure 2-12: Emissions Allocated to Economic Sectors

Table 2-12: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg CO_2 Eq. and Percent of Total in 2009)

Sector/Source	1990	2000	2005	2006	2007	2008	2009	Percent[a]
Electric Power Industry	**1,868.9**	**2,337.6**	**2,444.6**	**2,388.2**	**2,454.0**	**2,400.7**	**2,193.0**	**33.1%**
CO_2 from Fossil Fuel Combustion	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0	32.5%
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8	0.2%
Incineration of Waste	8.5	11.5	12.9	12.9	13.1	12.5	12.7	0.2%
Stationary Combustion	8.6	10.6	11.0	10.8	11.0	10.8	9.7	0.1%
Limestone and Dolomite Use	2.6	2.5	3.4	4.0	3.9	3.1	3.8	0.1%
Transportation	**1,545.2**	**1,932.3**	**2,017.4**	**1,994.4**	**2,003.8**	**1,890.7**	**1,812.4**	**27.3%**
CO_2 from Fossil Fuel Combustion	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7	25.9%
Substitution of Ozone Depleting Substances	+	55.7	72.9	72.2	68.8	64.9	60.2	0.9%
Mobile Combustion	47.4	55.1	37.7	34.2	30.7	26.4	24.0	0.4%
Non-Energy Use of Fuels	11.8	12.1	10.2	9.9	10.2	9.5	8.5	0.1%
Industry	**1,564.4**	**1,544.0**	**1,441.9**	**1,497.3**	**1,483.0**	**1,446.9**	**1,322.7**	**19.9%**
CO_2 from Fossil Fuel Combustion	815.4	812.3	776.3	799.2	793.6	757.4	683.8	10.3%

Natural Gas Systems	227.4	239.2	220.4	248.4	236.2	244.6	253.4	3.8%
Non-Energy Use of Fuels	101.1	122.8	125.2	126.8	119.8	123.1	111.1	1.7%
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0	1.1%
Iron and Steel Production & Metallurgical Coke Production	100.5	86.9	66.6	69.5	71.7	66.7	42.2	0.6%
Petroleum Systems	35.9	32.0	29.9	29.8	30.4	30.7	31.4	0.5%
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0	0.4%
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6	0.2%
Ammonia Production and Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8	0.2%
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2	0.2%
Substitution of Ozone Depleting Substances	+	3.2	6.4	7.1	7.8	8.5	10.9	0.2%
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5	0.1%
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4	0.1%
Semiconductor Manufacture	2.9	6.2	4.4	4.7	4.8	5.1	5.3	0.1%
Aluminum Production	25.4	14.7	7.1	6.3	8.1	7.2	4.6	0.1%
N_2O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4	0.1%
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3	0.1%
Limestone and Dolomite Use	2.6	2.5	3.4	4.0	3.9	3.1	3.8	0.1%
Stationary Combustion	4.7	4.8	4.4	4.6	4.4	4.1	3.6	0.1%
Petrochemical Production	4.2	5.7	5.3	4.8	4.9	4.4	3.6	0.1%
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9	+
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8	+
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5	+
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5	+
Mobile Combustion	0.9	1.1	1.3	1.3	1.3	1.3	1.3	+
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1	+
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0	+
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0	+
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5	+
Silicon Carbide Production and Consumption	0.4	0.3	0.2	0.2	0.2	0.2	0.2	+
Agriculture	**429.0**	**485.1**	**493.2**	**516.7**	**520.7**	**503.9**	**490.0**	**7.4%**
N_2O from Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6	3.1%
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8	2.1%
Manure Management	46.2	59.5	63.8	64.8	68.9	67.3	67.3	1.0%
CO_2 from Fossil Fuel Combustion	31.04	38.79	46.81	49.04	48.44	45.44	46.66	0.7%
CH_4 and N_2O from Forest Fires	5.8	26.0	17.8	39.2	36.4	21.7	14.2	0.2%
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3	0.1%
Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2	0.1%
Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6	0.1%
CO_2 and N_2O from Managed Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1	+
Mobile Combustion	0.3	0.4	0.5	0.5	0.5	0.5	0.5	+
N_2O from Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4	+
Field Burning of Agricultural Residues	0.4	0.4	0.3	0.3	0.3	0.4	0.4	+

Stationary Combustion	+	+	+	+	+	+	+	+
Commercial	**395.5**	**381.4**	**387.2**	**375.2**	**389.6**	**403.5**	**409.5**	**6.2%**
CO_2 from Fossil Fuel Combustion	219.0	230.8	223.5	208.6	219.4	224.2	224.0	3.4%
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5	1.8%
Substitution of Ozone Depleting Substances	+	5.4	17.6	21.1	24.9	29.1	33.7	0.5%
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5	0.4%
Human Sewage	3.7	4.5	4.8	4.8	4.9	5.0	5.0	0.1%
Composting	0.7	2.6	3.3	3.3	3.5	3.5	3.5	0.1%
Stationary Combustion	1.3	1.3	1.2	1.2	1.2	1.2	1.2	+
Residential	**345.1**	**386.2**	**371.0**	**335.8**	**358.9**	**367.1**	**360.1**	**5.4%**
CO_2 from Fossil Fuel Combustion	338.3	370.7	357.9	321.5	342.4	348.2	339.2	5.1%
Substitution of Ozone Depleting Substances	0.3	10.1	7.3	8.9	10.7	12.9	15.1	0.2%
Stationary Combustion	5.5	4.3	4.3	3.9	4.2	4.4	4.2	0.1%
Settlement Soil Fertilization	1.0	1.1	1.5	1.5	1.6	1.5	1.5	+
U.S. Territories	**33.7**	**46.0**	**58.2**	**59.3**	**53.5**	**48.4**	**45.5**	**0.7%**
CO_2 from Fossil Fuel Combustion	27.9	35.9	50.0	50.3	46.1	39.8	41.7	0.6%
Non-Energy Use of Fuels	5.7	10.0	8.1	8.8	7.2	8.4	3.7	0.1%
Stationary Combustion	0.1	0.1	0.2	0.2	0.2	0.2	0.2	+
Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**	**100.0%**
Sinks	**(861.5)**	**(576.6)**	**(1,056.5)**	**(1,064.3)**	**(1,060.9)**	**(1,040.5)**	**(1,015.1)**	**-15.3%**
CO_2 Flux from Forests[b]	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)	-13.0%
Urban Trees	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)	-1.4%
CO_2 Flux from Agricultural Soil Carbon Stocks	(99.2)	(107.6)	(45.6)	(46.1)	(46.3)	(44.4)	(43.4)	-0.7%
Landfilled Yard Trimmings and Food Scraps	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)	-0.2%
Net Emissions	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**	**84.7%**

Note: Includes all emissions of CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6. Parentheses indicate negative values or sequestration. Totals may not sum due to independent rounding.

ODS (Ozone Depleting Substances)

+ Does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.

[a] Percent of total emissions for year 2009.

[b] Includes the effects of net additions to stocks of carbon stored in harvested wood products.

Emissions with Electricity Distributed to Economic Sectors

It can also be useful to view greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). The generation, transmission, and distribution of electricity, which is the largest economic sector in the United States, accounted for 33 percent of total U.S. greenhouse gas emissions in 2009. Emissions increased by 17 percent since 1990, as electricity demand grew and fossil fuels remained the dominant energy source for generation. Electricity generation-related emissions decreased from 2008 to 2009 by 9 percent, primarily due to decreased CO_2 emissions from fossil fuel combustion. The decrease in electricity-related emissions was due to decreased economic output and the resulting decrease in electricity demand. Electricity-related emissions also declined due to a decrease in the carbon intensity of fuels used to generate electricity. This was caused by fuel switching as the price of coal increased and the price natural gas decreased significantly. The fuel switching from coal to natural gas and additional electricity generation from other energy sources in 2009, which included a 7 percent increase in hydropower generation from the previous year, resulted in a decrease in carbon intensity, and in turn, a decrease in emissions from electricity generation. The electricity generation sector in the United States is composed of traditional electric utilities as well as other entities, such as power marketers and non-utility power producers. The majority of electricity generated by these entities was through the combustion of coal in boilers to produce high-pressure steam that is passed through a turbine. Table 2-13 provides a detailed summary of emissions from electricity generation-related activities.

Table 2-13: Electricity Generation-Related Greenhouse Gas Emissions (Tg CO_2 Eq.)

Gas/Fuel Type or Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**1,831.4**	**2,310.5**	**2,418.0**	**2,363.0**	**2,429.4**	**2,376.2**	**2,170.1**
CO_2 from Fossil Fuel Combustion	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Coal	*1,547.6*	*1,927.4*	*1,983.8*	*1,953.7*	*1,987.3*	*1,959.4*	*1,747.6*
Natural Gas	*175.3*	*280.8*	*318.8*	*338.0*	*371.3*	*361.9*	*373.1*
Petroleum	*97.5*	*88.4*	*99.2*	*54.4*	*53.9*	*39.2*	*32.9*
Geothermal	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Limestone and Dolomite Use	2.6	2.5	3.4	4.0	3.9	3.1	3.8
CH_4	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Stationary Combustion*	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Incineration of Waste	+	+	+	+	+	+	+
N_2O	**8.5**	**10.4**	**10.7**	**10.5**	**10.6**	**10.4**	**9.4**
Stationary Combustion*	8.1	10.0	10.3	10.1	10.2	10.1	9.0
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
SF_6	**28.4**	**16.0**	**15.1**	**14.1**	**13.2**	**13.3**	**12.8**
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Total	**1,868.9**	**2,337.6**	**2,444.6**	**2,388.2**	**2,454.0**	**2,400.7**	**2,193.0**

Note: Totals may not sum due to independent rounding.

* Includes only stationary combustion emissions related to the generation of electricity.

\+ Does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.

To distribute electricity emissions among economic end-use sectors, emissions from the source categories assigned to the electricity generation sector were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity (EIA 2010 and Duffield 2006). These three source categories include CO_2 from Fossil Fuel Combustion, CH_4 and N_2O from Stationary Combustion, and SF_6 from Electrical Transmission and Distribution Systems.[49]

When emissions from electricity are distributed among these sectors, industry activities account for the largest share of total U.S. greenhouse gas emissions (28.8 percent), followed closely by emissions from transportation (27.4 percent). Emissions from the residential and commercial sectors also increase substantially when emissions from electricity are included. In all sectors except agriculture, CO_2 accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels.

Table 2-14 presents a detailed breakdown of emissions from each of these economic sectors, with emissions from electricity generation distributed to them. Figure 2-13 shows the trend in these emissions by sector from 1990 to 2009.

Figure 2-13: Emissions with Electricity Distributed to Economic Sectors

Table 2-14: U.S Greenhouse Gas Emissions by Economic Sector and Gas with Electricity-Related Emissions Distributed (Tg CO_2 Eq.) and Percent of Total in 2009

Sector/Gas	1990	2000	2005	2006	2007	2008	2009	Percent[a]
Industry	**2,238.3**	**2,314.4**	**2,162.5**	**2,194.6**	**2,192.9**	**2,146.5**	**1,910.9**	**28.8%**
Direct Emissions	*1,564.4*	*1,544.0*	*1,441.9*	*1,497.3*	*1,483.0*	*1,446.9*	*1,322.7*	19.9%

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[49] Emissions were not distributed to U.S. territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

CO_2	1,140.5	1,147.9	1,093.8	1,123.1	1,113.7	1,070.1	942.7	14.2%
CH_4	318.8	312.5	285.7	314.1	301.9	318.1	331.2	5.0%
N_2O	41.8	34.0	30.0	29.1	31.4	26.8	24.5	0.4%
HFCs, PFCs, and SF_6	63.3	49.6	32.5	31.0	36.0	31.9	24.2	0.4%
Electricity-Related	***673.9***	***770.4***	***720.5***	***697.3***	***709.9***	***699.7***	***588.3***	8.9%
CO_2	660.3	761.5	712.7	689.9	702.8	692.5	582.2	8.8%
CH_4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	+
N_2O	3.1	3.4	3.2	3.1	3.1	3.0	2.5	+
SF_6	10.2	5.3	4.5	4.1	3.8	3.9	3.4	0.1%
Transportation	**1,548.3**	**1,935.8**	**2,022.2**	**1,999.0**	**2,008.9**	**1,895.5**	**1,816.9**	**27.4%**
Direct Emissions	***1,545.2***	***1,932.3***	***2,017.4***	***1,994.4***	***2,003.8***	***1,890.7***	***1,812.4***	27.3%
CO_2	1,497.8	1,821.6	1,906.8	1,888.0	1,904.2	1,799.4	1,728.2	26.1%
CH_4	4.5	3.1	2.2	2.0	1.9	1.7	1.6	+
N_2O	42.9	51.9	35.5	32.1	28.8	24.6	22.4	0.3%
HFCs[b]	+	55.7	72.9	72.2	68.8	64.9	60.2	0.9%
Electricity-Related	***3.1***	***3.5***	***4.8***	***4.6***	***5.1***	***4.7***	***4.5***	0.1%
CO_2	3.1	3.5	4.8	4.6	5.1	4.7	4.5	0.1%
CH_4	+	+	+	+	+	+	+	+
N_2O	+	+	+	+	+	+	+	+
SF_6	+	+	+	+	+	+	+	+
Commercial	**947.7**	**1,135.8**	**1,205.1**	**1,188.5**	**1,225.3**	**1,224.5**	**1,184.9**	**17.9%**
Direct Emissions	***395.5***	***381.4***	***387.2***	***375.2***	***389.6***	***403.5***	***409.5***	6.2%
CO_2	219.0	230.8	223.5	208.6	219.4	224.2	224.0	3.4%
CH_4	172.1	139.0	139.3	138.7	138.2	143.1	144.5	2.2%
N_2O	4.4	6.2	6.8	6.9	7.1	7.2	7.2	0.1%
HFCs	+	5.4	17.6	21.1	24.9	29.1	33.7	0.5%
Electricity-Related	***552.2***	***754.4***	***817.9***	***813.2***	***835.7***	***821.0***	***775.4***	11.7%
CO_2	541.1	745.7	809.0	804.7	827.4	812.7	767.4	11.6%
CH_4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	+
N_2O	2.5	3.3	3.6	3.6	3.6	3.6	3.3	+
SF_6	8.4	5.2	5.1	4.8	4.5	4.6	4.5	0.1%
Residential	**953.8**	**1,162.2**	**1,242.9**	**1,181.5**	**1,229.6**	**1,215.1**	**1,158.9**	**17.5%**
Direct Emissions	***345.1***	***386.2***	***371.0***	***335.8***	***358.9***	***367.1***	***360.1***	5.4%
CO_2	338.3	370.7	357.9	321.5	342.4	348.2	339.2	5.1%
CH_4	4.4	3.4	3.4	3.1	3.4	3.5	3.4	0.1%
N_2O	2.1	2.1	2.4	2.3	2.4	2.4	2.4	+
HFCs	0.3	10.1	7.3	8.9	10.7	12.9	15.1	0.2%
Electricity-Related	***608.7***	***775.9***	***871.9***	***845.6***	***870.7***	***848.1***	***798.8***	12.0%
CO_2	596.5	767.0	862.4	836.7	862.0	839.4	790.5	11.9%
CH_4	0.2	0.2	0.3	0.3	0.3	0.2	0.2	+
N_2O	2.8	3.4	3.8	3.7	3.8	3.7	3.4	0.1%
SF_6	9.2	5.3	5.4	5.0	4.7	4.7	4.7	0.1%
Agriculture	**460.0**	**518.4**	**522.7**	**544.1**	**553.2**	**531.1**	**516.0**	**7.8%**
Direct Emissions	***429.0***	***485.1***	***493.2***	***516.7***	***520.7***	***503.9***	***490.0***	7.4%
CO_2	39.2	47.6	55.7	57.8	57.7	55.1	55.6	0.8%
CH_4	174.5	201.1	200.1	213.4	218.4	209.6	204.8	3.1%
N_2O	215.3	236.4	237.4	245.4	244.7	239.2	229.7	3.5%
Electricity-Related	***31.0***	***33.3***	***29.4***	***27.4***	***32.5***	***27.2***	***25.9***	0.4%
CO_2	30.4	32.9	29.1	27.1	32.2	26.9	25.7	0.4%
CH_4	+	+	+	+	+	+	+	+
N_2O	0.1	0.1	0.1	0.1	0.1	0.1	0.1	+
SF_6	0.5	0.2	0.2	0.2	0.2	0.2	0.2	+
U.S. Territories	**33.7**	**46.0**	**58.2**	**59.3**	**53.5**	**48.4**	**45.5**	**0.7%**
Total	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**	**100.0%**

Note: Emissions from electricity generation are allocated based on aggregate electricity consumption in each end-use sector.
Totals may not sum due to independent rounding.

+ Does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.
[a] Percent of total emissions for year 2009.
[b] Includes primarily HFC-134a.

Industry

The industrial end-use sector includes CO_2 emissions from fossil fuel combustion from all manufacturing facilities, in aggregate. This sector also includes emissions that are produced as a by-product of the non-energy-related industrial process activities. The variety of activities producing these non-energy-related emissions includes methane emissions from petroleum and natural gas systems, fugitive CH_4 emissions from coal mining, by-product CO_2 emissions from cement manufacture, and HFC, PFC, and SF_6 by-product emissions from semiconductor manufacture, to name a few. Since 1990, industrial sector emissions have declined. The decline has occurred both in direct emissions and indirect emissions associated with electricity use. However, the decline in direct emissions has been sharper. In theory, emissions from the industrial end-use sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions. In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy-intensive manufacturing products to less energy-intensive products (e.g., from steel to computer equipment) also have a significant effect on industrial emissions.

Transportation

When electricity-related emissions are distributed to economic end-use sectors, transportation activities accounted for 27 percent of U.S. greenhouse gas emissions in 2009. The largest sources of transportation greenhouse gases in 2009 were passenger cars (35 percent), light duty trucks, which include sport utility vehicles, pickup trucks, and minivans (30 percent), freight trucks (20 percent) and commercial aircraft (6 percent). These figures include direct emissions from fossil fuel combustion, as well as HFC emissions from mobile air conditioners and refrigerated transport allocated to these vehicle types. Table 2-15 provides a detailed summary of greenhouse gas emissions from transportation-related activities with electricity-related emissions included in the totals.

From 1990 to 2009, transportation emissions rose by 17 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 39 percent from 1990 to 2009, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

From 2008 to 2009, CO_2 emissions from the transportation end-use sector declined 4 percent. The decrease in emissions can largely be attributed to decreased economic activity in 2009 and an associated decline in the demand for transportation. Modes such as medium- and heavy-duty trucks were significantly impacted by the decline in freight transport. Similarly, increased jet fuel prices were a factor in the 19 percent decrease in commercial aircraft emissions since 2007.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO_2 from fossil fuel combustion, which increased by 16 percent from 1990 to 2009. This rise in CO_2 emissions, combined with an increase in HFCs from close to zero emissions in 1990 to 60.2 Tg CO_2 Eq. in 2009, led to an increase in overall emissions from transportation activities of 17 percent.

Although average fuel economy over this period increased slightly due primarily to the retirement of older vehicles, average fuel economy among new vehicles sold annually gradually declined from 1990 to 2004. The decline in new vehicle fuel economy between 1990 and 2004 reflected the increasing market share of light duty trucks, which grew from about one-fifth of new vehicle sales in the 1970s to slightly over half of the market by 2004. Increasing fuel prices have since decreased the momentum of light duty truck sales, and average new vehicle fuel economy has improved since 2005 as the market share of passenger cars increased. VMT growth among all passenger vehicles has also been impacted, remaining stagnant from 2004 to 2007, compared to an average annual growth rate of 2.5 percent over the period 1990 to 2004. The recession supplemented the effect of increasing fuel prices in 2008 and VMT declined by 2.1 percent, the first decrease in annual passenger vehicle VMT since 1990. Overall, VMT grew by 0.2 percent in 2009. Gasoline fuel consumption increased slightly, while consumption of diesel fuel continued to decrease, due in part to a decrease in commercial activity and freight trucking as a result of the economic recession.

Table 2-15: Transportation-Related Greenhouse Gas Emissions (Tg CO_2 Eq.)

Gas/Vehicle Type	1990	2000	2005	2006	2007	2008	2009
Passenger Cars	**657.4**	**695.3**	**709.5**	**682.9**	**672.0**	**632.5**	**627.4**
CO_2	629.3	644.2	662.3	639.1	632.8	597.9	597.2
CH_4	2.6	1.6	1.1	1.0	0.9	0.8	0.7
N_2O	25.4	25.2	17.8	15.7	13.8	11.7	10.1
HFCs	+	24.3	28.4	27.1	24.6	22.1	19.3
Light-Duty Trucks	**336.6**	**512.1**	**551.3**	**564.0**	**570.3**	**553.8**	**551.0**
CO_2	321.1	467.0	505.9	519.5	528.4	515.1	514.5
CH_4	1.4	1.1	0.7	0.7	0.6	0.6	0.6
N_2O	14.1	22.4	13.7	12.6	11.2	9.5	9.4
HFCs	+	21.7	31.0	31.2	30.1	28.6	26.6
Medium- and Heavy-Duty Trucks	**231.1**	**354.6**	**408.4**	**418.6**	**425.2**	**403.1**	**365.6**
CO_2	230.1	345.8	396.0	406.1	412.5	390.4	353.1
CH_4	0.2	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	0.8	1.2	1.1	1.1	1.1	1.0	0.8
HFCs	+	7.4	11.1	11.4	11.5	11.6	11.6
Buses	**8.4**	**11.2**	**12.0**	**12.3**	**12.5**	**12.2**	**11.2**
CO_2	8.4	11.1	11.8	12.0	12.1	11.8	10.8
CH_4	+	+	+	+	+	+	+
N_2O	+	+	+	+	+	+	+
HFCs	+	0.1	0.2	0.3	0.3	0.4	0.4
Motorcycles	**1.8**	**1.9**	**1.7**	**1.9**	**2.1**	**2.2**	**2.2**
CO_2	1.7	1.8	1.6	1.9	2.1	2.1	2.1
CH_4	+	+	+	+	+	+	+
N_2O	+	+	+	+	+	+	+
Commercial Aircraft[a]	**136.8**	**170.9**	**162.8**	**138.5**	**139.5**	**123.4**	**112.5**
CO_2	135.4	169.2	161.2	137.1	138.1	122.2	111.4
CH_4	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	1.3	1.6	1.5	1.3	1.3	1.2	1.1
Other Aircraft[b]	**44.4**	**33.5**	**35.9**	**35.1**	**33.2**	**35.2**	**29.6**
CO_2	43.9	33.1	35.5	34.7	32.8	34.8	29.3
CH_4	0.1	0.1	0.1	0.1	0.1	0.1	+
N_2O	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Ships and Boats[c]	**45.1**	**61.0**	**45.2**	**48.4**	**55.2**	**37.1**	**30.5**
CO_2	44.5	60.0	44.5	47.7	54.4	36.6	30.0
CH_4	+	+	+	+	+	+	+
N_2O	0.6	0.9	0.6	0.7	0.8	0.5	0.4
HFCs	+	0.1	+	+	+	+	+
Rail	**39.0**	**48.1**	**53.0**	**55.1**	**54.3**	**50.6**	**43.3**
CO_2	38.5	45.6	50.3	52.4	51.6	47.9	40.6
CH_4	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	0.3	0.3	0.4	0.4	0.4	0.4	0.3
HFCs	+	2.0	2.2	2.2	2.2	2.3	2.3
Other Emissions from Electricity Generation[d]	0.1	+	0.1	0.1	0.1	0.1	0.1
Pipelines[e]	**36.0**	**35.2**	**32.2**	**32.3**	**34.3**	**35.7**	**35.2**
CO_2	36.0	35.2	32.2	32.3	34.3	35.7	35.2
Lubricants	**11.8**	**12.1**	**10.2**	**9.9**	**10.2**	**9.5**	**8.5**
CO_2	11.8	12.1	10.2	9.9	10.2	9.5	8.5
Total Transportation	**1,548.3**	**1,935.8**	**2,022.2**	**1,999.0**	**2,008.9**	**1,895.4**	**1,816.9**
International Bunker	*113.0*	*99.5*	*110.9*	*129.7*	*129.0*	*135.1*	*124.4*

Fuels[f]		

Note: Totals may not sum due to independent rounding. Passenger cars and light-duty trucks include vehicles typically used for personal travel and less than 8500 lbs; medium- and heavy-duty trucks include vehicles larger than 8500 lbs. HFC emissions primarily reflect HFC-134a.

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Consists of emissions from jet fuel consumed by domestic operations of commercial aircraft (no bunkers).

[b] Consists of emissions from jet fuel and aviation gasoline consumption by general aviation and military aircraft.

[c] Fluctuations in emission estimates are associated with fluctuations in reported fuel consumption, and may reflect data collection problems.

[d] Other emissions from electricity generation are a result of waste incineration (as the majority of municipal solid waste is combusted in “trash-to-steam” electricity generation plants), electrical transmission and distribution, and a portion of limestone and dolomite use (from pollution control equipment installed in electricity generation plants).

[e] CO_2 estimates reflect natural gas used to power pipelines, but not electricity. While the operation of pipelines produces CH_4 and N_2O, these emissions are not directly attributed to pipelines in the US Inventory.

[f] Emissions from International Bunker Fuels include emissions from both civilian and military activities; these emissions are not included in the transportation totals.

Commercial

The commercial sector is heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Energy-related emissions from the residential and commercial sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. Landfills and wastewater treatment are included in this sector, with landfill emissions decreasing since 1990 and wastewater treatment emissions increasing slightly.

Residential

The residential sector is heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Emissions from the residential sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. In the long-term, this sector is also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).

Agriculture

The agriculture sector includes a variety of processes, including enteric fermentation in domestic livestock, livestock manure management, and agricultural soil management. In 2009, agricultural soil management was the largest source of N_2O emissions, and enteric fermentation was the second largest source of CH_4 emissions in the United States. This sector also includes small amounts of CO_2 emissions from fossil fuel combustion by motorized farm equipment like tractors. The agriculture sector relies less heavily on electricity than the other sectors.

[BEGIN BOX]

Box 2-1: Methodology for Aggregating Emissions by Economic Sector

In presenting the Economic Sectors in the annual Inventory of U.S. Greenhouse Gas Emissions and Sinks, the Inventory expands upon the standard IPCC sectors common for UNFCCC reporting. Discussing greenhouse gas emissions relevant to U.S.-specific sectors improves communication of the report’s findings.

In the Electricity Generation economic sector, CO_2 emissions from the combustion of fossil fuels included in the

EIA electric utility fuel consuming sector are apportioned to this economic sector. Stationary combustion emissions of CH_4 and N_2O are also based on the EIA electric utility sector. Additional sources include CO_2, CH_4, and N_2O from waste incineration, as the majority of municipal solid waste is combusted in "trash-to-steam" electricity generation plants. The Electricity Generation economic sector also includes SF_6 from Electrical Transmission and Distribution, and a portion of CO_2 from Limestone and Dolomite Use (from pollution control equipment installed in electricity generation plants).

In the Transportation economic sector, the CO_2 emissions from the combustion of fossil fuels included in the EIA transportation fuel consuming sector are apportioned to this economic sector (additional analyses and refinement of the EIA data is further explained in the Energy chapter of this report). Additional emissions are apportioned from the CH_4 and N_2O from Mobile Combustion, based on the EIA transportation sector. Substitutes of Ozone Depleting Substitutes are apportioned based on their specific end-uses within the source category, with emissions from transportation refrigeration/air-conditioning systems to this economic sector. Finally, CO_2 emissions from Non-Energy Uses of Fossil Fuels identified as lubricants for transportation vehicles are included in the Transportation economic sector.

For the Industry economic sector, the CO_2 emissions from the combustion of fossil fuels included in the EIA industrial fuel consuming sector, minus the agricultural use of fuel explained below, are apportioned to this economic sector. Stationary and mobile combustion emissions of CH_4 and N_2O are also based on the EIA industrial sector, minus emissions apportioned to the Agriculture economic sector described below. Substitutes of Ozone Depleting Substitutes are apportioned based on their specific end-uses within the source category, with most emissions falling within the Industry economic sector (minus emissions from the other economic sectors). Additionally, all process-related emissions from sources with methods considered within the IPCC Industrial Process guidance have been apportioned to this economic sector. This includes the process-related emissions (i.e., emissions from the actual process to make the material, not from fuels to power the plant) from such activities as Cement Production, Iron and Steel Production and Metallurgical Coke Production, and Ammonia Production. Additionally, fugitive emissions from energy production sources, such as Natural Gas Systems, Coal Mining, and Petroleum Systems are included in the Industry economic sector. A portion of CO_2 from Limestone and Dolomite Use (from pollution control equipment installed in large industrial facilities) are also included in the Industry economic sector. Finally, all remaining CO_2 emissions from Non-Energy Uses of Fossil Fuels are assumed to be industrial in nature (besides the lubricants for transportation vehicles specified above), and are attributed to the Industry economic sector.

As agriculture equipment is included in EIA's industrial fuel consuming sector surveys, additional data is used to extract the fuel used by agricultural equipment, to allow for accurate reporting in the Agriculture economic sector from all sources of emissions, such as motorized farming equipment. Energy consumption estimates are obtained from Department of Agriculture survey data, in combination with separate EIA fuel sales reports. This supplementary data is used to apportion CO_2 emissions from fossil fuel combustion, and CH_4 and N_2O emissions from stationary and mobile combustion (all data is removed from the Industrial economic sector, to avoid double-counting). The other emission sources included in this economic sector are intuitive for the agriculture sectors, such as N_2O emissions from Agricultural Soils, CH_4 from Enteric Fermentation (i.e., exhalation from the digestive tracts of domesticated animals), CH_4 and N_2O from Manure Management, CH_4 from Rice Cultivation, CO_2 emissions from Liming of Agricultural Soils and Urea Application, and CH_4 and N_2O from Forest Fires. N_2O emissions from the Application of Fertilizers to tree plantations (termed "forest land" by the IPCC) are also included in the Agriculture economic sector.

The Residential economic sector includes the CO_2 emissions from the combustion of fossil fuels reported for the EIA residential sector. Stationary combustion emissions of CH_4 and N_2O are also based on the EIA residential fuel consuming sector. Substitutes of Ozone Depleting Substitutes are apportioned based on their specific end-uses within the source category, with emissions from residential air-conditioning systems to this economic sector. N_2O emissions from the Application of Fertilizers to developed land (termed "settlements" by the IPCC) are also included in the Residential economic sector.

The Commercial economic sector includes the CO_2 emissions from the combustion of fossil fuels reported in the EIA commercial fuel consuming sector data. Stationary combustion emissions of CH_4 and N_2O are also based on the EIA commercial sector. Substitutes of Ozone Depleting Substitutes are apportioned based on their specific end-uses within the source category, with emissions from commercial refrigeration/air-conditioning systems to this economic sector. Public works sources including direct CH_4 from Landfills and CH_4 and N_2O from Wastewater Treatment and

Composting are included in this economic sector.

[END BOX]

[BEGIN BOX]

Box 2-2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and non-utilities combined—was the largest source of U.S. greenhouse gas emissions in 2009; (4) emissions per unit of total gross domestic product as a measure of national economic activity; or (5) emissions per capita.

Table 2-16 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.4 percent since 1990. This rate is slightly slower than that for total energy consumption and growth in national population since 1990 and much slower than that for electricity consumption and overall gross domestic product, respectively. Total U.S. greenhouse gas emissions are growing at a rate similar to that of fossil fuel consumption since 1990 (see Table 2-16).

Table 2-16: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**	**Growth Rate**[a]
GDP[b]	100	140	157	162	165	165	160	2.5%
Electricity Consumption[c]	100	127	134	135	138	138	132	1.5%
Fossil Fuel Consumption[c]	100	117	119	117	119	116	108	0.5%
Energy Consumption[c]	100	116	118	118	120	118	112	0.6%
Population[d]	100	113	118	120	121	122	123	1.1%
Greenhouse Gas Emissions[e]	100	115	117	116	117	114	107	0.4%

[a] Average annual growth rate
[b] Gross Domestic Product in chained 2005 dollars (BEA 2010)
[c] Energy-content-weighted values (EIA 2010)
[d] U.S. Census Bureau (2010)
[e] GWP-weighted values

Figure 2-14: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product
Source: BEA (2010), U.S. Census Bureau (2010), and emission estimates in this report.

[END BOX]

2.3. *Indirect Greenhouse Gas Emissions (CO, NO_x, NMVOCs, and SO_2)*

The reporting requirements of the UNFCCC[50] request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO_2. These gases do not have a direct global warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO_2, by affecting the absorptive characteristics of the atmosphere. Additionally, some of

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[50] See <http://unfccc.int/resource/docs/cop8/08.pdf>.

these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases. Carbon monoxide is produced when carbon-containing fuels are combusted incompletely. Nitrogen oxides (i.e., NO and NO_2) are created by lightning, fires, fossil fuel combustion, and in the stratosphere from N_2O. Non-CH_4 volatile organic compounds—which include hundreds of organic compounds that participate in atmospheric chemical reactions (i.e., propane, butane, xylene, toluene, ethane, and many others)—are emitted primarily from transportation, industrial processes, and non-industrial consumption of organic solvents. In the United States, SO_2 is primarily emitted from coal combustion for electric power generation and the metals industry. Sulfur-containing compounds emitted into the atmosphere tend to exert a negative radiative forcing (i.e., cooling) and therefore are discussed separately.

One important indirect climate change effect of NMVOCs and NO_x is their role as precursors for tropospheric ozone formation. They can also alter the atmospheric lifetimes of other greenhouse gases. Another example of indirect greenhouse gas formation into greenhouse gases is CO's interaction with the hydroxyl radical—the major atmospheric sink for CH_4 emissions—to form CO_2. Therefore, increased atmospheric concentrations of CO limit the number of hydroxyl molecules (OH) available to destroy CH_4.

Since 1970, the United States has published estimates of annual emissions of CO, NO_x, NMVOCs, and SO_2 (EPA 2010, EPA 2009),[51] which are regulated under the Clean Air Act. Table 2-17 shows that fuel combustion accounts for the majority of emissions of these indirect greenhouse gases. Industrial processes—such as the manufacture of chemical and allied products, metals processing, and industrial uses of solvents—are also significant sources of CO, NO_x, and NMVOCs.

Table 2-17: Emissions of NO_x, CO, NMVOCs, and SO_2 (Gg)

Gas/Activity	1990	2000	2005	2006	2007	2008	2009
NO_x	**21,707**	**19,116**	**15,900**	**15,039**	**14,380**	**13,547**	**11,468**
Mobile Fossil Fuel Combustion	10,862	10,199	9,012	8,488	7,965	7,441	6,206
Stationary Fossil Fuel Combustion	10,023	8,053	5,858	5,545	5,432	5,148	4,159
Industrial Processes	591	626	569	553	537	520	568
Oil and Gas Activities	139	111	321	319	318	318	393
Incineration of Waste	82	114	129	121	114	106	128
Agricultural Burning	8	8	6	7	8	8	8
Solvent Use	1	3	3	4	4	4	3
Waste	0	2	2	2	2	2	2
CO	**130,038**	**92,243**	**70,809**	**67,238**	**63,625**	**60,039**	**51,452**
Mobile Fossil Fuel Combustion	119,360	83,559	62,692	58,972	55,253	51,533	43,355
Stationary Fossil Fuel Combustion	5,000	4,340	4,649	4,695	4,744	4,792	4,543
Industrial Processes	4,125	2,216	1,555	1,597	1,640	1,682	1,549
Incineration of Waste	978	1,670	1,403	1,412	1,421	1,430	1,403
Agricultural Burning	268	259	184	233	237	270	247
Oil and Gas Activities	302	146	318	319	320	322	345
Waste	1	8	7	7	7	7	7
Solvent Use	5	45	2	2	2	2	2
NMVOCs	**20,930**	**15,227**	**13,761**	**13,594**	**13,423**	**13,254**	**9,313**
Mobile Fossil Fuel Combustion	10,932	7,229	6,330	6,037	5,742	5,447	4,151
Solvent Use	5,216	4,384	3,851	3,846	3,839	3,834	2,583
Industrial Processes	2,422	1,773	1,997	1,933	1,869	1,804	1,322
Stationary Fossil Fuel Combustion	912	1,077	716	918	1,120	1,321	424

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[51] NO_x and CO emission estimates from field burning of agricultural residues were estimated separately, and therefore not taken from EPA (2009) and EPA (2010).

Oil and Gas Activities	554	388	510	510	509	509	599
Incineration of Waste	222	257	241	238	234	230	159
Waste	673	119	114	113	111	109	76
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO_2	**20,935**	**14,830**	**13,466**	**12,388**	**11,799**	**10,368**	**8,599**
Stationary Fossil Fuel Combustion	18,407	12,849	11,541	10,612	10,172	8,891	7,167
Industrial Processes	1,307	1,031	831	818	807	795	798
Mobile Fossil Fuel Combustion	793	632	889	750	611	472	455
Oil and Gas Activities	390	287	181	182	184	187	154
Incineration of Waste	38	29	24	24	24	23	24
Waste	0	1	1	1	1	1	1
Solvent Use	0	1	0	0	0	0	0
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA

Source: (EPA 2010, EPA 2009) except for estimates from field burning of agricultural residues.
NA (Not Available)
Note: Totals may not sum due to independent rounding.

[BEGIN BOX]

Box 2-3: Sources and Effects of Sulfur Dioxide

Sulfur dioxide (SO_2) emitted into the atmosphere through natural and anthropogenic processes affects the earth's radiative budget through its photochemical transformation into sulfate aerosols that can (1) scatter radiation from the sun back to space, thereby reducing the radiation reaching the earth's surface; (2) affect cloud formation; and (3) affect atmospheric chemical composition (e.g., by providing surfaces for heterogeneous chemical reactions). The indirect effect of sulfur-derived aerosols on radiative forcing can be considered in two parts. The first indirect effect is the aerosols' tendency to decrease water droplet size and increase water droplet concentration in the atmosphere. The second indirect effect is the tendency of the reduction in cloud droplet size to affect precipitation by increasing cloud lifetime and thickness. Although still highly uncertain, the radiative forcing estimates from both the first and the second indirect effect are believed to be negative, as is the combined radiative forcing of the two (IPCC 2001). However, because SO_2 is short-lived and unevenly distributed in the atmosphere, its radiative forcing impacts are highly uncertain.

Sulfur dioxide is also a major contributor to the formation of regional haze, which can cause significant increases in acute and chronic respiratory diseases. Once SO_2 is emitted, it is chemically transformed in the atmosphere and returns to the earth as the primary source of acid rain. Because of these harmful effects, the United States has regulated SO_2 emissions in the Clean Air Act.

Electricity generation is the largest anthropogenic source of SO_2 emissions in the United States, accounting for 83 percent in 2009. Coal combustion contributes nearly all of those emissions (approximately 92 percent). Sulfur dioxide emissions have decreased in recent years, primarily as a result of electric power generators switching from high-sulfur to low-sulfur coal and installing flue gas desulfurization equipment.

[END BOX]

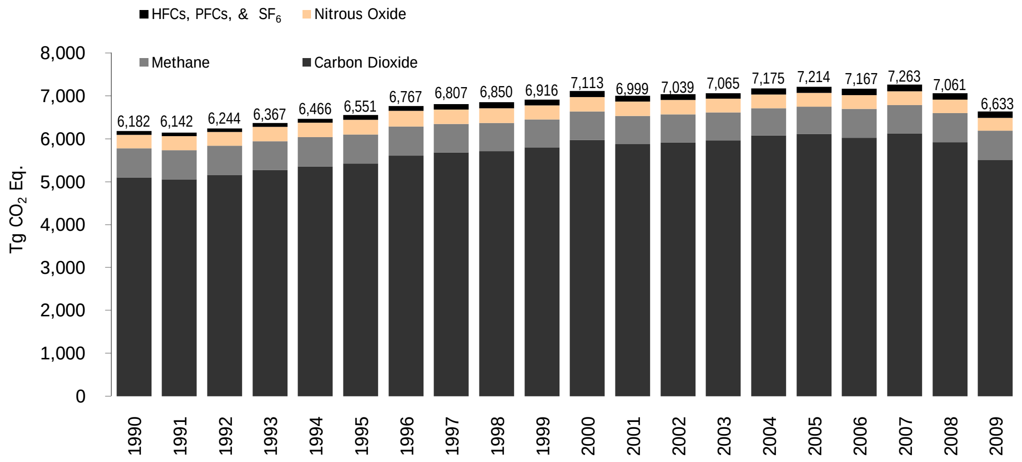


Figure 2-1: U.S. Greenhouse Gas Emissions by Gas

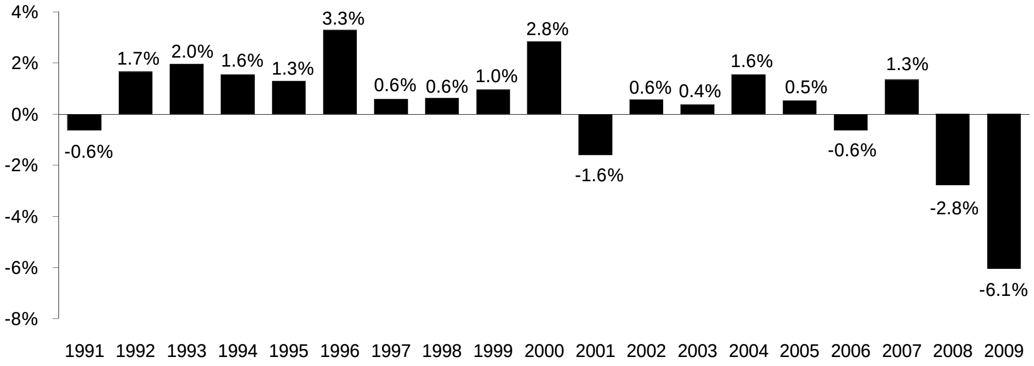


Figure 2-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

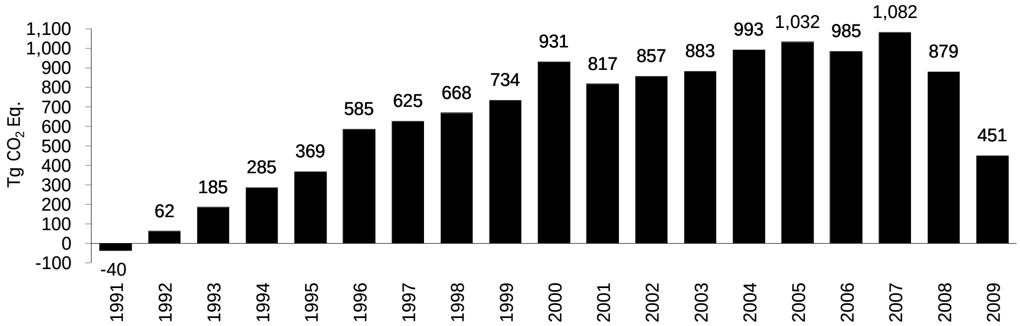
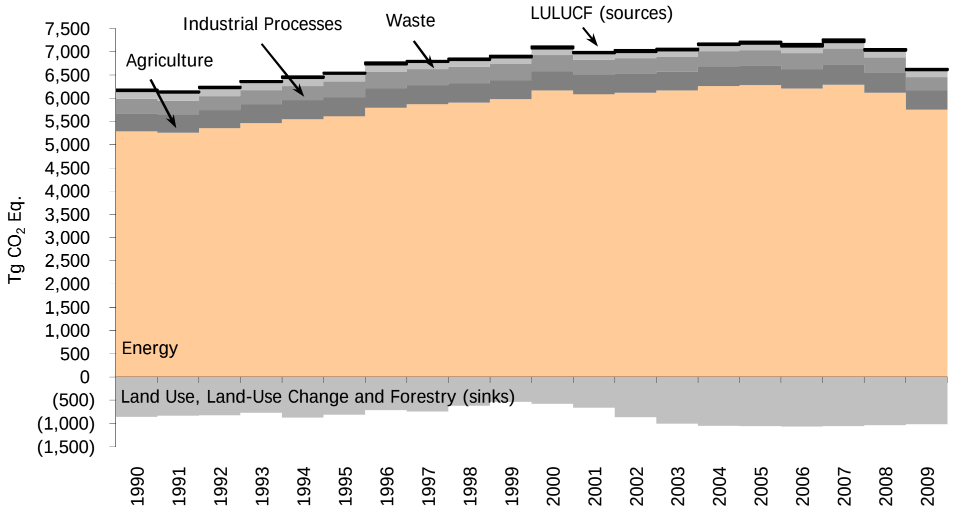


Figure 2-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990



Note: Relatively smaller amounts of GWP-weighted emissions are also emitted from the Solvent and Other Product Use sector

Figure 2-4: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

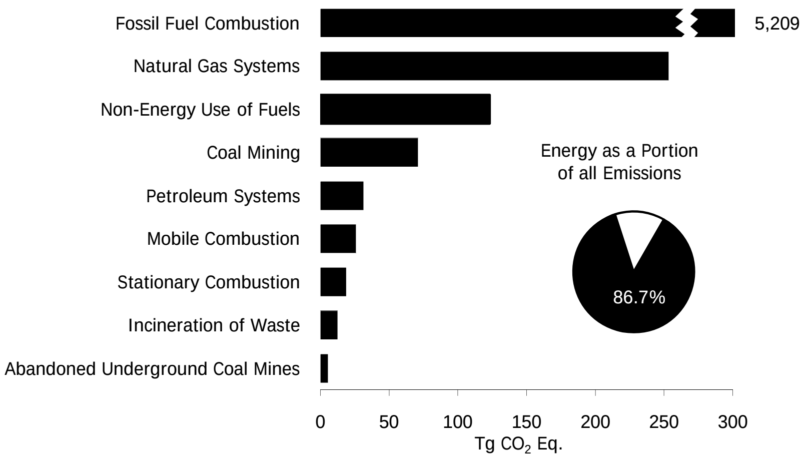
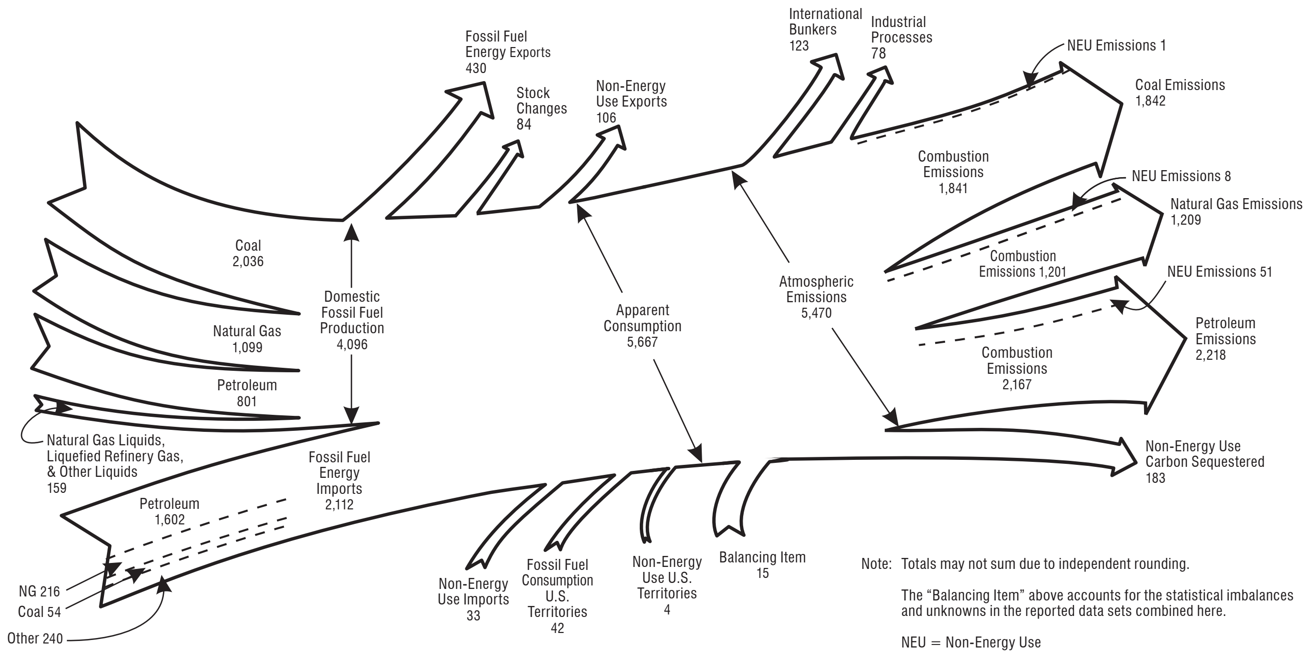


Figure 2-5: 2009 Energy Sector Greenhouse Gas Sources



Note: Totals may not sum due to independent rounding.

The “Balancing Item” above accounts for the statistical imbalances and unknowns in the reported data sets combined here.

NEU = Non-Energy Use
NG = Natural Gas

Figure 2-6 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

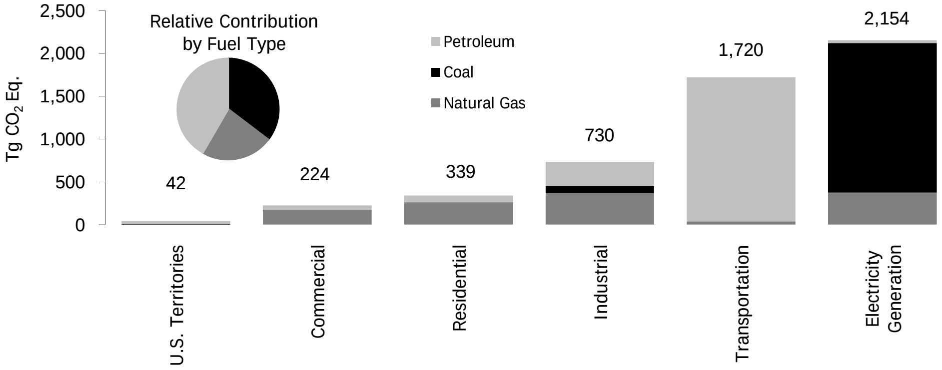


Figure 2-7: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type
Note: Electricity generation also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

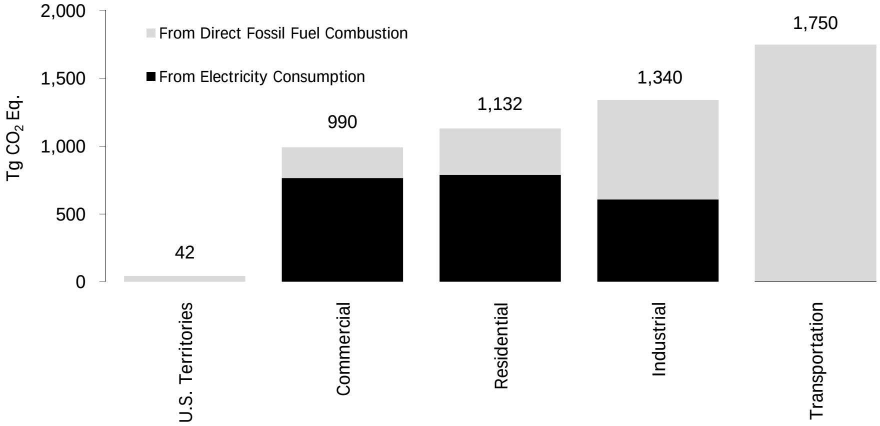


Figure 2-8: 2009 End-Use Sector Emissions from Fossil Fuel Combustion

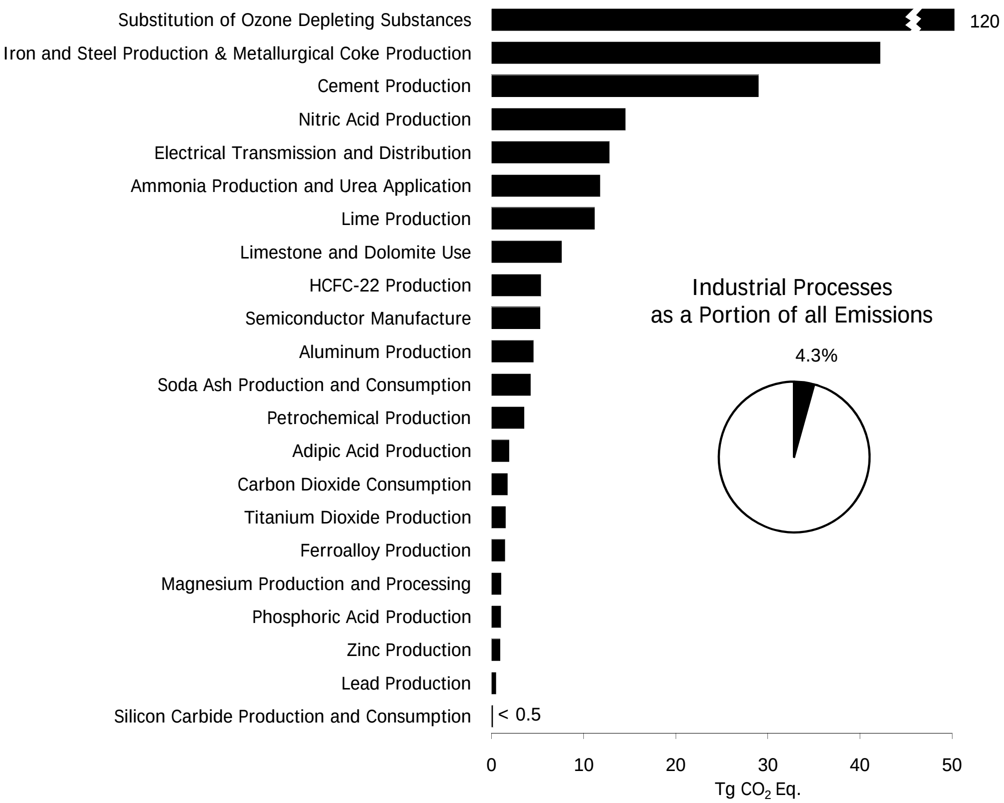


Figure 2-9: 2009 Industrial Processes Chapter Greenhouse Gas Sources

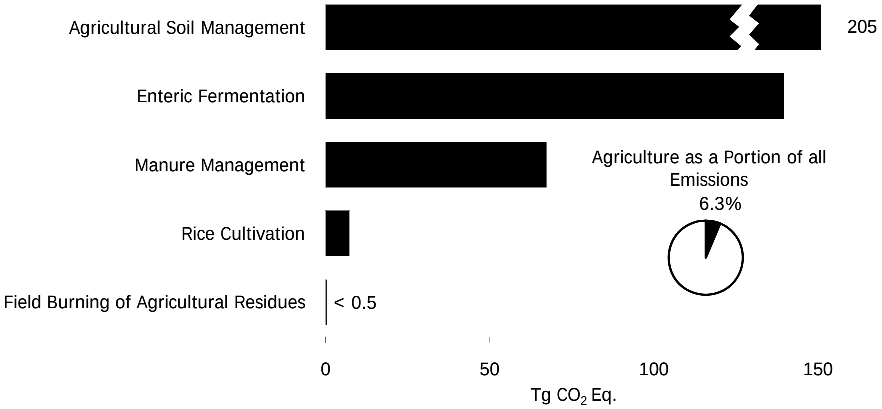


Figure 2-10: 2009 Agriculture Chapter Greenhouse Gas Sources

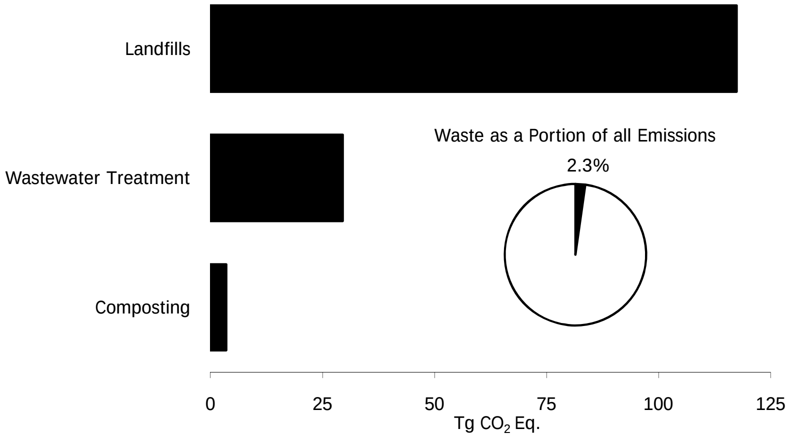


Figure 2-11: 2009 Waste Chapter Greenhouse Gas Sources

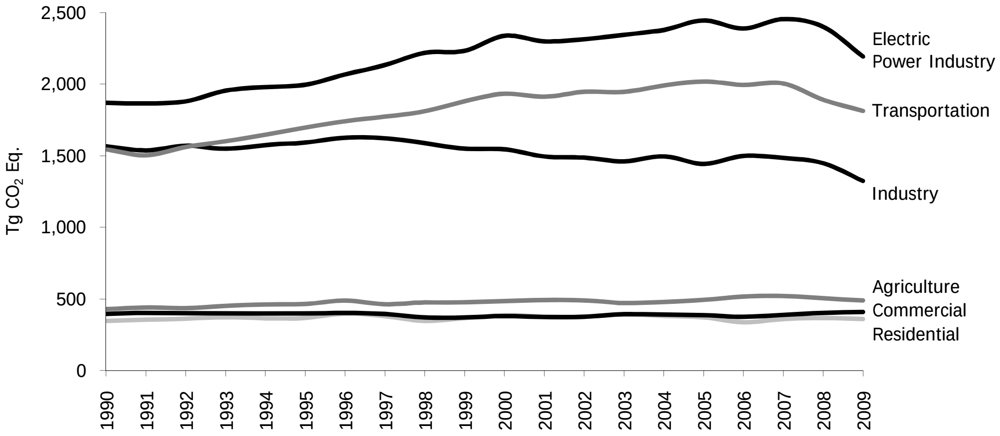


Figure 2-12: Emissions Allocated to Economic Sectors

Note: Does not include U.S. Territories.

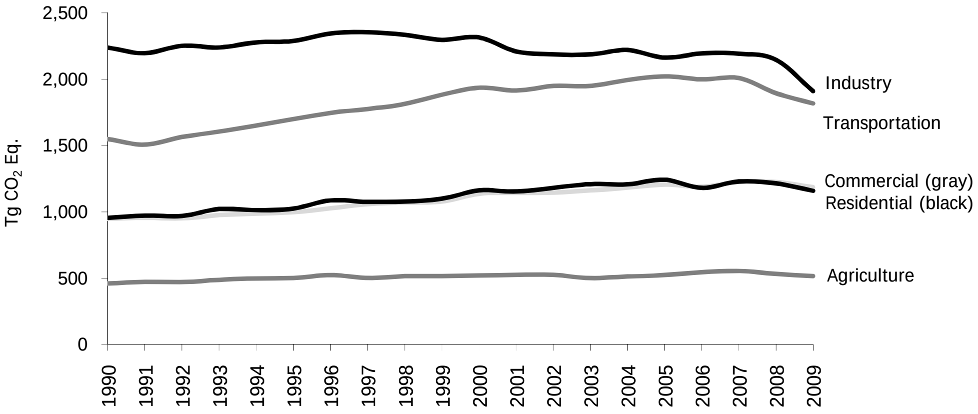


Figure 2-13: Emissions with Electricity Distributed to Economic Sectors

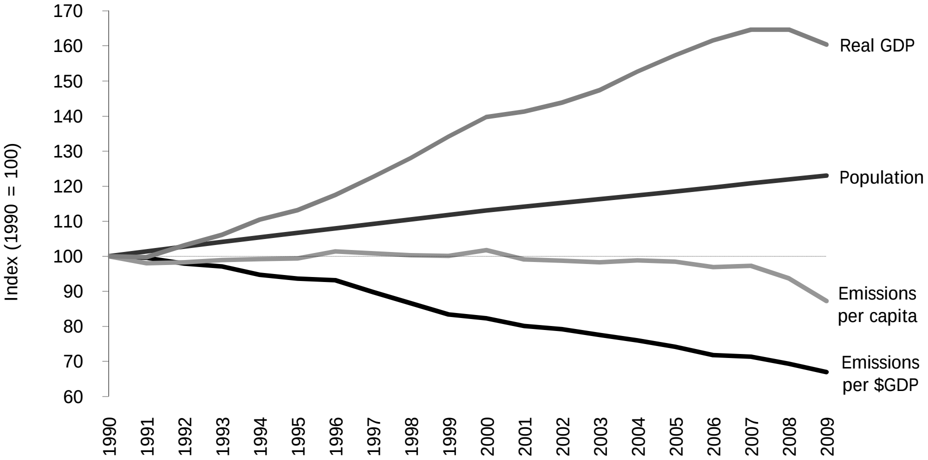


Figure 2-14: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 86.7 percent of total greenhouse gas emissions on a carbon dioxide (CO_2) equivalent basis[52] in 2009. This included 98, 49, and 13 percent of the nation's CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 81 percent of national emissions from all sources on a CO_2 equivalent basis, while the non-CO_2 emissions from energy-related activities represented a much smaller portion of total national emissions (5.6 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO_2 being the primary gas emitted (see Figure 3-1). Globally, approximately 30,398 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[53] Due to their relative importance, fossil fuel combustion-related CO_2 emissions are considered separately, and in more detail than other energy-related emissions (see Figure 3-2). Fossil fuel combustion also emits CH_4 and N_2O, and mobile fossil fuel combustion was the second largest source of N_2O emissions in the United States.

Figure 3-1: 2009 Energy Chapter Greenhouse Gas Sources

Figure 3-2: 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of fugitive CH_4 from natural gas systems, petroleum systems, and coal mining.

Table 3-1 summarizes emissions from the Energy sector in units of teragrams (or million metric tons) of CO_2 equivalents (Tg CO_2 Eq.), while unweighted gas emissions in gigagrams (Gg) are provided in Table 3-2. Overall, emissions due to energy-related activities were 5,751.1 Tg CO_2 Eq. in 2009, an increase of 9 percent since 1990.

Table 3-1: CO_2, CH_4, and N_2O Emissions from Energy (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**4,903.2**	**5,781.3**	**5,939.4**	**5,842.5**	**5,938.2**	**5,752.3**	**5,377.3**
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
*Biomass - Wood**	*215.2*	*218.1*	*206.9*	*203.8*	*203.3*	*198.4*	*183.8*
*International Bunker Fuels**	*111.8*	*98.5*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*
*Biomass – Ethanol**	*4.2*	*9.4*	*23.0*	*31.0*	*38.9*	*54.8*	*61.2*
CH_4	**327.4**	**318.6**	**291.3**	**319.2**	**307.3**	**323.6**	**336.8**
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2

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[52] Estimates are presented in units of teragrams of carbon dioxide equivalent (Tg CO_2 Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

[53] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010).

Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Incineration of Waste	+	+	+	+	+	+	+
*International Bunker Fuels**	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**57.2**	**68.1**	**52.1**	**48.5**	**45.2**	**40.7**	**37.0**
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
*International Bunker Fuels**	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
Total	**5,287.8**	**6,168.0**	**6,282.8**	**6,210.2**	**6,290.7**	**6,116.6**	**5,751.1**

+ Does not exceed 0.05 Tg CO_2 Eq.

* These values are presented for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations, and are not included in the specific energy sector contribution to the totals, and are already accounted for elsewhere.

Note: Totals may not sum due to independent rounding.

Table 3-2: CO_2, CH_4, and N_2O Emissions from Energy (Gg)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**4,903,171**	**5,781,303**	**5,939,434**	**5,842,464**	**5,938,203**	**5,752,327**	**5,377,271**
Fossil Fuel Combustion	4,738,422	5,594,848	5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
Non-Energy Use of Fuels	118,630	144,933	143,392	145,574	137,233	140,952	123,356
Natural Gas Systems	37,574	29,877	29,902	30,755	31,050	32,828	32,171
Incineration of Waste	7,989	11,112	12,450	12,531	12,700	12,169	12,300
Petroleum Systems	555	534	490	488	474	453	463
*Biomass -Wood**	*215,186*	*218,088*	*206,865*	*203,846*	*203,316*	*198,361*	*183,777*
*International Bunker Fuels**	*111,828*	*98,482*	*109,750*	*128,384*	*127,618*	*133,704*	*123,127*
*Biomass - Ethanol**	*4,229*	*9,352*	*22,956*	*31,002*	*38,946*	*54,770*	*61,231*
CH_4	**15,590**	**15,171**	**13,872**	**15,202**	**14,634**	**15,408**	**16,037**
Natural Gas Systems	9,038	9,968	9,069	10,364	9,771	10,087	10,535
Coal Mining	4,003	2,877	2,710	2,774	2,756	3,196	3,382
Petroleum Systems	1,685	1,501	1,398	1,398	1,427	1,439	1,473
Stationary Combustion	354	315	312	293	308	310	293
Abandoned Underground Coal Mines	288	350	264	261	267	279	262
Mobile Combustion	223	160	119	112	105	97	93
Incineration of Waste	+	+	+	+	+	+	+
*International Bunker Fuels**	*8*	*6*	*7*	*8*	*8*	*8*	*7*
N_2O	**185**	**220**	**168**	**156**	**146**	**131**	**120**
Mobile Combustion	142	172	119	108	98	84	77
Stationary Combustion	41	47	47	47	47	46	41
Incineration of Waste	2	1	1	1	1	1	1
*International Bunker Fuels**	*3*	*3*	*3*	*4*	*4*	*4*	*4*

+ Does not exceed 0.05 Tg CO_2 Eq.

* These values are presented for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations, and are not included in the specific energy sector contribution to the totals, and are already accounted for elsewhere.

Note: Totals may not sum due to independent rounding.

3.1. Fossil Fuel Combustion (IPCC Source Category 1A)

Emissions from the combustion of fossil fuels for energy include the gases CO_2, CH_4, and N_2O. Given that CO_2 is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total emissions, CO_2 emissions from fossil fuel combustion are discussed at the beginning of this section. Following that is a discussion of emissions of all three gases from fossil fuel combustion presented by sectoral breakdowns. Methodologies for estimating CO_2 from fossil fuel combustion also differ from the estimation of CH_4 and N_2O emissions from stationary combustion and mobile combustion. Thus, three separate descriptions of methodologies, uncertainties, recalculations, and planned improvements are provided at the end of this section. Total CO_2, CH_4, and N_2O emissions from fossil fuel combustion are presented in Table 3-3 and Table 3-4.

Table 3-3: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion (Tg CO_2 Eq.)

Gas	1990	2000	2005	2006	2007	2008	2009
CO_2	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
CH_4	12.1	10.0	9.1	8.5	8.7	8.5	8.1
N_2O	56.8	67.7	51.7	48.1	44.9	40.4	36.7
Total	**4,807.3**	**5,627.6**	**5,813.9**	**5,709.7**	**5,810.3**	**5,614.8**	**5,253.8**

Note: Totals may not sum due to independent rounding.

Table 3-4: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion (Gg)

Gas	1990	2000	2005	2006	2007	2008	2009
CO_2	4,738,422	5,594,848	5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
CH_4	577	476	431	405	413	407	386
N_2O	183	219	167	155	145	130	118

Note: Totals may not sum due to independent rounding.

CO_2 from Fossil Fuel Combustion

CO_2 is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total greenhouse gas emissions. CO_2 emissions from fossil fuel combustion are presented in Table 3-5. In 2009, CO_2 emissions from fossil fuel combustion decreased by 6.4 percent relative to the previous year. This decrease represents the largest annual decrease in CO_2 emissions from fossil fuel combustion for the twenty-year period.[54] The decrease in CO_2 emissions from fossil fuel combustion was a result of multiple factors including: (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price natural gas decreased significantly; and (3) an increase in non-fossil fuel consumption by approximately 2 percent. In 2009, CO_2 emissions from fossil fuel combustion were 5,209.0 Tg CO_2 Eq., or almost 10 percent above emissions in 1990 (see Table 3-5).[55]

Table 3-5: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq.)

Fuel/Sector	1990	2000	2005	2006	2007	2008	2009
Coal	**1,718.4**	**2,065.5**	**2,112.3**	**2,076.5**	**2,106.0**	**2,072.5**	**1,841.0**
Residential	3.0	1.1	0.8	0.6	0.7	0.7	0.6
Commercial	12.0	8.8	9.3	6.2	6.7	6.5	5.8
Industrial	155.3	127.3	115.3	112.6	107.0	102.6	83.4
Transportation	NE	NE	NE	NE	NE	NE	NE
Electricity Generation	1,547.6	1,927.4	1,983.8	1,953.7	1,987.3	1,959.4	1,747.6
U.S. Territories	0.6	0.9	3.0	3.4	4.3	3.3	3.5
Natural Gas	**1,000.6**	**1,217.4**	**1,159.0**	**1,141.3**	**1,218.0**	**1,226.0**	**1,200.9**

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[54] This decrease also represents the largest absolute and percentage decrease since the beginning of EIA's record of annual energy consumption data, beginning in 1949 (EIA 2010a).

[55] An additional discussion of fossil fuel emission trends is presented in the Trends in U.S. Greenhouse Gas Emissions Chapter.

Residential	238.0	270.7	262.2	237.3	257.0	264.4	257.2
Commercial	142.1	172.5	162.9	153.8	164.0	170.2	167.9
Industrial	409.1	457.2	380.8	377.7	389.0	391.0	365.0
Transportation	36.0	35.6	33.1	33.1	35.3	36.8	36.3
Electricity Generation	175.3	280.8	318.8	338.0	371.3	361.9	373.1
U.S. Territories	NO	0.7	1.3	1.4	1.4	1.6	1.5
Petroleum	**2,019.0**	**2,311.6**	**2,481.5**	**2,434.9**	**2,432.4**	**2,267.1**	**2,166.7**
Residential	97.4	98.8	94.9	83.6	84.6	83.1	81.4
Commercial	64.9	49.6	51.3	48.5	48.7	47.4	50.3
Industrial	282.1	266.6	326.9	357.9	346.0	309.3	282.0
Transportation	1,449.9	1,773.9	1,863.5	1,845.0	1,858.7	1,753.1	1,683.4
Electricity Generation	97.5	88.4	99.2	54.4	53.9	39.2	32.9
U.S. Territories	27.2	34.2	45.7	45.5	40.4	35.0	36.7
Geothermal*	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Total	**4,738.4**	**5,594.8**	**5,753.2**	**5,653.1**	**5,756.7**	**5,565.9**	**5,209.0**

NE (Not estimated)

NO (Not occurring)

* Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes.

Note: Totals may not sum due to independent rounding.

Trends in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors. On a year-to-year basis, the overall demand for fossil fuels in the United States and other countries generally fluctuates in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

Longer-term changes in energy consumption patterns, however, tend to be more a function of aggregate societal trends that affect the scale of consumption (e.g., population, number of cars, size of houses, and number of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs), and social planning and consumer behavior (e.g., walking, bicycling, or telecommuting to work instead of driving).

CO_2 emissions also depend on the source of energy and its carbon (C) intensity. The amount of C in fuels varies significantly by fuel type. For example, coal contains the highest amount of C per unit of useful energy. Petroleum has roughly 75 percent of the C per unit of energy as coal, and natural gas has only about 55 percent.[56] Table 3-6 shows annual changes in emissions during the last five years for coal, petroleum, and natural gas in selected sectors.

Table 3-6: Annual Change in CO_2 Emissions and Total 2009 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (Tg CO_2 Eq. and Percent)

Sector	Fuel Type	2005 to 2006		2006 to 2007		2007 to 2008		2008 to 2009		Total 2009
Electricity Generation	Coal	-30.1	-1.5%	33.6	1.7%	-27.9	-1.4%	-211.7	-10.8%	1,747.6
Electricity Generation	Natural Gas	19.2	6.0%	33.3	9.9%	-9.3	-2.5%	11.1	3.1%	373.1
Electricity Generation	Petroleum	-44.8	-45.2%	-0.5	-0.9%	-14.7	-27.2%	-6.3	-16.0%	32.9
Transportation [a]	Petroleum	-18.5	-1.0%	13.7	0.7%	-105.6	-5.7%	-69.7	-4.0%	1,683.4
Residential	Natural Gas	-24.9	-9.5%	19.7	8.3%	7.4	2.9%	-7.3	-2.8%	257.2
Commercial	Natural Gas	-9.1	-5.6%	10.2	6.6%	6.2	3.8%	-2.3	-1.3%	167.9
Industrial	Coal	-2.8	-2.4%	-5.6	-5.0%	-4.4	-4.1%	-19.2	-18.7%	83.4
Industrial	Natural Gas	-3.1	-0.8%	11.3	3.0%	2.0	0.5%	-26.0	-6.6%	365.0
All Sectors [b]	**All Fuels [b]**	**-100.1**	**-1.7%**	**103.6**	**1.8%**	**-190.8**	**-3.3%**	**-356.9**	**-6.4%**	**5,209.0**

[a] Excludes emissions from International Bunker Fuels.

[b] Includes fuels and sectors not shown in table.

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[56] Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States.

In the United States, 83 percent of the energy consumed in 2009 was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum (see Figure 3-3 and Figure 3-4). The remaining portion was supplied by nuclear electric power (9 percent) and by a variety of renewable energy sources[57] (8 percent), primarily hydroelectric power and biofuels (EIA 2010). Specifically, petroleum supplied the largest share of domestic energy demands, accounting for an average of 42 percent of total fossil fuel based energy consumption in 2009. Natural gas and coal followed in order of importance, accounting for approximately 32 and 27 percent of total consumption, respectively. Petroleum was consumed primarily in the transportation end-use sector and the vast majority of coal was used in electricity generation. Natural gas was broadly consumed in all end-use sectors except transportation (see Figure 3-5) (EIA 2010).

Figure 3-3: 2009 U.S. Energy Consumption by Energy Source

Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)

Figure 3-5: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the C stored in the fuels is oxidized and emitted as CO_2 and smaller amounts of other gases, including CH_4, CO, and NMVOCs.[58] These other C containing non-CO_2 gases are emitted as a by-product of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO_2 in the atmosphere. Therefore, it is assumed that all of the C in fossil fuels used to produce energy is eventually converted to atmospheric CO_2.

[BEGIN BOX]

Box 3-1: Weather and Non-Fossil Energy Effects on CO_2 from Fossil Fuel Combustion Trends

In 2009, weather conditions remained constant in the winter and slightly cooler in the summer compared to 2008, as heating degree days decreased slightly and cooling degree days decreased by 3.8 percent. Winter conditions were relatively constant in 2009 compared to 2008, and the winter was slightly warmer than normal, with heating degree days in the United States 0.7 percent below normal (see Figure 3-6). Summer conditions were slightly cooler in 2009 compared to 2008, and summer temperatures were slightly cooler than normal, with cooling degree days 1 percent below normal (see Figure 3-7) (EIA 2010).[59]

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950–2009)

Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2009)

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[57] Renewable energy, as defined in EIA's energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biofuels, solar energy, and wind energy

[58] See the sections entitled Stationary Combustion and Mobile Combustion in this chapter for information on non-CO_2 gas emissions from fossil fuel combustion.

[59] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F, while cooling degree days are deviations of the mean daily temperature above 65° F. Heating degree days have a considerably greater affect on energy demand and related emissions than do cooling degree days. Excludes Alaska and Hawaii. Normals are based on data from 1971 through 2000. The variation in these normals during this time period was ±10 percent and ±14 percent for heating and cooling degree days, respectively (99 percent confidence interval).

Although no new U.S. nuclear power plants have been constructed in recent years, the utilization (i.e., capacity factors[60]) of existing plants in 2009 remained high at just over 90 percent. Electricity output by hydroelectric power plants increased in 2009 by approximately 6.8 percent. Electricity generated by nuclear plants in 2009 provided nearly 3 times as much of the energy consumed in the United States as hydroelectric plants (EIA 2010). Nuclear, hydroelectric, and wind power capacity factors since 1990 are shown in Figure 3-8.

Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990–2009)

[END BOX]

Fossil Fuel Combustion Emissions by Sector

In addition to the CO_2 emitted from fossil fuel combustion, CH_4 and N_2O are emitted from stationary and mobile combustion as well. Table 3-7 provides an overview of the CO_2, CH_4, and N_2O emissions from fossil fuel combustion by sector.

Table 3-7: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by Sector (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Electricity Generation	**1,829.5**	**2,307.5**	**2,413.2**	**2,357.2**	**2,423.8**	**2,371.7**	**2,163.7**
CO_2	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
CH_4	0.6	0.7	0.7	0.7	0.7	0.7	0.7
N_2O	8.1	10.0	10.3	10.1	10.3	10.1	9.0
Transportation	**1,534.6**	**1,866.0**	**1,936.0**	**1,914.1**	**1,926.5**	**1,818.1**	**1,745.5**
CO_2	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
CH_4	4.7	3.4	2.5	2.3	2.2	2.0	2.0
N_2O	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Industrial	**851.2**	**855.9**	**827.5**	**852.8**	**846.5**	**807.0**	**734.1**
CO_2	846.5	851.1	823.1	848.2	842.0	802.9	730.4
CH_4	1.5	1.6	1.4	1.5	1.4	1.3	1.2
N_2O	3.2	3.2	3.0	3.1	3.0	2.8	2.5
Residential	**343.8**	**375.0**	**362.2**	**325.4**	**346.6**	**352.6**	**343.4**
CO_2	338.3	370.7	357.9	321.5	342.4	348.2	339.2
CH_4	4.4	3.4	3.4	3.1	3.4	3.5	3.4
N_2O	1.1	0.9	0.9	0.8	0.9	0.9	0.9
Commercial	**220.2**	**232.1**	**224.8**	**209.7**	**220.6**	**225.4**	**225.2**
CO_2	219.0	230.8	223.5	208.6	219.4	224.2	224.0
CH_4	0.9	0.9	0.9	0.8	0.9	0.9	0.9
N_2O	0.4	0.4	0.4	0.3	0.3	0.3	0.3
U.S. Territories*	**28.0**	**36.0**	**50.2**	**50.5**	**46.3**	**40.0**	**41.8**
Total	**4,807.3**	**5,672.6**	**5,813.9**	**5,709.7**	**5,810.3**	**5,614.8**	**5,253.8**

Note: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.
* U.S. Territories are not apportioned by sector, and emissions are total greenhouse gas emissions from all fuel combustion sources.

Other than CO_2, gases emitted from stationary combustion include the greenhouse gases CH_4 and N_2O and the

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[60] The capacity factor equals generation divided by net summer capacity. Summer capacity is defined as "The maximum output that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30)." Data for both the generation and net summer capacity are from EIA (2010b).

indirect greenhouse gases NO_x, CO, and NMVOCs.[61] CH_4 and N_2O emissions from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. N_2O emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. CH_4 emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency.

Mobile combustion produces greenhouse gases other than CO_2, including CH_4, N_2O, and indirect greenhouse gases including NO_x, CO, and NMVOCs. As with stationary combustion, N_2O and NO_x emissions from mobile combustion are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, and the use of pollution control equipment. N_2O from mobile sources, in particular, can be formed by the catalytic processes used to control NO_x, CO, and hydrocarbon emissions. Carbon monoxide emissions from mobile combustion are significantly affected by combustion efficiency and the presence of post-combustion emission controls. CO emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. These emissions occur especially in idle, low speed, and cold start conditions. CH_4 and NMVOC emissions from motor vehicles are a function of the CH_4 content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions (such as catalytic converters).

An alternative method of presenting combustion emissions is to allocate emissions associated with electricity generation to the sectors in which it is used. Four end-use sectors were defined: industrial, transportation, residential, and commercial. In the table below, electricity generation emissions have been distributed to each end-use sector based upon the sector's share of national electricity consumption, with the exception of CH_4 and N_2O from transportation.[62] Emissions from U.S. territories are also calculated separately due to a lack of end-use-specific consumption data. This method of distributing emissions assumes that 564 combustion sources focus on the alternative method as presented in Table 3-8.

Table 3-8: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	**1,537.6**	**1,869.5**	**1,940.8**	**1,918.6**	**1,931.5**	**1,822.8**	**1,750.0**
CO_2	1,489.0	1,813.0	1,901.3	1,882.6	1,899.0	1,794.6	1,724.1
CH_4	4.7	3.4	2.5	2.4	2.2	2.0	2.0
N_2O	44.0	53.2	37.0	33.6	30.3	26.2	23.9
Industrial	**1,541.2**	**1,649.3**	**1,567.9**	**1,568.1**	**1,579.7**	**1,525.1**	**1,340.1**
CO_2	1,533.2	1,640.8	1,560.0	1,560.2	1,572.0	1,517.7	1,333.7
CH_4	1.8	1.8	1.7	1.7	1.6	1.6	1.4
N_2O	6.3	6.7	6.2	6.2	6.1	5.8	5.0
Residential	**939.7**	**1,140.9**	**1,222.9**	**1,160.1**	**1,206.7**	**1,190.4**	**1,131.6**
CO_2	931.4	1,133.1	1,214.7	1,152.4	1,198.5	1,182.2	1,123.8
CH_4	4.6	3.6	3.7	3.3	3.6	3.7	3.6
N_2O	3.7	4.2	4.6	4.4	4.5	4.5	4.2
Commercial	**760.8**	**976.8**	**1,032.2**	**1,012.4**	**1,046.0**	**1,036.5**	**990.3**
CO_2	757.0	972.1	1,027.2	1,007.6	1,041.1	1,031.6	985.7
CH_4	1.0	1.1	1.1	1.1	1.1	1.2	1.1
N_2O	2.8	3.6	3.8	3.8	3.8	3.8	3.5
U.S. Territories*	**28.0**	**36.0**	**50.2**	**50.5**	**46.3**	**40.0**	**41.8**
Total	**4,807.3**	**5,672.6**	**5,813.9**	**5,709.7**	**5,810.3**	**5,614.8**	**5,253.8**

Note: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

* U.S. Territories are not apportioned by sector, and emissions are total greenhouse gas emissions from all fuel combustion sources.

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[61] Sulfur dioxide (SO_2) emissions from stationary combustion are addressed in Annex 6.3.

[62] Separate calculations were performed for transportation-related CH_4 and N_2O. The methodology used to calculate these emissions are discussed in the mobile combustion section.

Stationary Combustion

The direct combustion of fuels by stationary sources in the electricity generation, industrial, commercial, and residential sectors represent the greatest share of U.S. greenhouse gas emissions. Table 3-9 presents CO_2 emissions from fossil fuel combustion by stationary sources. The CO_2 emitted is closely linked to the type of fuel being combusted in each sector (see Methodology section for CO_2 from fossil fuel combustion). Other than CO_2, gases emitted from stationary combustion include the greenhouse gases CH_4 and N_2O. Table 3-10 and Table 3-11 present CH_4 and N_2O emissions from the combustion of fuels in stationary sources. CH_4 and N_2O emissions from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. N_2O emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. CH_4 emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency. Please refer to Table 3-7 for the corresponding presentation of all direct emission sources of fuel combustion.

Table 3-9: CO_2 Emissions from Stationary Fossil Fuel Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	2000	2005	2006	2007	2008	2009
Electricity Generation	**1,820.8**	**2,296.9**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,154.0**
Coal	1,547.6	1,927.4	1,983.8	1,953.7	1,987.3	1,959.4	1,747.6
Natural Gas	175.3	280.8	318.8	338.0	371.3	361.9	373.1
Fuel Oil	97.5	88.4	99.2	54.4	53.9	39.2	32.9
Geothermal	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Industrial	**846.5**	**851.1**	**823.1**	**848.2**	**842.0**	**802.9**	**730.4**
Coal	155.3	127.3	115.3	112.6	107.0	102.6	83.4
Natural Gas	409.1	457.2	380.8	377.7	389.0	391.0	365.0
Fuel Oil	282.1	266.6	326.9	357.9	346.0	309.3	282.0
Commercial	**219.0**	**230.8**	**223.5**	**208.6**	**219.4**	**224.2**	**224.0**
Coal	12.0	8.8	9.3	6.2	6.7	6.5	5.8
Natural Gas	142.1	172.5	162.9	153.8	164.0	170.2	167.9
Fuel Oil	64.9	49.6	51.3	48.5	48.7	47.4	50.3
Residential	**338.3**	**370.7**	**357.9**	**321.5**	**342.4**	**348.2**	**339.2**
Coal	3.0	1.1	0.8	0.6	0.7	0.7	0.6
Natural Gas	238.0	270.7	262.2	237.3	257.0	264.4	257.2
Fuel Oil	97.4	98.8	94.9	83.6	84.6	83.1	81.4
U.S. Territories	**27.9**	**35.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**
Coal	0.6	0.9	3.0	3.4	4.3	3.3	3.5
Natural Gas	NO	0.7	1.3	1.4	1.4	1.6	1.5
Fuel Oil	27.2	34.2	45.7	45.5	40.4	35.0	36.7
Total	**3,252.5**	**3,785.3**	**3,856.6**	**3,775.0**	**3,862.8**	**3,776.0**	**3,489.3**

* U.S. Territories are not apportioned by sector, and emissions are from all fuel combustion sources (stationary and mobile) are presented in this table.

Table 3-10: CH_4 Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	2000	2005	2006	2007	2008	2009
Electricity Generation	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Fuel Oil	0.1	0.1	0.1	+	+	+	+
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Industrial	**1.5**	**1.6**	**1.4**	**1.5**	**1.4**	**1.3**	**1.2**
Coal	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Fuel Oil	0.2	0.1	0.2	0.2	0.2	0.2	0.1
Natural Gas	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Wood	0.9	1.0	0.9	0.9	0.8	0.8	0.7
Commercial	**0.9**	**0.9**	**0.9**	**0.8**	**0.9**	**0.9**	**0.9**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.2	0.1	0.1	0.1	0.1
Natural Gas	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Wood	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Residential	**4.4**	**3.4**	**3.4**	**3.1**	**3.4**	**3.5**	**3.4**
Coal	0.2	0.1	0.1	+	+	+	+
Fuel Oil	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Natural Gas	0.4	0.5	0.5	0.4	0.5	0.5	0.5
Wood	3.5	2.5	2.6	2.3	2.6	2.7	2.6
U.S. Territories	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+
Fuel Oil	+	+	0.1	0.1	0.1	0.1	0.1
Natural Gas	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+
Total	**7.4**	**6.6**	**6.6**	**6.2**	**6.5**	**6.5**	**6.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 3-11: N_2O Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	2000	2005	2006	2007	2008	2009
Electricity Generation	**8.1**	**10.0**	**10.3**	**10.1**	**10.2**	**10.1**	**9.0**
Coal	7.6	9.4	9.7	9.5	9.7	9.6	8.5
Fuel Oil	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Wood	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Industrial	**3.2**	**3.2**	**3.0**	**3.1**	**3.0**	**2.8**	**2.5**
Coal	0.8	0.6	0.6	0.6	0.5	0.5	0.4
Fuel Oil	0.5	0.4	0.5	0.6	0.6	0.5	0.4
Natural Gas	0.2	0.3	0.2	0.2	0.2	0.2	0.2
Wood	1.7	1.9	1.7	1.7	1.7	1.6	1.4
Commercial	**0.4**	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**
Coal	0.1	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential	**1.1**	**0.9**	**0.9**	**0.8**	**0.9**	**0.9**	**0.9**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Natural Gas	0.1	0.2	0.1	0.1	0.1	0.1	0.1
Wood	0.7	0.5	0.5	0.5	0.5	0.5	0.5
U.S. Territories	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+

Fuel Oil	0.1		0.1		0.1	0.1	0.1	0.1	0.1
Natural Gas	+		+		+	+	+	+	+
Wood	+		+		+	+	+	+	+
Total	**12.8**		**14.6**		**14.7**	**14.4**	**14.6**	**14.2**	**12.8**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Electricity Generation

The process of generating electricity is the single largest source of CO_2 emissions in the United States, representing 39 percent of total CO_2 emissions from all CO_2 emissions sources across the United States. CH_4 and N_2O accounted for a small portion of emissions from electricity generation, representing less than 0.1 percent and 0.4 percent, respectively.[63] Electricity generation also accounted for the largest share of CO_2 emissions from fossil fuel combustion, approximately 41 percent in 2009. CH_4 and N_2O from electricity generation represented 8 and 25 percent of emissions from CH_4 and N_2O emissions from fossil fuel combustion in 2009, respectively. Electricity was consumed primarily in the residential, commercial, and industrial end-use sectors for lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 3-9).

Figure 3-9: Electricity Generation Retail Sales by End-Use Sector

The electric power industry includes all power producers, consisting of both regulated utilities and nonutilities (e.g. independent power producers, qualifying cogenerators, and other small power producers). For the underlying energy data used in this chapter, the Energy Information Administration (EIA) places electric power generation into three functional categories: the electric power sector, the commercial sector, and the industrial sector. The electric power sector consists of electric utilities and independent power producers whose primary business is the production of electricity,[64] while the other sectors consist of those producers that indicate their primary business is something other than the production of electricity.

The industrial, residential, and commercial end-use sectors, as presented in Table 3-8, were reliant on electricity for meeting energy needs. The residential and commercial end-use sectors were especially reliant on electricity consumption for lighting, heating, air conditioning, and operating appliances. Electricity sales to the residential and commercial end-use sectors in 2009 decreased approximately 1.2 percent and 1.0 percent, respectively. The trend in the commercial and residential sectors can largely be attributed to the decreased carbon intensity in the fuels used to generate electricity for these sectors. In addition, electricity consumption in both sectors decreased as a result of the less energy-intensive weather conditions compared to 2008. In 2009, the amount of electricity generated (in kWh) decreased by 4 percent from the previous year. This decline was due to the economic downturn, a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly, and an increase in non-fossil fuel sources used to generate electricity. As a result, CO_2 emissions from the electric power sector decreased by 8.8 percent as the consumption of coal and petroleum for electricity generation decreased by 10.8 percent and 16.6 percent, respectively, in 2009 and the consumption of natural gas for electricity generation, increased by 3.1 percent. The decrease in C intensity of the electricity supply (see Table 3-15) was the result of a decrease in the carbon intensity of fossil fuels consumed to generate electricity and an increase in renewable generation of 5 percent spurred by a 28 percent increase in wind-generated electricity.

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[63] Since emissions estimates for U.S. territories cannot be disaggregated by gas in Table 3-7and Table 3-8, the percentages for CH_4 and N_2O exclude U.S. territory estimates.

[64] Utilities primarily generate power for the U.S. electric grid for sale to retail customers. Nonutilities produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market (e.g., to utilities for distribution and resale to customers).

Industrial Sector

The industrial sector accounted for 14 percent of CO_2 emissions from fossil fuel combustion, 15 percent of CH_4 emissions from fossil fuel combustion, and 7 percent of N_2O emissions from fossil fuel combustion. CO_2, CH_4, and N_2O emissions resulted from the direct consumption of fossil fuels for steam and process heat production.

The industrial sector, per the underlying energy consumption data from EIA, includes activities such as manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy consumption is manufacturing, of which six industries—Petroleum Refineries, Chemicals, Paper, Primary Metals, Food, and Nonmetallic Mineral Products—represent the vast majority of the energy use (EIA 2010 and EIA 2009c).

In theory, emissions from the industrial sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions.[65] In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy-intensive manufacturing products to less energy-intensive products (e.g., from steel to computer equipment) also have a significant effect on industrial emissions.

From 2008 to 2009, total industrial production and manufacturing output decreased by 9.3 and 10.9 percent, respectively (FRB 2010). Over this period, output decreased across all production indices for Food, Petroleum Refineries, Chemicals, Paper, Primary Metals, and Nonmetallic Mineral Products (see Figure 3-10).

Figure 3-10: Industrial Production Indices (Index 2002=100)

Despite the growth in industrial output (41 percent) and the overall U.S. economy (60 percent) from 1990 to 2009, CO_2 emissions from fossil fuel combustion in the industrial sector decreased by 13.7 percent over that time. A number of factors are believed to have caused this disparity between growth in industrial output and decrease in industrial emissions, including: (1) more rapid growth in output from less energy-intensive industries relative to traditional manufacturing industries, and (2) energy-intensive industries such as steel are employing new methods, such as electric arc furnaces, that are less carbon intensive than the older methods. In 2009, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,340.1 Tg CO_2 Eq., or approximately 12.1 percent below 2008 emissions.

Residential and Commercial Sectors

The residential and commercial sectors accounted for 7 and 4 percent of CO_2 emissions from fossil fuel combustion, 42 and 11 percent of CH_4 emissions from fossil fuel combustion, and 2 and 1 percent of N_2O emissions from fossil fuel combustion, respectively. Emissions from these sectors were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Coal consumption was a minor component of energy use in both of these end-use sectors. In 2009, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,131.6 Tg CO_2 Eq. and 990.3Tg CO_2 Eq., respectively. Total CO_2, CH_4, and N_2O emissions from the residential and commercial sectors decreased by 4.9 and 4.5 percent from 2008 to 2009, respectively.

Emissions from the residential and commercial sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. In the long-term, both sectors are also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).

Emissions from natural gas consumption represent about 76 and 75 percent of the direct fossil fuel CO_2 emissions from the residential and commercial sectors, respectively. In 2009, natural gas CO_2 emissions from the residential and commercial sectors decreased by 2.8 percent and 1.3 percent, respectively. The decrease in natural gas emissions in both sectors is a result of less energy-intensive weather conditions in the United States compared to

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[65] Some commercial customers are large enough to obtain an industrial price for natural gas and/or electricity and are consequently grouped with the industrial end-use sector in U.S. energy statistics. These misclassifications of large commercial customers likely cause the industrial end-use sector to appear to be more sensitive to weather conditions.

2008.

U.S. Territories

Emissions from U.S. territories are based on the fuel consumption in American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands. As described the Methodology section for CO_2 from fossil fuel combustion, this data is collected separately from the sectoral-level data available for the general calculations. As sectoral information is not available for U.S. Territories, CO_2, CH_4, and N_2O emissions are not presented for U.S. Territories in the tables above, though the emissions will include some transportation and mobile combustion sources.

Transportation Sector

This discussion of transportation emissions follows the alternative method of presenting combustion emissions by allocating emissions associated with electricity generation to the transportation end-use sector, as presented in Table 3-8. For direct emissions from transportation (i.e., not including emissions associated with the sector's electricity consumption), please see Table 3-7.

The transportation end-use sector accounted for 1,745.5 Tg CO_2 Eq. in 2009, which represented 33 percent of CO_2 emissions, 24 percent of CH_4 emissions, and 65 percent of N_2O emissions from fossil fuel combustion, respectively. Fuel purchased in the U.S. for international aircraft and marine travel accounted for an additional 123.1 Tg CO_2 in 2009; these emissions are recorded as international bunkers and are not included in U.S. totals according to UNFCCC reporting protocols. Among domestic transportation sources, light duty vehicles (including passenger cars and light-duty trucks) represented 64 percent of CO_2 emissions, medium- and heavy-duty trucks 20 percent, commercial aircraft 6 percent, and other sources 9 percent. Light-duty truck CO_2 emissions increased by 60 percent (193.4 Tg) from 1990 to 2009, representing the largest percentage increase of any transportation mode. General aviation aircraft CO_2 emissions also increased by nearly 60 percent (5.7 Tg) from 1990 to 2009. CO_2 from the domestic operation of commercial aircraft decreased by 18 percent (24.0 Tg) from 1990 to 2009. Across all categories of aviation, CO_2 emissions decreased by 21.6 percent (38.7 Tg) between 1990 and 2009. This includes a 59 percent (20.3 Tg) decrease in emissions from domestic military operations. For further information on all greenhouse gas emissions from transportation sources, please refer to Annex 3.2. See Table 3-12 for a detailed breakdown of CO_2 emissions by mode and fuel type.

From 1990 to 2009, transportation emissions rose by 17 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 39 percent from 1990 to 2009, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

From 2008 to 2009, CO_2 emissions from the transportation end-use sector declined 4 percent. The decrease in emissions can largely be attributed to decreased economic activity in 2009 and an associated decline in the demand for transportation. Modes such as medium- and heavy-duty trucks were significantly impacted by the decline in freight transport. Similarly, increased jet fuel prices were a factor in the 19 percent decrease in commercial aircraft emissions since 2007.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO_2 from fossil fuel combustion, which increased by 16 percent from 1990 to 2009. This rise in CO_2 emissions, combined with an increase in HFCs from close to zero emissions in 1990 to 60.2 Tg CO_2 Eq. in 2009, led to an increase in overall emissions from transportation activities of 17 percent.

Transportation Fossil Fuel Combustion CO_2 Emissions

Domestic transportation CO_2 emissions increased by 16 percent (235.1 Tg) between 1990 and 2009, an annualized increase of 0.8 percent. The 4 percent decline in emissions between 2008 and 2009 followed the previous year's trend of decreasing emissions. Almost all of the energy consumed by the transportation sector is petroleum-based, including motor gasoline, diesel fuel, jet fuel, and residual oil.[66] Transportation sources also produce CH_4 and N_2O; these emissions are included in Table 3-13 and Table 3-14 in the "Mobile Combustion" Section. Annex 3.2 presents total emissions from all transportation and mobile sources, including CO_2, N_2O, CH_4, and HFCs.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,111.7 Tg in 2009, an increase of 17 percent (161.3 Tg) from 1990. CO_2 emissions from passenger cars and light-duty trucks peaked at 1,184.3 Tg in 2004, and since then have declined about 6 percent. Over the 1990s through early this decade, growth in vehicle travel substantially outweighed improvements in vehicle fuel economy; however, the rate of Vehicle Miles Traveled (VMT) growth slowed considerably starting in 2005 (and declined rapidly in 2008) while average vehicle fuel economy increased. Among new vehicles sold annually, average fuel economy gradually declined from 1990 to 2004 (Figure 3-11), reflecting substantial growth in sales of light-duty trucks—in particular, growth in the market share of sport utility vehicles—relative to passenger cars (Figure 3-12). New vehicle fuel economy improved beginning in 2005, largely due to higher light-duty truck fuel economy standards, which have risen each year since 2005. The overall increase in fuel economy is also due to a slightly lower light-duty truck market share, which peaked in 2004 at 52 percent and declined to 40 percent in 2009.

Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2008

Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2008

Light-duty truck[67] CO_2 emissions increased by 60 percent (193.4 Tg) from 1990 to 2009, representing the largest percentage increase of any transportation mode. General aviation aircraft CO_2 emissions also increased by nearly 60 percent (5.7 Tg) from 1990 to 2009. CO_2 from the domestic operation of commercial aircraft decreased by 18 percent (24.0 Tg) from 1990 to 2009. Across all categories of aviation[68], CO_2 emissions decreased by 21.6 percent (38.7 Tg) between 1990 and 2009. This includes a 59 percent (20.3 Tg) decrease in emissions from domestic military operations. For further information on all greenhouse gas emissions from transportation sources, please refer to Annex 3.2.

Table 3-12: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (Tg CO_2 Eq.) [a]

Fuel/Vehicle Type	1990	2000	2005	2006	2007	2008	2009
Gasoline	**983.7**	**1,135.0**	**1,187.8**	**1,178.2**	**1,181.2**	**1,130.3**	**1,125.7**
Passenger Cars	621.4	640.6	658.0	635.0	628.7	594.0	593.3
Light-Duty Trucks	309.1	446.4	478.7	491.5	500.1	486.5	485.9
Medium- and Heavy-Duty Trucks[b]	38.7	36.0	34.9	35.5	36.1	33.7	30.6
Buses	0.3	0.4	0.4	0.4	0.4	0.4	0.3
Motorcycles	1.7	1.8	1.6	1.9	2.1	2.1	2.1
Recreational Boats	12.4	9.8	14.1	14.0	13.9	13.5	13.4
Distillate Fuel Oil (Diesel)	**262.9**	**402.5**	**451.8**	**470.3**	**476.3**	**443.5**	**402.5**
Passenger Cars	7.9	3.7	4.2	4.1	4.1	3.9	3.9
Light-Duty Trucks	11.5	20.1	25.8	26.8	27.3	26.9	26.7
Medium- and Heavy-Duty	190.5	309.6	360.6	370.1	376.1	356.0	321.8

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[66] Biofuel estimates are presented for informational purposes only in the Energy chapter, in line with IPCC methodological guidance and UNFCCC reporting obligations. Net carbon fluxes from changes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change, and Forestry (see Chapter 7). More information and additional analyses on biofuels are available at EPA's "Renewable Fuels: Regulations & Standards" web page: http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm

[67] Includes "light-duty trucks" fueled by gasoline, diesel and LPG.

[68] Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not included in national emission totals, in line with IPCC methodological guidance and UNFCCC reporting obligations.

Trucks[b]							
Buses	8.0	10.2	10.6	10.8	10.8	10.3	9.3
Rail	35.5	42.1	45.6	47.8	46.6	43.2	36.2
Recreational Boats	2.0	2.7	3.1	3.2	3.3	0.9	3.5
Ships and Other Boats	7.5	14.1	8.1	7.5	8.2	2.2	1.2
International Bunker Fuels [c]	*11.7*	*6.3*	*9.4*	*8.8*	*8.2*	*9.0*	*8.3*
Jet Fuel	**176.2**	**199.8**	**194.2**	**169.5**	**168.7**	**155.1**	**138.8**
Commercial Aircraft	135.4	169.2	161.2	137.1	138.1	122.2	111.4
Military Aircraft	34.4	21.1	18.1	16.4	16.1	16.3	14.1
General Aviation Aircraft	6.4	9.5	14.9	16.0	14.5	16.6	13.3
International Bunker Fuels [c]	*46.4*	*58.8*	*56.7*	*74.6*	*73.8*	*75.5*	*69.4*
Aviation Gasoline	**3.1**	**2.5**	**2.4**	**2.3**	**2.2**	**2.0**	**1.8**
General Aviation Aircraft	3.1	2.5	2.4	2.3	2.2	2.0	1.8
Residual Fuel Oil	**22.6**	**33.3**	**19.3**	**23.0**	**29.0**	**19.9**	**12.0**
Ships and Other Boats[d]	22.6	33.3	19.3	23.0	29.0	19.9	12.0
International Bunker Fuels [c]	*53.7*	*33.3*	*43.6*	*45.0*	*45.6*	*49.2*	*45.4*
Natural Gas	**36.0**	**35.6**	**33.1**	**33.1**	**35.3**	**36.8**	**36.3**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Buses	+	0.4	0.8	0.8	1.0	1.1	1.1
Pipeline	36.0	35.2	32.2	32.3	34.3	35.7	35.2
LPG	**1.4**	**0.7**	**1.7**	**1.7**	**1.4**	**2.4**	**2.5**
Light-Duty Trucks	0.6	0.5	1.3	1.2	1.0	1.8	1.8
Medium- and Heavy-Duty Trucks[b]	0.8	0.3	0.4	0.5	0.4	0.7	0.7
Buses	+	+	+	+	+	+	+
Electricity	**3.0**	**3.4**	**4.7**	**4.5**	**5.0**	**4.7**	**4.4**
Rail	3.0	3.4	4.7	4.5	5.0	4.7	4.4
Total	**1,489.0**	**1,813.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.6**	**1,724.1**
Total (Including Bunkers) [c]	**1,600.8**	**1,911.4**	**2,011.1**	**2,011.0**	**2,026.6**	**1,928.3**	**1,847.2**

[a] This table does not include emissions from non-transportation mobile sources, such as agricultural equipment and construction/mining equipment; it also does not include emissions associated with electricity consumption by pipelines or lubricants used in transportation.

[b] Includes medium- and heavy-duty trucks over 8,500 lbs.

[c] Official estimates exclude emissions from the combustion of both aviation and marine international bunker fuels; however, estimates including international bunker fuel-related emissions are presented for informational purposes.

Note: Totals may not sum due to independent rounding.

Note: See section 3.10 of this chapter, in line with IPCC methodological guidance and UNFCCC reporting obligations, for more information on ethanol.

+ Less than 0.05 Tg CO_2 Eq.

- Unreported or zero

Mobile Fossil Fuel Combustion CH_4 and N_2O Emissions

Mobile combustion includes emissions of CH_4 and N_2O from all transportation sources identified in the U.S. inventory with the exception of pipelines, which are stationary; mobile sources also include non-transportation sources such as construction/mining equipment, agricultural equipment, vehicles used off-road, and other sources (e.g., snowmobiles, lawnmowers, etc.). Annex 3.2 includes a summary of all emissions from both transportation and mobile sources. Table 3-13 and Table 3-14 provide CH_4 and N_2O emission estimates in Tg CO_2 Eq.[69]

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[69] See Annex 3.2 for a complete time series of emission estimates for 1990 through 2009.

Mobile combustion was responsible for a small portion of national CH_4 emissions (0.3 percent) but was the second largest source of U.S. N_2O emissions (9 percent). From 1990 to 2009, mobile source CH_4 emissions declined by 58 percent, to 2.0 Tg CO_2 Eq. (93 Gg), due largely to control technologies employed in on-road vehicles since the mid-1990s to reduce CO, NO_x, NMVOC, and CH_4 emissions. Mobile source emissions of N_2O decreased by 46 percent, to 23.9 Tg CO_2 Eq. (77 Gg). Earlier generation control technologies initially resulted in higher N_2O emissions, causing a 26 percent increase in N_2O emissions from mobile sources between 1990 and 1998. Improvements in later-generation emission control technologies have reduced N_2O output, resulting in a 50 percent decrease in mobile source N_2O emissions from 1998 to 2009 (Figure 3-13). Overall, CH_4 and N_2O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks.

Figure 3-13: Mobile Source CH_4 and N_2O Emissions

Table 3-13: CH_4 Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2000	2005	2006	2007	2008	2009
Gasoline On-Road	**4.2**	**2.8**	**1.9**	**1.7**	**1.6**	**1.4**	**1.3**
Passenger Cars	2.6	1.6	1.1	1.0	0.9	0.8	0.7
Light-Duty Trucks	1.4	1.1	0.7	0.6	0.6	0.6	0.6
Medium- and Heavy-Duty Trucks and Buses	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	+	+	+	+	+	+	+
Alternative Fuel On-Road	**+**	**+**	**+**	**0.1**	**0.1**	**0.1**	**0.1**
Non-Road	**0.4**	**0.5**	**0.6**	**0.6**	**0.5**	**0.5**	**0.5**
Ships and Boats	+	+	+	+	+	+	+
Rail	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Agricultural Equipment[b]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Construction/Mining Equipment[c]	+	0.1	0.1	0.1	0.1	0.1	0.1
Other[d]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**4.7**	**3.4**	**2.5**	**2.3**	**2.2**	**2.0**	**2.0**

[a] See Annex 3.2 for definitions of on-road vehicle types.

[b] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

[c] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

[d] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Note: Totals may not sum due to independent rounding.

+ Less than 0.05 Tg CO_2 Eq.

Table 3-14: N_2O Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2000	2005	2006	2007	2008	2009
Gasoline On-Road	**40.1**	**48.4**	**32.1**	**29.0**	**25.5**	**21.8**	**19.9**
Passenger Cars	25.4	25.2	17.7	15.7	13.7	11.7	10.0
Light-Duty Trucks	14.1	22.4	13.6	12.5	11.1	9.5	9.3
Medium- and Heavy-Duty Trucks and Buses	0.6	0.9	0.8	0.7	0.7	0.6	0.5
Motorcycles	+	+	+	+	+	+	+

Diesel On-Road	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Alternative Fuel On-Road	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Non-Road	**3.6**	**4.3**	**4.3**	**4.2**	**4.3**	**3.8**	**3.6**
Ships and Boats	0.6	0.9	0.6	0.7	0.8	0.5	0.4
Rail	0.3	0.3	0.4	0.4	0.4	0.3	0.3
Aircraft	1.7	1.9	1.9	1.6	1.6	1.5	1.3
Agricultural Equipment[b]	0.2	0.3	0.4	0.4	0.4	0.4	0.4
Construction/Mining Equipment[c]	0.3	0.4	0.5	0.5	0.5	0.5	0.5
Other[d]	0.4	0.5	0.6	0.6	0.6	0.6	0.6
Total	**43.9**	**53.2**	**36.9**	**33.6**	**30.3**	**26.1**	**23.9**

[a] See Annex 3.2 for definitions of on-road vehicle types.

[b] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

[c] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

[d] “Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Note: Totals may not sum due to independent rounding.

+ Less than 0.05 Tg CO_2 Eq.

CO_2 from Fossil Fuel Combustion

Methodology

The methodology used by the United States for estimating CO_2 emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed, sectoral-based emission estimates in line with a Tier 2 method in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). A detailed description of the U.S. methodology is presented in Annex 2.1, and is characterized by the following steps:

1. *Determine total fuel consumption by fuel type and sector.* Total fossil fuel consumption for each year is estimated by aggregating consumption data by end-use sector (e.g., commercial, industrial, etc.), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil, etc.). Fuel consumption data for the United States were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE), primarily from the Monthly Energy Review and published supplemental tables on petroleum product detail (EIA 2011). The EIA does not include territories in its national energy statistics, so fuel consumption data for territories were collected separately from Jacobs (2010).[70]

   For consistency of reporting, the IPCC has recommended that countries report energy data using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA on an annual basis and used in this inventory are predominantly from mid-stream or conversion energy consumers such as refiners and electric power generators. These annual surveys are supplemented with end-use energy consumption surveys, such as the Manufacturing Energy Consumption Survey, that are conducted on a periodic basis (every 4 years). These consumption data sets help inform the annual surveys to arrive at the

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[70] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report and contributed emissions of 42 Tg CO_2 Eq. in 2009.

national total and sectoral breakdowns for that total. [71]

It is also important to note that U.S. fossil fuel energy statistics are generally presented using gross calorific values (GCV) (i.e., higher heating values). Fuel consumption activity data presented here have not been adjusted to correspond to international standards, which are to report energy statistics in terms of net calorific values (NCV) (i.e., lower heating values).[72]

2. *Subtract uses accounted for in the Industrial Processes chapter.* Portions of the fuel consumption data for seven fuel categories—coking coal, distillate fuel, industrial other coal, petroleum coke, natural gas, residual fuel oil, and other oil—were reallocated to the industrial processes chapter, as they were consumed during non-energy related industrial activity. To make these adjustments, additional data were collected from AISI (2004 through 2010), Coffeyville (2010), U.S. Census Bureau (2010), EIA (2010c), USGS (1991 through 2010), USGS (1994 through 2010), USGS (1995, 1998, 2000 through 2002, 2007, and 2009), USGS (1991 through 2009a), and USGS (1991 through 2009b).[73]
3. *Adjust for conversion of fuels and exports of CO_2.* Fossil fuel consumption estimates are adjusted downward to exclude fuels created from other fossil fuels and exports of CO_2.[74] Synthetic natural gas is created from industrial coal, and is currently included in EIA statistics for both coal and natural gas. Therefore, synthetic natural gas is subtracted from energy consumption statistics.[75] Since October 2000, the Dakota Gasification Plant has been exporting CO_2 to Canada by pipeline. Since this CO_2 is not emitted to the atmosphere in the United States, energy used to produce this CO_2 is subtracted from energy consumption statistics. To make these adjustments, additional data for ethanol were collected from EIA (2011) and data for synthetic natural gas were collected from EIA (2009b), and data for CO_2 exports were collected from the Dakota Gasification Company (2006), Fitzpatrick (2002), Erickson (2003), and EIA (2007b).
4. *Adjust Sectoral Allocation of Distillate Fuel Oil and Motor Gasoline.* EPA had conducted a separate bottom-up analysis of transportation fuel consumption based on the Federal Highway Administration's (FHWA) VMT that indicated that the amount of distillate and motor gasoline consumption allocated to the transportation sector in the EIA statistics should be adjusted. Therefore, for these estimates, the transportation sector's distillate fuel and motor gasoline consumption was adjusted upward to match the value obtained from the bottom-up analysis based on VMT. As the total distillate and motor gasoline consumption estimate from EIA are considered to be accurate at the national level, the distillate consumption totals for the residential, commercial, and industrial sectors were adjusted downward proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2009 through 2010), Benson (2002 through 2004), DOE (1993 through 2010), EIA (2009a), EIA (1991 through 2010), EPA (2009), and FHWA (1996 through 2010).[76]

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[71] See IPCC Reference Approach for estimating CO_2 emissions from fossil fuel combustion in Annex 4 for a comparison of U.S. estimates using top-down and bottom-up approaches.

[72] A crude convention to convert between gross and net calorific values is to multiply the heat content of solid and liquid fossil fuels by 0.95 and gaseous fuels by 0.9 to account for the water content of the fuels. Biomass-based fuels in U.S. energy statistics, however, are generally presented using net calorific values.

[73] See sections on Iron and Steel Production and Metallurgical Coke Production, Ammonia Production and Urea Consumption, Petrochemical Production, Titanium Dioxide Production, Ferroalloy Production, Aluminum Production, and Silicon Carbide Production and Consumption in the Industrial Processes chapter.

[74] Energy statistics from EIA(2010c) are already adjusted downward to account for ethanol added to motor gasoline, and biogas in natural gas.

[75] These adjustments are explained in greater detail in Annex 2.1.

[76] FHWA data on vehicle miles traveled from the VM-1 table were not available for 2009 due to a delay caused by changes in data collection procedures. Based on data from FHWA's Traffic Volume Trends Program, the overall increase in VMT between 2008 and 2009 was estimated to be 0.2%. Total VMT was distributed among vehicle classes based on trends in fuel consumption by fuel type between 2008 and 2009, as described below.

Fuel use by vehicle class (also in the VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline was estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel

5. *Adjust for fuels consumed for non-energy uses.* U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. These are fossil fuels that are manufactured into plastics, asphalt, lubricants, or other products. Depending on the end-use, this can result in storage of some or all of the C contained in the fuel for a period of time. As the emission pathways of C used for non-energy purposes are vastly different than fuel combustion (since the C in these fuels ends up in products instead of being combusted), these emissions are estimated separately in the Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter. Therefore, the amount of fuels used for non-energy purposes was subtracted from total fuel consumption. Data on non-fuel consumption was provided by EIA (2011).

6. *Subtract consumption of international bunker fuels.* According to the UNFCCC reporting guidelines emissions from international transport activities, or bunker fuels, should not be included in national totals. U.S. energy consumption statistics include these bunker fuels (e.g., distillate fuel oil, residual fuel oil, and jet fuel) as part of consumption by the transportation end-use sector, however, so emissions from international transport activities were calculated separately following the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, and determination of C content).[77] The Office of the Under Secretary of Defense (Installations and Environment) and the Defense Energy Support Center (Defense Logistics Agency) of the U.S. Department of Defense (DoD) (DESC 2011) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from FAA (2006 and 2009); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2010) for 1990 through 2001, 2007 and 2008, and DHS (2008) for 2003 through 2006. Consumption of these fuels was subtracted from the corresponding fuels in the transportation end-use sector. Estimates of international bunker fuel emissions for the United States are discussed in detail later in the International Bunker Fuels section of this chapter.

7. *Determine the total C content of fuels consumed.* Total C was estimated by multiplying the amount of fuel consumed by the amount of C in each fuel. This total C estimate defines the maximum amount of C that could potentially be released to the atmosphere if all of the C in each fuel was converted to CO_2. The C content coefficients used by the United States were obtained from EIA's Emissions of Greenhouse Gases in the United States 2008 (EIA 2009a), and an EPA analysis of C content coefficients used in the mandatory reporting rule (EPA 2010a). A discussion of the methodology used to develop the C content coefficients are presented in Annexes 2.1 and 2.2.

8. *Estimate CO_2 Emissions.* Total CO_2 emissions are the product of the adjusted energy consumption (from the previous methodology steps 1 through 6), the C content of the fuels consumed, and the fraction of C that is oxidized. The fraction oxidized was assumed to be 100 percent for petroleum, coal, and natural gas based on guidance in IPCC (2006) (see Annex 2.1).

9. *Allocate transportation emissions by vehicle type.* This report provides a more detailed accounting of emissions from transportation because it is such a large consumer of fossil fuels in the United States. For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector.

    - For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2010); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2010). Fuel use by vehicle class (found in the VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline was estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel were estimated to fall by the same rate that diesel fuel consumption fell overall in 2009.

    - For non-road vehicles, activity data were obtained from AAR (2009 through 2010), APTA (2007 through 2010), BEA (1991 through 2009), Benson (2002 through 2004), DOE (1993 through 2010),

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was estimated to fall by the same rate that diesel fuel consumption fell overall in 2009. VMT was then distributed to vehicle classes based on these fuel consumption estimates, assuming no relative change in MPG between vehicle classes.

[77] See International Bunker Fuels section in this chapter for a more detailed discussion.

DESC (2011), DOC (1991 through 2010), DOT (1991 through 2010), EIA (2009a), EIA (2009d), EIA (2007a), EIA (2002), EIA (1991 through 2011), EPA (2010b), FAA (2008), and Gaffney (2007).

- For jet fuel used by aircraft, CO_2 emissions were calculated directly based on reported consumption of fuel as reported by EIA, and allocated to commercial aircraft using flight-specific fuel consumption data from the Federal Aviation Administration's (FAA) Aviation Environmental Design Tool (AEDT) (FAA 2011).[78] Allocation to domestic general aviation was made using FAA Aerospace Forecast data, and allocation to domestic military uses was made using DoD data (see Annex 3.7).

Heat contents and densities were obtained from EIA (2010) and USAF (1998).[79]

[BEGIN BOX]

Box 3-2: Carbon Intensity of U.S. Energy Consumption

Fossil fuels are the dominant source of energy in the United States, and CO_2 is the dominant greenhouse gas emitted as a product from their combustion. Energy-related CO_2 emissions are impacted by not only lower levels of energy consumption but also by lowering the C intensity of the energy sources employed (e.g., fuel switching from coal to natural gas). The amount of C emitted from the combustion of fossil fuels is dependent upon the C content of the fuel and the fraction of that C that is oxidized. Fossil fuels vary in their average C content, ranging from about 53 Tg CO_2 Eq./QBtu for natural gas to upwards of 95 Tg CO_2 Eq./QBtu for coal and petroleum coke.[80] In general, the C content per unit of energy of fossil fuels is the highest for coal products, followed by petroleum, and then natural gas. The overall C intensity of the U.S. economy is thus dependent upon the quantity and combination of fuels and other energy sources employed to meet demand.

Table 3-15 provides a time series of the C intensity for each sector of the U.S. economy. The time series incorporates only the energy consumed from the direct combustion of fossil fuels in each sector. For example, the C intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest C intensity, which is related to the large percentage of its energy derived from natural gas for heating. The C intensity of the commercial sector has predominantly declined since 1990 as commercial businesses shift away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had higher C intensities over this period. The C intensity of the transportation sector was closely related to the C content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 Tg CO_2 Eq./EJ), which were the primary sources of energy. Lastly, the electricity generation sector had the highest C intensity due to its heavy reliance on coal for generating electricity.

Table 3-15: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (Tg CO_2 Eq./QBtu)

Sector	1990		2000		2005	2006	2007	2008	2009
Residential [a]	57.4		56.6		56.6	56.5	56.3	56.1	56.0
Commercial [a]	59.2		57.2		57.5	57.2	57.1	56.8	56.9
Industrial [a]	64.3		62.8		64.3	64.5	64.0	63.6	63.2
Transportation [a]	71.1		71.3		71.4	71.6	71.9	71.6	71.5

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[78] Data for inventory years 2000 through 2005 were developed using the FAA's System for assessing Aviation's Global Emissions (SAGE) model. That tool has been incorporated into the Aviation Environmental Design Tool (AEDT), which calculates noise in addition to aircraft fuel burn and emissions for all commercial flights globally in a given year. Data for inventory years 2006-2009 were developed using AEDT. The AEDT model dynamically models aircraft performance in space and time to produce fuel burn, emissions and noise. Full flight gate-to-gate analyses are possible for study sizes ranging from a single flight at an airport to scenarios at the regional, national, and global levels. AEDT is currently used by the U.S. government to consider the interdependencies between aircraft-related fuel burn, noise and emissions.

[79] For a more detailed description of the data sources used for the analysis of the transportation end use sector see the Mobile Combustion (excluding CO_2) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.7.

[80] One exajoule (EJ) is equal to 10^{18} joules or 0.9478 QBtu.

Electricity Generation [b]	87.3		86.2		85.8	85.4	84.7	84.9	83.7
U.S. Territories [c]	73.0		72.5		73.4	73.5	73.8	73.3	73.1
All Sectors [c]	**73.0**		**73.0**		**73.5**	**73.5**	**73.3**	**73.1**	**72.4**

[a] Does not include electricity or renewable energy consumption.

[b] Does not include electricity produced using nuclear or renewable energy.

[c] Does not include nuclear or renewable energy consumption.

Note: Excludes non-energy fuel use emissions and consumption.

Over the twenty-year period of 1990 through 2009, however, the C intensity of U.S. energy consumption has been fairly constant, as the proportion of fossil fuels used by the individual sectors has not changed significantly. Per capita energy consumption fluctuated little from 1990 to 2007, but in 2009 was approximately 9 percent below levels in 1990 (see Figure 3-14). Due to a general shift from a manufacturing-based economy to a service-based economy, as well as overall increases in efficiency, energy consumption and energy-related CO_2 emissions per dollar of gross domestic product (GDP) have both declined since 1990 (BEA 2010).

Figure 3-14: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP

C intensity estimates were developed using nuclear and renewable energy data from EIA (2010), EPA (2010a), and fossil fuel consumption data as discussed above and presented in Annex 2.1.

[END BOX]

Uncertainty and Time Series Consistency

For estimates of CO_2 from fossil fuel combustion, the amount of CO_2 emitted is directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and production of fossil fuel-based products with long-term carbon storage should yield an accurate estimate of CO_2 emissions.

Nevertheless, there are uncertainties in the consumption data, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., coal, petroleum, or natural gas), the amount of carbon contained in the fuel per unit of useful energy can vary. For the United States, however, the impact of these uncertainties on overall CO_2 emission estimates is believed to be relatively small. See, for example, Marland and Pippin (1990).

Although statistics of total fossil fuel and other energy consumption are relatively accurate, the allocation of this consumption to individual end-use sectors (i.e., residential, commercial, industrial, and transportation) is less certain. For example, for some fuels the sectoral allocations are based on price rates (i.e., tariffs), but a commercial establishment may be able to negotiate an industrial rate or a small industrial establishment may end up paying an industrial rate, leading to a misallocation of emissions. Also, the deregulation of the natural gas industry and the more recent deregulation of the electric power industry have likely led to some minor problems in collecting accurate energy statistics as firms in these industries have undergone significant restructuring.

To calculate the total CO_2 emission estimate from energy-related fossil fuel combustion, the amount of fuel used in these non-energy production processes were subtracted from the total fossil fuel consumption for 2009. The amount of CO_2 emissions resulting from non-energy related fossil fuel use has been calculated separately and reported in the Carbon Emitted from Non-Energy Uses of Fossil Fuels section of this report. These factors all contribute to the uncertainty in the CO_2 estimates. Detailed discussions on the uncertainties associated with C emitted from Non-Energy Uses of Fossil Fuels can be found within that section of this chapter.

Various sources of uncertainty surround the estimation of emissions from international bunker fuels, which are subtracted from the U.S. totals (see the detailed discussions on these uncertainties provided in the International Bunker Fuels section of this chapter). Another source of uncertainty is fuel consumption by U.S. territories. The

United States does not collect energy statistics for its territories at the same level of detail as for the fifty states and the District of Columbia. Therefore, estimating both emissions and bunker fuel consumption by these territories is difficult.

Uncertainties in the emission estimates presented above also result from the data used to allocate CO_2 emissions from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom-up estimates of fuel consumption by vehicle type do not match aggregate fuel-type estimates from EIA. Further research is planned to improve the allocation into detailed transportation end-use sector emissions.

The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO_2 from fossil fuel combustion was integrated with the relevant variables from the inventory estimation model for International Bunker Fuels, to realistically characterize the interaction (or endogenous correlation) between the variables of these two models. About 120 input variables were modeled for CO_2 from energy-related Fossil Fuel Combustion (including about 10 for non-energy fuel consumption and about 20 for International Bunker Fuels).

In developing the uncertainty estimation model, uniform distributions were assumed for all activity-related input variables and emission factors, based on the SAIC/EIA (2001) report.[81] Triangular distributions were assigned for the oxidization factors (or combustion efficiencies). The uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001) and on conversations with various agency personnel.[82]

The uncertainty ranges for the activity-related input variables were typically asymmetric around their inventory estimates; the uncertainty ranges for the emissions factors were symmetric. Bias (or systematic uncertainties) associated with these variables accounted for much of the uncertainties associated with these variables (SAIC/EIA 2001).[83] For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte Carlo Sampling.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-16. Fossil fuel combustion CO_2 emissions in 2009 were estimated to be between 5,149.0 and 5,522.4 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 1 percent below to 6 percent above the 2009 emission estimate of 5,209.0.0 Tg CO_2 Eq.

Table 3-16: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Energy-related Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq. and Percent)

Fuel/Sector	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
		Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Coal [b]	**1,841.0**	**1,779.3**	**2,015.6**	**-3%**	**+9%**
Residential	0.6	0.6	0.7	-6%	+15%
Commercial	5.8	5.5	6.7	-5%	+15%
Industrial	83.4	80.5	97.5	-3%	+17%
Transportation	NE	NE	NE	NA	NA
Electricity Generation	1,747.6	1,680.4	1,915.8	-4%	+10%
U.S. Territories	3.5	3.1	4.2	-12%	+19%

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[81] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

[82] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

[83] Although, in general, random uncertainties are the main focus of statistical uncertainty analysis, when the uncertainty estimates are elicited from experts, their estimates include both random and systematic uncertainties. Hence, both these types of uncertainties are represented in this uncertainty analysis.

Natural Gas [b]	**1,200.9**	**1,209.4**	**1,276.6**	**+1%**	**+6%**
Residential	257.2	250.0	275.2	-3%	+7%
Commercial	167.9	163.2	179.7	-3%	+7%
Industrial	365.0	374.9	412.7	+3%	+13%
Transportation	36.3	35.2	38.8	-3%	+7%
Electricity Generation	373.1	362.3	392.0	-3%	+5%
U.S. Territories	1.5	1.3	1.7	-12%	+17%
Petroleum [b]	**2,166.7**	**2,067.2**	**2,323.5**	**-5%**	**+7%**
Residential	81.4	76.9	85.7	-6%	+5%
Commercial	50.3	47.9	52.4	-5%	+4%
Industrial	282.0	231.2	330.4	-18%	+17%
Transportation	1,683.4	1,598.6	1,826.8	-5%	+9%
Electric Utilities	32.9	31.5	35.4	-4%	+7%
U.S. Territories	36.7	33.8	40.9	-8%	+11%
Total (excluding Geothermal) [b]	**5,208.6**	**5,148.76**	**5,522.0**	**-1%**	**+6%**
Geothermal	0.4	NE	NE	NE	NE
Total (including Geothermal) [b,c]	**5,209.0**	**5,149.0**	**5,522.4**	**-1%**	**+6%**

NA (Not Applicable)

NE (Not Estimated)

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

[b] The low and high estimates for total emissions were calculated separately through simulations and, hence, the low and high emission estimates for the sub-source categories do not sum to total emissions.

[c] Geothermal emissions added for reporting purposes, but an uncertainty analysis was not performed for CO_2 emissions from geothermal production.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for CO_2 from fossil fuel combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology used for estimating CO_2 emissions from fossil fuel combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated to determine whether any corrective actions were needed. Minor corrective actions were taken.

Recalculations Discussion

The Energy Information Administration (EIA 2011) updated energy consumption statistics across the time series. These revisions primarily impacted the emission estimates for 2007 and 2008. In addition, the coal emissions for U.S. Territories decreased from 2001 to 2008 due to the closure of a coal power plant in the U.S. Virgin Islands. Overall, these changes resulted in an average annual increase of 0.5 Tg CO_2 Eq. (less than 0.1 percent) in CO_2 emissions from fossil fuel combustion for the period 1990 through 2008.

Planned Improvements

To reduce uncertainty of CO_2 from fossil fuel combustion estimates, efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data. This improvement is not all-inclusive, and is part of an ongoing analysis and efforts to continually improve the CO_2 from fossil fuel combustion estimates. In addition, further expert elicitation may be conducted to better quantify the total uncertainty associated with emissions from this source.

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to

EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

CH_4 and N_2O from Stationary Combustion

Methodology

CH_4 and N_2O emissions from stationary combustion were estimated by multiplying fossil fuel and wood consumption data by emission factors (by sector and fuel type). National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial, residential, electricity generation, and U.S. territories. For the CH_4 and N_2O estimates, wood consumption data for the United States was obtained from EIA's Annual Energy Review (EIA 2010). Fuel consumption data for coal, natural gas, and fuel oil for the United States were obtained from EIA's Monthly Energy Review and unpublished supplemental tables on petroleum product detail (EIA 2011). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by Jacobs (2010).[84] Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.[85] Construction and agricultural fuel use was obtained from EPA (2010a). Estimates for wood biomass consumption for fuel combustion do not include wood wastes, liquors, municipal solid waste, tires, etc., that are reported as biomass by EIA.

Emission factors for the four end-use sectors were provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). U.S. territories' emission factors were estimated using the U.S. emission factors for the primary sector in which each fuel was combusted.

More detailed information on the methodology for calculating emissions from stationary combustion, including emission factors and activity data, is provided in Annex 3.1.

Uncertainty and Time-Series Consistency

CH_4 emission estimates from stationary sources exhibit high uncertainty, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH_4 and N_2O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control).

An uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software.

The uncertainty estimation model for this source category was developed by integrating the CH_4 and N_2O stationary source inventory estimation models with the model for CO_2 from fossil fuel combustion to realistically characterize the interaction (or endogenous correlation) between the variables of these three models. About 55 input variables were simulated for the uncertainty analysis of this source category (about 20 from the CO_2 emissions from fossil fuel combustion inventory estimation model and about 35 from the stationary source inventory models).

In developing the uncertainty estimation model, uniform distribution was assumed for all activity-related input variables and N_2O emission factors, based on the SAIC/EIA (2001) report.[86] For these variables, the uncertainty

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[84] U.S. territories data also include combustion from mobile activities because data to allocate territories' energy use were unavailable. For this reason, CH_4 and N_2O emissions from combustion by U.S. territories are only included in the stationary combustion totals.

[85] Though emissions from construction and farm use occur due to both stationary and mobile sources, detailed data was not available to determine the magnitude from each. Currently, these emissions are assumed to be predominantly from mobile sources.

[86] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former distribution to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[87] However, the CH_4 emission factors differ from those used by EIA. Since these factors were obtained from IPCC/UNEP/OECD/IEA (1997), uncertainty ranges were assigned based on IPCC default uncertainty estimates (IPCC 2000).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-17. Stationary combustion CH_4 emissions in 2009 (including biomass) were estimated to be between 4.1 and 14.0 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 34 percent below to 127 percent above the 2009 emission estimate of 6.2 Tg CO_2 Eq.[88] Stationary combustion N_2O emissions in 2009 (*including* biomass) were estimated to be between 9.8 and 36.7 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 23 percent below to 187 percent above the 2009 emissions estimate of 12.8 Tg CO_2 Eq.

Table 3-17: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Energy-Related Stationary Combustion, Including Biomass (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**[a] **(Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Stationary Combustion	CH_4	6.2	4.1	14.0	-34%	+127%
Stationary Combustion	N_2O	12.8	9.8	36.7	-23%	+187%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

The uncertainties associated with the emission estimates of CH_4 and N_2O are greater than those associated with estimates of CO_2 from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH_4 and N_2O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the indirect greenhouse gases, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and activity data projections.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for stationary combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CH_4, N_2O, and the indirect greenhouse gases from stationary combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated.

Recalculations Discussion

Historical CH_4 and N_2O emissions from stationary sources (excluding CO_2) were revised due to a couple of changes, mainly impacting 2007 and 2008 estimates. Slight changes to emission estimates for sectors are due to revised data from EIA (2010). Wood consumption data in EIA (2011) were revised for the residential, commercial, and industrial sectors for 2007 and 2008 as well as for the electric power sector for 2006 through 2008. The combination of the methodological and historical data changes resulted in an average annual increase of 0.01 Tg CO_2 Eq. (0.2 percent) in CH_4 emissions from stationary combustion and an average annual decrease of 0.08 Tg CO_2 Eq. (0.5 percent) in N_2O emissions from stationary combustion for the period 1990 through 2008.

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[87] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

[88] The low emission estimates reported in this section have been rounded down to the nearest integer values and the high emission estimates have been rounded up to the nearest integer values.

Planned Improvements

Several items are being evaluated to improve the CH_4 and N_2O emission estimates from stationary combustion and to reduce uncertainty. Efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data. Because these data are not broken out by stationary and mobile uses, further research will be aimed at trying to allocate consumption appropriately. In addition, the uncertainty of biomass emissions will be further investigated since it was expected that the exclusion of biomass from the uncertainty estimates would reduce the uncertainty; and in actuality the exclusion of biomass increases the uncertainty. These improvements are not all-inclusive, but are part of an ongoing analysis and efforts to continually improve these stationary estimates.

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

CH_4 and N_2O from Mobile Combustion

Methodology

Estimates of CH_4 and N_2O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each fuel and vehicle type (e.g., light-duty gasoline trucks). Activity data included vehicle miles traveled (VMT) for on-road vehicles and fuel consumption for non-road mobile sources. The activity data and emission factors used are described in the subsections that follow. A complete discussion of the methodology used to estimate CH_4 and N_2O emissions from mobile combustion and the emission factors used in the calculations is provided in Annex 3.2.

On-Road Vehicles

Estimates of CH_4 and N_2O emissions from gasoline and diesel on-road vehicles are based on VMT and emission factors by vehicle type, fuel type, model year, and emission control technology. Emission estimates for alternative fuel vehicles (AFVs)[89] are based on VMT and emission factors by vehicle and fuel type.

Emission factors for gasoline and diesel on-road vehicles utilizing Tier 2 and Low Emission Vehicle (LEV) technologies were developed by ICF (2006b); all other gasoline and diesel on-road vehicle emissions factors were developed by ICF (2004). These factors were derived from EPA, California Air Resources Board (CARB) and Environment Canada laboratory test results of different vehicle and control technology types. The EPA, CARB and Environment Canada tests were designed following the Federal Test Procedure (FTP), which covers three separate driving segments, since vehicles emit varying amounts of greenhouse gases depending on the driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot start and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust was collected; the content of this bag was then analyzed to determine quantities of gases present. The emissions characteristics of segment 2 were used to define running emissions, and subtracted from the total FTP emissions to determine start emissions. These were then recombined based upon the ratio of start to running emissions for each vehicle class from MOBILE6.2, an EPA emission factor model that predicts gram per mile emissions of CO_2, CO, HC, NO_x, and PM from vehicles under various conditions, to approximate average driving characteristics.[90]

Emission factors for AFVs were developed by ICF (2006a) after examining Argonne National Laboratory's GREET 1.7–Transportation Fuel Cycle Model (ANL 2006) and Lipman and Delucchi (2002). These sources describe AFV emission factors in terms of ratios to conventional vehicle emission factors. Ratios of AFV to conventional vehicle emissions factors were then applied to estimated Tier 1 emissions factors from light-duty gasoline vehicles to estimate light-duty AFVs. Emissions factors for heavy-duty AFVs were developed in relation to gasoline heavy-duty vehicles. A complete discussion of the data source and methodology used to determine emission factors from

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[89] Alternative fuel and advanced technology vehicles are those that can operate using a motor fuel other than gasoline or diesel. This includes electric or other bi-fuel or dual-fuel vehicles that may be partially powered by gasoline or diesel.

[90] Additional information regarding the model can be found online at http://www.epa.gov/OMS/m6.htm.

AFVs is provided in Annex 3.2.

Annual VMT data for 1990 through 2010 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2010).[91] VMT estimates were then allocated from FHWA's vehicle categories to fuel-specific vehicle categories using the calculated shares of vehicle fuel use for each vehicle category by fuel type reported in DOE (1993 through 2010) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2010). VMT for AFVs were taken from Browning (2003). The age distributions of the U.S. vehicle fleet were obtained from EPA (2010a, 2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2000).

Control technology and standards data for on-road vehicles were obtained from EPA's Office of Transportation and Air Quality (EPA 2007a, 2007b, 2000, 1998, and 1997) and Browning (2005). These technologies and standards are defined in Annex 3.2, and were compiled from EPA (1993, 1994a, 1994b, 1998, 1999a) and IPCC/UNEP/OECD/IEA (1997).

Non-Road Vehicles

To estimate emissions from non-road vehicles, fuel consumption data were employed as a measure of activity, and multiplied by fuel-specific emission factors (in grams of N_2O and CH_4 per kilogram of fuel consumed).[92] Activity data were obtained from AAR (2009 through 2010), APTA (2007 through 2010), APTA (2006), BEA (1991 through 2005), Benson (2002 through 2004), DHS (2008), DOC (1991 through 2008), DOE (1993 through 2010), DESC (2011), DOT (1991 through 2010), EIA (2008a, 2007a, 2007b, 2002), EIA (2007 through 2010), EIA (1991 through 2011), EPA (2009), Esser (2003 through 2004), FAA (2011, 2010, and 2006), Gaffney (2007), and (2006 through 2010). Emission factors for non-road modes were taken from IPCC/UNEP/OECD/IEA (1997) and Browning (2009).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo simulation technique, using @RISK software. The uncertainty analysis was performed on 2009 estimates of CH_4 and N_2O emissions, incorporating probability distribution functions associated with the major input variables. For the purposes of this analysis, the uncertainty was modeled for the following four major sets of input variables: (1) vehicle miles traveled (VMT) data, by on-road vehicle and fuel type and (2) emission factor data, by on-road vehicle, fuel, and control technology type, (3) fuel consumption, data, by non-road vehicle and equipment type, and (4) emission factor data, by non-road vehicle and equipment type.

Uncertainty analyses were not conducted for NO_x, CO, or NMVOC emissions. Emission factors for these gases have been extensively researched since emissions of these gases from motor vehicles are regulated in the United States, and the uncertainty in these emission estimates is believed to be relatively low. However, a much higher level of uncertainty is associated with CH_4 and N_2O emission factors, because emissions of these gases are not regulated in the United States (and, therefore, there are not adequate emission test data), and because, unlike CO_2 emissions, the emission pathways of CH_4 and N_2O are highly complex.

Mobile combustion CH_4 emissions from all mobile sources in 2009 were estimated to be between 1.8 and 2.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 9 percent below to 15 percent above the corresponding 2009 emission estimate of 2.0 Tg CO_2 Eq. Also at a 95 percent confidence level, mobile combustion N_2O emissions from mobile sources in 2009 were estimated to be between 20.5 and 27.9 Tg CO_2 Eq., indicating a range of 14 percent below to 17 percent above the corresponding 2009 emission estimate of 23.9 Tg CO_2 Eq.

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[91] Fuel use by vehicle class (VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline were estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel were estimated to fall by the same rate that diesel fuel consumption fell overall in 2009. VMT was then distributed to vehicle classes based on these fuel consumption estimates, assuming no relative change in MPG between vehicle classes.

[92] The consumption of international bunker fuels is not included in these activity data, but is estimated separately under the International Bunker Fuels source category.

Table 3-18: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Mobile Sources (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate[a] (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a]**			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Mobile Sources	CH_4	2.0	1.8	2.2	-9%	+15%
Mobile Sources	N_2O	23.9	20.5	27.9	-14%	+17%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

This uncertainty analysis is a continuation of a multi-year process for developing quantitative uncertainty estimates for this source category using the IPCC Tier 2 approach to uncertainty analysis. As a result, as new information becomes available, uncertainty characterization of input variables may be improved and revised. For additional information regarding uncertainty in emission estimates for CH_4 and N_2O please refer to the Uncertainty Annex.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2008. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for mobile combustion was developed and implemented. This plan is based on the IPCC-recommended QA/QC Plan. The specific plan used for mobile combustion was updated prior to collection and analysis of this current year of data. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on the emission factor and activity data sources, as well as the methodology used for estimating emissions. These procedures included a qualitative assessment of the emissions estimates to determine whether they appear consistent with the most recent activity data and emission factors available. A comparison of historical emissions between the current Inventory and the previous Inventory was also conducted to ensure that the changes in estimates were consistent with the changes in activity data and emission factors.

Recalculations Discussion

In order to ensure that these estimates are continuously improved, the calculation methodology is revised annually based on comments from internal and external reviewers. Each year, a number of adjustments are made to the methodologies used in calculating emissions in the current Inventory relative to previous Inventory reports. One of the revisions that were made this year was incorporating motor vehicle age distribution from EPA's MOtor Vehicle Emission Simulator (MOVES) model. MOVES is EPA's tool for estimating emissions from highway vehicles, based on analysis of millions of emission test results and considerable advances in EPA's understanding of vehicle emissions. Population data from the MOVES model was used to estimate the age distribution of motor vehicles in the United States.

Planned Improvements

While the data used for this report represent the most accurate information available, four areas have been identified that could potentially be improved in the short-term given available resources.

1. Develop updated emissions factors for diesel vehicles, motorcycle, and biodiesel vehicles. Previous emission factors were based upon extrapolations from other vehicle classes and new test data from Environment Canada and other sources may allow for better estimation of emission factors for these vehicles.
2. Develop new emission factors for non-road equipment. The current inventory estimates for non-CO_2 emissions from non-road sources are based on emission factors from IPCC guidelines published in 1996. Recent data on non-road sources from Environment Canada and the California Air Resources Board will be investigated in order to assess the feasibility of developing new N_2O and CH_4 emissions factors for non-road equipment.
3. Examine the feasibility of estimating aircraft N_2O and CH_4 emissions by the number of takeoffs and landings, instead of total fuel consumption. Various studies have indicated that aircraft N_2O and CH_4

emissions are more dependent on aircraft takeoffs and landings than on total aircraft fuel consumption; however, aircraft emissions are currently estimated from fuel consumption data. FAA's SAGE and AEDT databases contain detailed data on takeoffs and landings for each calendar year starting in 2000, and could potentially be used to conduct a Tier II analysis of aircraft emissions. This methodology will require a detailed analysis of the number of takeoffs and landings by aircraft type on domestic trips, the development of procedures to develop comparable estimates for years prior to 2000, and the dynamic interaction of ambient air with aircraft exhausts is developed. The feasibility of this approach will be explored.

Develop improved estimates of domestic waterborne fuel consumption. The inventory estimates for residual and distillate fuel used by ships and boats is based in part on data on bunker fuel use from the U.S. Department of Commerce. Domestic fuel consumption is estimated by subtracting fuel sold for international use from the total sold in the United States. It may be possible to more accurately estimate domestic fuel use and emissions by using detailed data on marine ship activity. The feasibility of using domestic marine activity data to improve the estimates will be investigated. Continue to examine the use of EPA's MOVES model in the development of the inventory estimates, including use for uncertainty analysis. Although the inventory uses some of the underlying data from MOVES, such as vehicle age distributions by model year, MOVES is not used directly in calculating mobile source emissions. As MOVES goes through additional testing and refinement, the use of MOVES will be further explored.

3.2. Carbon Emitted from Non-Energy Uses of Fossil Fuels (IPCC Source Category 1A)

In addition to being combusted for energy, fossil fuels are also consumed for non-energy uses (NEU) in the United States. The fuels used for these purposes are diverse, including natural gas, liquefied petroleum gases (LPG), asphalt (a viscous liquid mixture of heavy crude oil distillates), petroleum coke (manufactured from heavy oil), and coal (metallurgical) coke (manufactured from coking coal). The non-energy applications of these fuels are equally diverse, including feedstocks for the manufacture of plastics, rubber, synthetic fibers and other materials; reducing agents for the production of various metals and inorganic products; and non-energy products such as lubricants, waxes, and asphalt (IPCC 2006).

CO_2 emissions arise from non-energy uses via several pathways. Emissions may occur during the manufacture of a product, as is the case in producing plastics or rubber from fuel-derived feedstocks. Additionally, emissions may occur during the product's lifetime, such as during solvent use. Overall, throughout the time series and across all uses, about 61 percent of the total C consumed for non-energy purposes was stored in products, and not released to the atmosphere; the remaining 39 percent was emitted.

There are several areas in which non-energy uses of fossil fuels are closely related to other parts of the inventory. For example, some of the NEU products release CO_2 at the end of their commercial life when they are combusted after disposal; these emissions are reported separately within the Energy chapter in the Incineration of Waste source category. In addition, there is some overlap between fossil fuels consumed for non-energy uses and the fossil-derived CO_2 emissions accounted for in the Industrial Processes chapter, especially for fuels used as reducing agents. To avoid double-counting, the "raw" non-energy fuel consumption data reported by EIA are modified to account for these overlaps. There are also net exports of petrochemicals that are not completely accounted for in the EIA data, and the inventory calculations make adjustments to address the effect of net exports on the mass of C in non-energy applications.

As shown in Table 3-19, fossil fuel emissions in 2009 from the non-energy uses of fossil fuels were 123.4 Tg CO_2 Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2009, the consumption of fuels for non-energy uses (after the adjustments described above) was 4,451.0 TBtu, an increase of 0.2 percent since 1990 (see Table 3-20). About 49.9 Tg of the C (182.8 Tg CO_2 Eq.) in these fuels was stored, while the remaining 33.6 Tg C (123.4 Tg CO_2 Eq.) was emitted.

Table 3-19: CO_2 Emissions from Non-Energy Use Fossil Fuel Consumption (Tg CO_2 Eq.)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Potential Emissions	310.8	383.6	381.6	381.7	370.1	344.9	306.1
C Stored	192.2	238.6	238.3	236.1	232.8	204.0	182.8
Emissions as a % of Potential	38%	38%	38%	38%	37%	41%	40%
Emissions	**118.6**	**144.9**	**143.4**	**145.6**	**137.2**	**141.0**	**123.4**

Methodology

The first step in estimating C stored in products was to determine the aggregate quantity of fossil fuels consumed for non-energy uses. The C content of these feedstock fuels is equivalent to potential emissions, or the product of consumption and the fuel-specific C content values. Both the non-energy fuel consumption and C content data were supplied by the EIA (2011) (see Annex 2.1). Consumption of natural gas, LPG, pentanes plus, naphthas, other oils, and special naphtha were adjusted to account for net exports of these products that are not reflected in the raw data from EIA. Consumption values for industrial coking coal, petroleum coke, other oils, and natural gas in Table 3-20 and Table 3-21 have been adjusted to subtract non-energy uses that are included in the source categories of the Industrial Processes chapter.[93] Consumption values were also adjusted to subtract net exports of intermediary chemicals.

For the remaining non-energy uses, the quantity of C stored was estimated by multiplying the potential emissions by a storage factor.

- For several fuel types—petrochemical feedstocks (including natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha, and industrial other coal), asphalt and road oil, lubricants, and waxes—U.S. data on C stocks and flows were used to develop C storage factors, calculated as the ratio of (a) the C stored by the fuel's non-energy products to (b) the total C content of the fuel consumed. A lifecycle approach was used in the development of these factors in order to account for losses in the production process and during use. Because losses associated with municipal solid waste management are handled separately in this sector under the Incineration of Waste source category, the storage factors do not account for losses at the disposal end of the life cycle.
- For industrial coking coal and distillate fuel oil, storage factors were taken from IPCC/UNEP/OECD/IEA (1997), which in turn draws from Marland and Rotty (1984).
- For the remaining fuel types (petroleum coke, miscellaneous products, and other petroleum), IPCC does not provide guidance on storage factors, and assumptions were made based on the potential fate of C in the respective NEU products.

Table 3-20: Adjusted Consumption of Fossil Fuels for Non-Energy Uses (TBtu)

Year	1990	2000	2005	2006	2007	2008	2009
Industry	**4,181.1**	**5,214.4**	**5,174.4**	**5,163.2**	**5,060.7**	**4,671.9**	**4,267.7**
Industrial Coking Coal	+	53.0	79.8	62.3	1.7	28.4	6.1
Industrial Other Coal	8.2	12.4	11.9	12.4	12.4	12.4	12.4
Natural Gas to Chemical Plants	277.3	420.3	397.0	407.7	412.5	395.2	366.0
Asphalt & Road Oil	1,170.2	1,275.7	1,323.2	1,261.2	1,197.0	1,012.0	873.1
LPG	1,119.2	1,607.0	1,444.0	1,488.6	1,483.0	1,409.6	1,446.2
Lubricants	186.3	189.9	160.2	156.1	161.2	149.6	134.5
Pentanes Plus	77.5	229.3	146.3	105.5	132.7	114.9	93.4
Naphtha (<401 ° F)	325.9	593.7	679.6	618.1	542.6	467.3	450.7
Other Oil (>401 ° F)	661.4	527.0	514.8	573.4	669.2	599.2	392.5
Still Gas	21.3	12.6	67.7	57.2	44.2	47.3	133.9
Petroleum Coke	54.8	35.3	128.8	172.2	155.9	174.4	133.0
Special Naphtha	100.8	94.4	60.9	68.9	75.5	83.2	44.2
Distillate Fuel Oil	7.0	11.7	16.0	17.5	17.5	17.5	17.5
Waxes	33.3	33.1	31.4	26.1	21.9	19.1	12.2
Miscellaneous Products	137.8	119.2	112.8	136.0	133.5	142.0	151.8
Transportation	**176.0**	**179.4**	**151.3**	**147.4**	**152.2**	**141.3**	**127.1**
Lubricants	176.0	179.4	151.3	147.4	152.2	141.3	127.1
U.S. Territories	**86.7**	**152.2**	**121.9**	**133.4**	**108.4**	**126.7**	**56.3**
Lubricants	0.7	3.1	4.6	6.2	5.9	2.7	1.0

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[93] These source categories include Iron and Steel Production, Lead Production, Zinc Production, Ammonia Manufacture, Carbon Black Manufacture (included in Petrochemical Production), Titanium Dioxide Production, Ferroalloy Production, Silicon Carbide Production, and Aluminum Production.

Other Petroleum (Misc. Prod.)	86.0		149.1		117.3	127.2	102.5	124.1	55.2
Total	**4,443.8**		**5,546.0**		**5,447.6**	**5,444.0**	**5,321.3**	**4,940.0**	**4,451.0**

+ Does not exceed 0.05 TBtu

Note: To avoid double-counting, coal coke, petroleum coke, natural gas consumption, and other oils are adjusted for industrial process consumption reported in the Industrial Processes sector. Natural gas, LPG, Pentanes Plus, Naphthas, Special Naphtha, and Other Oils are adjusted to account for exports of chemical intermediates derived from these fuels. For residual oil (not shown in the table), all non-energy use is assumed to be consumed in C black production, which is also reported in the Industrial Processes chapter.

Note: Totals may not sum due to independent rounding.

Table 3-21: 2009 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and Emissions

Sector/Fuel Type	Adjusted Non-Energy Use[a] (TBtu)	Carbon Content Coefficient (Tg C/QBtu)	Potential Carbon (Tg C)	Storage Factor	Carbon Stored (Tg C)	Carbon Emissions (Tg C)	Carbon Emissions (Tg CO_2 Eq.)
Industry	**4,267.7**	**-**	**79.8**	**-**	**49.5**	**30.3**	**111.1**
Industrial Coking Coal	6.1	31.00	0.2	0.10	0.0	0.2	0.6
Industrial Other Coal	12.4	25.82	0.3	0.58	0.2	0.1	0.5
Natural Gas to Chemical Plants	366.0	14.47	5.3	0.58	3.1	2.2	8.1
Asphalt & Road Oil	873.1	20.55	17.9	1.00	17.9	0.1	0.3
LPG	1,446.2	17.06	24.7	0.58	14.3	10.3	37.9
Lubricants	134.5	20.20	2.7	0.09	0.2	2.5	9.0
Pentanes Plus	93.4	19.10	1.8	0.58	1.0	0.7	2.7
Naphtha (<401° F)	450.7	18.55	8.4	0.58	4.9	3.5	12.9
Other Oil (>401° F)	392.5	20.17	7.9	0.58	4.6	3.3	12.2
Still Gas	133.9	17.51	2.3	0.58	1.4	1.0	3.6
Petroleum Coke	133.0	27.85	3.7	0.30	1.1	2.6	9.5
Special Naphtha	44.2	19.74	0.9	0.58	0.5	0.4	1.3
Distillate Fuel Oil	17.5	20.17	0.4	0.50	0.2	0.2	0.6
Waxes	12.2	19.80	0.2	0.58	0.1	0.1	0.4
Miscellaneous Products	151.8	20.31	3.1	0.00	0.0	3.1	11.3
Transportation	**127.1**	**-**	**2.6**	**-**	**0.2**	**2.3**	**8.5**
Lubricants	127.1	20.20	2.6	0.09	0.2	2.3	8.5
U.S. Territories	**56.3**	**-**	**1.1**	**-**	**0.1**	**1.0**	**3.7**
Lubricants	1.0	20.20	+	0.09	+	+	0.1
Other Petroleum (Misc. Prod.)	55.2	20.00	1.1	0.10	0.1	1.0	3.6
Total	**4,451.0**	**-**	**83.5**	**-**	**49.9**	**33.6**	**123.4**

+ Does not exceed 0.05 Tg

- Not applicable.

[a] To avoid double counting, net exports have been deducted.

Note: Totals may not sum due to independent rounding.

Lastly, emissions were estimated by subtracting the C stored from the potential emissions (see Table 3-19). More detail on the methodology for calculating storage and emissions from each of these sources is provided in Annex 2.3.

Where storage factors were calculated specifically for the United States, data were obtained on (1) products such as asphalt, plastics, synthetic rubber, synthetic fibers, cleansers (soaps and detergents), pesticides, food additives, antifreeze and deicers (glycols), and silicones; and (2) industrial releases including energy recovery, Toxics Release Inventory (TRI) releases, hazardous waste incineration, and volatile organic compound, solvent, and non-combustion CO emissions. Data were taken from a variety of industry sources, government reports, and expert communications. Sources include EPA reports and databases such as compilations of air emission factors (EPA 2001), *National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data* (EPA 2010), *Toxics Release Inventory, 1998* (2000b), *Biennial Reporting System* (EPA 2004, 2007a), and pesticide sales and use estimates

(EPA 1998, 1999, 2002, 2004); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005, 2010); the National Petrochemical & Refiners Association (NPRA 2002); the U.S. Bureau of the Census (1999, 2004, 2009); Bank of Canada (2009); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (2011); Gosselin, Smith, and Hodge (1984); the Rubber Manufacturers' Association (RMA 2009a,b); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2010); and the American Chemistry Council (ACC 2003-2010). Specific data sources are listed in full detail in Annex 2.3.

Uncertainty and Time-Series Consistency

An uncertainty analysis was conducted to quantify the uncertainty surrounding the estimates of emissions and storage factors from non-energy uses. This analysis, performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results presented below provide the 95 percent confidence interval, the range of values within which emissions are likely to fall, for this source category.

As noted above, the non-energy use analysis is based on U.S.-specific storage factors for (1) feedstock materials (natural gas, LPG, pentanes plus, naphthas, other oils, still gas, special naphthas, and other industrial coal), (2) asphalt, (3) lubricants, and (4) waxes. For the remaining fuel types (the "other" category in Table 3-22 and Table 3-23), the storage factors were taken directly from the IPCC *Guidelines for National Greenhouse Gas Inventories*, where available, and otherwise assumptions were made based on the potential fate of carbon in the respective NEU products. To characterize uncertainty, five separate analyses were conducted, corresponding to each of the five categories. In all cases, statistical analyses or expert judgments of uncertainty were not available directly from the information sources for all the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-22 (emissions) and Table 3-23 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2009 was estimated to be between 97.6 and 135.3 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 21 percent below to 10 percent above the 2009 emission estimate of 123.4 Tg CO_2 Eq. The uncertainty in the emission estimates is a function of uncertainty in both the quantity of fuel used for non-energy purposes and the storage factor.

Table 3-22: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Non-Energy Uses of Fossil Fuels (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Feedstocks	CO_2	79.3	63.4	96.1	-20%	21%
Asphalt	CO_2	0.3	0.1	0.6	-58%	119%
Lubricants	CO_2	17.7	14.6	20.5	-17%	16%
Waxes	CO_2	0.4	0.3	0.7	-29%	74%
Other	CO_2	25.7	10.3	27.0	-60%	5%
Total	**CO_2**	123.4	97.6	135.3	-21%	10%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

NA (Not Applicable)

Table 3-23: Tier 2 Quantitative Uncertainty Estimates for Storage Factors of Non-Energy Uses of Fossil Fuels (Percent)

Source	Gas	2009 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate[a] (%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	58%	56%	60%	-3%	4%
Asphalt	CO_2	99.6%	99.1%	99.8%	-0.5%	0.3%
Lubricants	CO_2	9%	4%	17%	-57%	91%
Waxes	CO_2	58%	49%	71%	-15%	22%
Other	CO_2	17%	16%	66%	-3%	292%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval, as a percentage of the inventory value (also expressed in percent terms).

In Table 3-23, feedstocks and asphalt contribute least to overall storage factor uncertainty on a percentage basis. Although the feedstocks category—the largest use category in terms of total carbon flows—appears to have tight confidence limits, this is to some extent an artifact of the way the uncertainty analysis was structured. As discussed in Annex 2.3, the storage factor for feedstocks is based on an analysis of six fates that result in long-term storage (e.g., plastics production), and eleven that result in emissions (e.g., volatile organic compound emissions). Rather than modeling the total uncertainty around all of these fate processes, the current analysis addresses only the storage fates, and assumes that all C that is not stored is emitted. As the production statistics that drive the storage values are relatively well-characterized, this approach yields a result that is probably biased toward understating uncertainty.

As is the case with the other uncertainty analyses discussed throughout this document, the uncertainty results above address only those factors that can be readily quantified. More details on the uncertainty analysis are provided in Annex 2.3.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for non-energy uses of fossil fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis for non-energy uses involving petrochemical feedstocks and for imports and exports. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology for estimating the fate of C (in terms of storage and emissions) across the various end-uses of fossil C. Emission and storage totals for the different subcategories were compared, and trends across the time series were analyzed to determine whether any corrective actions were needed. Corrective actions were taken to rectify minor errors and to improve the transparency of the calculations, facilitating future QA/QC.

For petrochemical import and export data, special attention was paid to NAICS numbers and titles to verify that none had changed or been removed. Import and export totals were compared for 2009 as well as their trends across the time series.

Recalculations Discussion

In previous Inventories, the storage factor for asphalt was incorrectly assumed to be 100 percent. For the current Inventory, it has been updated to 99.6 percent to reflect some loss of VOCs (see Annex 2.3 for more detailed discussion).

Updates to the EIA Manufacturer's Energy Consumption Survey (MECS) for 2006 were released in the past year. MECS data are only released once every four years and contribute to approximately 28 percent (as a time-weighted average) of the C accounted for in feedstocks. MECS data are used to estimate the amount of C emitted from energy recovery. Updating the energy recovery emission estimates with this new data affected emissions from 2003 through 2009, resulting in annual average increases of 7 percent from 2003 through 2009. In addition, the entire energy recovery time series was recalculated to adjust for energy recovered from combustion of scrap tires. Carbon emissions from scrap tires were inadvertently included in the energy recovery estimates; however, they are already accounted for in the Incineration of Waste category.[94] MECS data were adjusted to remove C from scrap tires used as fuel in cement kilns, lime kilns, and electric arc furnaces. This adjustment resulted in decreases in emissions across the entire time series. Emissions decreased by 0.3, 2.1, 1.3, and 1.5 percent for MECS-reporting years 1991, 1994, 1998, and 2002, respectively. Updating the energy recovery emission estimates with the 2006 MECS data combined with adjusting for combustion of scrap tires increased the 2006 emission estimate by 9.5 percent. Overall, emissions from energy recovery averaged over the entire time series increased by 1.2 percent when compared to last year's inventory estimate because the increase resulting from updating the MECS data more than offsets the decrease from adjusting for scrap tire combustion across the time series.

Planned Improvements

There are several improvements planned for the future:

- Improving the uncertainty analysis. Most of the input parameter distributions are based on professional judgment rather than rigorous statistical characterizations of uncertainty.
- Better characterizing flows of fossil C. Additional fates may be researched, including the fossil C load in organic chemical wastewaters, plasticizers, adhesives, films, paints, and coatings. There is also a need to further clarify the treatment of fuel additives and backflows (especially methyl tert-butyl ether, MTBE).
- Reviewing the trends in fossil fuel consumption for non-energy uses. Annual consumption for several fuel types is highly variable across the time series, including industrial coking coal and other petroleum (miscellaneous products). EPA plans to better understand these trends to identify any mischaracterized or misreported fuel consumption for non-energy uses.
- More accurate accounting of C in petrochemical feedstocks. Since 2001, the C accounted for in the feedstocks C balance outputs (i.e., storage plus emissions) exceeds C inputs. Prior to 2001, the C balance inputs exceed outputs. EPA plans to research this discrepancy by assessing the trends on both sides of the C balance. An initial review of EIA (2011) data indicates that trends in LPG consumption for non-energy uses may largely contribute to this discrepancy.
- More accurate accounting of C in imports and exports. As part of its effort to address the C balance discrepancy, EPA will examine its import/export adjustment methodology to ensure that net exports of intermediaries such as ethylene and propylene are fully accounted for.
- EPA recently researched updating the average carbon content of solvents, since the entire time series depends on one year's worth of solvent composition data. Unfortunately, the data on C emissions from solvents that were readily available do not provide composition data for all categories of solvent emissions and also have conflicting definitions for volatile organic compounds, the source of emissive carbon in solvents. EPA plans to identify additional sources of solvents data in order to update the C content assumptions.

Finally, although U.S.-specific storage factors have been developed for feedstocks, asphalt, lubricants, and waxes, default values from IPCC are still used for two of the non-energy fuel types (industrial coking coal and distillate oil), and broad assumptions are being used for miscellaneous products and other petroleum. Over the long term, there are plans to improve these storage factors by conducting analyses of C fate similar to those described in Annex 2.3 or deferring to more updated default storage factors from IPCC where available.

3.3. Incineration of Waste (IPCC Source Category 1A1a)

Incineration is used to manage about 7 to 19 percent of the solid wastes generated in the United States, depending on the source of the estimate and the scope of materials included in the definition of solid waste (EPA 2000, Goldstein

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[94] From a regulatory-definition perspective combustion of scrap tires in cement kilns, lime kilns, and electric arc furnaces is not considered "incineration;" however the use of the term "incineration" in this document also applies to the combustion of scrap tires and other materials for energy recovery.

and Matdes 2001, Kaufman et al. 2004, Simmons et al. 2006, van Haaren et al. 2010). In the context of this section, waste includes all municipal solid waste (MSW) as well as tires. In the United States, almost all incineration of MSW occurs at waste-to-energy facilities or industrial facilities where useful energy is recovered, and thus emissions from waste incineration are accounted for in the Energy chapter. Similarly, tires are combusted for energy recovery in industrial and utility boilers. Incineration of waste results in conversion of the organic inputs to CO_2. According to IPCC guidelines, when the CO_2 emitted is of fossil origin, it is counted as a net anthropogenic emission of CO_2 to the atmosphere. Thus, the emissions from waste incineration are calculated by estimating the quantity of waste combusted and the fraction of the waste that is C derived from fossil sources.

Most of the organic materials in municipal solid wastes are of biogenic origin (e.g., paper, yard trimmings), and have their net C flows accounted for under the Land Use, Land-Use Change, and Forestry chapter. However, some components—plastics, synthetic rubber, synthetic fibers, and carbon black—are of fossil origin. Plastics in the U.S. waste stream are primarily in the form of containers, packaging, and durable goods. Rubber is found in durable goods, such as carpets, and in non-durable goods, such as clothing and footwear. Fibers in municipal solid wastes are predominantly from clothing and home furnishings. As noted above, tires (which contain rubber and carbon black) are also considered a “non-hazardous” waste and are included in the waste incineration estimate, though waste disposal practices for tires differ from municipal solid waste. Estimates on emissions from hazardous waste incineration can be found in Annex 2.3 and are accounted for as part of the carbon mass balance for non-energy uses of fossil fuels.

Approximately 26 million metric tons of MSW was incinerated in the United States in 2009 (EPA 2011). CO_2 emissions from incineration of waste rose 54 percent since 1990, to an estimated 12.3 Tg CO_2 Eq. (12,300 Gg) in 2009, as the volume of tires and other fossil C-containing materials in waste increased (see Table 3-24 and Table 3-25). Waste incineration is also a source of N_2O and CH_4 emissions (De Soete 1993; IPCC 2006). N_2O emissions from the incineration of waste were estimated to be 0.4 Tg CO_2 Eq. (1 Gg N_2O) in 2009, and have not changed significantly since 1990. CH_4 emissions from the incineration of waste were estimated to be less than 0.05 Tg CO_2 Eq. (less than 0.5 Gg CH_4) in 2009, and have not changed significantly since 1990.

Table 3-24: CO_2 and N_2O Emissions from the Incineration of Waste (Tg CO_2 Eq.)

Gas/Waste Product	1990	2000	2005	2006	2007	2008	2009
CO_2	**8.0**	**11.1**	**12.5**	**12.5**	**12.7**	**12.2**	**12.3**
Plastics	5.6	6.1	6.9	6.7	6.7	6.1	6.2
Synthetic Rubber in Tires	0.3	1.5	1.6	1.7	1.8	1.8	1.8
Carbon Black in Tires	0.4	1.8	2.0	2.1	2.3	2.3	2.3
Synthetic Rubber in MSW	0.9	0.7	0.8	0.8	0.8	0.8	0.8
Synthetic Fibers	0.8	1.0	1.2	1.2	1.2	1.2	1.2
N_2O	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
CH_4	+	+	+	+	+	+	+
Total	**8.5**	**11.5**	**12.9**	**12.9**	**13.1**	**12.5**	**12.7**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 3-25: CO_2 and N_2O Emissions from the Incineration of Waste (Gg)

Gas/Waste Product	1990	2000	2005	2006	2007	2008	2009
CO_2	**7,989**	**11,112**	**12,450**	**12,531**	**12,700**	**12,169**	**12,300**
Plastics	5,588	6,104	6,919	6,722	6,660	6,148	6,233
Synthetic Rubber in Tires	308	1,454	1,599	1,712	1,823	1,823	1,823
Carbon Black in Tires	385	1,818	1,958	2,113	2,268	2,268	2,268
Synthetic Rubber in MSW	872	689	781	775	791	770	782
Synthetic Fibers	838	1,046	1,194	1,208	1,159	1,161	1,195
N_2O	**2**	**1**	**1**	**1**	**1**	**1**	**1**
CH_4	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg.

Methodology

Emissions of CO_2 from the incineration of waste include CO_2 generated by the incineration of plastics, synthetic fibers, and synthetic rubber, as well as the incineration of synthetic rubber and carbon black in tires. These emissions were estimated by multiplying the amount of each material incinerated by the C content of the material and the fraction oxidized (98 percent). Plastics incinerated in municipal solid wastes were categorized into seven plastic resin types, each material having a discrete C content. Similarly, synthetic rubber is categorized into three product types, and synthetic fibers were categorized into four product types, each having a discrete C content. Scrap tires contain several types of synthetic rubber, as well as carbon black. Each type of synthetic rubber has a discrete C content, and carbon black is 100 percent C. Emissions of CO_2 were calculated based on the amount of scrap tires used for fuel and the synthetic rubber and carbon black content of tires.

More detail on the methodology for calculating emissions from each of these waste incineration sources is provided in Annex 3.6.

For each of the methods used to calculate CO_2 emissions from the incineration of waste, data on the quantity of product combusted and the C content of the product are needed. For plastics, synthetic rubber, and synthetic fibers, the amount of specific materials discarded as municipal solid waste (i.e., the quantity generated minus the quantity recycled) was taken from *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* (EPA 1999 through 2003, 2005 through 2011) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). The proportion of total waste discarded that is incinerated was derived from data in BioCycle's "State of Garbage in America" (van Haaren et al. 2010). The most recent data provides the proportion of waste incinerated for 2008, so the corresponding proportion in 2009 is assumed to be equal to the proportion in 2008. For synthetic rubber and carbon black in scrap tires, information was obtained from U.S. Scrap Tire Markets in the United States, 2007 Edition (RMA 2009a). For 2008 and 2009, synthetic rubber mass in tires is assumed to be equal to that in 2007 due to a lack of more recently available data.

Average C contents for the "Other" plastics category and synthetic rubber in municipal solid wastes were calculated from 1998 and 2002 production statistics: carbon content for 1990 through 1998 is based on the 1998 value; content for 1999 through 2001 is the average of 1998 and 2002 values; and content for 2002 to date is based on the 2002 value. Carbon content for synthetic fibers was calculated from 1999 production statistics. Information about scrap tire composition was taken from the Rubber Manufacturers' Association internet site (RMA 2009b).

The assumption that 98 percent of organic C is oxidized (which applies to all waste incineration categories for CO_2 emissions) was reported in EPA's life cycle analysis of greenhouse gas emissions and sinks from management of solid waste (EPA 2006).

Incineration of waste, including MSW, also results in emissions of N_2O and CH_4. These emissions were calculated as a function of the total estimated mass of waste incinerated and an emission factor. As noted above, N_2O and CH_4 emissions are a function of total waste incinerated in each year; for 1990 through 2008, these data were derived from the information published in BioCycle (van Haaren et al. 2010). Data on total waste incinerated was not available for 2009, so this value was assumed to equal the most recent value available (2008). Table 3-26 provides data on municipal solid waste discarded and percentage combusted for the total waste stream. According to Covanta Energy (Bahor 2009) and confirmed by additional research based on ISWA (ERC 2009), all municipal solid waste combustors in the United States are continuously fed stoker units. The emission factors of N_2O and CH_4 emissions per quantity of municipal solid waste combusted are default emission factors for this technology type and were taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006).

Table 3-26: Municipal Solid Waste Generation (Metric Tons) and Percent Combusted.

Year	Waste Discarded	Waste Incinerated	Incinerated (% of Discards)
1990	235,733,657	30,632,057	13.0
2000	252,328,354	25,974,978	10.3
2005	259,559,787	25,973,520	10.0
2006	267,526,493	25,853,401	9.7
2007	268,279,240	24,788,539	9.2
2008	268,541,088	23,674,017	8.8
2009	268,541,088[a]	23,674,017 [a]	8.8[a]

[a] Assumed equal to 2008 value.

Source: van Haaren et al. (2010).

Uncertainty and Time-Series Consistency

A Tier 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO_2 emissions and N_2O emissions from the incineration of waste (given the very low emissions for CH_4, no uncertainty estimate was derived). IPCC Tier 2 analysis allows the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. Uncertainty estimates and distributions for waste generation variables (i.e., plastics, synthetic rubber, and textiles generation) were obtained through a conversation with one of the authors of the Municipal Solid Waste in the United States reports. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the other variables; thus, uncertainty estimates for these variables were determined using assumptions based on source category knowledge and the known uncertainty estimates for the waste generation variables.

The uncertainties in the waste incineration emission estimates arise from both the assumptions applied to the data and from the quality of the data. Key factors include MSW incineration rate; fraction oxidized; missing data on waste composition; average C content of waste components; assumptions on the synthetic/biogenic C ratio; and combustion conditions affecting N_2O emissions. The highest levels of uncertainty surround the variables that are based on assumptions (e.g., percent of clothing and footwear composed of synthetic rubber); the lowest levels of uncertainty surround variables that were determined by quantitative measurements (e.g., combustion efficiency, C content of C black).

The results of the Tier 2 quantitative uncertainty analysis are summarized inTable 3-27. Waste incineration CO_2 emissions in 2009 were estimated to be between 9.8 and 15.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 21 percent below to 24 percent above the 2009 emission estimate of 12.3 Tg CO_2 Eq. Also at a 95 percent confidence level, waste incineration N_2O emissions in 2009 were estimated to be between 0.2 and 1.5 Tg CO_2 Eq. This indicates a range of 51 percent below to 320 percent above the 2009 emission estimate of 0.4 Tg CO_2 Eq.

Table 3-27: Tier 2 Quantitative Uncertainty Estimates for CO_2 and N_2O from the Incineration of Waste (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Incineration of Waste	CO_2	12.3	9.8	15.2	-21%	+24%
Incineration of Waste	N_2O	0.4	0.2	1.5	-51%	+320%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990

through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan was implemented for incineration of waste. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and specifically focused on the emission factor and activity data sources and methodology used for estimating emissions from incineration of waste. Trends across the time series were analyzed to determine whether any corrective actions were needed. Actions were taken to streamline the activity data throughout the calculations on incineration of waste.

Recalculations Discussion

Several changes were made to input variables compared to the previous Inventory, resulting in an overall decrease in the total emissions from the incineration of waste. Formerly, the percentage of overall rubber waste that is synthetic (i.e., fossil-derived rather than biogenic) varied across the product categories, ranging from 25 percent for clothing and footwear to 100 percent synthetic rubber for durable goods and containers and packaging. For the current Inventory, this variable was updated to be 70 percent synthetic rubber for all four waste categories based on an industry average (RMA, 2011). This change resulted in an average 1 percent decrease in CO_2 emissions throughout the time series. In addition, the percentage of waste incinerated was updated for 2008 based on data obtained from The State of Garbage in America report (van Haaren et al., 2010). Because the report is released every other year, the percentage incinerated in 2007 was also updated using linear interpolation from the 2006 and 2008 values. The change in the percentage incinerated, along with the change in the percentage synthetic rubber noted above, decreased the 2007 and 2008 estimates by 4 percent and 7 percent, respectively, relative to the previous report.

Planned Improvements

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

Additional data sources for calculating the N_2O and CH_4 emission factors for U.S. incineration of waste may be investigated.

3.4. Coal Mining (IPCC Source Category 1B1a)

Three types of coal mining related activities release CH_4 to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. Underground coal mines contribute the largest share of CH_4 emissions. In 2009, 135 gassy underground coal mines in the United States employ ventilation systems to ensure that CH_4 levels remain within safe concentrations. These systems can exhaust significant amounts of CH_4 to the atmosphere in low concentrations. Additionally, 23 U.S. coal mines supplement ventilation systems with degasification systems. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of CH_4 before, during, or after mining. In 2009, 14 coal mines collected CH_4 from degasification systems and utilized this gas, thus reducing emissions to the atmosphere. Of these mines, 13 coal mines sold CH_4 to the natural gas pipeline and one coal mine used CH_4 from its degasification system to heat mine ventilation air on site. In addition, one of the coal mines that sold gas to pipelines also used CH_4 to fuel a thermal coal dryer. Surface coal mines also release CH_4 as the overburden is removed and the coal is exposed, but the level of emissions is much lower than from underground mines. Finally, some of the CH_4 retained in the coal after mining is released during processing, storage, and transport of the coal.

Total CH_4 emissions in 2009 were estimated to be 71.0 Tg CO_2 Eq. (3,382 Gg), a decline of 16 percent since 1990 (see Table 3-28 and Table 3-29). Of this amount, underground mines accounted for 71 percent, surface mines accounted for 18 percent, and post-mining emissions accounted for 11 percent. The decline in CH_4 emissions from underground mines from 1996 to 2002 was the result of the reduction of overall coal production, the mining of less gassy coal, and an increase in CH_4 recovered and used. Since that time, underground coal production and the associated methane emissions have remained fairly level, while surface coal production and its associated emissions have generally increased.

Table 3-28: CH_4 Emissions from Coal Mining (Tg CO_2 Eq.)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
UG Mining	62.3	39.4	35.0	35.7	35.7	44.4	50.4
Liberated	67.9	54.4	50.2	54.3	51.0	60.5	67.0
Recovered & Used	(5.6)	(14.9)	(15.1)	(18.7)	(15.3)	(16.1)	(16.5)
Surface Mining	12.0	12.3	13.3	14.0	13.8	14.3	12.9
Post-Mining (UG)	7.7	6.7	6.4	6.3	6.1	6.1	5.6
Post-Mining (Surface)	2.0	2.0	2.2	2.3	2.2	2.3	2.1
Total	**84.1**	**60.4**	**56.9**	**58.2**	**57.9**	**67.1**	**71.0**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Table 3-29: CH_4 Emissions from Coal Mining (Gg)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
UG Mining	2,968	1,878	1,668	1,699	1,700	2,113	2,401
Liberated	3,234	2,588	2,389	2,588	2,427	2,881	3,189
Recovered & Used	(265.9)	(710.4)	(720.8)	(889.4)	(727.2)	(768.0)	(787.1)
Surface Mining	573.6	585.7	633.1	668.0	658.9	680.5	614.2
Post-Mining (UG)	368.3	318.1	305.9	298.5	289.6	292.0	266.7
Post-Mining (Surface)	93.2	95.2	102.9	108.5	107.1	110.6	99.8
Total	**4,003**	**2,877**	**2,710**	**2,774**	**2,756**	**3,196**	**3,382**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Methodology

The methodology for estimating CH_4 emissions from coal mining consists of two parts. The first part involves estimating CH_4 emissions from underground mines. Because of the availability of ventilation system measurements, underground mine emissions can be estimated on a mine-by-mine basis and then summed to determine total emissions. The second step involves estimating emissions from surface mines and post-mining activities by multiplying basin-specific coal production by basin-specific emission factors.

Underground mines. Total CH_4 emitted from underground mines was estimated as the sum of CH_4 liberated from ventilation systems and CH_4 liberated by means of degasification systems, minus CH_4 recovered and used. The Mine Safety and Heath Administration (MSHA) samples CH_4 emissions from ventilation systems for all mines with detectable[95] CH_4 concentrations. These mine-by-mine measurements are used to estimate CH_4 emissions from ventilation systems.

Some of the higher-emitting underground mines also use degasification systems (e.g., wells or boreholes) that remove CH_4 before, during, or after mining. This CH_4 can then be collected for use or vented to the atmosphere. Various approaches were employed to estimate the quantity of CH_4 collected by each of the twenty mines using these systems, depending on available data. For example, some mines report to EPA the amount of CH_4 liberated from their degasification systems. For mines that sell recovered CH_4 to a pipeline, pipeline sales data published by state petroleum and natural gas agencies were used to estimate degasification emissions. For those mines for which no other data are available, default recovery efficiency values were developed, depending on the type of degasification system employed.

Finally, the amount of CH_4 recovered by degasification systems and then used (i.e., not vented) was estimated. In 2009, 13 active coal mines sold recovered CH_4 into the local gas pipeline networks and one coal mine used recovered CH_4 on site for heating. Emissions avoided for these projects were estimated using gas sales data reported by various state agencies. For most mines with recovery systems, companies and state agencies provided individual well production information, which was used to assign gas sales to a particular year. For the few remaining mines, coal mine operators supplied information regarding the number of years in advance of mining that gas recovery

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[95] MSHA records coal mine CH_4 readings with concentrations of greater than 50 ppm (parts per million) CH_4. Readings below this threshold are considered non-detectable.

occurs.

Surface Mines and Post-Mining Emissions. Surface mining and post-mining CH_4 emissions were estimated by multiplying basin-specific coal production, obtained from the Energy Information Administration's Annual Coal Report (see Table 3-30) (EIA 2010), by basin-specific emission factors. Surface mining emission factors were developed by assuming that surface mines emit two times as much CH_4 as the average in situ CH_4 content of the coal. Revised data on in situ CH_4 content and emissions factors are taken from EPA (2005), EPA (1996), and AAPG (1984). This calculation accounts for CH_4 released from the strata surrounding the coal seam. For post-mining emissions, the emission factor was assumed to be 32.5 percent of the average in situ CH_4 content of coals mined in the basin.

Table 3-30: Coal Production (Thousand Metric Tons)

Year	Underground	Surface	Total
1990	384,244	546,808	931,052
2000	338,168	635,581	973,749
2005	334,398	691,448	1,025,846
2006	325,697	728,447	1,054,144
2007	319,139	720,023	1,039,162
2008	323,932	737,832	1,061,764
2009	301,241	671,475	972,716

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Tier 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data, uncertainty is relatively low. A degree of imprecision was introduced because the measurements used were not continuous but rather an average of quarterly instantaneous readings. Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH_4 emissions (Mutmansky and Wang 2000). Estimates of CH_4 recovered by degasification systems are relatively certain because many coal mine operators provided information on individual well gas sales and mined through dates. Many of the recovery estimates use data on wells within 100 feet of a mined area. Uncertainty also exists concerning the radius of influence of each well. The number of wells counted, and thus the avoided emissions, may vary if the drainage area is found to be larger or smaller than currently estimated.

Compared to underground mines, there is considerably more uncertainty associated with surface mining and post-mining emissions because of the difficulty in developing accurate emission factors from field measurements. However, since underground emissions comprise the majority of total coal mining emissions, the uncertainty associated with underground emissions is the primary factor that determines overall uncertainty. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-31. Coal mining CH_4 emissions in 2009 were estimated to be between 62.0 and 82.4 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 12.7 percent below to 16.1 percent above the 2009 emission estimate of 71.0 Tg CO_2 Eq.

Table 3-31: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Coal Mining (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal Mining	CH_4	71.0	62.0	82.4	-12.7%	+16.1%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

For the current Inventory, there were some changes to pre-2009 emission estimates relative to the previous Inventory. For the current Inventory, the conversion factor for converting short tons to metric tons was updated to 0.90718474 to be consistent with the number of significant digits used in other source categories. In the past, 0.9072 had been used. The factor was updated for all years, thus coal production estimates in Table 3-31 have changed slightly.

Other changes include the recalculation of emissions avoided for two Jim Walter Resources (JWR) mines: Blue Creek #4 Mine and Blue Creek #7 Mine. This resulted in changes to emissions avoided numbers for 2007 and 2008.

In 1998, 2000, 2001, 2002, 2003, and 2004, the emissions avoided for the Blacksville No. 2 mine in West Virginia were assigned to Pennsylvania rather than West Virginia. These emissions avoided were correctly assigned to West Virginia in the current Inventory; however, total emissions were not affected.

The emissions avoided for the Emerald and Cumberland mines were adjusted going back to 2006 based on information provided by the project developer.

3.5. Abandoned Underground Coal Mines (IPCC Source Category 1B1a)

Underground coal mines contribute the largest share of CH_4 emissions, with active underground mines the leading source of underground emissions. However, mines also continue to release CH_4 after closure. As mines mature and coal seams are mined through, mines are closed and abandoned. Many are sealed and some flood through intrusion of groundwater or surface water into the void. Shafts or portals are generally filled with gravel and capped with a concrete seal, while vent pipes and boreholes are plugged in a manner similar to oil and gas wells. Some abandoned mines are vented to the atmosphere to prevent the buildup of CH_4 that may find its way to surface structures through overburden fractures. As work stops within the mines, the CH_4 liberation decreases but it does not stop completely. Following an initial decline, abandoned mines can liberate CH_4 at a near-steady rate over an extended period of time, or, if flooded, produce gas for only a few years. The gas can migrate to the surface through the conduits described above, particularly if they have not been sealed adequately. In addition, diffuse emissions can occur when CH_4 migrates to the surface through cracks and fissures in the strata overlying the coal mine. The following factors influence abandoned mine emissions:

- Time since abandonment;
- Gas content and adsorption characteristics of coal;
- CH4 flow capacity of the mine;
- Mine flooding;
- Presence of vent holes; and
- Mine seals.

Gross abandoned mine CH_4 emissions ranged from 6.0 to 9.1 Tg CO_2 Eq. from 1990 through 2009, varying, in general, by less than 1 to approximately 19 percent from year to year. Fluctuations were due mainly to the number of mines closed during a given year as well as the magnitude of the emissions from those mines when active. Gross abandoned mine emissions peaked in 1996 (9.1 Tg CO_2 Eq.) due to the large number of mine closures from 1994 to 1996 (70 gassy mines closed during the three-year period). In spite of this rapid rise, abandoned mine emissions have been generally on the decline since 1996. There were fewer than fifteen gassy mine closures during each of the years from 1998 through 2009, with only ten closures in 2009. By 2009, gross abandoned mine emissions decreased slightly to 8.5 Tg CO_2 Eq. (see Table 3-32 and Table 3-33). Gross emissions are reduced by CH_4 recovered and used at 38 mines, resulting in net emissions in 2009 of 5.5 Tg CO_2 Eq.

Table 3-32: CH_4 Emissions from Abandoned Coal Mines (Tg CO_2 Eq.)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Abandoned Underground Mines	6.0	8.9	7.0	7.6	8.9	9.0	8.5
Recovered & Used	0.0	1.5	1.5	2.2	3.3	3.2	3.0
Total	**6.0**	**7.4**	**5.5**	**5.5**	**5.6**	**5.9**	**5.5**

Note: Totals may not sum due to independent rounding.

Table 3-33: CH_4 Emissions from Abandoned Coal Mines (Gg)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Abandoned Underground Mines	288	422	334	364	425	430	406
Recovered & Used	0	72	70	103	158	150	144
Total	**288**	**350**	**264**	**261**	**267**	**279**	**262**

Note: Totals may not sum due to independent rounding.

Methodology

Estimating CH_4 emissions from an abandoned coal mine requires predicting the emissions of a mine from the time of abandonment through the inventory year of interest. The flow of CH_4 from the coal to the mine void is primarily dependent on the mine's emissions when active and the extent to which the mine is flooded or sealed. The CH_4 emission rate before abandonment reflects the gas content of the coal, rate of coal mining, and the flow capacity of the mine in much the same way as the initial rate of a water-free conventional gas well reflects the gas content of the producing formation and the flow capacity of the well. A well or a mine which produces gas from a coal seam and the surrounding strata will produce less gas through time as the reservoir of gas is depleted. Depletion of a reservoir will follow a predictable pattern depending on the interplay of a variety of natural physical conditions imposed on the reservoir. The depletion of a reservoir is commonly modeled by mathematical equations and mapped as a type curve. Type curves which are referred to as decline curves have been developed for abandoned coal mines. Existing data on abandoned mine emissions through time, although sparse, appear to fit the hyperbolic type of decline curve used in forecasting production from natural gas wells.

In order to estimate CH_4 emissions over time for a given mine, it is necessary to apply a decline function, initiated upon abandonment, to that mine. In the analysis, mines were grouped by coal basin with the assumption that they will generally have the same initial pressures, permeability and isotherm. As CH_4 leaves the system, the reservoir pressure, Pr, declines as described by the isotherm. The emission rate declines because the mine pressure (Pw) is essentially constant at atmospheric pressure, for a vented mine, and the PI term is essentially constant at the pressures of interest (atmospheric to 30 psia). A rate-time equation can be generated that can be used to predict future emissions. This decline through time is hyperbolic in nature and can be empirically expressed as:

$$q = q_i\,(1+bD_it)^{(-1/b)}$$

where,

q = Gas rate at time t in mmcf/d
q_i = Initial gas rate at time zero (t_o) in million cubic feet per day mmcfd)
b = The hyperbolic exponent, dimensionless
D_i = Initial decline rate, 1/yr
t = Elapsed time from t_o (years)

This equation is applied to mines of various initial emission rates that have similar initial pressures, permeability and adsorption isotherms (EPA 2003).

The decline curves created to model the gas emission rate of coal mines must account for factors that decrease the rate of emission after mining activities cease, such as sealing and flooding. Based on field measurement data, it was assumed that most U.S. mines prone to flooding will become completely flooded within eight years and therefore no longer have any measurable CH_4 emissions. Based on this assumption, an average decline rate for flooding mines was established by fitting a decline curve to emissions from field measurements. An exponential equation was developed from emissions data measured at eight abandoned mines known to be filling with water located in two of the five basins. Using a least squares, curve-fitting algorithm, emissions data were matched to the exponential equation shown below. There was not enough data to establish basin-specific equations as was done with the vented, non-flooding mines (EPA 2003).

$$q = q_{ie}^{\,(-Dt)}$$

where,

q = Gas flow rate at time t in mcf/d
q_i = Initial gas flow rate at time zero (t_o) in mcfd

D = Decline rate, 1/yr
t = Elapsed time from t_o (years)

Seals have an inhibiting effect on the rate of flow of CH_4 into the atmosphere compared to the rate that would be emitted if the mine had an open vent. The total volume emitted will be the same, but will occur over a longer period. The methodology, therefore, treats the emissions prediction from a sealed mine similar to emissions from a vented mine, but uses a lower initial rate depending on the degree of sealing. The computational fluid dynamics simulator was again used with the conceptual abandoned mine model to predict the decline curve for inhibited flow. The percent sealed is defined as 100 × (1 − (initial emissions from sealed mine / emission rate at abandonment prior to sealing)). Significant differences are seen between 50 percent, 80 percent and 95 percent closure. These decline curves were therefore used as the high, middle, and low values for emissions from sealed mines (EPA 2003).

For active coal mines, those mines producing over 100 mcfd account for 98 percent of all CH_4 emissions. This same relationship is assumed for abandoned mines. It was determined that 469 abandoned mines closing after 1972 produced emissions greater than 100 mcfd when active. Further, the status of 273 of the 469 mines (or 58 percent) is known to be either: (1) vented to the atmosphere; (2) sealed to some degree (either earthen or concrete seals); or, (3) flooded (enough to inhibit CH_4 flow to the atmosphere). The remaining 42 percent of the mines were placed in one of the three categories by applying a probability distribution analysis based on the known status of other mines located in the same coal basin (EPA 2003).

Table 3-34: Number of gassy abandoned mines occurring in U.S. basins grouped by class according to post-abandonment state

Basin	Sealed	Vented	Flooded	Total Known	Unknown	Total Mines
Central Appl.	25	25	48	98	127	224
Illinois	30	3	14	47	25	72
Northern Appl.	42	22	16	80	35	115
Warrior Basin	0	0	16	16	0	16
Western Basins	27	3	2	32	9	41
Total	**124**	**53**	**96**	**273**	**196**	**469**

Inputs to the decline equation require the average emission rate and the date of abandonment. Generally this data is available for mines abandoned after 1972; however, such data are largely unknown for mines closed before 1972. Information that is readily available such as coal production by state and county are helpful, but do not provide enough data to directly employ the methodology used to calculate emissions from mines abandoned after 1971. It is assumed that pre-1972 mines are governed by the same physical, geologic, and hydrologic constraints that apply to post-1972 mines; thus, their emissions may be characterized by the same decline curves.

During the 1970s, 78 percent of CH_4 emissions from coal mining came from seventeen counties in seven states. In addition, mine closure dates were obtained for two states, Colorado and Illinois, for the hundred year period extending from 1900 through 1999. The data were used to establish a frequency of mine closure histogram (by decade) and applied to the other five states with gassy mine closures. As a result, basin-specific decline curve equations were applied to 145 gassy coal mines estimated to have closed between 1920 and 1971 in the United States, representing 78 percent of the emissions. State-specific, initial emission rates were used based on average coal mine CH_4 emission rates during the 1970s (EPA 2003).

Abandoned mines emission estimates are based on all closed mines known to have active mine CH_4 ventilation emission rates greater than 100 mcfd at the time of abandonment. For example, for 1990 the analysis included 145 mines closed before 1972 and 258 mines closed between 1972 and 1990. Initial emission rates based on MSHA reports, time of abandonment, and basin-specific decline curves influenced by a number of factors were used to calculate annual emissions for each mine in the database. Coal mine degasification data are not available for years prior to 1990, thus the initial emission rates used reflect ventilation emissions only for pre-1990 closures. CH_4 degasification amounts were added to the quantity of CH_4 ventilated for the total CH_4 liberation rate for 21 mines that closed between 1992 and 2009. Since the sample of gassy mines (with active mine emissions greater than 100 mcfd) is assumed to account for 78 percent of the pre-1971 and 98 percent of the post-1971 abandoned mine emissions, the modeled results were multiplied by 1.22 and 1.02 to account for all U.S. abandoned mine emissions.

From 1993 through 2009, emission totals were downwardly adjusted to reflect abandoned mine CH_4 emissions avoided from those mines. The inventory totals were not adjusted for abandoned mine reductions in 1990 through 1992, because no data was reported for abandoned coal mining CH_4 recovery projects during that time.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted to estimate the uncertainty surrounding the estimates of emissions from abandoned underground coal mines. The uncertainty analysis described below provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

As discussed above, the parameters for which values must be estimated for each mine in order to predict its decline curve are: (1) the coal's adsorption isotherm; (2) CH_4 flow capacity as expressed by permeability; and (3) pressure at abandonment. Because these parameters are not available for each mine, a methodological approach to estimating emissions was used that generates a probability distribution of potential outcomes based on the most likely value and the probable range of values for each parameter. The range of values is not meant to capture the extreme values, but values that represent the highest and lowest quartile of the cumulative probability density function of each parameter. Once the low, mid, and high values are selected, they are applied to a probability density function.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-35. Abandoned coal mines CH_4 emissions in 2009 were estimated to be between 4.0 and 7.3 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 27 percent below to 32 percent above the 2009 emission estimate of 5.5 Tg CO_2 Eq. One of the reasons for the relatively narrow range is that mine-specific data is used in the methodology. The largest degree of uncertainty is associated with the unknown status mines (which account for 42 percent of the mines), with a ±57 percent uncertainty.

Table 3-35: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Abandoned Underground Coal Mines (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Abandoned Underground Coal Mines	CH_4	5.5	4.0	7.3	-27%	+32%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Recalculations Discussion

Changes in pre-2009 emissions avoided relative to the previous Inventory are due to the additions of pre-1972 Grayson Hills Energy and DTE Corinth projects, which were added to the current inventory. There were also two abandoned mines added to the current Inventory, one abandoned in 2007 and one in 2008, which resulted in changes in the liberated emissions relative to the previous report.

3.6. Natural Gas Systems (IPCC Source Category 1B2b)

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Overall, natural gas systems emitted 221.2 Tg CO_2 Eq. (10,535 Gg) of CH_4 in 2009, a 17 percent increase over 1990 emissions (see Table 3-36 and Table 3-37), and 32.2 Tg CO_2 Eq. (32,171 Gg) of non-combustion CO_2 in 2009, a 14 percent decrease over 1990 emissions (see Table 3-38 and Table 3-39). Improvements in management practices and technology, along with the replacement of older equipment, have helped to stabilize emissions. Methane emissions increased since 2008 due to an increase in production and production wells.

CH_4 and non-combustion CO_2 emissions from natural gas systems are generally process related, with normal operations, routine maintenance, and system upsets being the primary contributors. Emissions from normal operations include: natural gas engines and turbine uncombusted exhaust, bleed and discharge emissions from pneumatic devices, and fugitive emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. Below is a characterization of the four major stages of the natural gas system. Each of the stages is described and the different factors affecting CH_4 and non-combustion CO_2 emissions are discussed.

Field Production. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities such as dehydrators and separators. Emissions from pneumatic devices, well clean-ups, and gas well completions and re-completions with hydraulic fracturing account for the majority of CH_4 emissions. Flaring emissions account for the majority of the non-combustion CO_2 emissions. Emissions from field production accounted for approximately 59 percent of CH_4 emissions and about 34 percent of non-combustion CO_2 emissions from natural gas systems in 2009.

Processing. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in "pipeline quality" gas, which is injected into the transmission system. Fugitive CH_4 emissions from compressors, including compressor seals, are the primary emission source from this stage. The majority of non-combustion CO_2 emissions come from acid gas removal units, which are designed to remove CO_2 from natural gas. Processing plants account for about 8 percent of CH_4 emissions and approximately 66 percent of non-combustion CO_2 emissions from natural gas systems.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the United States transmission system. Fugitive CH_4 emissions from these compressor stations and from metering and regulating stations account for the majority of the emissions from this stage. Pneumatic devices and engine uncombusted exhaust are also sources of CH_4 emissions from transmission facilities.

Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. CH_4 emissions from the transmission and storage sector account for approximately 20 percent of emissions from natural gas systems, while CO_2 emissions from transmission and storage account for less than 1 percent of the non-combustion CO_2 emissions from natural gas systems.

Distribution. Distribution pipelines take the high-pressure gas from the transmission system at "city gate" stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. There were over 1,208,000 miles of distribution mains in 2009, an increase from just over 944,000 miles in 1990 (OPS 2010b). Distribution system emissions, which account for approximately 13 percent of CH_4 emissions from natural gas systems and less than 1 percent of non-combustion CO_2 emissions, result mainly from fugitive emissions from gate stations and pipelines. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced emissions from this stage. Distribution system CH_4 emissions in 2009 were 13 percent lower than 1990 levels.

Table 3-36: CH_4 Emissions from Natural Gas Systems (Tg CO_2 Eq.)*

Stage	1990	2000	2005	2006	2007	2008	2009
Field Production	89.2	113.5	105.4	134.0	118.2	122.9	130.3
Processing	18.0	17.7	14.3	14.5	15.1	15.7	17.5
Transmission and Storage	49.2	46.7	41.4	41.0	42.5	43.3	44.4
Distribution	33.4	31.4	29.3	28.3	29.4	29.9	29.0
Total	**189.8**	**209.3**	**190.4**	**217.7**	**205.2**	**211.8**	**221.2**

*Including CH_4 emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.

Note: Totals may not sum due to independent rounding.

Table 3-37: CH_4 Emissions from Natural Gas Systems (Gg)*

Stage	1990	2000	2005	2006	2007	2008	2009
Field Production	4,248	5,406	5,021	6,380	5,628	5,854	6,205
Processing	855	841	681	689	717	748	834
Transmission and Storage	2,344	2,224	1,973	1,950	2,025	2,062	2,115

Distribution	1,591	1,497	1,395	1,346	1,402	1,423	1,381
Total	**9,038**	**9,968**	**9,069**	**10,364**	**9,771**	**10,087**	**10,535**

*Including CH_4 emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.
Note: Totals may not sum due to independent rounding.

Table 3-38: Non-combustion CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq.)

Stage	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Field Production	9.7	6.4	8.0	9.4	9.7	11.3	10.9
Processing	27.8	23.3	21.7	21.2	21.2	21.4	21.2
Transmission and Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Distribution	+	+	+	+	+	+	+
Total	**37.6**	**29.9**	**29.9**	**30.8**	**31.1**	**32.8**	**32.2**

Note: Totals may not sum due to independent rounding.
+ Emissions are less than 0.1 Tg CO_2 Eq.

Table 3-39: Non-combustion CO_2 Emissions from Natural Gas Systems (Gg)

Stage	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Field Production	9,704	6,425	8,050	9,438	9,746	11,336	10,877
Processing	27,763	23,343	21,746	21,214	21,199	21,385	21,189
Transmission and Storage	62	64	64	63	64	65	65
Distribution	46	44	41	40	41	42	41
Total	**37,574**	**29,877**	**29,902**	**30,755**	**31,050**	**32,828**	**32,171**

Note: Totals may not sum due to independent rounding.

Methodology

The primary basis for estimates of CH_4 and non-combustion-related CO_2 emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute and EPA (EPA/GRI 1996). The EPA/GRI study developed over 80 CH_4 emission and activity factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The same activity factors were used to estimate both CH_4 and non-combustion CO_2 emissions. However, the CH_4 emission factors were adjusted for CO_2 content when estimating fugitive and vented non-combustion CO_2 emissions. The EPA/GRI study was based on a combination of process engineering studies and measurements at representative gas facilities. From this analysis, a 1992 emission estimate was developed using the emission and activity factors, except where direct activity data was available (e.g., offshore platform counts, processing plant counts, transmission pipeline miles, and distribution pipelines). For other years, a set of industry activity factor drivers was developed that can be used to update activity factors. These drivers include statistics on gas production, number of wells, system throughput, miles of various kinds of pipe, and other statistics that characterize the changes in the U.S. natural gas system infrastructure and operations.

Although the inventory primarily uses EPA/GRI emission factors, significant improvements were made to the emissions estimates for three sources this year: gas well cleanups, condensate storage tanks and centrifugal compressors. In addition, data for two sources not included in the EPA/GRI study – gas well completions and gas well workovers (re-completions) with hydraulic fracturing- was added this year. In the case of gas well cleanups, the methodology was revised to use a large sample of well and reservoir characteristics from the HPDI database (HPDI 2009) along with an engineering statics equation (EPA 2006a) to estimate the volume of natural gas necessary to expel a liquid column choking the well production. The same sample E&P Tank sample runs for condensate tank flashing emissions was used; however, the factor was improved by using a large sample distribution of condensate production by gravity from the HPDI database (HPDI 2009) to weigh the sample simulation flashing emissions rather than assuming a uniform distribution of condensate gravities. Additionally, TERC (TERC 2009) data representing two regions was used in the emission factors for those two regions to estimate the effects of separator dump valves malfunctioning and allowing natural gas to vent through the downstream storage tanks. The EPA/GRI emission factor for centrifugal compressors sampled emissions at the seal face of wet seal compressors. A World Gas Conference publication (WGC 2009) on the seal oil degassing vents was used to update this factor and to also account for the emergence of dry seal centrifugal compressors (EPA 2006b), which eliminates seal oil degassing vents and reduces overall emissions. Gas well completions and workovers with hydraulic fracturing were not common at the time the EPA/GRI survey was conducted. Since then, emissions data has become available through Natural Gas STAR experiences and presentations (EPA 2004, 2007) as these activities became more prevalent. The EPA/GRI study and previous Inventories did, however, include an estimate for well completions without hydraulic fracturing under the source category Completion Flaring. The changes for gas well cleanups, condensate storage tanks, centrifugal compressors, and gas well completions and gas well workovers (re-completions) with hydraulic fracturing are described below in the Recalculations section. See Annex 3.4 for more detailed information on the methodology and data used to calculate CH_4 and non-combustion CO_2 emissions from natural gas systems.

Activity factor data were taken from the following sources: American Gas Association (AGA 1991–1998); Bureau of Ocean Energy Management, Regulation and Enforcement (previous Minerals and Management Service) (BOEMRE 2010a-d); Monthly Energy Review (EIA 2010f); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2010b,c,e); the Natural Gas STAR Program annual emissions savings (EPA 2010); Oil and Gas Journal (OGJ 1997–2010); Office of Pipeline Safety (OPS 2010a-b); Federal Energy Regulatory Commission (FERC 2010) and other Energy Information Administration publications (EIA 2001, 2004, 2010a,d); World Oil Magazine (2010a-b). Data for estimating emissions from hydrocarbon production tanks were incorporated (EPA 1999). Coalbed CH_4 well activity factors were taken from the Wyoming Oil and Gas Conservation Commission (Wyoming 2009) and the Alabama State Oil and Gas Board (Alabama 2010). Other state well data was taken from: American Association of Petroleum Geologists (AAPG 2004); Brookhaven College (Brookhaven 2004); Kansas Geological Survey (Kansas 2010); Montana Board of Oil and Gas Conservation (Montana 2010); Oklahoma Geological Survey (Oklahoma 2010); Morgan Stanley (Morgan Stanley 2005); Rocky Mountain Production Report (Lippman 2003); New Mexico Oil Conservation Division (New Mexico 2010, 2005); Texas Railroad Commission (Texas 2010a-d); Utah Division of Oil, Gas and Mining (Utah 2010). Emission factors were taken from EPA/GRI (1996). GTI's Unconventional Natural Gas and Gas Composition Databases (GTI 2001) were used to adapt the CH_4 emission factors into non-combustion related CO_2 emission factors and adjust CH_4 emission factors from the EPA/GRI survey. Methane compositions from GTI 2001 are adjusted year to year using gross production by NEMS for oil and gas supply regions from the EIA. Therefore, emission factors may vary from year to year due to slight changes in the methane composition for each NEMS oil and gas supply module region. Additional information about CO_2 content in transmission quality natural gas was obtained via the internet from numerous U.S. transmission companies to help further develop the non-combustion CO_2 emission factors.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted to determine the level of uncertainty surrounding estimates of emissions from natural gas systems. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), this analysis provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The @RISK model utilizes 1992 (base year) emissions to quantify the uncertainty associated with the emissions estimates using the top twelve emission sources for the year 2009.

The results presented below provide with 95 percent certainty the range within which emissions from this source category are likely to fall for the year 2009. The heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry. Because of this, scaling up from model facilities introduces a degree of uncertainty. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-40. Natural gas systems CH_4 emissions in 2009 were estimated to be between 179.1 and 287.6 Tg CO_2 Eq. at a 95 percent confidence level. Natural gas systems non-energy CO_2 emissions in 2009 were estimated to be between 26.1 and 41.9 Tg CO_2 Eq. at 95 percent confidence level.

Table 3-40: Tier 2 Quantitative Uncertainty Estimates for CH_4 and Non-energy CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)[c]	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound[c]	Upper Bound[c]	Lower Bound[c]	Upper Bound[c]

Natural Gas Systems	CH_4	221.2	179.1	287.6	-19%	+30%
Natural Gas Systems[b]	CO_2	32.2	26.1	41.9	-19%	+30%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

[b] An uncertainty analysis for the non-energy CO_2 emissions was not performed. The relative uncertainty estimated (expressed as a percent) from the CH_4 uncertainty analysis was applied to the point estimate of non-energy CO_2 emissions.

[c] All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

A number of potential data sources were investigated to improve selected emission factors in the natural gas industry. First, the HPDI database for well production and well properties was investigated for potential engineering parameters to be used in engineering equations to develop a new emission factor for well cleanups (HPDI 2009). The database was queried to obtain average well depth, shut-in pressure, well counts, and well production from each basin. These parameters were used along with industry experiences to develop an engineering estimate of emissions from each well in each basin of the sample data. The analysis led to a new emission factor for the gas well cleanup source.

Additionally, industry experiences with hydraulic fracturing of tight formations for the completion or workover of natural gas wells were reviewed to account for this source of emissions. Several Partners of the Natural Gas STAR Program have reported recovering substantial volumes of natural gas that would have otherwise been vented following completions or re-completions (workovers) involving hydraulic fracturing. This completion method, which is a large emission source, was not characterized by the base EPA/GRI 1996 study and has not been accounted for in the national Inventory until this year.

A World Gas Conference paper (WGC 2009) gathered 48 sample measurements of centrifugal compressor wet seal oil degassing emissions and published the results. The base year EPA/GRI 1996 study did not measure emissions from the seal oil degassing vent. Instead seal face emissions were quantified and as such this emission source has gone uncharacterized in the national Inventory until this year.

In some production areas the separator liquid level may drop too low such that the produced associated gas blows through the dump valve and vents through the storage tank. These data were included where available for the Inventory. More data will be necessary to potentially separate this source from storage tank flashing emissions and also to represent the true scope of activity across the United States.

A number of other data sources for fugitive emission factors from the processing and transmission and storage segments were reviewed. Several studies have been published since the EPA/GRI 1996 base year study that sample emissions from the same common equipment components. The raw emissions data from these surveys can potentially be combined with the raw data from the base year study to develop stronger emission factors. In addition to common component leaks, several of these studies propose emission factors for pneumatic devices or other sources. These studies require further review and thus the data are not included in the Inventory at this time.

Recalculations Discussion

Methodologies for gas well cleanups and condensate storage tanks were revised for the current Inventory, and new sources of data for centrifugal compressors with wet seals, gas well completions with hydraulic fracturing, and gas well workovers with hydraulic fracturing were used.

The largest increase in emissions relative to the previous Inventory was due to the revised emission factor for gas well cleanups (also referred to in industry as gas well liquids unloading). HPDI well production and well property sample data on well depth, shut-in pressure, and production rates were used in an engineering equation to re-estimate the average unloading emissions by NEMS oil and gas module region for this source (HPDI 2009). This methodological change increased emissions by more than 22 times while decreasing the substantial uncertainty that was associated with the previous emission factor from the EPA/GRI 1996 study. The activity data remained the same as the previous methodology. Emissions from non-Gas STAR Partners were not considered, nor was an independent estimate of the scope of those emissions accounted for. Reductions beyond those reported from Natural

Gas STAR Partners will be considered for inclusion in the next Inventory of sufficient data are available.

The next largest increase in emissions was due to the inclusion of gas well completions and workovers involving hydraulic fracture (i.e. unconventional completions and workovers). The EPA/GRI 1996 study did not account for this emerging technology and the source was previously unaccounted for in the Inventory. The Inventory did account for completion flaring, however, this only includes emissions from completions without hydraulic fracturing (i.e. conventional completions), which the EPA/GRI 1996 study assumes are mostly flared. Unlike completions and workovers without hydraulic fracturing (i.e. conventional workovers), the high pressure venting of gas in order to expel the large volumes of liquid used to fracture the well formation, results in a large emission of natural gas. The Inventory tracks activity data for wells completed with hydraulic fracturing in each region. The gas well completions with hydraulic fracturing was approximated using total number of producing gas wells completed with hydraulic fracturing and the total number of shut-in gas wells completed with hydraulic fracturing from each year. This approximation is made by taking the difference between the number of unconventional wells reported by EIA for the current year and the previous year. Since drilling and hydraulic fracturing in unconventional (e.g. shale, tight, and coal bed methane) formations is a relatively new technology, it is assumed that zero gas wells completed with hydraulic fracturing are shut-in each year. This activity data was used along with a newly developed emission factor to estimate emissions from these sources. It was assumed that approximately 50 percent of emissions from gas well completions and workovers with hydraulic fracturing would be flared due to states such as Wyoming that do not permit the venting of natural gas during well completions.

The same E&P Tank simulation data for hydrocarbon liquids above 45˚API flashing emission in tanks was used as in previous Inventories to estimate emissions from condensate tanks; however, these flashing emissions simulations were coupled with a large sample of condensate production gravities from the HPDI database to improve the factor to account for the average national distribution of condensate gravities. Previously, a simple average of simulation results for each liquid gravity was used. Additionally, the TERC (2009) study provided a small sample of data representing two regions in Texas where separator dump valve malfunctions were detected and measured. This data was applied only to the regions represented by the study to account for this emission source.

Finally, WGC (2009) sample data on centrifugal compressor seal oil degassing vent rates was used to divide the centrifugal compressors source in the processing and transmission and storage segments into two sources—centrifugal compressors equipped with wet seals and centrifugal compressors equipped with dry seals. The seal oil degassing vent (found with compressors using wet seals) was previously unaccounted for in the Inventory. This improved methodology accounted for an increase in emissions from these sources between 50 and 100 percent.

Finally, the previous Inventory activity data are updated with revised values each year. However, the impact of these changes was small compared to the changes described above.

The net effect of these changes was to increase total CH_4 emissions from natural gas systems between 47 and 120 percent each year between 1990 and 2008 relative to the previous report. The natural gas production segment accounted for the largest increases, largely due to the methodological changes to gas well cleanups and the addition of gas well completions and workovers with hydraulic fracturing.

Planned Improvements

Emission reductions reported to Natural Gas STAR are deducted from the total sector emissions each year in the natural gas systems inventory model to estimate emissions. These reported reductions often rely on Inventory emission factors to quantify the extent of reductions. These reductions are also a source of uncertainty that is not currently analyzed in the Inventory. Emissions reductions—in particular from gas well cleanups—may be underestimated, and we intend to investigate whether additional data are available, and if appropriate, revisions to more accurately account for emissions from natural gas systems will be incorporated into future inventories. Additionally, accounting for the uncertainty of these reductions to more accurately provide upper and lower bounds within the 95 percent confidence interval, will be investigated.

Separately, a larger study is currently underway to update selected compressor emission factors used in the national inventory. Most of the activity factors and emission factors in the natural gas inventory are from the EPA/GRI (1996) study. The current measurement-based study to develop updated emission factors for compressors is intended to better reflect current national circumstances. Results from these studies are expected in 2011, and will be incorporated into the Inventory, pending a peer review.

Malfunctioning separator dump valves is not an occurrence isolated to the Texas counties in which the sample data was obtained. New data will be reviewed as it becomes available on this emissions source and emissions will be updated, as appropriate.

Data collected through EPA's Greenhouse Gas Reporting Program (40 CFR Part 98, Mandatory Reporting of Greenhouse Gases; Final Rule, Subpart W) will be reviewed for potential improvements to the natural gas systems emissions estimates. The rule will collect actual activity data using improved quantification methods from those used in several of the studies which form the basis of this Inventory. Data collection for Subpart W began January 1, 2011 with emissions reporting beginning in 2012. These base year 2011 data will be reviewed for inclusion into a future Inventory to improve the accuracy and reduce the uncertainty of the emission estimates.

3.7. Petroleum Systems (IPCC Source Category 1B2a)

CH_4 emissions from petroleum systems are primarily associated with crude oil production, transportation, and refining operations. During each of these activities, CH_4 emissions are released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. Fugitive and vented CO_2 emissions from petroleum systems are primarily associated with crude oil production and refining operations but are negligible in transportation operations. Combusted CO_2 emissions from fuels are already accounted for in the Fossil Fuels Combustion source category, and hence have not been taken into account in the Petroleum Systems source category. Total CH_4 and CO_2 emissions from petroleum systems in 2009 were 30.9 Tg CO_2 Eq. (1,473 Gg CH_4) and 0.5 Tg CO_2 (463 Gg), respectively. Since 1990, CH_4 emissions have declined by 13 percent, due to industry efforts to reduce emissions and a decline in domestic oil production (see Table 3-41and Table 3-42). CO_2 emissions have also declined by 17 percent since 1990 due to similar reasons (see Table 3-43 and Table 3-44).

Production Field Operations. Production field operations account for about 98 percent of total CH_4 emissions from petroleum systems. Vented CH_4 from field operations account for over 90 percent of the emissions from the production sector, unburned CH_4 combustion emissions account for 6.4 percent, fugitive emissions are 3.4 percent, and process upset emissions are slightly under two-tenths of a percent. The most dominant sources of emissions, in order of magnitude, are shallow water offshore oil platforms, natural-gas-powered high bleed pneumatic devices, oil tanks, natural-gas powered low bleed pneumatic devices, gas engines, deep water offshore platforms, and chemical injection pumps. These seven sources alone emit about 94 percent of the production field operations emissions. Offshore platform emissions are a combination of fugitive, vented, and unburned fuel combustion emissions from all equipment housed on oil platforms producing oil and associated gas. Emissions from high and low-bleed pneumatics occur when pressurized gas that is used for control devices is bled to the atmosphere as they cycle open and closed to modulate the system. Emissions from oil tanks occur when the CH_4 entrained in crude oil under pressure volatilizes once the crude oil is put into storage tanks at atmospheric pressure. Emissions from gas engines are due to unburned CH_4 that vents with the exhaust. Emissions from chemical injection pumps are due to the 25 percent that use associated gas to drive pneumatic pumps. The remaining six percent of the emissions are distributed among 26 additional activities within the four categories: vented, fugitive, combustion and process upset emissions. For more detailed, source-level data on CH_4 emissions in production field operations, refer to Annex 3.5.

Vented CO_2 associated with natural gas emissions from field operations account for 99 percent of the total CO_2 emissions from this source category, while fugitive and process upsets together account for less than 1 percent of the emissions. The most dominant sources of vented emissions are oil tanks, high bleed pneumatic devices, shallow water offshore oil platforms, low bleed pneumatic devices, and chemical injection pumps. These five sources together account for 98.5 percent of the non-combustion CO_2 emissions from this source category, while the remaining 1.5 percent of the emissions is distributed among 24 additional activities within the three categories: vented, fugitive and process upsets.

Crude Oil Transportation. Crude oil transportation activities account for less than one half of one percent of total CH_4 emissions from the oil industry. Venting from tanks and marine vessel loading operations accounts for 61 percent of CH_4 emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for 19 percent. The remaining 20 percent is distributed among six additional sources within these two categories. Emissions from pump engine drivers and heaters were not estimated due to lack of data.

Crude Oil Refining. Crude oil refining processes and systems account for slightly less than two percent of total CH_4 emissions from the oil industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH_4 in all refined products. Within refineries, vented emissions account for about 86 percent of the emissions, while both fugitive and combustion emissions account for approximately seven percent each. Refinery system blowdowns for maintenance and the process of asphalt blowing—with air, to harden the asphalt—are the primary venting contributors. Most of the fugitive CH_4 emissions from refineries are from leaks in the fuel gas system. Refinery combustion emissions include small amounts of unburned CH_4 in process heater stack emissions and unburned CH_4 in engine exhausts and flares.

Asphalt blowing from crude oil refining accounts for 36 percent of the total non-combustion CO_2 emissions in petroleum systems.

Table 3-41: CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Production Field Operations	**34.7**	**30.8**	**28.7**	**28.7**	**29.3**	**29.6**	**30.3**
Pneumatic device venting	10.3	9.0	8.4	8.3	8.4	8.7	8.8
Tank venting	5.3	4.5	3.9	3.9	4.0	4.0	4.5
Combustion & process upsets	1.9	1.6	1.5	1.5	1.5	1.6	2.0
Misc. venting & fugitives	16.8	15.3	14.5	14.6	15.0	14.8	14.6
Wellhead fugitives	0.6	0.5	0.4	0.4	0.4	0.5	0.5
Crude Oil Transportation	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Refining	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.5**	**0.5**
Total	**35.4**	**31.5**	**29.4**	**29.4**	**30.0**	**30.2**	**30.9**

Note: Totals may not sum due to independent rounding.

Table 3-42: CH_4 Emissions from Petroleum Systems (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
Production Field Operations	**1,653**	**1,468**	**1,366**	**1,365**	**1,396**	**1,409**	**1,444**
Pneumatic device venting	489	428	397	396	398	416	419
Tank venting	250	214	187	188	192	189	212
Combustion & process upsets	88	76	71	71	72	75	94
Misc. venting & fugitives	799	727	691	693	714	707	696
Wellhead fugitives	26	22	19	17	20	23	23
Crude Oil Transportation	**7**	**5**	**5**	**5**	**5**	**5**	**5**
Refining	**25**	**28**	**28**	**28**	**27**	**25**	**24**
Total	**1,685**	**1,501**	**1,398**	**1,398**	**1,427**	**1,439**	**1,473**

Note: Totals may not sum due to independent rounding.

Table 3-43: CO_2 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Production Field Operations	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Pneumatic device venting	+	+	+	+	+	+	+
Tank venting	0.3	0.3	0.2	0.2	0.3	0.2	0.3
Misc. venting & fugitives	+	+	+	+	+	+	+
Wellhead fugitives	+	+	+	+	+	+	+
Crude Refining	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.1**
Total	**0.6**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 3-44: CO_2 Emissions from Petroleum Systems (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
Production Field Operations	**376**	**323**	**285**	**285**	**292**	**288**	**319**
Pneumatic device venting	27	24	22	22	22	23	23
Tank venting	328	281	246	246	252	247	278
Misc. venting & fugitives	18	17	16	16	16	16	16
Wellhead fugitives	1	1	1	1	1	1	1
Crude Refining	**180**	**211**	**205**	**203**	**182**	**165**	**144**
Total	**555**	**534**	**490**	**488**	**474**	**453**	**463**

Note: Totals may not sum due to independent rounding.

Methodology

The methodology for estimating CH_4 emissions from petroleum systems is a bottom-up approach, based on comprehensive studies of CH_4 emissions from U.S. petroleum systems (EPA 1996, EPA 1999). These studies combined emission estimates from 64 activities occurring in petroleum systems from the oil wellhead through crude oil refining, including 33 activities for crude oil production field operations, 11 for crude oil transportation activities, and 20 for refining operations. Annex 3.5 provides greater detail on the emission estimates for these 64 activities. The estimates of CH_4 emissions from petroleum systems do not include emissions downstream of oil refineries because these emissions are negligible.

The methodology for estimating CH_4 emissions from the 64 oil industry activities employs emission factors initially developed by EPA (1999). Activity factors for the years 1990 through 2009 were collected from a wide variety of statistical resources. Emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment item or per activity) by their corresponding activity factor (e.g., equipment count or frequency of activity). EPA (1999) provides emission factors for all activities except those related to offshore oil production and field storage tanks. For offshore oil production, two emission factors were calculated using data collected over a one-year period for all federal offshore platforms (EPA 2005, BOEMRE 2004). One emission factor is for oil platforms in shallow water, and one emission factor is for oil platforms in deep water. Emission factors are held constant for the period 1990 through 2009. The number of platforms in shallow water and the number of platforms in deep water are used as activity factors and are taken from Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) (formerly Minerals Management Service) statistics (BOEMRE 2010a-c). For oil storage tanks, the emissions factor was calculated as the total emissions per barrel of crude charge from E&P Tank data weighted by the distribution of produced crude oil gravities from the HPDI production database (EPA 1999, HPDI 2009).

For some years, complete activity factor data were not available. In such cases, one of three approaches was employed. Where appropriate, the activity factor was calculated from related statistics using ratios developed for EPA (1996). For example, EPA (1996) found that the number of heater treaters (a source of CH_4 emissions) is related to both number of producing wells and annual production. To estimate the activity factor for heater treaters, reported statistics for wells and production were used, along with the ratios developed for EPA (1996). In other cases, the activity factor was held constant from 1990 through 2009 based on EPA (1999). Lastly, the previous year's data were used when data for the current year were unavailable. The CH_4 and CO_2 sources in the production sector share common activity factors. See Annex 3.5 for additional detail.

Among the more important references used to obtain activity factors are the Energy Information Administration annual and monthly reports (EIA 1990 through 2010, 1995 through 2010, 1995 through 2010a-b), Methane Emissions from the Natural Gas Industry by the Gas Research Institute and EPA (EPA/GRI 1996a-d), Estimates of Methane Emissions from the U.S. Oil Industry (EPA 1999), consensus of industry peer review panels, BOEMRE reports (BOEMRE 2005, 2010a-c), analysis of BOEMRE data (EPA 2005, BOEMRE 2004), the Oil & Gas Journal (OGJ 2010a,b), the Interstate Oil and Gas Compact Commission (IOGCC 2008), and the United States Army Corps of Engineers (1995-2008).

The methodology for estimating CO_2 emissions from petroleum systems combines vented, fugitive, and process upset emissions sources from 29 activities for crude oil production field operations and one activity from petroleum refining. Emissions are estimated for each activity by multiplying emission factors by their corresponding activity factors. The emission factors for CO_2 are estimated by multiplying the CH_4 emission factors by a conversion factor, which is the ratio of CO_2 content and methane content in produced associated gas. The only exceptions to this methodology are the emission factors for crude oil storage tanks, which are obtained from E&P Tank simulation runs, and the emission factor for asphalt blowing, which was derived using the methodology and sample data from API (2009).

Uncertainty and Time-Series Consistency

This section describes the analysis conducted to quantify uncertainty associated with the estimates of emissions from petroleum systems. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), the method employed provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the Inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

The detailed, bottom-up Inventory analysis used to evaluate U.S. petroleum systems reduces the uncertainty related to the CH_4 emission estimates in comparison to a top-down approach. However, some uncertainty still remains. Emission factors and activity factors are based on a combination of measurements, equipment design data, engineering calculations and studies, surveys of selected facilities and statistical reporting. Statistical uncertainties arise from natural variation in measurements, equipment types, operational variability and survey and statistical methodologies. Published activity factors are not available every year for all 64 activities analyzed for petroleum systems; therefore, some are estimated. Because of the dominance of the seven major sources, which account for 92 percent of the total methane emissions, the uncertainty surrounding these seven sources has been estimated most rigorously, and serves as the basis for determining the overall uncertainty of petroleum systems emission estimates.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-45. Petroleum systems CH_4 emissions in 2009 were estimated to be between 23.5 and 76.9 Tg CO_2 Eq., while CO_2 emissions were estimated to be between 0.4 and 1.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 24 percent below to 149 percent above the 2009 emission estimates of 30.9 and 0.5 Tg CO_2 Eq. for CH_4 and CO_2, respectively.

Table 3-45: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)[b]	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound[b]	Upper Bound[b]	Lower Bound[b]	Upper Bound[b]
Petroleum Systems	CH_4	30.9	23.5	76.9	-24%	149%
Petroleum Systems	CO_2	0.5	0.4	1.2	-24%	149%

[a] Range of 2009 relative uncertainty predicted by Monte Carlo Simulation, based on 1995 base year activity factors, for a 95 percent confidence interval.

[b] All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.

Note: Totals may not sum due to independent rounding

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

As part of QA/QC and verification activities done for the Inventory, potential improvements were identified, which include a new emissions source associated with fixed roof storage tank emissions in the production segment. In some production areas the separator liquid level may drop too low such that the produced associated gas blows through the dump valve and vents through the storage tank. This data was included where available for the Inventory (see Recalculation discussion below). More data will be necessary to potentially add this as a separate source from storage tank flashing emissions and also to represent the true scope of activity across the United States.

Recalculations Discussion

Most revisions for the current Inventory relative to the previous report were due to updating previous years' data with revised data from existing data sources. Well completion venting, well drilling, and offshore platform activity factors were updated from existing data sources from 1990 onward.

Additionally, the emission factor for venting from fixed roof storage tanks in the crude oil production segment was revised. Using the same E&P Tank sample data runs on crude oil gravities ranging up to 45˚API, a new national level flashing emissions factor was developed by using a large sample of production data, sorted by gravity, available from the HPDI database.

A study prepared for the Texas Environmental Research Consortium measured emissions rates from several oil and condensate tanks in Texas (TERC 2009). This data was plotted and compared to the flashing emissions simulated via E&P Tank simulation. EPA observed that additional emissions beyond the flashing were present in approximately 50 percent of the tanks. These emissions may be attributed to separator dump valves malfunctioning or other methods of associated gas entering the tank and venting from the roof. Because the dataset was limited to represent production from only 14 counties that represent 0.5 percent of U.S. production, the national emission factor was scaled up such that only production from these counties is affected by the occurrence of associated gas venting through the storage tank.

Planned Improvements

As noted above, nearly all emission factors used in the development of the petroleum systems estimates were taken from EPA (1995, 1996, 1999), with the remaining emission factors taken from EPA default values (EPA 2005) and a consensus of industry peer review panels. These emission factors will be reviewed as part of future Inventory work. Results of this review and analysis will be incorporated into future inventories, as appropriate.

Malfunctioning separator dump valves is not an occurrence isolated to the Texas counties in which the sample data was obtained. New data will be reviewed as they become available on this emissions source and emissions updated, as appropriate.

Data collected through EPA's Greenhouse Gas Reporting Program will be reviewed for potential improvements to petroleum systems emissions sources. The rule will collect actual activity data and improved quantification methods from those used in several of the studies which form the basis of this Inventory. This data will be incorporated as appropriate into the current Inventory to improve the accuracy and uncertainty of the emissions estimates. In particular, EPA will investigate whether certain emissions sources currently accounted for in the Energy sector should be separately accounted for in the petroleum systems inventory (e.g., CO_2 process emissions from hydrogen production).

In 2010, all U.S. petroleum refineries were required to collect information on their greenhouse gas emissions. This data will be reported to EPA through its Greenhouse Gas Reporting Program in 2011. Data collected under this program will be evaluated for use in future inventories to improve the calculation of national emissions from petroleum systems.

[BEGIN BOX]

Box 3-3. Carbon Dioxide Transport, Injection, and Geological Storage

Carbon dioxide is produced, captured, transported, and used for Enhanced Oil Recovery (EOR) as well as commercial and non-EOR industrial applications. This CO_2 is produced from both naturally-occurring CO_2 reservoirs and from industrial sources such as natural gas processing plants and ammonia plants. In the current Inventory, emissions from naturally-produced CO_2 are estimated based on the application.

In the current Inventory report, the CO_2 that is used in non-EOR industrial and commercial applications (e.g., food processing, chemical production) is assumed to be emitted to the atmosphere during its industrial use. These emissions are discussed in the Carbon Dioxide Consumption section. The naturally-occurring CO_2 used in EOR operations is assumed to be fully sequestered. Additionally, all anthropogenic CO_2 emitted from natural gas processing and ammonia plants is assumed to be emitted to the atmosphere, regardless of whether the CO_2 is captured or not. These emissions are currently included in the Natural Gas Systems and the Ammonia Production sections of the Inventory report, respectively.

IPCC (IPCC, 2006) included, for the first time, methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO_2. The methodology is based on the principle that the carbon capture and storage system should be handled in a complete and consistent manner across the entire Energy sector. The approach accounts for CO_2 captured at natural and industrial sites as well as emissions from capture, transport, and use. For storage specifically, a Tier 3 methodology is outlined for estimating and reporting emissions based on site-specific evaluations. However, IPCC (IPCC, 2006) notes that if a national regulatory process exists, emissions information available through that process may support development of CO_2 emissions estimates for geologic storage.

Beginning in 2010, facilities that conduct geologic sequestration of CO_2 and all other facilities that inject CO_2 underground will be required to calculate and report greenhouse gas data annually to EPA through its Greenhouse

Gas Reporting Program. The Greenhouse Gas Reporting Rule requires greenhouse gas reporting from facilities that inject CO_2 underground for geologic sequestration, and requires greenhouse gas reporting from all other facilities that inject CO_2 underground for any reason, including enhanced oil and gas recovery. Beginning in 2010, facilities conducting geologic sequestration of CO_2 are required to develop and implement an EPA-approved site-specific monitoring, reporting and verification (MRV) plan, and to report the amount of CO_2 sequestered using a mass balance approach. Data from this program, which will be reported to EPA in early 2012, for the 2011 calendar year, will provide additional facility-specific information about the carbon capture, transport and storage chain, EPA intends to evaluate that information closely and consider opportunities for improving our current inventory estimates.

Preliminary estimates indicate that the amount of CO_2 captured from industrial and natural sites is 47.3 Tg CO_2 (47,340 Gg CO_2) (see Table 3-46 and Table 3-47). Site-specific monitoring and reporting data for CO_2 injection sites (i.e., EOR operations) were not readily available, therefore, these estimates assume all CO_2 is emitted.

Table 3-46: Potential Emissions from CO_2 Capture and Transport (Tg CO_2 Eq.)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Acid Gas Removal Plants	4.8	2.3	5.8	6.2	6.4	6.6	7.0
Naturally Occurring CO_2	20.8	23.2	28.3	30.2	33.1	36.1	39.7
Ammonia Production Plants	+	0.7	0.7	0.7	0.7	0.6	0.6
Pipelines Transporting CO_2	+	+	+	+	+	+	+
Total	**25.6**	**26.1**	**34.7**	**37.1**	**40.1**	**43.3**	**47.3**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note; Totals may not sum due to independent rounding.

Table 3-47: Potential Emissions from CO_2 Capture and Transport (Gg)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Acid Gas Removal Plants	4,832	2,264	5,798	6,224	6,088	6,630	7,035
Naturally Occurring CO_2	20,811	23,208	28,267	30,224	33,086	36,102	39,725
Ammonia Production Plants	+	676	676	676	676	580	580
Pipelines Transporting CO_2	8	8	7	7	7	8	8
Total	**25,643**	**26,149**	**34,742**	**37,124**	**40,141**	**43,311**	**47,340**

+ Does not exceed 0.5 Gg.

Note: Totals do not include emissions from pipelines transporting CO_2

Note; Totals may not sum due to independent rounding.

[END BOX]

3.8. Energy Sources of Indirect Greenhouse Gas Emissions

In addition to the main greenhouse gases addressed above, many energy-related activities generate emissions of indirect greenhouse gases. Total emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs) from energy-related activities from 1990 to 2009 are reported in Table 3-48.

Table 3-48: NO_x, CO, and NMVOC Emissions from Energy-Related Activities (Gg)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
NO_x	**21,106**	**18,477**	**15,319**	**14,473**	**13,829**	**13,012**	**10,887**
Mobile Combustion	10,862	10,199	9,012	8,488	7,965	7,441	6,206
Stationary Combustion	10,023	8,053	5,858	5,545	5,432	5,148	4,159
Oil and Gas Activities	139	111	321	319	318	318	393
Incineration of Waste	82	114	129	121	114	106	128
*International Bunker Fuels**	*2,020*	*1,344*	*1,703*	*1,793*	*1,791*	*1,917*	*1,651*
CO	**125,640**	**89,714**	**69,062**	**65,399**	**61,739**	**58,078**	**49,647**
Mobile Combustion	119,360	83,559	62,692	58,972	55,253	51,533	43,355
Stationary Combustion	5,000	4,340	4,649	4,695	4,744	4,792	4,543

Incineration of Waste	978		1,670		1,403	1,412	1,421	1,430	1,403
Oil and Gas Activities	302		146		318	319	320	322	345
*International Bunker Fuels**	*130*		*128*		*132*	*161*	*160*	*165*	*149*
NMVOCs	**12,620**		**8,952**		**7,798**	**7,702**	**7,604**	**7,507**	**5,333**
Mobile Combustion	10,932		7,229		6,330	6,037	5,742	5,447	4,151
Stationary Combustion	912		1,077		716	918	1,120	1,321	424
Oil and Gas Activities	554		388		510	510	509	509	599
Incineration of Waste	222		257		241	238	234	230	159
*International Bunker Fuels**	*61*		*45*		*54*	*59*	*59*	*62*	*57*

* These values are presented for informational purposes only and are not included in totals.
Note: Totals may not sum due to independent rounding.

Methodology

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual categories from various agencies. Depending on the category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

Activity data were used in conjunction with emission factors, which together relate the quantity of emissions to the activity. Emission factors are generally available from the EPA's Compilation of Air Pollutant Emission Factors, AP-42 (EPA 1997). The EPA currently derives the overall emission control efficiency of a source category from a variety of information sources, including published reports, the 1985 National Acid Precipitation and Assessment Program emissions inventory, and other EPA databases.

Uncertainty and Time-Series Consistency

Uncertainties in these estimates are partly due to the accuracy of the emission factors used and accurate estimates of activity data. A quantitative uncertainty analysis was not performed.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

3.9. International Bunker Fuels (IPCC Source Category 1: Memo Items)

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the UNFCCC, are not included in national emission totals, but are reported separately based upon location of fuel sales. The decision to report emissions from international bunker fuels separately, instead of allocating them to a particular country, was made by the Intergovernmental Negotiating Committee in establishing the Framework Convention on Climate Change.[96] These decisions are reflected in the IPCC methodological guidance, including the 2006 IPCC Guidelines, in which countries are requested to report emissions from ships or aircraft that depart from their ports with fuel purchased within national boundaries and are engaged in international transport separately from national totals (IPCC 2006).[97]

Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO_2, CH_4 and N_2O. Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[98] Emissions from ground transport activities—by road vehicles and trains—even when crossing

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[96] See report of the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change on the work of its ninth session, held at Geneva from 7 to 18 February 1994 (A/AC.237/55, annex I, para. 1c).

[97] Note that the definition of international bunker fuels used by the UNFCCC differs from that used by the International Civil Aviation Organization.

[98] Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation

international borders are allocated to the country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

The IPCC Guidelines distinguish between different modes of air traffic. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The IPCC Guidelines further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, and in keeping with the IPCC Guidelines, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.[99]

Emissions of CO_2 from aircraft are essentially a function of fuel use. CH_4 and N_2O emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). CH_4 is the product of incomplete combustion and occur mainly during the landing and take-off phases. In jet engines, N_2O is primarily produced by the oxidation of atmospheric nitrogen, and the majority of emissions occur during the cruise phase. International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags that are engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying, military (i.e., U.S. Navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels, which is the largest of the four categories, and military vessels. Two main types of fuels are used on sea-going vessels: distillate diesel fuel and residual fuel oil. CO_2 is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2009 from the combustion of international bunker fuels from both aviation and marine activities were 124.4 Tg CO_2 Eq., or ten percent above emissions in 1990 (see Table 3-49 and Table 3-50). Emissions from international flights and international shipping voyages departing from the United States have increased by 49 percent and decreased by 18 percent, respectively, since 1990. The majority of these emissions were in the form of CO_2; however, small amounts of CH_4 and N_2O were also emitted.

Table 3-49: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (Tg CO_2 Eq.)

Gas/Mode	1990	2000	2005	2006	2007	2008	2009
CO_2	**111.8**	**98.5**	**109.7**	**128.4**	**127.6**	**133.7**	**123.1**
Aviation	46.4	58.8	56.7	74.6	73.8	75.5	69.4
Marine	65.4	39.7	53.0	53.8	53.9	58.2	53.7
CH_4	**0.2**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.1**
Aviation	+	+	+	+	+	+	+
Marine	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**1.1**	**0.9**	**1.0**	**1.2**	**1.2**	**1.2**	**1.1**
Aviation	0.5	0.6	0.6	0.8	0.8	0.8	0.7
Marine	0.5	0.3	0.4	0.4	0.4	0.5	0.4
Total	**113.0**	**99.5**	**110.9**	**129.7**	**129.0**	**135.1**	**124.4**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Table 3-50: CO_2, CH_4 and N_2O Emissions from International Bunker Fuels (Gg)

Gas/Mode	1990	2000	2005	2006	2007	2008	2009
CO_2	**111,828**	**98,482**	**109,750**	**128,384**	**127,618**	**133,704**	**123,127**
Aviation	46,399	58,785	56,736	74,552	73,762	75,508	69,404
Marine	65,429	39,697	53,014	53,832	53,856	58,196	53,723
CH_4	**8**	**6**	**7**	**8**	**8**	**8**	**7**
Aviation	2	2	2	2	2	2	2

Organization (ICAO) or the International Maritime Organization (IMO), which develop international codes, recommendations, and conventions, such as the International Convention of the Prevention of Pollution from Ships (MARPOL).

[99] Naphtha-type jet fuel was used in the past by the military in turbojet and turboprop aircraft engines.

Marine	7	4	5	5	5	6	5
N_2O	**3**	**3**	**3**	**4**	**4**	**4**	**4**
Aviation	2	2	2	2	2	2	2
Marine	2	1	1	1	1	1	1

Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Methodology

Emissions of CO_2 were estimated by applying C content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under CO_2 from Fossil Fuel Combustion. C content and fraction oxidized factors for jet fuel, distillate fuel oil, and residual fuel oil were taken directly from EIA and are presented in Annex 2.1, Annex 2.2, and Annex 3.7 of this Inventory. Density conversions were taken from Chevron (2000), ASTM (1989), and USAF (1998). Heat content for distillate fuel oil and residual fuel oil were taken from EIA (2010) and USAF (1998), and heat content for jet fuel was taken from EIA (2010). A complete description of the methodology and a listing of the various factors employed can be found in Annex 2.1. See Annex 3.7 for a specific discussion on the methodology used for estimating emissions from international bunker fuel use by the U.S. military.

Emission estimates for CH_4 and N_2O were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Emission factors used in the calculations of CH_4 and N_2O emissions were obtained from the Revised 1996 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1997). For aircraft emissions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.09 for CH_4 and 0.1 for N_2O For marine vessels consuming either distillate diesel or residual fuel oil the following values (g/MJ), were employed: 0.32 for CH_4 and 0.08 for N_2O. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Activity data on aircraft fuel consumption for inventory years 2000 through 2005 were developed using the FAA's System for assessing Aviation's Global Emissions (SAGE) model (FAA 2006). That tool has been subsequently replaced by the Aviation Environmental Design Tool (AEDT), which calculates noise in addition to aircraft fuel burn and emissions for flights globally in a given year (FAA 2010). Data for inventory years 2006 through 2009 were developed using AEDT.

International aviation bunker fuel consumption from 1990 to 2009 was calculated by assigning the difference between the sum of domestic activity data (in Tbtu) from SAGE and the AEDT, and the reported EIA transportation jet fuel consumption to the international bunker fuel category for jet fuel from EIA (2010). Data on U.S. Department of Defense (DoD) aviation bunker fuels and total jet fuel consumed by the U.S. military was supplied by the Office of the Under Secretary of Defense (Installations and Environment), DoD. Estimates of the percentage of each Service's total operations that were international operations were developed by DoD. Military aviation bunkers included international operations, operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea. Military aviation bunker fuel emissions were estimated using military fuel and operations data synthesized from unpublished data by the Defense Energy Support Center, under DoD's Defense Logistics Agency (DESC 2011). Together, the data allow the quantity of fuel used in military international operations to be estimated. Densities for each jet fuel type were obtained from a report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are presented in Table 3-51. See Annex 3.7 for additional discussion of military data.

Activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were taken from unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 1991 through 2010) for 1990 through 2001, 2007, through 2009, and the Department of Homeland Security's Bunker Report for 2003 through 2006 (DHS 2008). Fuel consumption data for 2002 was interpolated due to inconsistencies in reported fuel consumption data. Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by DESC (2011). The total amount of fuel provided to naval vessels was reduced by 13 percent to account for fuel used while the vessels were not-underway (i.e., in port). Data on the percentage of steaming hours underway versus not-underway were provided by the U.S. Navy. These fuel consumption estimates are presented in. Table 3-52.

Table 3-51: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**

U.S. and Foreign Carriers	4,934		6,157		5,943	7,809	7,726	7,909	7,270
U.S. Military	862		480		462	400	410	386	368
Total	**5,796**		**6,638**		**6,405**	**8,209**	**8,137**	**8,295**	**7,638**

Note: Totals may not sum due to independent rounding.

Table 3-52: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Residual Fuel Oil	4,781		2,967		3,881	4,004	4,059	4,373	4,040
Distillate Diesel Fuel & Other	617		290		444	446	358	445	426
U.S. Military Naval Fuels	522		329		471	414	444	437	384
Total	**5,920**		**3,586**		**4,796**	**4,864**	**4,861**	**5,254**	**4,850**

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.[100] For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

Uncertainties exist with regard to the total fuel used by military aircraft and ships, and in the activity data on military operations and training that were used to estimate percentages of total fuel use reported as bunker fuel emissions. Total aircraft and ship fuel use estimates were developed from DoD records, which document fuel sold to the Navy and Air Force from the Defense Logistics Agency. These data may slightly over or under estimate actual total fuel use in aircraft and ships because each Service may have procured fuel from, and/or may have sold to, traded with, and/or given fuel to other ships, aircraft, governments, or other entities. There are uncertainties in aircraft operations and training activity data. Estimates for the quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel emissions had to be estimated based on a combination of available data and expert judgment. Estimates of marine bunker fuel emissions were based on Navy vessel steaming hour data, which reports fuel used while underway and fuel used while not underway. This approach does not capture some voyages that would be classified as domestic for a commercial vessel. Conversely, emissions from fuel used while not underway preceding an international voyage are reported as domestic rather than international as would be done for a commercial vessel. There is uncertainty associated with ground fuel estimates for 1997 through 2001. Small fuel quantities may have been used in vehicles or equipment other than that which was assumed for each fuel type.

There are also uncertainties in fuel end-uses by fuel-type, emissions factors, fuel densities, diesel fuel sulfur content, aircraft and vessel engine characteristics and fuel efficiencies, and the methodology used to back-calculate the data set to 1990 using the original set from 1995. The data were adjusted for trends in fuel use based on a closely correlating, but not matching, data set. All assumptions used to develop the estimate were based on process knowledge, Department and military Service data, and expert judgments. The magnitude of the potential errors related to the various uncertainties has not been calculated, but is believed to be small. The uncertainties associated with future military bunker fuel emission estimates could be reduced through additional data collection.

Although aggregate fuel consumption data have been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO_2 in the Revised 1996 IPCC Guidelines is to use data by specific aircraft type (IPCC/UNEP/OECD/IEA 1997). The IPCC also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate

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[100] See uncertainty discussions under Carbon Dioxide Emissions from Fossil Fuel Combustion.

near-ground level emissions of gases other than CO_2.[101]

There is also concern as to the reliability of the existing DOC (1991 through 2010) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2008. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for international bunker fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CO_2, CH_4, and N_2O from international bunker fuels in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated. No corrective actions were necessary.

Recalculations Discussion

Slight changes to emission estimates are due to revisions made to historical activity data for aviation jet fuel consumption using the FAA's AEDT. These historical data changes resulted in changes to the emission estimates for 1990 through 2008 relative to the previous Inventory, which averaged to an annual decrease in emissions from international bunker fuels of 0.13 Tg CO_2 Eq. (0.1 percent) in CO_2 emissions, an annual decrease of less than 0.01 Tg CO_2 Eq. (0.05 percent) in CH_4 emissions, and an annual decrease of less than 0.01 Tg CO_2 Eq. (0.1 percent) in N_2O emissions.

3.10. Wood Biomass and Ethanol Consumption (IPCC Source Category 1A)

The combustion of biomass fuels such as wood, charcoal, and wood waste and biomass-based fuels such as ethanol from corn and woody crops generates CO_2 in addition to CH_4 and N_2O already covered in this chapter. In line with the reporting requirements for inventories submitted under the UNFCCC, CO_2 emissions from biomass combustion have been estimated separately from fossil fuel CO_2 emissions and are not directly included in the energy sector contributions to U.S. totals. In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net carbon (C) fluxes from changes in biogenic C reservoirs in wooded or crop lands. For a more complete description of this methodological approach, see the Land Use, Land-Use Change, and Forestry chapter (Chapter 7), which accounts for the contribution of any resulting CO_2 emissions to U.S. totals within the Land Use, Land-Use Change and Forestry sector's approach.

In 2009, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 183.8 Tg CO_2 Eq. (183,777 Gg) (see Table 3-53 and Table 3-54). As the largest consumer of woody biomass, the industrial sector was responsible for 62 percent of the CO_2 emissions from this source. Emissions from this sector decreased from 2008 to 2009 due to a corresponding decrease in wood consumption. The residential sector was the second largest emitter, constituting 24 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

Table 3-53: CO_2 Emissions from Wood Consumption by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Industrial	135.3	153.6	136.3	138.2	132.6	126.1	114.2
Residential	59.8	43.3	44.3	40.2	44.3	46.4	44.3

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[101] U.S. aviation emission estimates for CO, NO_x, and NMVOCs are reported by EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends web site, and reported under the Mobile Combustion section. It should be noted that these estimates are based solely upon LTO cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates reported under the Mobile Combustion section overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including landing and take-off (LTO) cycles by aircraft on international flights, but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes. The estimates in Mobile Combustion are also likely to include emissions from ocean-going vessels departing from U.S. ports on international voyages.

Commercial	6.8	7.4	7.2	6.7	7.2	7.5	7.4
Electricity Generation	13.3	13.9	19.1	18.7	19.2	18.3	17.8
Total	**215.2**	**218.1**	**206.9**	**203.8**	**203.3**	**198.4**	**183.8**

Note: Totals may not sum due to independent rounding.

Table 3-54: CO_2 Emissions from Wood Consumption by End-Use Sector (Gg)

End-Use Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Industrial	135,348	153,559	136,269	138,207	132,642	126,145	114,222
Residential	59,808	43,309	44,340	40,215	44,340	46,402	44,340
Commercial	6,779	7,370	7,182	6,675	7,159	7,526	7,406
Electricity Generation	13,252	13,851	19,074	18,748	19,175	18,288	17,809
Total	**215,186**	**218,088**	**206,865**	**203,846**	**203,316**	**198,361**	**183,777**

Note: Totals may not sum due to independent rounding.

Biomass-derived fuel consumption in the United States transportation sector consisted primarily of ethanol use. Ethanol is primarily produced from corn grown in the Midwest, and was used mostly in the Midwest and South. Pure ethanol can be combusted, or it can be mixed with gasoline as a supplement or octane-enhancing agent. The most common mixture is a 90 percent gasoline, 10 percent ethanol blend known as gasohol. Ethanol and ethanol blends are often used to fuel public transport vehicles such as buses, or centrally fueled fleet vehicles.

In 2009, the United States consumed an estimated 894 trillion Btu of ethanol, and as a result, produced approximately 61.2 Tg CO_2 Eq. (61,231 Gg) (see Table 3-55 and Table 3-56) of CO_2 emissions. Ethanol production and consumption has grown steadily every year since 1990, with the exception of 1996 due to short corn supplies and high prices in that year.

Table 3-55: CO_2 Emissions from Ethanol Consumption (Tg CO_2 Eq.)

End-Use Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Transportation	4.1	9.2	22.4	30.3	38.1	53.8	60.2
Industrial	0.1	0.1	0.5	0.7	0.7	0.8	0.9
Commercial	+	+	0.1	0.1	0.1	0.1	0.2
Total	**4.2**	**9.4**	**23.0**	**31.0**	**38.9**	**54.8**	**61.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 3-56: CO_2 Emissions from Ethanol Consumption (Gg)

End-Use Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Transportation[a]	4,139	9,239	22,427	30,255	38,138	53,827	60,176
Industrial	56	87	469	662	674	798	892
Commercial	34	26	60	86	135	146	163
Total	**4,229**	**9,352**	**22,956**	**31,002**	**38,946**	**54,770**	**61,231**

[a] See Annex 3.2, Table A-88 for additional information on transportation consumption of these fuels.

Methodology

Woody biomass emissions were estimated by applying two EIA gross heat contents (Lindstrom 2006) to U.S. consumption data (EIA 2010) (see Table 3-57), provided in energy units for the industrial, residential, commercial, and electric generation sectors. One heat content (16.95 MMBtu/MT wood and wood waste) was applied to the industrial sector's consumption, while the other heat content (15.43 MMBtu/MT wood and wood waste) was applied to the consumption data for the other sectors. An EIA emission factor of 0.434 MT C/MT wood (Lindstrom 2006) was then applied to the resulting quantities of woody biomass to obtain CO_2 emission estimates. It was assumed that the woody biomass contains black liquor and other wood wastes, has a moisture content of 12 percent, and is converted into CO_2 with 100 percent efficiency. The emissions from ethanol consumption were calculated by applying an emission factor of 18.67 Tg C/QBtu (EPA 2010) to U.S. ethanol consumption estimates that were provided in energy units (EIA 2010) (see Table 3-58).

Table 3-57: Woody Biomass Consumption by Sector (Trillion Btu)

End-Use Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Industrial	1,442	1,636	1,452	1,472	1,413	1,344	1,217

Residential	580	420	430	390	430	450	430
Commercial	66	71	70	65	69	73	72
Electricity Generation	129	134	185	182	186	177	173
Total	**2,216**	**2,262**	**2,136**	**2,109**	**2,098**	**2,044**	**1,891**

Table 3-58: Ethanol Consumption by Sector (Trillion Btu)

End-Use Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Transportation	60.5	135.0	327.6	442.0	557.1	786.3	879.0
Industrial	0.8	1.3	6.8	9.7	9.8	11.7	13.0
Commercial	0.5	0.4	0.9	1.3	2.0	2.1	2.4
Total	**61.8**	**136.6**	**335.3**	**452.9**	**568.9**	**800.1**	**894.5**

Uncertainty and Time-Series Consistency

It is assumed that the combustion efficiency for woody biomass is 100 percent, which is believed to be an overestimate of the efficiency of wood combustion processes in the United States. Decreasing the combustion efficiency would decrease emission estimates. Additionally, the heat content applied to the consumption of woody biomass in the residential, commercial, and electric power sectors is unlikely to be a completely accurate representation of the heat content for all the different types of woody biomass consumed within these sectors. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Wood consumption values were revised for 2006 through 2008 based on updated information from EIA's Annual Energy Review (EIA 2010). This adjustment of historical data for wood biomass consumption resulted in an average annual decrease in emissions from wood biomass consumption of 0.8 Tg CO_2 Eq. (0.4 percent) from 1990 through 2008. The C content coefficient for ethanol was also revised to be consistent with the carbon content coefficients used for EPA's Mandatory Greenhouse Gas Reporting Rule. Slight adjustments were made to ethanol consumption based on updated information from EIA (2010), which slightly decreased estimates for ethanol consumed. As a result of these adjustments, average annual emissions from ethanol consumption increased by about 0.3 Tg CO_2 Eq. (1.9 percent) relative to the previous Inventory.

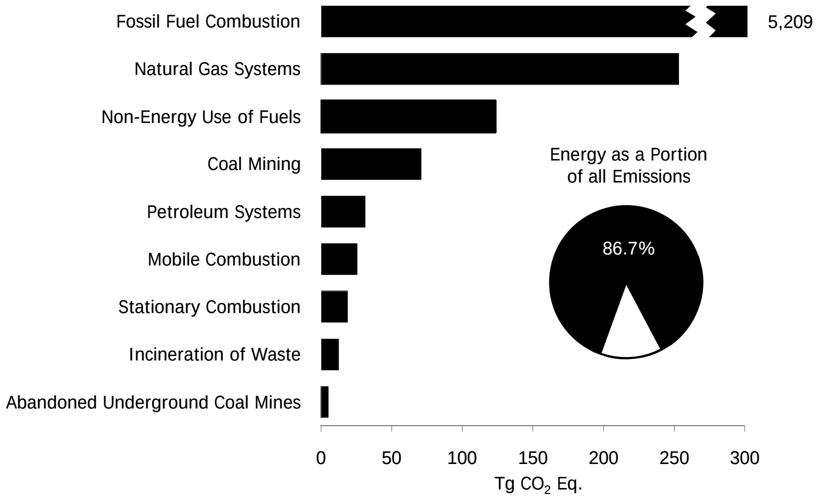
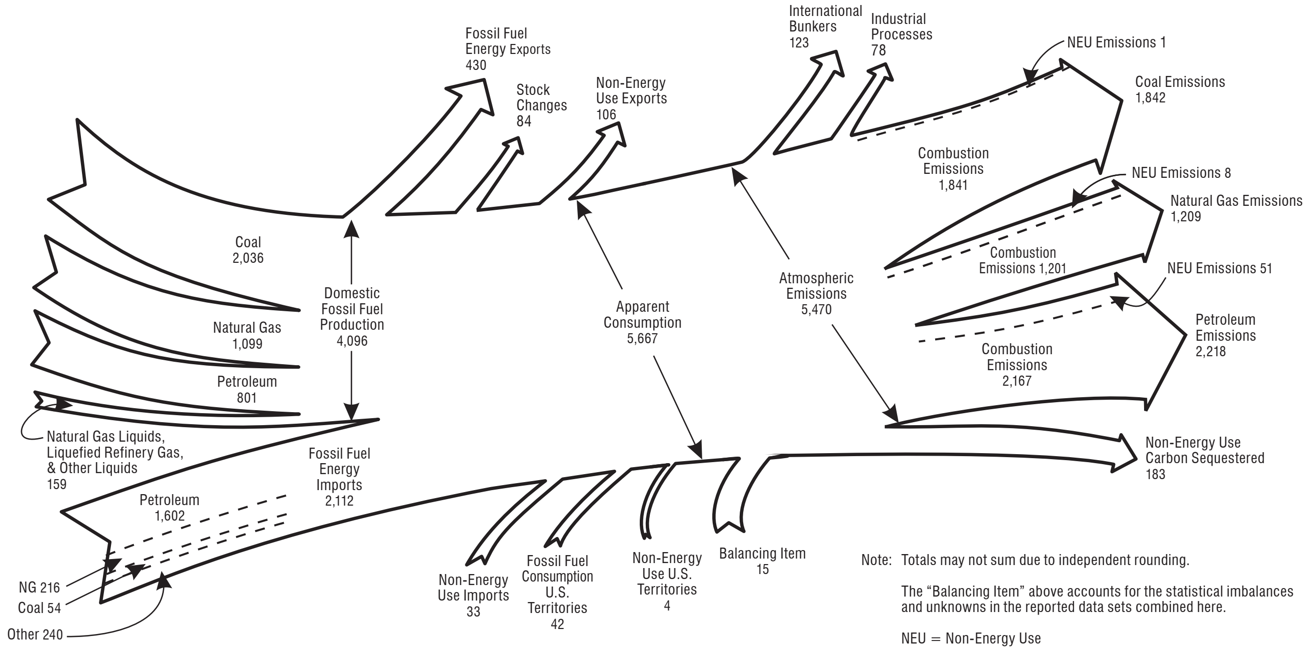


Figure 3-1: 2009 Energy Chapter Greenhouse Gas Sources



Note: Totals may not sum due to independent rounding.

The "Balancing Item" above accounts for the statistical imbalances and unknowns in the reported data sets combined here.

NEU = Non-Energy Use
NG = Natural Gas

Figure 3-2 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

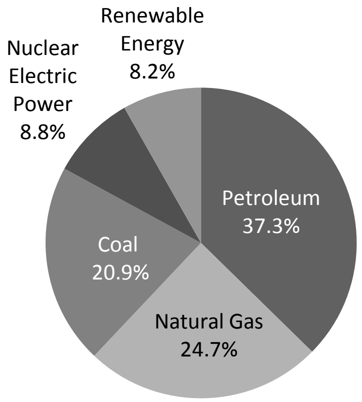


Figure 3-3: 2009 U.S. Energy Consumption by Energy Source

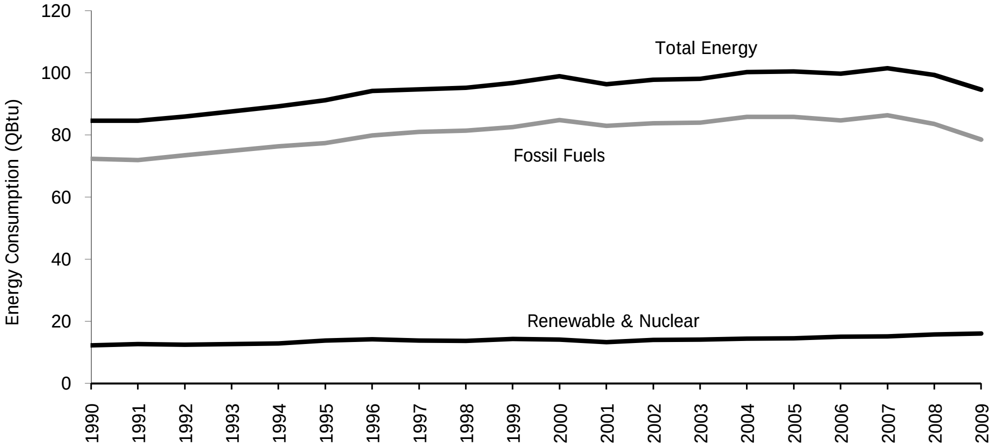


Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)
Note: Expressed as gross calorific values.

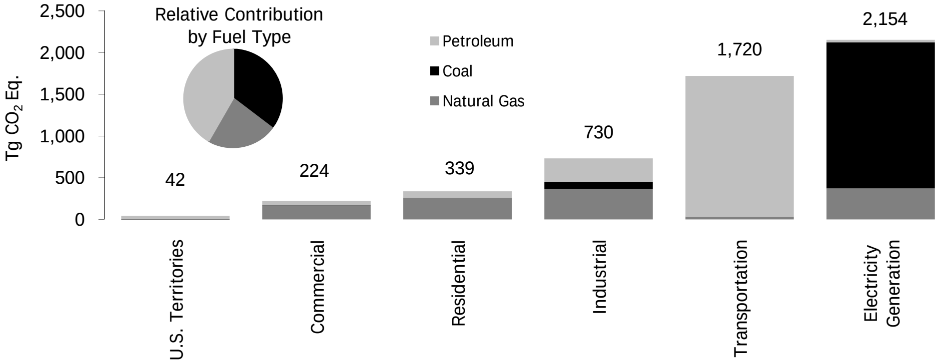


Figure 3-5: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type
Note: The electricity generation sector also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

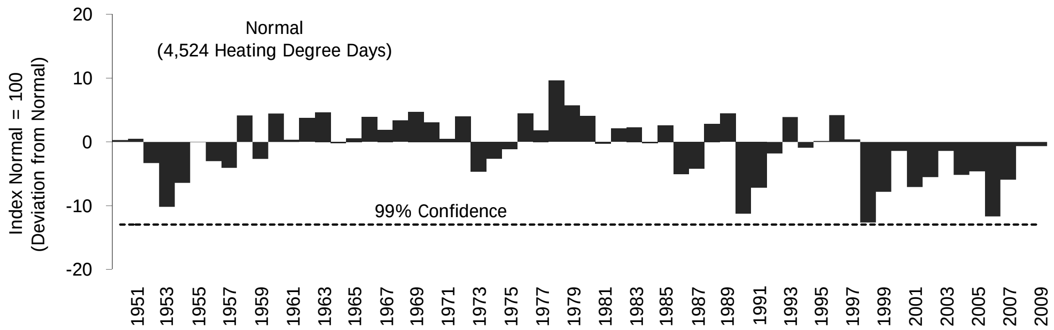


Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950-2009)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1971 through 2000.

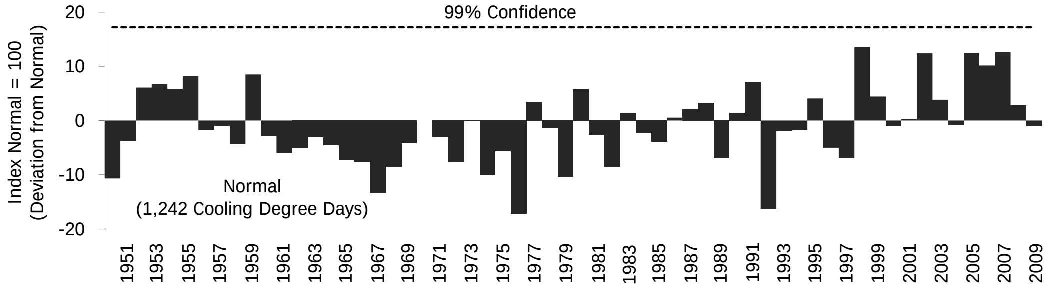


Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950-2009)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1971 through 2000.

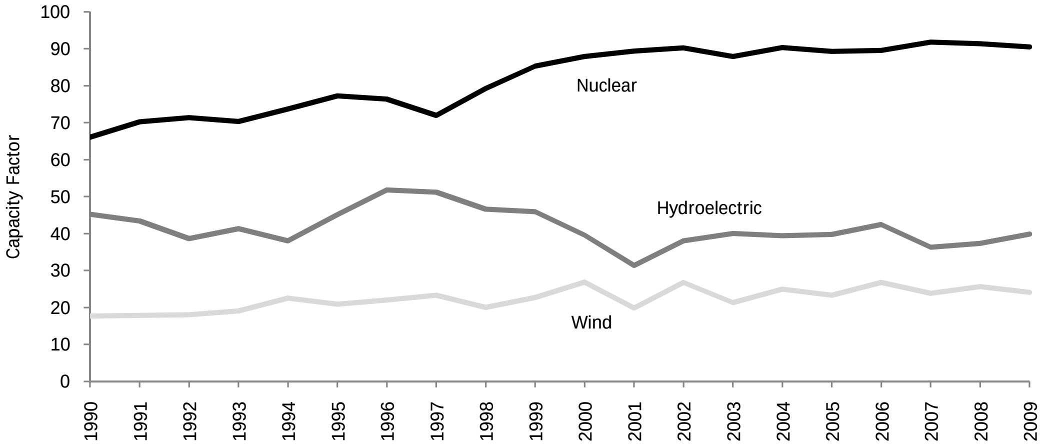


Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990-2009)

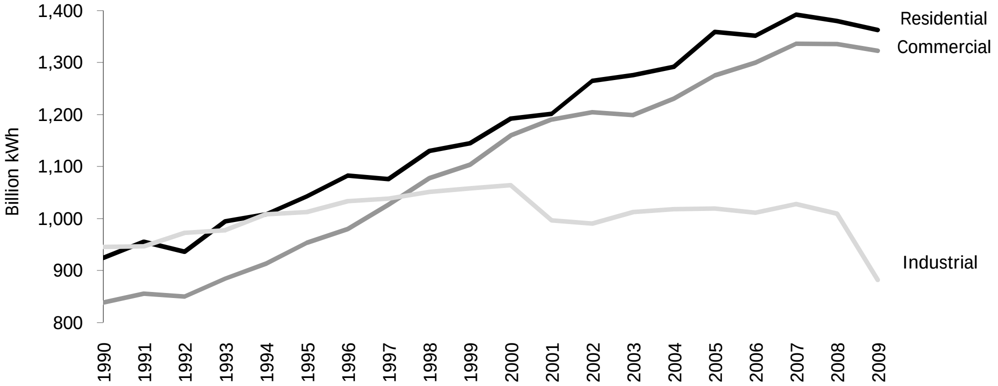


Figure 3-9: Electric Generation Retail Sales by End-Use Sector

Note: The transportation end-use sector consumes minor quanties of electricity.

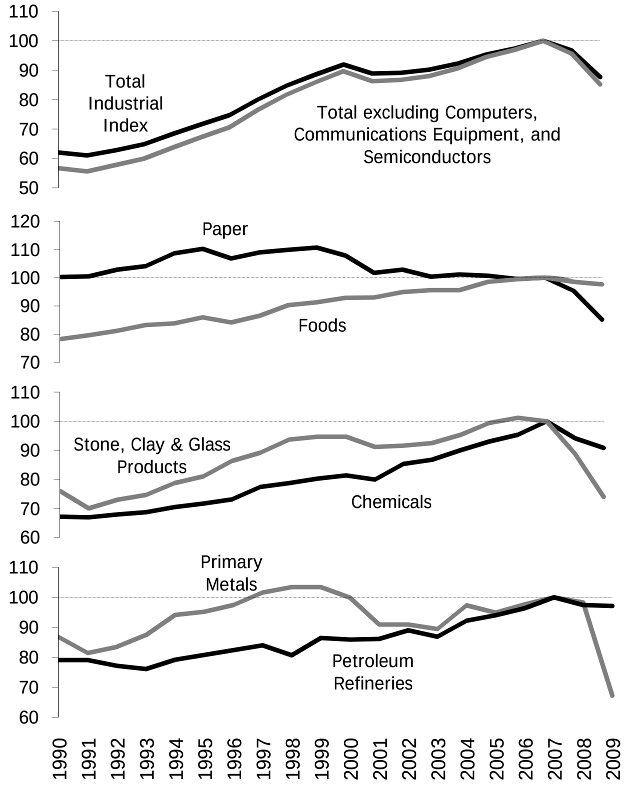


Figure 3-10: Industrial Production Indexes (Index 2007=100)

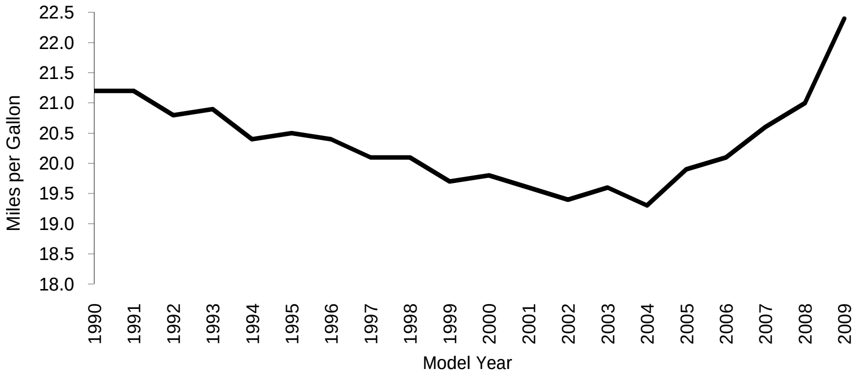


Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990-2009

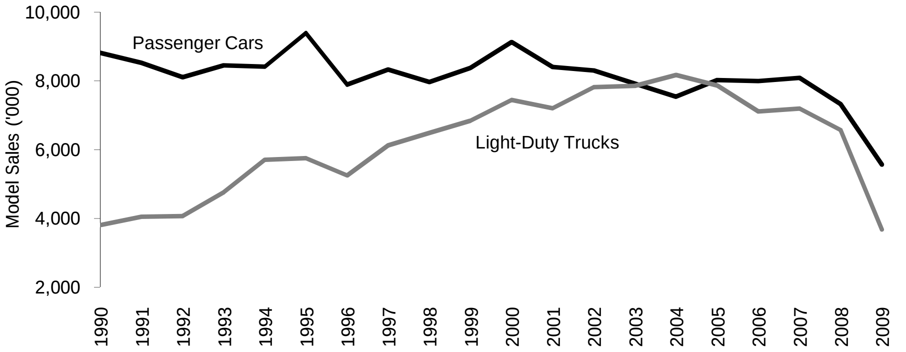


Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990-2009

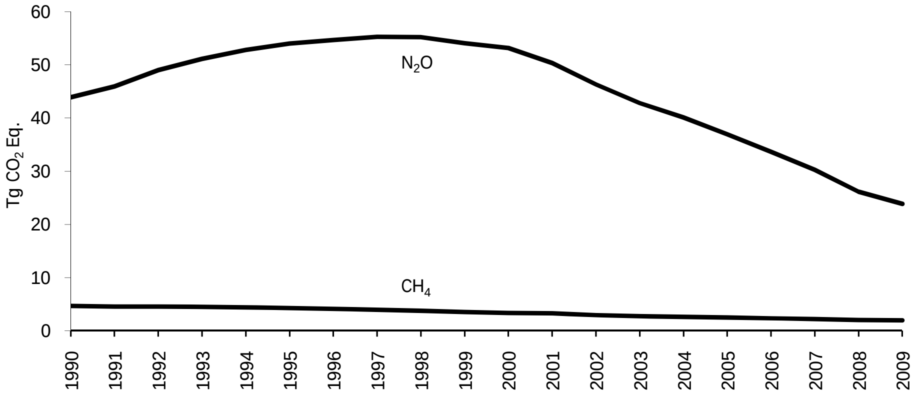


Figure 3-13: Mobile Source CH_4 and N_2O Emissions

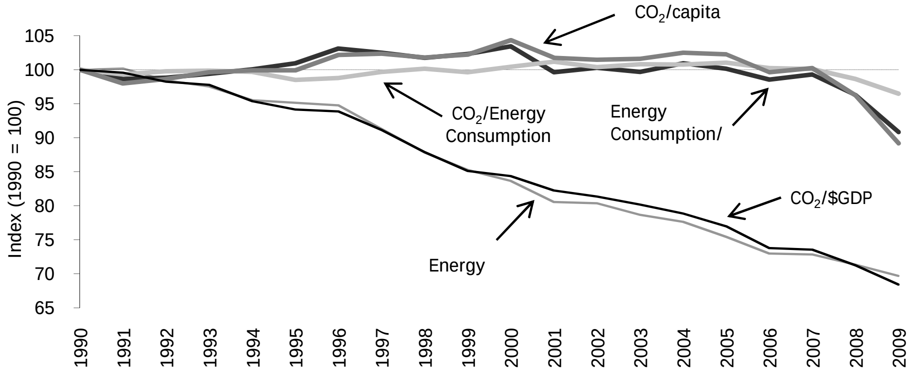


Figure 3-14: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP

4. Industrial Processes

Greenhouse gas emissions are produced as the by-products of various non-energy-related industrial activities. That is, these emissions are produced from an industrial process itself and are not directly a result of energy consumed during the process. For example, raw materials can be chemically transformed from one state to another. This transformation can result in the release of greenhouse gases such as carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The processes addressed in this chapter include iron and steel production and metallurgical coke production, cement production, lime production, ammonia production and urea consumption, limestone and dolomite consumption (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and use, aluminum production, titanium dioxide production, CO_2 consumption, ferroalloy production, phosphoric acid production, zinc production, lead production, petrochemical production, silicon carbide production and consumption, nitric acid production, and adipic acid production (see Figure 4-1).

Figure 4-1: 2009 Industrial Processes Chapter Greenhouse Gas Sources

In addition to the three greenhouse gases listed above, there are also industrial sources of man-made fluorinated compounds called hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). The present contribution of these gases to the radiative forcing effect of all anthropogenic greenhouse gases is small; however, because of their extremely long lifetimes, many of them will continue to accumulate in the atmosphere as long as emissions continue. In addition, many of these gases have high global warming potentials; SF_6 is the most potent greenhouse gas the Intergovernmental Panel on Climate Change (IPCC) has evaluated. Usage of HFCs is growing rapidly since they are the primary substitutes for ozone depleting substances (ODSs), which are being phased-out under the Montreal Protocol on Substances that Deplete the Ozone Layer. In addition to their use as ODS substitutes, HFCs, PFCs, and SF_6 are employed and emitted by a number of other industrial sources in the United States. These industries include aluminum production, HCFC-22 production, semiconductor manufacture, electric power transmission and distribution, and magnesium metal production and processing.

In 2009, industrial processes generated emissions of 282.9 teragrams of CO_2 equivalent (Tg CO_2 Eq.), or 4 percent of total U.S. greenhouse gas emissions. CO_2 emissions from all industrial processes were 119.0 Tg CO_2 Eq. (119,010 Gg) in 2009, or 2 percent of total U.S. CO_2 emissions. CH_4 emissions from industrial processes resulted in emissions of approximately 1.2 Tg CO_2 Eq. (58 Gg) in 2009, which was less than 1 percent of U.S. CH_4 emissions. N_2O emissions from adipic acid and nitric acid production were 16.5 Tg CO_2 Eq. (53 Gg) in 2009, or 6 percent of total U.S. N_2O emissions. In 2009 combined emissions of HFCs, PFCs and SF_6 totaled 146.1 Tg CO_2 Eq. Despite the significant increase in HFC emissions associated with increased usage of ODSs, total emissions from industrial processes in 2009 were less than 1990 for the first time since 1994. This decrease is primarily due to significant reductions in emissions from iron and steel production, metallurgical coke production, ammonia production and urea consumption, adipic acid production, HCFC-22 production, aluminum production and cement production.

Table 4-1 summarizes emissions for the Industrial Processes chapter in Tg CO_2 Eq., while unweighted native gas emissions in Gg are provided in Table 4-2. The source descriptions that follow in the chapter are presented in the order as reported to the UNFCCC in the common reporting format tables, corresponding generally to: mineral products, chemical production, metal production, and emissions from the uses of HFCs, PFCs, and SF_6.

Table 4-1: Emissions from Industrial Processes (Tg CO_2 Eq.)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**188.4**	**184.9**	**165.4**	**169.9**	**172.6**	**159.5**	**119.0**
Iron and Steel Production an Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Iron and Steel Productio	*97.1*	*83.7*	*63.9*	*66.9*	*69.0*	*63.7*	*40.9*
Metallurgical Coke Production	*2.5*	*2.2*	*2.0*	*1.9*	*2.1*	*2.3*	*1.0*
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Ammonia Production & Ure Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8

Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Limestone and Dolomite Us	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumptio	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Productio	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
CH_4	**1.9**	**2.2**	**1.8**	**1.7**	**1.7**	**1.6**	**1.2**
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production an Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Iron and Steel Productio	*1.0*	*0.9*	*0.7*	*0.7*	*0.7*	*0.6*	*0.4*
Metallurgical Coke Production	+	+	+	+	+	+	+
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
N_2O	**33.5**	**24.9**	**21.5**	**20.5**	**22.9**	**18.5**	**16.5**
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
HFCs	**36.9**	**103.2**	**120.2**	**123.5**	**129.5**	**129.4**	**125.7**
Substitution of Ozone Depleting Substances[a]	0.3	74.3	104.2	109.4	112.3	115.5	120.0
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacturi HFCs	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	**20.8**	**13.5**	**6.2**	**6.0**	**7.5**	**6.7**	**5.6**
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
Semiconductor Manufacturi PFCs	2.2	4.9	3.2	3.5	3.7	4.0	4.0
SF_6	**34.4**	**20.1**	**19.0**	**17.9**	**16.7**	**16.1**	**14.8**
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Semiconductor Manufacturi SF_6	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Total	**315.8**	**348.8**	**334.1**	**339.4**	**350.9**	**331.7**	**282.9**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

[a] Small amounts of PFC emissions also result from this source.

Table 4-2: Emissions from Industrial Processes (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**188,431**	**184,919**	**165,384**	**169,870**	**172,592**	**159,470**	**119,010**
Iron and Steel Production and Metallurgical Coke Production	99,528	85,935	65,925	68,772	71,045	66,015	41,871

Iron and Steel Production	*97,058*	*83,740*	*63,882*	*66,852*	*68,991*	*63,682*	*40,914*
Metallurgical Coke Production	*2,470*	*2,195*	*2,043*	*1,919*	*2,054*	*2,334*	*956*
Cement Production	33,278	40,405	45,197	45,792	44,538	40,531	29,018
Ammonia Production & Urea Consumption	16,831	16,402	12,849	12,300	14,038	11,949	11,797
Lime Production	11,533	14,088	14,379	15,100	14,595	14,330	11,223
Limestone and Dolomite Use	5,127	5,056	6,768	8,035	7,702	6,276	7,649
Soda Ash Production and Consumption	4,141	4,181	4,228	4,162	4,140	4,111	4,265
Aluminum Production	6,831	6,086	4,142	3,801	4,251	4,477	3,009
Petrochemical Production	3,311	4,479	4,181	3,837	3,931	3,449	2,735
Carbon Dioxide Consumption	1,416	1,421	1,321	1,709	1,867	1,780	1,763
Titanium Dioxide Production	1,195	1,752	1,755	1,836	1,930	1,809	1,541
Ferroalloy Production	2,152	1,893	1,392	1,505	1,552	1,599	1,469
Phosphoric Acid Production	1,529	1,382	1,386	1,167	1,166	1,187	1,035
Zinc Production	667	997	1,088	1,088	1,081	1,230	966
Lead Production	516	594	553	560	562	551	525
Silicon Carbide Production and Consumption	375	248	219	207	196	175	145
CH_4	**88**	**104**	**86**	**83**	**82**	**75**	**58**
Petrochemical Production	41	59	51	48	48	43	40
Iron and Steel Production and Metallurgical Coke Production	46	44	34	35	33	31	17
Iron and Steel Production	*46*	*44*	*34*	*35*	*33*	*31*	*17*
Metallurgical Coke Production	+	+	+	+	+	+	+
Ferroalloy Production	1	1	+	+	+	+	+
Silicon Carbide Production and Consumption	1	1	+	+	+	+	+
N_2O	**108**	**80**	**69**	**66**	**74**	**60**	**53**
Nitric Acid Production	57	63	53	52	62	53	47
Adipic Acid Production	51	18	16	14	12	7	6
HFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Substitution of Ozone Depleting Substances[a]	M	M	M	M	M	M	M
HCFC-22 Production	3	2	1	1	1	1	+
Semiconductor Manufacturing HFCs	+	+	+	+	+	+	+
PFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Aluminum Production	M	M	M	M	M	M	M
Semiconductor Manufacturing PFCs	M	M	M	M	M	M	M
SF_6	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Electrical Transmission and Distribution	1	1	1	1	1	1	1
Semiconductor	+	+	+	+	+	+	+

Manufacturing SF_6							
Magnesium Production and Processing	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg
M (Mixture of gases)
Note: Totals may not sum due to independent rounding.
[a] Small amounts of PFC emissions also result from this source.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Procedures

Tier 1 quality assurance and quality control procedures have been performed for all industrial process sources. For industrial process sources of CO_2 and CH_4 emissions, a detailed plan was developed and implemented. This plan was based on the overall U.S. strategy, but was tailored to include specific procedures recommended for these sources. Two types of checks were performed using this plan: (1) general, or Tier 1, procedures that focus on annual procedures and checks to be used when gathering, maintaining, handling, documenting, checking, and archiving the data, supporting documents, and files, and (2) source-category specific, or Tier 2, procedures that focus on procedures and checks of the emission factors, activity data, and methodologies used for estimating emissions from the relevant industrial process sources. Examples of these procedures include checks to ensure that activity data and emission estimates are consistent with historical trends; that, where possible, consistent and reputable data sources are used across sources; that interpolation or extrapolation techniques are consistent across sources; and that common datasets and factors are used where applicable.

The general method employed to estimate emissions for industrial processes, as recommended by the IPCC, involves multiplying production data (or activity data) for each process by an emission factor per unit of production. The uncertainty in the emission estimates is therefore generally a function of a combination of the uncertainties surrounding the production and emission factor variables. Uncertainty of activity data and the associated probability density functions for industrial processes CO_2 sources were estimated based on expert assessment of available qualitative and quantitative information. Uncertainty estimates and probability density functions for the emission factors used to calculate emissions from this source were devised based on IPCC recommendations.

Activity data is obtained through a survey of manufacturers conducted by various organizations (specified within each source); the uncertainty of the activity data is a function of the reliability of plant-level production data and is influenced by the completeness of the survey response. The emission factors used were either derived using calculations that assume precise and efficient chemical reactions, or were based upon empirical data in published references. As a result, uncertainties in the emission coefficients can be attributed to, among other things, inefficiencies in the chemical reactions associated with each production process or to the use of empirically-derived emission factors that are biased; therefore, they may not represent U.S. national averages. Additional assumptions are described within each source.

The uncertainty analysis performed to quantify uncertainties associated with the 2009 inventory estimates from industrial processes continues a multi-year process for developing credible quantitative uncertainty estimates for these source categories using the IPCC Tier 2 approach. As the process continues, the type and the characteristics of the actual probability density functions underlying the input variables are identified and better characterized (resulting in development of more reliable inputs for the model, including accurate characterization of correlation between variables), based primarily on expert judgment. Accordingly, the quantitative uncertainty estimates reported in this section should be considered illustrative and as iterations of ongoing efforts to produce accurate uncertainty estimates. The correlation among data used for estimating emissions for different sources can influence the uncertainty analysis of each individual source. While the uncertainty analysis recognizes very significant connections among sources, a more comprehensive approach that accounts for all linkages will be identified as the uncertainty analysis moves forward.

4.1. Cement Production (IPCC Source Category 2A1)

Cement production is an energy- and raw-material-intensive process that results in the generation of CO_2 from both the energy consumed in making the cement and the chemical process itself.[102] Cement is produced in 36 states and Puerto Rico. CO_2 emitted from the chemical process of cement production is the second largest source of industrial CO_2 emissions in the United States.

During the cement production process, calcium carbonate ($CaCO_3$) is heated in a cement kiln at a temperature of about 1,450°C (2,400°F) to form lime (i.e., calcium oxide or CaO) and CO_2 in a process known as calcination or calcining. A very small amount of carbonates other than $CaCO_3$ and non-carbonates are also present in the raw material; however, for calculation purposes all of the raw material is assumed to be $CaCO_3$. Next, the lime is combined with silica-containing materials to produce clinker (an intermediate product), with the earlier by-product CO_2 being released to the atmosphere. The clinker is then allowed to cool, mixed with a small amount of gypsum and potentially other materials (e.g., slag), and used to make portland cement.[103]

In 2009, U.S. clinker production—including Puerto Rico—totaled 56,116 thousand metric tons (USGS 2011). The resulting CO_2 emissions were estimated to be 29.0 Tg CO_2 Eq. (29,018 Gg) (see Table 4-3).

Table 4-3: CO_2 Emissions from Cement Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	33.3	33,278
2000	40.4	40,405
2005	45.2	45,197
2006	45.8	45,792
2007	44.5	44,538
2008	40.5	40,531
2009	29.0	29,018

Greenhouse gas emissions from cement production grew every year from 1991 through 2006, but have decreased since. Emissions since 1990 have decreased by 13 percent. Emissions decreased significantly between 2008 and 2009, due to the economic recession and associated decrease in demand for construction materials. Cement continues to be a critical component of the construction industry; therefore, the availability of public construction funding, as well as overall economic conditions, have considerable influence on cement production.

Methodology

CO_2 emissions from cement production are created by the chemical reaction of carbon-containing minerals (i.e., calcining limestone) in the cement kiln. While in the kiln, limestone is broken down into CO_2 and lime with the CO_2 released to the atmosphere. The quantity of CO_2 emitted during cement production is directly proportional to the lime content of the clinker. During calcination, each mole of $CaCO_3$ (i.e., limestone) heated in the clinker kiln forms one mole of lime (CaO) and one mole of CO_2:

$$CaCO_3 + \text{heat} \rightarrow CaO + CO_2$$

CO_2 emissions were estimated by applying an emission factor, in tons of CO_2 released per ton of clinker produced, to the total amount of clinker produced. The emission factor used in this analysis is the product of the average lime fraction for clinker of 65 percent and a constant reflecting the mass of CO_2 released per unit of lime (van Oss 2008). This calculation yields an emission factor of 0.51 tons of CO_2 per ton of clinker produced, which was determined as follows:

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[102] The CO_2 emissions related to the consumption of energy for cement manufacture are accounted for under CO_2 from Fossil Fuel Combustion in the Energy chapter.

[103] Approximately three percent of total clinker production is used to produce masonry cement, which is produced using plasticizers (e.g., ground limestone, lime) and portland cement (USGS 2011). CO_2 emissions that result from the production of lime used to create masonry cement are included in the Lime Manufacture source category.

$$EF_{\text{Clinker}} = 0.6460\ \text{CaO} \times \left[\frac{44.01\ \text{g/mole}\,\text{CO}_2}{56.08\ \text{g/mole}\,\text{CaO}} \right] = 0.5070\ \text{tons}\ \text{CO}_2/\text{ton clinker}$$

During clinker production, some of the clinker precursor materials remain in the kiln as non-calcinated, partially calcinated, or fully calcinated cement kiln dust (CKD). The emissions attributable to the calcinated portion of the CKD are not accounted for by the clinker emission factor. The IPCC recommends that these additional CKD CO_2 emissions should be estimated as two percent of the CO_2 emissions calculated from clinker production.[104] Total cement production emissions were calculated by adding the emissions from clinker production to the emissions assigned to CKD (IPCC 2006).[105]

The 1990 through 2009 activity data for clinker production (see Table 4-4) were obtained from USGS (US Bureau of Mines 1990 through 1993, USGS 1995 through 2011). The data were compiled by USGS through questionnaires sent to domestic clinker and cement manufacturing plants.

Table 4-4: Clinker Production (Gg)

Year	Clinker
1990	64,355
2000	78,138
2005	87,405
2006	88,555
2007	86,130
2008	78,382
2009	56,116

Uncertainty and Time-Series Consistency

The uncertainties contained in these estimates are primarily due to uncertainties in the lime content of clinker and in the percentage of CKD recycled inside the cement kiln. Uncertainty is also associated with the assumption that all calcium-containing raw materials are $CaCO_3$, when a small percentage likely consists of other carbonate and non-carbonate raw materials. The lime content of clinker varies from 60 to 67 percent; 65 percent is used as a representative value (van Oss 2008). CKD loss can range from 1.5 to 8 percent depending upon plant specifications. Additionally, some amount of CO_2 is reabsorbed when the cement is used for construction. As cement reacts with water, alkaline substances such as calcium hydroxide are formed. During this curing process, these compounds may react with CO_2 in the atmosphere to create calcium carbonate. This reaction only occurs in roughly the outer 0.2 inches of surface area. Because the amount of CO_2 reabsorbed is thought to be minimal, it was not estimated.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-5. 2009 CO_2 emissions from cement production were estimated to be between 25.3 and 33.0 Tg CO_2 Eq. at the 95 percent confidence level. This confidence level indicates a range of approximately 13 percent below and 14 percent above the emission estimate of 29.0 Tg CO_2 Eq.

Table 4-5: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Cement Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower	**Upper**	**Lower**	**Upper**

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[104] Default IPCC clinker and CKD emission factors were verified through expert consultation with the Portland Cement Association (PCA 2008) and van Oss (2008).

[105] The two percent CO_2 addition associated with CKD is included in the emission estimate for completeness. The cement emission estimate also includes an assumption that all raw material is limestone ($CaCO_3$) when in fact a small percentage is likely composed of non-carbonate materials. Together these assumptions may result in a small emission overestimate (van Oss 2008).

			Bound	Bound	Bound	Bound
Cement Production	CO_2	29.0	25.3	33.0	-13%	+14%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Recalculations Discussion

Activity data for the time series was revised for the current Inventory. Specifically, clinker production data for 1995 through 2008 (excluding 2001) were revised to reflect published USGS data. In a given Inventory year, advance clinker data is typically used. This data is typically finalized several years later by USGS. The published time series was reviewed to ensure time series consistency. Published data generally differed from advance data by approximately 1,000 metric tons, or 1 percent of the total. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the cement source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from cement production. Beginning in 2010, all U.S. cement production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. cement industry, including also improving emission factors for clinker production and CKD.

4.2. Lime Production (IPCC Source Category 2A2)

Lime is an important manufactured product with many industrial, chemical, and environmental applications. Its major uses are in steel making, flue gas desulfurization systems at coal-fired electric power plants, construction, and water purification. For U.S. operations, the term “lime” actually refers to a variety of chemical compounds. These include calcium oxide (CaO), or high-calcium quicklime; calcium hydroxide ($Ca(OH)_2$), or hydrated lime; dolomitic quicklime ([CaO•MgO]); and dolomitic hydrate ([$Ca(OH)_2$•MgO] or [$Ca(OH)_2$•$Mg(OH)_2$]).

Lime production involves three main processes: stone preparation, calcination, and hydration. CO_2 is generated during the calcination stage, when limestone—mostly calcium carbonate ($CaCO_3$)—is roasted at high temperatures in a kiln to produce CaO and CO_2. The CO_2 is given off as a gas and is normally emitted to the atmosphere. Some of the CO_2 generated during the production process, however, is recovered at some facilities for use in sugar refining and precipitated calcium carbonate (PCC) production.[106] In certain additional applications, lime reabsorbs CO_2 during use.

Lime production in the United States—including Puerto Rico—was reported to be 15,781 thousand metric tons in 2009 (USGS 2010). This production resulted in estimated CO_2 emissions of 11.2 Tg CO_2 Eq. (11,223 Gg) (see Table 4-6 and Table 4-7).

Table 4-6: CO_2 Emissions from Lime Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	11.5	11,533
2000	14.1	14,088
2005	14.4	14,379
2006	15.1	15,100
2007	14.6	14,595
2008	14.3	14,330
2009	11.2	11,223

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[106] PCC is obtained from the reaction of CO_2 with calcium hydroxide. It is used as a filler and/or coating in the paper, food, and plastic industries.

Table 4-7: Potential, Recovered, and Net CO_2 Emissions from Lime Production (Gg)

Year	Potential	Recovered*	Net Emissions
1990	12,004	471	11,533
2000	14,872	784	14,088
2005	15,131	752	14,379
2006	15,825	725	15,100
2007	15,264	669	14,595
2008	14,977	647	14,330
2009	11,913	690	11,223

* For sugar refining and PCC production.
Note: Totals may not sum due to rounding

Lime production in 2009 decreased by 21 percent compared to 2008, owing mostly to a significant downturn in major markets such as construction and steel. Because of this significant downturn, overall lime production in 2009 was approximately equal to production in 1990. The contemporary lime market is approximately distributed across five end-use categories as follows: environmental uses, 34 percent; metallurgical uses, 31 percent; chemical and industrial uses, 25 percent; construction uses, 9 percent; and refractory dolomite, 1 percent. In the construction sector, lime is used to improve durability in plaster, stucco, and mortars, as well as to stabilize soils. Consumption for metallurgical uses accounted for 57 percent of the overall decrease in lime consumption (USGS 2010).

Methodology

During the calcination stage of lime production, CO_2 is given off as a gas and normally exits the system with the stack gas. To calculate emissions, the amounts of high-calcium and dolomitic lime produced were multiplied by their respective emission factors. The emission factor is the product of a constant reflecting the mass of CO_2 released per unit of lime and the average calcium plus magnesium oxide (CaO + MgO) content for lime (95 percent for both types of lime) (IPCC 2006). The emission factors were calculated as follows:

For high-calcium lime:

$$[(44.01 \text{ g/mole } CO_2) \div (56.08 \text{ g/mole CaO})] \times (0.9500 \text{ CaO/lime}) = 0.7455 \text{ g } CO_2\text{/g lime}$$

For dolomitic lime:

$$[(88.02 \text{ g/mole } CO_2) \div (96.39 \text{ g/mole CaO})] \times (0.9500 \text{ CaO/lime}) = 0.8675 \text{ g } CO_2\text{/g lime}$$

Production was adjusted to remove the mass of chemically combined water found in hydrated lime, determined according to the molecular weight ratios of H_2O to (Ca(OH)2 and [$Ca(OH)_2$•$Mg(OH)_2$]) (IPCC 2000). These factors set the chemically combined water content to 24.3 percent for high-calcium hydrated lime, and 27.2 percent for dolomitic hydrated lime.

Lime emission estimates were multiplied by a factor of 1.02 to account for lime kiln dust (LKD), which is produced as a by-product during the production of lime (IPCC 2006).

Lime emission estimates were further adjusted to account for PCC producers and sugar refineries that recover CO_2 emitted by lime production facilities for use as an input into production or refining processes. For CO_2 recovery by sugar refineries, lime consumption estimates from USGS were multiplied by a CO_2 recovery factor to determine the total amount of CO_2 recovered from lime production facilities. According to industry surveys, sugar refineries use captured CO_2 for 100 percent of their CO_2 input (Lutter 2009). CO_2 recovery by PCC producers was determined by multiplying estimates for the percentage CO_2 of production weight for PCC production at lime plants by a CO_2 recovery factor based on the amount of purchased CO_2 by PCC manufacturers (Prillaman 2008 through 2010). As data were only available starting in 2007, CO_2 recovery for the period 1990 through 2006 was extrapolated by determining a ratio of PCC production at lime facilities to lime consumption for PCC (USGS 1992 through 2008).

Lime production data (high-calcium- and dolomitic-quicklime, high-calcium- and dolomitic-hydrated, and dead-burned dolomite) for 1990 through 2009 (see Table 4-8) were obtained from USGS (1992 through 2010). Natural hydraulic lime, which is produced from CaO and hydraulic calcium silicates, is not produced in the United States (USGS 2009). Total lime production was adjusted to account for the water content of hydrated lime by converting hydrate to oxide equivalent based on recommendations from the IPCC, and is presented in Table 4-9 (IPCC 2000). The CaO and CaO•MgO contents of lime were obtained from the IPCC (IPCC 2006). Since data for the individual lime types (high calcium and dolomitic) was not provided prior to 1997, total lime production for 1990 through 1996 was calculated according to the three year distribution from 1997 to 1999.

Table 4-8: High-Calcium- and Dolomitic-Quicklime, High-Calcium- and Dolomitic-Hydrated, and Dead-Burned-Dolomite Lime Production (Gg)

Year	High-Calcium Quicklime	Dolomitic Quicklime	High-Calcium Hydrated	Dolomitic Hydrated	Dead-Burned Dolomite
1990	11,166	2,234	1,781	319	342
2000	14,300	3,000	1,550	421	200
2005	14,100	2,990	2,220	474	200
2006	15,000	2,950	2,370	409	200
2007	14,700	2,700	2,240	352	200
2008	14,900	2,310	2,070	358	200
2009	11,800	1,830	1,690	261	200

Table 4-9: Adjusted Lime Production[a] (Gg)

Year	High-Calcium	Dolomitic
1990	12,514	2,809
2000	15,473	3,506
2005	15,781	3,535
2006	16,794	3,448
2007	16,396	3,156
2008	16,467	2,771
2009	13,079	2,220

[a] Minus water content of hydrated lime

Uncertainty and Time-Series Consistency

The uncertainties contained in these estimates can be attributed to slight differences in the chemical composition of these products and recovery rates for sugar refineries and PCC manufacturers located at lime plants. Although the methodology accounts for various formulations of lime, it does not account for the trace impurities found in lime, such as iron oxide, alumina, and silica. Due to differences in the limestone used as a raw material, a rigid specification of lime material is impossible. As a result, few plants produce lime with exactly the same properties.

In addition, a portion of the CO_2 emitted during lime production will actually be reabsorbed when the lime is consumed. As noted above, lime has many different chemical, industrial, environmental, and construction applications. In many processes, CO_2 reacts with the lime to create calcium carbonate (e.g., water softening). CO_2 reabsorption rates vary, however, depending on the application. For example, 100 percent of the lime used to produce precipitated calcium carbonate reacts with CO_2; whereas most of the lime used in steel making reacts with impurities such as silica, sulfur, and aluminum compounds. A detailed accounting of lime use in the United States and further research into the associated processes are required to quantify the amount of CO_2 that is reabsorbed.[107]

In some cases, lime is generated from calcium carbonate by-products at pulp mills and water treatment plants.[108]

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[107] Representatives of the National Lime Association estimate that CO_2 reabsorption that occurs from the use of lime may offset as much as a quarter of the CO_2 emissions from calcination (Males 2003).

[108] Some carbide producers may also regenerate lime from their calcium hydroxide by-products, which does not result in

The lime generated by these processes is not included in the USGS data for commercial lime consumption. In the pulping industry, mostly using the Kraft (sulfate) pulping process, lime is consumed in order to causticize a process liquor (green liquor) composed of sodium carbonate and sodium sulfide. The green liquor results from the dilution of the smelt created by combustion of the black liquor where biogenic C is present from the wood. Kraft mills recover the calcium carbonate "mud" after the causticizing operation and calcine it back into lime—thereby generating CO_2—for reuse in the pulping process. Although this re-generation of lime could be considered a lime manufacturing process, the CO_2 emitted during this process is mostly biogenic in origin, and therefore is not included in the industrial processes totals (Miner and Upton 2002). In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net carbon (C) fluxes from changes in biogenic C reservoirs in wooded or crop lands (see Chapter 7).

In the case of water treatment plants, lime is used in the softening process. Some large water treatment plants may recover their waste calcium carbonate and calcine it into quicklime for reuse in the softening process. Further research is necessary to determine the degree to which lime recycling is practiced by water treatment plants in the United States.

Uncertainties also remain surrounding recovery rates used for sugar refining and PCC production. The recovery rate for sugar refineries is based on two sugar beet processing and refining facilities located in California that use 100 percent recovered CO_2 from lime plants (Lutter 2010). This analysis assumes that all sugar refineries located on-site at lime plants also use 100 percent recovered CO_2. The recovery rate for PCC producers located on-site at lime plants is based on the 2009 value for PCC manufactured at commercial lime plants, given by the National Lime Association (Prillaman 2010).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-10. Lime CO_2 emissions were estimated to be between 10.4 and 12.3 Tg CO_2 Eq. at the 95 percent confidence level. This confidence level indicates a range of approximately 7 percent below and 10 percent above the emission estimate of 11.2 Tg CO_2 Eq.

Table 4-10: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Lime Production (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Lime Production	CO_2	11.2	10.4	12.3	-7%	+10%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

No methodological or activity data changes to the time series were made to this source for the current Inventory. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the lime source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from lime production. Beginning in 2010, all U.S. lime production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. lime industry, including improving emission factors for various lime types and LKD.

Future improvements to the lime source category will also involve continued research into CO_2 recovery associated with lime use during sugar refining and precipitate calcium carbonate (PCC) production. Currently, two sugar refining facilities in California have been identified to capture CO_2 produced in lime kilns located on the same site as the sugar refinery (Lutter 2010). Data on CO_2 production by these lime facilities is unavailable. Future work will

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emissions of CO_2. In making calcium carbide, quicklime is mixed with coke and heated in electric furnaces. The regeneration of lime in this process is done using a waste calcium hydroxide (hydrated lime) [$CaC_2 + 2H_2O \rightarrow C_2H_2 + Ca(OH)_2$], not calcium carbonate [$CaCO_3$]. Thus, the calcium hydroxide is heated in the kiln to simply expel the water [$Ca(OH)_2$ + heat $\rightarrow CaO + H_2O$] and no CO_2 is released.

include research to determine the number of sugar refineries that employ the carbonation technique, the percentage of these that use captured CO_2 from lime production facilities, and the amount of CO_2 recovered per unit of lime production. Future research will also aim to improve estimates of CO_2 recovered as part of the PCC production process using estimates of PCC production and CO_2 inputs rather than lime consumption by PCC facilities.

4.3. Limestone and Dolomite Use (IPCC Source Category 2A3)

Limestone ($CaCO_3$) and dolomite ($CaCO_3MgCO_3$)[109] are basic raw materials used by a wide variety of industries, including construction, agriculture, chemical, metallurgy, glass production, and environmental pollution control. Limestone is widely distributed throughout the world in deposits of varying sizes and degrees of purity. Large deposits of limestone occur in nearly every state in the United States, and significant quantities are extracted for industrial applications. For some of these applications, limestone is heated sufficiently enough to calcine the material and generate CO_2 as a by-product. Examples of such applications include limestone used as a flux or purifier in metallurgical furnaces, as a sorbent in flue gas desulfurization (FGD) systems for utility and industrial plants, or as a raw material in glass manufacturing and magnesium production.

In 2009, approximately 14,928 thousand metric tons of limestone and 3,020 thousand metric tons of dolomite were consumed for these emissive applications. Overall, usage of limestone and dolomite resulted in aggregate CO_2 emissions of 7.6 Tg CO_2 Eq. (7,649 Gg) (see Table 4-11and Table 4-12). Overall, emissions have increased 49 percent from 1990 through 2009.

Table 4-11: CO_2 Emissions from Limestone & Dolomite Use (Tg CO_2 Eq.)

Year	Flux Stone	Glass Making	FGD	Magnesium Production	Other Miscellaneous Uses	Total
1990	2.6	0.2	1.4	0.1	0.8	5.1
2000	2.1	0.4	1.8	0.1	0.7	5.1
2005	2.7	0.4	3.0	0.0	0.7	6.8
2006	4.5	0.7	2.1	0.0	0.7	8.0
2007	2.0	0.3	3.2	0.0	2.2	7.7
2008	1.0	0.4	3.8	0.0	1.1	6.3
2009	1.8	0.1	5.4	0.0	0.4	7.6

Notes: Totals may not sum due to independent rounding. “Other miscellaneous uses” include chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining.

Table 4-12: CO_2 Emissions from Limestone & Dolomite Use (Gg)

Year	Flux Stone	Glass Making	FGD	Magnesium Production	Other Miscellaneous Uses	Total
1990	2,593	217	1,433	64	819	5,127
2000	2,104	371	1,787	73	722	5,056
2005	2,650	425	2,975	0	718	6,768
2006	4,492	747	2,061	0	735	8,035
2007	1,959	333	3,179	0	2,231	7,702
2008	974	387	3,801	0	1,114	6,276
2009	1,785	61	5,406	0	396	7,649

Methodology

CO_2 emissions were calculated by multiplying the quantity of limestone or dolomite consumed by the average C

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[109] Limestone and dolomite are collectively referred to as limestone by the industry, and intermediate varieties are seldom distinguished.

content, 12.0 percent for limestone and 13.0 percent for dolomite (based on stoichiometry), and converting this value to CO_2. This methodology was used for flux stone, glass manufacturing, flue gas desulfurization systems, chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining and then converting to CO_2 using a molecular weight ratio. Flux stone used during the production of iron and steel was deducted from the Limestone and Dolomite Use estimate and attributed to the Iron and Steel Production estimate.

Traditionally, the production of magnesium metal was the only other significant use of limestone and dolomite that produced CO_2 emissions. At the start of 2001, there were two magnesium production plants operating in the United States and they used different production methods. One plant produced magnesium metal using a dolomitic process that resulted in the release of CO_2 emissions, while the other plant produced magnesium from magnesium chloride using a CO_2-emissions-free process called electrolytic reduction. However, the plant utilizing the dolomitic process ceased its operations prior to the end of 2001, so beginning in 2002 there were no emissions from this particular sub-use.

Consumption data for 1990 through 2008 of limestone and dolomite used for flux stone, glass manufacturing, flue gas desulfurization systems, chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining (see Table 4-13) were obtained from the USGS *Minerals Yearbook: Crushed Stone Annual Report* (1995 through 2010a) and the U.S. Bureau of Mines (1991 & 1993a). Consumption data for 2009 were obtained from personal communication with the USGS crushed stone commodity specialist (Willett 2010). The production capacity data for 1990 through 2009of dolomitic magnesium metal also came from the USGS (1995 through 2010b) and the U.S. Bureau of Mines (1990 through 1993b). The last plant in the United States that used the dolomitic production process for magnesium metal closed in 2001. The USGS does not mention this process in the *Minerals Yearbook: Magnesium*; therefore, it is assumed that this process continues to be non-existent in the United States (USGS 2010b). During 1990 and 1992, the USGS did not conduct a detailed survey of limestone and dolomite consumption by end-use. Consumption for 1990 was estimated by applying the 1991 percentages of total limestone and dolomite use constituted by the individual limestone and dolomite uses to 1990 total use. Similarly, the 1992 consumption figures were approximated by applying an average of the 1991 and 1993 percentages of total limestone and dolomite use constituted by the individual limestone and dolomite uses to the 1992 total.

Additionally, each year the USGS withholds data on certain limestone and dolomite end-uses due to confidentiality agreements regarding company proprietary data. For the purposes of this analysis, emissive end-uses that contained withheld data were estimated using one of the following techniques: (1) the value for all the withheld data points for limestone or dolomite use was distributed evenly to all withheld end-uses; (2) the average percent of total limestone or dolomite for the withheld end-use in the preceding and succeeding years; or (3) the average fraction of total limestone or dolomite for the end-use over the entire time period.

There is a large quantity of crushed stone reported to the USGS under the category “unspecified uses.” A portion of this consumption is believed to be limestone or dolomite used for emissive end uses. The quantity listed for “unspecified uses” was, therefore, allocated to each reported end use according to each end uses fraction of total consumption in that year.[110]

Table 4-13: Limestone and Dolomite Consumption (Thousand Metric Tons)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Flux Stone	6,737	6,283	7,022	11,030	5,305	3,253	4,623
Limestone	5,804	4,151	3,165	5,208	3,477	1,970	1,631
Dolomite	933	2,132	3,857	5,822	1,827	1,283	2,992
Glass Making	489	843	962	1,693	757	879	139
Limestone	430	843	920	1,629	757	879	139
Dolomite	59	0	43	64	0	0	0
FGD	3,258	4,061	6,761	4,683	7,225	8,639	12,288
Other Miscellaneous Uses	1,835	1,640	1,632	1,671	5,057	2,531	898
Total	**12,319**	**12,826**	**16,377**	**19,078**	**18,344**	**15,302**	**17,948**

Notes: "Other miscellaneous uses" includes chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining. Zero values for limestone and dolomite consumption for glass making result during years when the USGS reports that no limestone or dolomite are consumed for this use.

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[110] This approach was recommended by USGS.

Uncertainty and Time Series Consistency

The uncertainty levels presented in this section arise in part due to variations in the chemical composition of limestone. In addition to calcium carbonate, limestone may contain smaller amounts of magnesia, silica, and sulfur, among other minerals. The exact specifications for limestone or dolomite used as flux stone vary with the pyrometallurgical process and the kind of ore processed. Similarly, the quality of the limestone used for glass manufacturing will depend on the type of glass being manufactured.

The estimates below also account for uncertainty associated with activity data. Large fluctuations in reported consumption exist, reflecting year-to-year changes in the number of survey responders. The uncertainty resulting from a shifting survey population is exacerbated by the gaps in the time series of reports. The accuracy of distribution by end use is also uncertain because this value is reported by the manufacturer and not the end user. Additionally, there is significant inherent uncertainty associated with estimating withheld data points for specific end uses of limestone and dolomite. The uncertainty of the estimates for limestone used in glass making is especially high; however, since glass making accounts for a small percent of consumption, its contribution to the overall emissions estimate is low. Lastly, much of the limestone consumed in the United States is reported as “other unspecified uses;” therefore, it is difficult to accurately allocate this unspecified quantity to the correct end-uses.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-14. Limestone and Dolomite Use CO_2 emissions were estimated to be between 6.6 and 9.1 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 13 percent below and 19 percent above the emission estimate of 7.6 Tg CO_2 Eq.

Table 4-14: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Limestone and Dolomite Use (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a]**			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Limestone and Dolomite Use	CO_2	7.6	6.6	9.1	-13%	+19%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the limestone and dolomite source category involve research into the availability of limestone and dolomite end-use data, including from EPA’s new Greenhouse Gas Reporting Program. If sufficient data are available, limestone and dolomite used as process materials in source categories included in future inventories (e.g., glass production, other process use of carbonates) may be removed from this section and will be reported under the appropriate source categories. Additionally, future improvements include revisiting the methodology to distribute withheld data across emissive end-uses for all years to improve consistency of calculations.

4.4. Soda Ash Production and Consumption (IPCC Source Category 2A4)

Soda ash (sodium carbonate, Na_2CO_3) is a white crystalline solid that is readily soluble in water and strongly alkaline. Commercial soda ash is used as a raw material in a variety of industrial processes and in many familiar consumer products such as glass, soap and detergents, paper, textiles, and food. It is used primarily as an alkali, either in glass manufacturing or simply as a material that reacts with and neutralizes acids or acidic substances. Internationally, two types of soda ash are produced, natural and synthetic. The United States produces only natural soda ash and is second only to China in total soda ash production. Trona is the principal ore from which natural soda ash is made.

Only two states produce natural soda ash: Wyoming and California. Of these two states, only net emissions of CO_2

from Wyoming were calculated due to specifics regarding the production processes employed in the state.[111] During the production process used in Wyoming, trona ore is calcined to produce crude soda ash. CO_2 is generated as a by-product of this reaction, and is eventually emitted into the atmosphere. In addition, CO_2 may also be released when soda ash is consumed.

In 2009, CO_2 emissions from the production of soda ash from trona were approximately 1.7 Tg CO_2 Eq. (1,733 Gg). Soda ash consumption in the United States generated 2.5 Tg CO_2 Eq. (2,532 Gg) in 2009. Total emissions from soda ash production and consumption in 2009 were 4.3 Tg CO_2 Eq. (4,265 Gg) (see Table 4-15 and Table 4-16). Emissions have remained relatively constant with some fluctuations since 1990. These fluctuations were strongly related to the behavior of the export market and the U.S. economy. Emissions from the production of soda ash from trona in 2009 are currently proxied to emissions in 2008, due to lack of available data at time of publication. Emissions in 2009 increased by approximately 4 percent from emissions in 2008, and have also increased overall by 3 percent since 1990.

Table 4-15: CO_2 Emissions from Soda Ash Production and Consumption (Tg CO_2 Eq.)

Year	Production	Consumption	Total
1990	1.4	2.7	4.1
2000	1.5	2.7	4.2
2005	1.7	2.6	4.2
2006	1.6	2.5	4.2
2007	1.7	2.5	4.1
2008	1.7	2.4	4.1
2009	1.7	2.5	4.3

Note: Totals may not sum due to independent rounding.

Table 4-16: CO_2 Emissions from Soda Ash Production and Consumption (Gg)

Year	Production	Consumption	Total
1990	1,431	2,710	4,141
2000	1,529	2,652	4,181
2005	1,655	2,573	4,228
2006	1,626	2,536	4,162
2007	1,675	2,465	4,140
2008	1,733	2,378	4,111
2009	1,733	2,532	4,265

Note: Totals may not sum due to independent rounding.

The United States represents about one-fourth of total world soda ash output. Based on final 2007 reported data, the estimated distribution of soda ash by end-use in 2008 was glass making, 49 percent; chemical production, 30 percent; soap and detergent manufacturing, 8 percent; distributors, 5 percent; flue gas desulfurization, 2 percent; water treatment, 2 percent; pulp and paper production, 2 percent; and miscellaneous, 3 percent (USGS 2009). The same distribution by end-use is currently assumed for 2009, due to lack of available data at time of publication.

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[111] In California, soda ash is manufactured using sodium carbonate-bearing brines instead of trona ore. To extract the sodium carbonate, the complex brines are first treated with CO_2 in carbonation towers to convert the sodium carbonate into sodium bicarbonate, which then precipitates from the brine solution. The precipitated sodium bicarbonate is then calcined back into sodium carbonate. Although CO_2 is generated as a by-product, the CO_2 is recovered and recycled for use in the carbonation stage and is not emitted. A third state, Colorado, produced soda ash until the plant was idled in 2004. The lone producer of sodium bicarbonate no longer mines trona in the state. For a brief time, $NaHCO_3$ was produced using soda ash feedstocks mined in Wyoming and shipped to Colorado. Because the trona is mined in Wyoming, the production numbers given by the USGS included the feedstocks mined in Wyoming and shipped to Colorado. In this way, the sodium bicarbonate production that took place in Colorado was accounted for in the Wyoming numbers.

Although the United States continues to be a major supplier of world soda ash, China, which surpassed the United States in soda ash production in 2003, is the world's leading producer. While Chinese soda ash production appears to be stabilizing, U.S. competition in Asian markets is expected to continue. Despite this competition, U.S. soda ash production is expected to increase by about 0.5 percent annually (USGS 2008).

Methodology

During the production process, trona ore is calcined in a rotary kiln and chemically transformed into a crude soda ash that requires further processing. CO_2 and water are generated as by-products of the calcination process. CO_2 emissions from the calcination of trona can be estimated based on the following chemical reaction:

$$\underset{\text{[trona]}}{2(Na_3(CO_3)(HCO_3)\bullet 2H_2O)} \rightarrow \underset{\text{[soda ash]}}{3Na_2CO_3} + 5H_2O + CO_2$$

Based on this formula, approximately 10.27 metric tons of trona are required to generate one metric ton of CO_2, or an emission factor of 0.097 metric tons CO_2 per metric ton trona (IPCC 2006). Thus, the 17.8 million metric tons of trona mined in 2008 for soda ash production (USGS 2008) resulted in CO_2 emissions of approximately 1.7 Tg CO_2 Eq. (1,733 Gg). The same production and associated emissions estimates are assumed for 2009 due to lack of available data at time of publication.

Once produced, most soda ash is consumed in glass and chemical production, with minor amounts in soap and detergents, pulp and paper, flue gas desulfurization and water treatment. As soda ash is consumed for these purposes, additional CO_2 is usually emitted. In these applications, it is assumed that one mole of C is released for every mole of soda ash used. Thus, approximately 0.113 metric tons of C (or 0.415 metric tons of CO_2) are released for every metric ton of soda ash consumed.

The activity data for trona production and soda ash consumption (see Table 4-17) were taken from USGS (1994 through 2008). Data for soda ash consumption in 2009 was taken from USGS (2010) *Mineral Commodity Summary: Soda Ash*. Due to lack of 2009 trona production data at time of publication, the 2008 estimate is used as a proxy for 2009. Soda ash production and consumption data were collected by the USGS from voluntary surveys of the U.S. soda ash industry.

Table 4-17: Soda Ash Production and Consumption (Gg)

Year	Production*	Consumption
1990	14,700	6,530
2000	15,700	6,390
2005	17,000	6,200
2006	16,700	6,110
2007	17,200	5,940
2008	17,800	5,730
2009	17,800	6,100

* Soda ash produced from trona ore only.

Uncertainty and Time-Series Consistency

Emission estimates from soda ash production have relatively low associated uncertainty levels in that reliable and accurate data sources are available for the emission factor and activity data. The primary source of uncertainty, however, results from the fact that emissions from soda ash consumption are dependent upon the type of processing employed by each end-use. Specific information characterizing the emissions from each end-use is limited. Therefore, there is uncertainty surrounding the emission factors from the consumption of soda ash.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-18. Soda Ash Production and Consumption CO_2 emissions were estimated to be between 4.0 and 4.6 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below and 7 percent above the emission estimate of 4.3 Tg CO_2 Eq.

Table 4-18: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Soda Ash Production and Consumption (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Soda Ash Production and Consumption	CO_2	4.3	4.0	4.6	-7%	+7%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future inventories are anticipated to estimate emissions from glass production and other use of carbonates. These inventories will extract soda ash consumed for glass production and other use of carbonates from the current soda ash consumption emission estimates and include them under those sources.

In addition, future improvements to the soda ash production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from soda ash production. Beginning in 2010, all U.S. soda ash production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. soda ash production industry, including also improving emission factors associated with trona consumption.

4.5. Ammonia Production (IPCC Source Category 2B1) and Urea Consumption

Emissions of CO_2 occur during the production of synthetic ammonia, primarily through the use of natural gas as a feedstock. The natural gas-based, naphtha-based, and petroleum coke-based processes produce CO_2 and hydrogen (H_2), the latter of which is used in the production of ammonia. One N production plant located in Kansas is producing ammonia from petroleum coke feedstock. In some plants the CO_2 produced is captured and used to produce urea. The brine electrolysis process for production of ammonia does not lead to process-based CO_2 emissions.

There are five principal process steps in synthetic ammonia production from natural gas feedstock. The primary reforming step converts CH_4 to CO_2, carbon monoxide (CO), and H_2 in the presence of a catalyst. Only 30 to 40 percent of the CH_4 feedstock to the primary reformer is converted to CO and CO_2. The secondary reforming step converts the remaining CH_4 feedstock to CO and CO_2. The CO in the process gas from the secondary reforming step (representing approximately 15 percent of the process gas) is converted to CO_2 in the presence of a catalyst, water, and air in the shift conversion step. CO_2 is removed from the process gas by the shift conversion process, and the hydrogen gas is combined with the nitrogen (N_2) gas in the process gas during the ammonia synthesis step to produce ammonia. The CO_2 is included in a waste gas stream with other process impurities and is absorbed by a scrubber solution. In regenerating the scrubber solution, CO_2 is released.

The conversion process for conventional steam reforming of CH_4, including primary and secondary reforming and the shift conversion processes, is approximately as follows:

$$0.88\ CH_4 + 1.26\ \text{Air} + 1.24\ H_2O \xrightarrow{\text{(catalyst)}} 0.88\ CO_2 + N_2 + 3\ H_2$$

$$N_2 + 3\ H_2 \rightarrow 2\ NH_3$$

To produce synthetic ammonia from petroleum coke, the petroleum coke is gasified and converted to CO_2 and H_2. These gases are separated, and the H_2 is used as a feedstock to the ammonia production process, where it is reacted with N_2 to form ammonia.

Not all of the CO_2 produced in the production of ammonia is emitted directly to the atmosphere. Both ammonia and CO_2 are used as raw materials in the production of urea [$CO(NH_2)_2$], which is another type of nitrogenous fertilizer that contains C as well as N. The chemical reaction that produces urea is:

$$2\,NH_3 + CO_2 \rightarrow NH_2COONH_4 \rightarrow CO(NH_2)_2 + H_2O$$

Urea is consumed for a variety of uses, including as a nitrogenous fertilizer, in urea-formaldehyde resins, and as a deicing agent (TIG 2002). The C in the consumed urea is assumed to be released into the environment as CO_2 during use. Therefore, the CO_2 produced by ammonia production that is subsequently used in the production of urea is still emitted during urea consumption. The majority of CO_2 emissions associated with urea consumption are those that result from its use as a fertilizer. These emissions are accounted for in the Cropland Remaining Cropland section of the Land Use, Land-Use Change, and Forestry chapter. CO_2 emissions associated with other uses of urea are accounted for in this chapter. Net emissions of CO_2 from ammonia production in 2009 were 11.8 Tg CO_2 Eq. (11,797 Gg), and are summarized in Table 4-19 and Table 4-20. Emissions of CO_2 from urea consumed for non-fertilizer purposes in 2009 totaled 3.9 Tg CO_2 Eq. (3,942 Gg), and are summarized in Table 4-19 and Table 4-20. The decrease in ammonia production in recent years is due to several factors, including market fluctuations and high natural gas prices. Ammonia production relies on natural gas as both a feedstock and a fuel, and as such, domestic producers are competing with imports from countries with lower gas prices. If natural gas prices remain high, it is likely that domestically produced ammonia will continue to decrease with increasing ammonia imports (EEA 2004).

Table 4-19: CO_2 Emissions from Ammonia Production and Urea Consumption (Tg CO_2 Eq.)

Source	1990	2000	2005	2006	2007	2008	2009
Ammonia Production	13.0	12.2	9.2	8.8	9.1	7.9	7.9
Urea Consumption[a]	3.8	4.2	3.7	3.5	5.0	4.1	3.9
Total	**16.8**	**16.4**	**12.8**	**12.3**	**14.0**	**11.9**	**11.8**

Note: Totals may not sum due to independent rounding.

[a] Urea Consumption is for non-fertilizer purposes only. Urea consumed as a fertilizer is accounted for in the Land Use, Land-Use Change, and Forestry chapter.

Table 4-20: CO_2 Emissions from Ammonia Production and Urea Consumption (Gg)

Source	1990	2000	2005	2006	2007	2008	2009
Ammonia Production	13,047	12,172	9,196	8,781	9,074	7,883	7,855
Urea Consumption[a]	3,784	4,231	3,653	3,519	4,963	4,066	3,942
Total	**16,831**	**16,402**	**12,849**	**12,300**	**14,038**	**11,949**	**11,797**

[a] Urea Consumption is for non-fertilizer purposes only. Urea consumed as a fertilizer is accounted for in the Land Use, Land-Use Change, and Forestry chapter.

Methodology

The calculation methodology for non-combustion CO_2 emissions from production of nitrogenous fertilizers from natural gas feedstock is based on a CO_2 emission factor published by the European Fertilizer Manufacturers Association (EFMA). The selected EFMA factor is based on ammonia production technologies that are similar to those employed in the United States. The CO_2 emission factor (1.2 metric tons CO_2/metric ton NH_3) is applied to the percent of total annual domestic ammonia production from natural gas feedstock. Emissions from fuels consumed for energy purposes during the production of ammonia are accounted for in the Energy chapter. Emissions of CO_2 from ammonia production are then adjusted to account for the use of some of the CO_2 produced from ammonia production as a raw material in the production of urea. For each ton of urea produced, 8.8 of every 12 tons of CO_2 are consumed and 6.8 of every 12 tons of ammonia are consumed (IPCC 2006, EFMA 2000). The CO_2 emissions reported for ammonia production are therefore reduced by a factor of 0.73 multiplied by total annual domestic urea production. Total CO_2 emissions resulting from nitrogenous fertilizer production do not change as a result of this calculation, but some of the CO_2 emissions are attributed to ammonia production and some of the CO_2 emissions are attributed to urea consumption. Those CO_2 emissions that result from the use of urea as a fertilizer are accounted for in the Land Use, Land-Use Change, and Forestry chapter.

The total amount of urea consumed for non-agricultural purposes is estimated by deducting the quantity of urea fertilizer applied to agricultural lands, which is obtained directly from the Land Use, Land-Use Change, and Forestry Chapter and is reported in Table 4-21, from total U.S. production. Total urea production is estimated based on the amount of urea produced plus the sum of net urea imports and exports. CO_2 emissions associated with urea that is used for non-fertilizer purposes are estimated using a factor of 0.73 tons of CO_2 per ton of urea consumed.

All ammonia production and subsequent urea production are assumed to be from the same process—conventional catalytic reforming of natural gas feedstock, with the exception of ammonia production from petroleum coke feedstock at one plant located in Kansas. The CO_2 emission factor for production of ammonia from petroleum coke is based on plant specific data, wherein all C contained in the petroleum coke feedstock that is not used for urea production is assumed to be emitted to the atmosphere as CO_2 (Bark 2004). Ammonia and urea are assumed to be manufactured in the same manufacturing complex, as both the raw materials needed for urea production are produced by the ammonia production process. The CO_2 emission factor (3.57 metric tons CO_2/metric ton NH_3) is applied to the percent of total annual domestic ammonia production from petroleum coke feedstock.

The emission factor of 1.2 metric ton CO_2/metric ton NH_3 for production of ammonia from natural gas feedstock was taken from the EFMA Best Available Techniques publication, Production of Ammonia (EFMA 1995). The EFMA reported an emission factor range of 1.15 to 1.30 metric ton CO_2/metric ton NH_3, with 1.2 metric ton CO_2/metric ton NH_3 as a typical value. Technologies (e.g., catalytic reforming process) associated with this factor are found to closely resemble those employed in the U.S. for use of natural gas as a feedstock. The EFMA reference also indicates that more than 99 percent of the CH_4 feedstock to the catalytic reforming process is ultimately converted to CO_2. The emission factor of 3.57 metric ton CO_2/metric ton NH_3 for production of ammonia from petroleum coke feedstock was developed from plant-specific ammonia production data and petroleum coke feedstock utilization data for the ammonia plant located in Kansas (Bark 2004). As noted earlier, emissions from fuels consumed for energy purposes during the production of ammonia are accounted for in the Energy chapter. Ammonia production data (see Table 4-21) was obtained from Coffeyville Resources (Coffeyville 2005, 2006, 2007a, 2007b, 2009, 2010) and the Census Bureau of the U.S. Department of Commerce (U.S. Census Bureau 1991 through 1994, 1998 through 2010) as reported in Current Industrial Reports Fertilizer Materials and Related Products annual and quarterly reports. Urea-ammonia nitrate production was obtained from Coffeyville Resources (Coffeyville 2005, 2006, 2007a, 2007b, 2009, 2010). Urea production data for 1990 through 2008 were obtained from the Minerals Yearbook: Nitrogen (USGS 1994 through 2009). Urea production data for 2009 was obtained from the U.S. Bureau of the Census (2010). Import data for urea were obtained from the U.S. Census Bureau Current Industrial Reports Fertilizer Materials and Related Products annual and quarterly reports for 1997 through 2009 (U.S. Census Bureau 1998 through 2010), The Fertilizer Institute (TFI 2002) for 1993 through 1996, and the United States International Trade Commission Interactive Tariff and Trade DataWeb (U.S. ITC 2002) for 1990 through 1992 (see Table 4-21). Urea export data for 1990 through 2009 were taken from U.S. Fertilizer Import/Exports from USDA Economic Research Service Data Sets (U.S. Department of Agriculture 2010).

Table 4-21: Ammonia Production, Urea Production, Urea Net Imports, and Urea Exports (Gg)

Year	Ammonia Production	Urea Production	Urea Applied as Fertilizer	Urea Imports	Urea Exports
1990	15,425	7,450	3,296	1,860	854
2000	14,342	6,910	4,382	3,904	663
2005	10,143	5,270	4,779	5,026	536
2006	9,962	5,410	4,985	5,029	656
2007	10,393	5,590	5,097	6,546	271
2008	9,570	5,240	4,925	5,459	230
2009	9,372	5,084	4,295	5,505	289

Uncertainty and Time-Series Consistency

The uncertainties presented in this section are primarily due to how accurately the emission factor used represents an average across all ammonia plants using natural gas feedstock. Uncertainties are also associated with natural gas feedstock consumption data for the U.S. ammonia industry as a whole, the assumption that all ammonia production and subsequent urea production was from the same process—conventional catalytic reforming of natural gas feedstock, with the exception of one ammonia production plant located in Kansas that is manufacturing ammonia from petroleum coke feedstock. It is also assumed that ammonia and urea are produced at collocated plants from the same natural gas raw material.

Such recovery may or may not affect the overall estimate of CO_2 emissions depending upon the end use to which the recovered CO_2 is applied. Further research is required to determine whether byproduct CO_2 is being recovered from other ammonia production plants for application to end uses that are not accounted for elsewhere.

Additional uncertainty is associated with the estimate of urea consumed for non-fertilizer purposes. Emissions associated with this consumption are reported in this source category, while those associated with consumption as fertilizer are reported in Cropland Remaining Cropland section of the Land Use, Land-Use Change, and Forestry chapter. The amount of urea used for non-fertilizer purposes is estimated based on estimates of urea production, net urea imports, and the amount of urea used as fertilizer. There is uncertainty associated with the accuracy of these estimates as well as the fact that each estimate is obtained from a different data source.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-22. Ammonia Production and Urea Consumption CO_2 emissions were estimated to be between 10.9 and 12.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below and 8 percent above the emission estimate of 11.8 Tg CO_2 Eq.

Table 4-22: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Ammonia Production and Urea Consumption (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Ammonia Production and Urea Consumption	CO_2	11.8	10.9	12.7	-7%	+8%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

The uncertainty range (-7 percent/+8 percent) has decreased by 7 percent compared to the uncertainty range in the previous Inventory (±11 percent), due to two stoichiometric variables being removed from the uncertainty analysis.

Planned Improvements

Future improvements to the ammonia production and urea consumption category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from ammonia production. Beginning in 2010, all U.S. ammonia production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from U.S. ammonia production. Specifically, the planned improvements include assessing data to update the emission factors to include both fuel and feedstock CO_2 emissions and incorporate CO_2 capture and storage. Methodologies will also be updated if additional ammonia-production plants are found to use hydrocarbons other than natural gas for ammonia production. Additional efforts will be made to find consistent data sources for urea consumption and to report emissions from this consumption appropriately as defined.

4.6. Nitric Acid Production (IPCC Source Category 2B2)

Nitric acid (HNO_3) is an inorganic compound used primarily to make synthetic commercial fertilizers. It is also a major component in the production of adipic acid—a feedstock for nylon—and explosives. Virtually all of the nitric acid produced in the United States is manufactured by the catalytic oxidation of ammonia (EPA 1997). During this reaction, N_2O is formed as a by-product and is released from reactor vents into the atmosphere.

Currently, the nitric acid industry controls for emissions of NO and NO_2 (i.e., NO_x). As such, the industry in the US uses a combination of non-selective catalytic reduction (NSCR) and selective catalytic reduction (SCR) technologies. In the process of destroying NO_x, NSCR systems are also very effective at destroying N_2O. However, NSCR units are generally not preferred in modern plants because of high energy costs and associated high gas temperatures. NSCRs were widely installed in nitric plants built between 1971 and 1977. Approximately 25 percent of nitric acid plants use NSCR and they represent 15.3 percent of estimated national production (EPA 2010a). The remaining 84.7 percent of production occurs using SCR or extended absorption, neither of which is known to reduce N_2O emissions.

N_2O emissions from this source were estimated to be 14.6 Tg CO_2 Eq. (47 Gg) in 2009 (see Table 4-23). Emissions from nitric acid production have decreased by 18 percent since 1990, with the trend in the time series closely tracking the changes in production. Emissions decreased 11.4 percent between 2008 and 2009. Emissions have decreased by 30.8 percent since 1997, the highest year of production in the time series.

Table 4-23: N_2O Emissions from Nitric Acid Production (Tg CO_2 Eq. and Gg)

Year	**Tg CO_2 Eq.**	**Gg**
1990	17.7	57
2000	19.4	63
2005	16.5	53
2006	16.2	52
2007	19.2	62
2008	16.4	53
2009	14.6	47

Methodology

N_2O emissions were calculated by multiplying nitric acid production by the amount of N_2O emitted per unit of nitric acid produced. The emission factor was determined as a weighted average of two known emission factors: 2 kg N_2O/metric ton HNO_3 produced at plants using non-selective catalytic reduction (NSCR) systems and 9 kg N_2O/metric ton HNO_3 produced at plants not equipped with NSCR (IPCC 2006). In the process of destroying NO_x, NSCR systems destroy 80 to 90 percent of the N_2O, which is accounted for in the emission factor of 2 kg N_2O/metric ton HNO_3. Approximately 25 percent of HNO_3 plants in the United States are equipped with NSCR representing 15.3 percent of estimated national production (EPA 2010a). Hence, the emission factor is equal to $(9 \times 0.847) + (2 \times 0.153) = 7.9$ kg N_2O per metric ton HNO_3.

Nitric acid production data for 1990 through 2002 were obtained from the U.S. Census Bureau, Current Industrial Reports (2006). Production data for 2003 were obtained from the U.S. Census Bureau, Current Industrial Reports (2008). Production data for 2004 through 2009 were obtained from the U.S. Census Bureau, Current Industrial Reports (2010) (see Table 4-24).

Table 4-24: Nitric Acid Production (Gg)

Year	**Gg**
1990	7,195
2000	7,900
2005	6,711
2006	6,572
2007	7,827
2008	6,686
2009	5,924

Uncertainty and Time-Series Consistency

The overall uncertainty associated with the 2009 N_2O emissions estimate from nitric acid production was calculated using the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) Tier 2 methodology.

Uncertainty associated with the parameters used to estimate N_2O emissions included that of production data, the share of U.S. nitric acid production attributable to each emission abatement technology over the time series, and the emission factors applied to each abatement technology type.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 4-25. N_2O emissions from nitric acid production were estimated to be between 8.8 and 20.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 40 percent below to 42 percent above the 2009 emissions estimate of 14.6 Tg CO_2 Eq.

Table 4-25: Tier 2 Quantitative Uncertainty Estimates for N_2O Emissions from Nitric Acid Production (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a]**			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Nitric Acid Production	N_2O	14.6	8.8	20.7	-40%	+42%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the nitric acid production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from nitric acid production. Beginning in 2010, all U.S. nitric acid production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from U.S. nitric acid production. Specifically, the planned improvements include assessing data to update the N_2O emission factors, abatement utilization and destruction factors, and the current share of nitric acid production attributable to various abatement technologies.

Recalculations Discussion

Historical estimates for N_2O emissions from nitric acid production have been revised relative to the previous Inventory based on updated information from EPA (2010) on abatement technologies in use and based on revised production data published by the U.S. Census Bureau (2010). The previous Inventory assumed that approximately 17 percent of facilities accounting for less than 8 percent of national production were equipped with NSCR systems (EPA 2010b). The current Inventory assumes that approximately 25 percent of facilities, accounting for roughly 15 percent of national production, were equipped with NSCR systems (EPA 2010a). This change resulted in a decrease in the weighted average emission factor of 0.6 kg N_2O/metric ton HNO_3 (6.3 percent). Additionally, national nitric acid production values for 1991, 1993-1995, 1997-1999, 2002, and 2008 have been updated relative to the previous Inventory (US Census Bureau 2009, 2010). Revised production in 2008 contributed to an overall decrease in emissions of 2.6 Tg CO_2 Eq. (13.6 percent) in that year; revised production in the other historical years had a negligible impact on emissions. Overall, changes relative to the previous Inventory resulted in an average annual decrease in emissions of 1.3 Tg CO_2 Eq. (6.7 percent) for the period 1990 through 2008.

4.7. Adipic Acid Production (IPCC Source Category 2B3)

Adipic acid production is an anthropogenic source of N_2O emissions. Worldwide, few adipic acid plants exist. The United States and Europe are the major producers. In 2009, the United States had two companies with a total of three adipic acid processes, two of which were operational (CW 2007; Desai 2010; VA DEQ 2009). The United States accounts for the largest share of global adipic acid production capacity (30 percent), followed by the European Union (29 percent) and China (22 percent) (SEI 2010). Adipic acid is a white crystalline solid used in the manufacture of synthetic fibers, plastics, coatings, urethane foams, elastomers, and synthetic lubricants. Commercially, it is the most important of the aliphatic dicarboxylic acids, which are used to manufacture polyesters.

84 percent of all adipic acid produced in the United States is used in the production of nylon 6,6; nine percent is used in the production of polyester polyols; four percent is used in the production of plasticizers; and the remaining four percent is accounted for by other uses, including unsaturated polyester resins and food applications (ICIS 2007). Food grade adipic acid is used to provide some foods with a “tangy” flavor (Thiemens and Trogler 1991).

Adipic acid is produced through a two-stage process during which N_2O is generated in the second stage. The first stage of manufacturing usually involves the oxidation of cyclohexane to form a cyclohexanone/cyclohexanol mixture. The second stage involves oxidizing this mixture with nitric acid to produce adipic acid. N_2O is generated as a by-product of the nitric acid oxidation stage and is emitted in the waste gas stream (Thiemens and Trogler 1991). Process emissions from the production of adipic acid vary with the types of technologies and level of emission controls employed by a facility. In 1990, two of the three major adipic acid-producing plants had N_2O abatement technologies in place and, as of 1998, the three major adipic acid production facilities had control systems in place (Reimer et al. 1999). One small plant, which last operated in April 2006 and represented approximately two percent of production, did not control for N_2O (VA DEQ 2009; ICIS 2007; VA DEQ 2006).

N_2O emissions from adipic acid production were estimated to be 1.9 Tg CO_2 Eq. (6 Gg) in 2009 (see Table 4-26). National adipic acid production has increased by approximately 11 percent over the period of 1990 through 2009, to roughly 820,000 metric tons. Over the same period, emissions have been reduced by 88 percent due to both the widespread installation of pollution control measures in the late 1990s and plant idling in the late 2000s. In April 2006, the smallest of the four facilities ceased production of adipic acid (VA DEQ 2009); furthermore, one of the major adipic acid production facilities was not operational in 2009 (Desai 2010).

Table 4-26: N_2O Emissions from Adipic Acid Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	15.8	51
2000	5.5	18
2005	5.0	16
2006	4.3	14
2007	3.7	12
2008	2.0	7
2009	1.9	6

Methodology

Due to confidential business information, plant names are not provided in this section. The four adipic acid-producing plants will henceforth be referred to as Plants 1 through 4.

For Plants 1 and 2, 1990 to 2009 emission estimates were obtained directly from the plant engineer and account for reductions due to control systems in place at these plants during the time series (Desai 2010). These estimates were based on continuous emissions monitoring equipment installed at the two facilities. In 2009, no Adipic acid production occurred at Plant 1. For Plants 3 and 4, N_2O emissions were calculated by multiplying adipic acid production by an emission factor (i.e., N_2O emitted per unit of adipic acid produced) and adjusting for the percentage of N_2O released as a result of plant-specific emission controls. On the basis of experiments, the overall reaction stoichiometry for N_2O production in the preparation of adipic acid was estimated at approximately 0.3 metric tons of N_2O per metric ton of product (IPCC 2006). Emissions are estimated using the following equation:

$$N_2O \text{ emissions} = (\text{production of adipic acid [metric tons \{MT\} of adipic acid]}) \times (0.3 \text{ MT } N_2O / \text{MT adipic acid}) \times (1 - [N_2O \text{ destruction factor} \times \text{abatement system utility factor}])$$

The “N_2O destruction factor” represents the percentage of N_2O emissions that are destroyed by the installed abatement technology. The “abatement system utility factor” represents the percentage of time that the abatement equipment operates during the annual production period. Overall, in the United States, two of the plants employ catalytic destruction (Plants 1 and 2), one plant employs thermal destruction (Plant 3), and the smallest plant used no N_2O abatement equipment (Plant 4). For Plant 3, which uses thermal destruction and for which no reported plant-specific emissions are available, the N_2O abatement system destruction factor is assumed to be 98.5 percent, and the abatement system utility factor is assumed to be 97 percent (IPCC 2006).

From 1990 to 2003, plant-specific production data were estimated for Plant 3 where direct emission measurements were not available. In order to calculate plant-specific production for this plant, national adipic acid production was allocated to the plant level using the ratio of known plant capacity to total national capacity for all U.S. plants. The estimated plant production for this plant was then used for calculating emissions as described above. For 2004 and 2006, actual plant production data were obtained and used for emission calculations (CW 2007; CW 2005). For 2005, interpolated national production was used for calculating emissions. Updated production data were not available for Plant 3 for 2007 through 2009; therefore, production values for 2007 through 2009 were proxied using 2006 data.

For Plant 4, which last operated in April 2006 (VA DEQ 2009), plant-specific production data were obtained across the time series from 1990 through 2008 (VA DEQ 2010). Since the plant has not operated since 2006, production in 2009 is assumed to be equal to the 2008 estimate, which was zero. The plant-specific production data were then used for calculating emissions as described above.

National adipic acid production data (see Table 4-27) from 1990 through 2009 were obtained from the American Chemistry Council (ACC 2010).

Plant capacities for 1990 through 1994 were obtained from Chemical and Engineering News, “Facts and Figures” and “Production of Top 50 Chemicals” (C&EN 1992 through 1995). Plant capacities for 1995 and 1996 were kept the same as 1994 data. The 1997 plant capacities were taken from Chemical Market Reporter “Chemical Profile: Adipic Acid” (CMR 1998). The 1998 plant capacities for all four plants and 1999 plant capacities for three of the plants were obtained from Chemical Week, Product Focus: Adipic Acid/Adiponitrile (CW 1999). Plant capacities for 2000 for three of the plants were updated using Chemical Market Reporter, “Chemical Profile: Adipic Acid” (CMR 2001). For 2001 through 2005, the plant capacities for three plants were kept the same as the year 2000 capacities. Plant capacity for 1999 to 2005 for the one remaining plant was kept the same as 1998. For 2004 to 2009, although some plant capacity data are available (CW 1999, CMR 2001, ICIS 2007), they are not used to calculate plant-specific production for these years because plant-specific production data for 2004 and 2006 are also available and are used in our calculations instead (CW 2005, CW 2007).

Table 4-27: Adipic Acid Production (Gg)

Year	Gg
1990	735
2000	925
2005	903
2006	964
2007	930
2008	869
2009	819

Uncertainty and Time-Series Consistency

The overall uncertainty associated with the 2009 N_2O emission estimate from adipic acid production was calculated using the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) Tier 2 methodology. Uncertainty associated with the parameters used to estimate N_2O emissions included that of company specific production data, emission factors for abated and unabated emissions, and company-specific historical emission estimates.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 4-28. N_2O emissions from adipic acid production were estimated to be between 1.2 and 2.8 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 40 percent below to 42 percent above the 2009 emission estimate of 1.9 Tg CO_2 Eq.

Table 4-28: Tier 2 Quantitative Uncertainty Estimates for N_2O Emissions from Adipic Acid Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate	Uncertainty Range Relative to Emission Estimate[a]	
		(Tg CO_2 Eq.)	(Tg CO_2 Eq.)	(%)

			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Adipic Acid Production	N_2O	1.9	1.2	2.8	-40%	+42%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations

The current Inventory uses national production data from the ACC (2010) across the full time series. Previous Inventories relied upon a variety of sources and linear interpolation for missing intervening years in the national production time series. This change resulted in an average annual decrease in the national production estimate of approximately 2 percent for the period 1990 through 2008 relative to the previous Inventory. Emissions decreased by less than 0.1 percent over the same time period relative to the previous Inventory.

Planned Improvements

Future improvements to the adipic acid production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from adipic acid production. Beginning in 2010, all U.S. adipic acid production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from U.S. adipic acid production. Specifically, the planned improvements include assessing data to update the N_2O emission factors and update abatement utility and destruction factors based on actual performance of the latest catalytic and thermal abatement equipment at plants with continuous process and emission monitoring equipment.

4.8. Silicon Carbide Production (IPCC Source Category 2B4) and Consumption

CO_2 and CH_4 are emitted from the production[112] of silicon carbide (SiC), a material used as an industrial abrasive. To make SiC, quartz (SiO_2) is reacted with C in the form of petroleum coke. A portion (about 35 percent) of the C contained in the petroleum coke is retained in the SiC. The remaining C is emitted as CO_2, CH_4, or CO.

CO_2 is also emitted from the consumption of SiC for metallurgical and other non-abrasive applications. The USGS reports that a portion (approximately 50 percent) of SiC is used in metallurgical and other non-abrasive applications, primarily in iron and steel production (USGS 2006).

CO_2 from SiC production and consumption in 2009 were 0.1 Tg CO_2 Eq. (145 Gg) (USGS 2009). Approximately 63 percent of these emissions resulted from SiC production while the remainder results from SiC consumption. CH_4 emissions from SiC production in 2009 were 0.01 Tg CO_2 Eq. CH_4 (0.4 Gg) (see Table 4-29 and Table 4-30).

Table 4-29: CO_2 and CH_4 Emissions from Silicon Carbide Production and Consumption (Tg CO_2 Eq.)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	0.4	0.2	0.2	0.2	0.2	0.2	0.1
CH_4	+	+	+	+	+	+	+
Total	**0.4**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 4-30: CO_2 and CH_4 Emissions from Silicon Carbide Production and Consumption (Gg)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**

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[112] Silicon carbide is produced for both abrasive and metallurgical applications in the United States. Production for metallurgical applications is not available and therefore both CH_4 and CO_2 estimates are based solely upon production estimates of silicon carbide for abrasive applications.

CO_2	375		248		219	207	196	175	145
CH_4	1		1		+	+	+	+	+

+ Does not exceed 0.5 Gg.

Methodology

Emissions of CO_2 and CH_4 from the production of SiC were calculated by multiplying annual SiC production by the emission factors (2.62 metric tons CO_2/metric ton SiC for CO_2 and 11.6 kg CH_4/metric ton SiC for CH_4) provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006).

Emissions of CO_2 from silicon carbide consumption were calculated by multiplying the annual SiC consumption (production plus net imports) by the percent used in metallurgical and other non-abrasive uses (50 percent) (USGS 2009). The total SiC consumed in metallurgical and other non-abrasive uses was multiplied by the C content of SiC (31.5 percent), which was determined according to the molecular weight ratio of SiC.

Production data for 1990 through 2008 were obtained from the Minerals Yearbook: Manufactured Abrasives (USGS 1991a through 2005a, 2007, and 2009). Production data for 2009 was taken from the Minerals Commodity Summary: Abrasives (Manufactured) (USGS 2010). Silicon carbide consumption by major end use was obtained from the Minerals Yearbook: Silicon (USGS 1991b through 2005b) (see Table 4-31) for years 1990 through 2004 and from the USGS Minerals Commodity Specialist for 2005 and 2006 (Corathers 2006, 2007). Silicon carbide consumption by major end use data for 2009 is proxied using 2008 data due to unavailability of data at time of publication. Net imports for the entire time series were obtained from the U.S. Census Bureau (2005 through 2010).

Table 4-31: Production and Consumption of Silicon Carbide (Metric Tons)

Year	Production	Consumption
1990	105,000	172,465
2000	45,000	225,070
2005	35,000	220,149
2006	35,000	199,937
2007	35,000	179,741
2008	35,000	144,928
2009	35,000	92,280

Uncertainty and Time-Series Consistency

There is uncertainty associated with the emission factors used because they are based on stoichiometry as opposed to monitoring of actual SiC production plants. An alternative would be to calculate emissions based on the quantity of petroleum coke used during the production process rather than on the amount of silicon carbide produced. However, these data were not available. For CH_4, there is also uncertainty associated with the hydrogen-containing volatile compounds in the petroleum coke (IPCC 2006). There is also some uncertainty associated with production, net imports, and consumption data as well as the percent of total consumption that is attributed to metallurgical and other non-abrasive uses.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-32. Silicon carbide production and consumption CO_2 emissions were estimated to be between 9 percent below and 9 percent above the emission estimate of 0.2 Tg CO_2 Eq. at the 95 percent confidence level. Silicon carbide production CH_4 emissions were estimated to be between 9 percent below and 9 percent above the emission estimate of 0.01 Tg CO_2 Eq. at the 95 percent confidence level.

Table 4-32: Tier 2 Quantitative Uncertainty Estimates for CH_4 and CO_2 Emissions from Silicon Carbide Production and Consumption (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Silicon Carbide Production	CO_2	0.2	0.13	0.16	-9%	+9%

and Consumption						
Silicon Carbide Production	CH_4	+	+	+	-9%	+9%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.
+ Does not exceed 0.05 Tg CO_2 Eq. or 0.5 Gg.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the silicon carbide production source category include evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from silicon carbide production. Beginning in 2010, all U.S. silicon carbide production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. silicon carbide production industry. In addition, improvements will involve continued research to determine if calcium carbide production and consumption data are available for the United States. If these data are available, calcium carbide emission estimates will be included in this source category. Additionally, as future improvement to the silicon carbide uncertainty analysis, USGS Mineral Commodity Specialists will be contacted to verify the uncertainty range associated with silicon carbide emissive utilization.

4.9. Petrochemical Production (IPCC Source Category 2B5)

The production of some petrochemicals results in the release of small amounts of CH_4 and CO_2 emissions. Petrochemicals are chemicals isolated or derived from petroleum or natural gas. CH_4 emissions are presented here from the production of carbon black, ethylene, ethylene dichloride, and methanol, while CO_2 emissions are presented here for only carbon black production. The CO_2 emissions from petrochemical processes other than carbon black are currently included in the Carbon Stored in Products from Non-Energy Uses of Fossil Fuels Section of the Energy chapter. The CO_2 from carbon black production is included here to allow for the direct reporting of CO_2 emissions from the process and direct accounting of the feedstocks used in the process.

Carbon black is an intense black powder generated by the incomplete combustion of an aromatic petroleum or coal-based feedstock. Most carbon black produced in the United States is added to rubber to impart strength and abrasion resistance, and the tire industry is by far the largest consumer. Ethylene is consumed in the production processes of the plastics industry including polymers such as high, low, and linear low density polyethylene (HDPE, LDPE, LLDPE), polyvinyl chloride (PVC), ethylene dichloride, ethylene oxide, and ethylbenzene. Ethylene dichloride is one of the first manufactured chlorinated hydrocarbons with reported production as early as 1795. In addition to being an important intermediate in the synthesis of chlorinated hydrocarbons, ethylene dichloride is used as an industrial solvent and as a fuel additive. Methanol is an alternative transportation fuel as well as a principle ingredient in windshield wiper fluid, paints, solvents, refrigerants, and disinfectants. In addition, methanol-based acetic acid is used in making PET plastics and polyester fibers.

Emissions of CO_2 and CH_4 from petrochemical production in 2009 were 2.7 Tg CO_2 Eq. (2,735 Gg) and 0.8 Tg CO_2 Eq. (40 Gg), respectively (see Table 4-33 and Table 4-34), totaling 3.6 Tg CO_2 Eq. There has been an overall decrease in CO_2 emissions from carbon black production of 17 percent since 1990. CH_4 emissions from petrochemical production decreased by approximately two percent since 1990.

Table 4-33: CO_2 and CH_4 Emissions from Petrochemical Production (Tg CO_2 Eq.)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	3.3	4.5	4.2	3.8	3.9	3.4	2.7
CH_4	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Total	**4.2**	**5.7**	**5.3**	**4.8**	**4.9**	**4.4**	**3.6**

Note: Totals may not sum due to independent rounding.

Table 4-34: CO_2 and CH_4 Emissions from Petrochemical Production (Gg)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**

CO_2	3,311		4,479		4,181	3,837	3,931	3,449	2,735
CH_4	41		59		51	48	48	43	40

Methodology

Emissions of CH_4 were calculated by multiplying annual estimates of chemical production by the appropriate emission factor, as follows: 11 kg CH_4/metric ton carbon black, 1 kg CH_4/metric ton ethylene, 0.4 kg CH_4/metric ton ethylene dichloride,[113] and 2 kg CH_4/metric ton methanol. Although the production of other chemicals may also result in CH_4 emissions, insufficient data were available to estimate their emissions.

Emission factors were taken from the Revised 1996 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1997). Annual production data (see Table 4-35) were obtained from the American Chemistry Council's Guide to the Business of Chemistry (ACC 2002, 2003, 2005 through 2010) and the International Carbon Black Association (Johnson 2003, 2005 through 2010). Note that 2009 production data for Methanol was not available at time of publication, as such, 2008 methanol production is used as a proxy for 2009.

Table 4-35: Production of Selected Petrochemicals (Thousand Metric Tons)

Chemical	1990		2000		2005	2006	2007	2008	2009
Carbon Black	1,307		1,769		1,651	1,515	1,552	1,362	1,080
Ethylene	16,541		24,970		23,954	25,000	25,392	22,539	22,596
Ethylene Dichloride	6,282		9,866		11,260	9,736	9,566	8,981	8,131
Methanol	3,785		5,221		2,336	1,123	1,068	1,136	1,136

Almost all carbon black in the United States is produced from petroleum-based or coal-based feedstocks using the "furnace black" process (European IPPC Bureau 2004). The furnace black process is a partial combustion process in which a portion of the carbon black feedstock is combusted to provide energy to the process. Carbon black is also produced in the United States by the thermal cracking of acetylene-containing feedstocks ("acetylene black process") and by the thermal cracking of other hydrocarbons ("thermal black process"). One U.S carbon black plant produces carbon black using the thermal black process, and one U.S. carbon black plant produces carbon black using the acetylene black process (The Innovation Group 2004).

The furnace black process produces carbon black from "carbon black feedstock" (also referred to as "carbon black oil"), which is a heavy aromatic oil that may be derived as a byproduct of either the petroleum refining process or the metallurgical (coal) coke production process. For the production of both petroleum-derived and coal-derived carbon black, the "primary feedstock" (i.e., carbon black feedstock) is injected into a furnace that is heated by a "secondary feedstock" (generally natural gas). Both the natural gas secondary feedstock and a portion of the carbon black feedstock are oxidized to provide heat to the production process and pyrolyze the remaining Carbon black feedstock to carbon black. The "tail gas" from the furnace black process contains CO_2, carbon monoxide, sulfur compounds, CH_4, and non-CH_4 volatile organic compounds. A portion of the tail gas is generally burned for energy recovery to heat the downstream carbon black product dryers. The remaining tail gas may also be burned for energy recovery, flared, or vented uncontrolled to the atmosphere.

The calculation of the C lost during the production process is the basis for determining the amount of CO_2 released during the process. The C content of national carbon black production is subtracted from the total amount of C contained in primary and secondary carbon black feedstock to find the amount of C lost during the production process. It is assumed that the C lost in this process is emitted to the atmosphere as either CH_4 or CO_2. The C content of the CH_4 emissions, estimated as described above, is subtracted from the total C lost in the process to calculate the amount of C emitted as CO_2. The total amount of primary and secondary carbon black feedstock consumed in the process (see Table 4-36) is estimated using a primary feedstock consumption factor and a secondary feedstock consumption factor estimated from U.S. Census Bureau (1999, 2004, and 2007) data. The average carbon black feedstock consumption factor for U.S. carbon black production is 1.69 metric tons of carbon black feedstock consumed per metric ton of carbon black produced. The average natural gas consumption factor for

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[113] The emission factor obtained from IPCC/UNEP/OECD/IEA (1997), page 2.23 is assumed to have a misprint; the chemical identified should be ethylene dichloride ($C_2H_4Cl_2$) rather than dichloroethylene ($C_2H_2Cl_2$).

U.S. carbon black production is 321 normal cubic meters of natural gas consumed per metric ton of carbon black produced. The amount of C contained in the primary and secondary feedstocks is calculated by applying the respective C contents of the feedstocks to the respective levels of feedstock consumption (EIA 2003, 2004).

Table 4-36: Carbon Black Feedstock (Primary Feedstock) and Natural Gas Feedstock (Secondary Feedstock) Consumption (Thousand Metric Tons)

Activity	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Primary Feedstock	2,213		2,993		2,794	2,564	2,627	2,305	1,828
Secondary Feedstock	284		384		359	329	337	296	235

For the purposes of emissions estimation, 100 percent of the primary carbon black feedstock is assumed to be derived from petroleum refining byproducts. Carbon black feedstock derived from metallurgical (coal) coke production (e.g., creosote oil) is also used for carbon black production; however, no data are available concerning the annual consumption of coal-derived carbon black feedstock. Carbon black feedstock derived from petroleum refining byproducts is assumed to be 89 percent elemental C (Srivastava et al. 1999). It is assumed that 100 percent of the tail gas produced from the carbon black production process is combusted and that none of the tail gas is vented to the atmosphere uncontrolled. The furnace black process is assumed to be the only process used for the production of carbon black because of the lack of data concerning the relatively small amount of carbon black produced using the acetylene black and thermal black processes. The carbon black produced from the furnace black process is assumed to be 97 percent elemental C (Othmer et al. 1992).

Uncertainty and Time-Series Consistency

The CH_4 emission factors used for petrochemical production are based on a limited number of studies. Using plant-specific factors instead of average factors could increase the accuracy of the emission estimates; however, such data were not available. There may also be other significant sources of CH_4 arising from petrochemical production activities that have not been included in these estimates.

The results of the quantitative uncertainty analysis for the CO_2 emissions from carbon black production calculation are based on feedstock consumption, import and export data, and carbon black production data. The composition of carbon black feedstock varies depending upon the specific refinery production process, and therefore the assumption that carbon black feedstock is 89 percent C gives rise to uncertainty. Also, no data are available concerning the consumption of coal-derived carbon black feedstock, so CO_2 emissions from the utilization of coal-based feedstock are not included in the emission estimate. In addition, other data sources indicate that the amount of petroleum-based feedstock used in carbon black production may be underreported by the U.S. Census Bureau. Finally, the amount of carbon black produced from the thermal black process and acetylene black process, although estimated to be a small percentage of the total production, is not known. Therefore, there is some uncertainty associated with the assumption that all of the carbon black is produced using the furnace black process.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-37. Petrochemical production CO_2 emissions were estimated to be between 2.0 and 3.6 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 27 percent below to 31 percent above the emission estimate of 2.7 Tg CO_2 Eq. Petrochemical production CH_4 emissions were estimated to be between 0.6 and 1.1 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 26 percent below to 27 percent above the emission estimate of 0.8 Tg CO_2 Eq.

Table 4-37: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Petrochemical Production and CO_2 Emissions from Carbon Black Production (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**[a]			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Petrochemical Production	CO_2	2.7	2.0	3.6	-27%	+31%
Petrochemical Production	CH_4	0.8	0.6	1.1	-26%	+27%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990

through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the petrochemicals source category involve updating the methodology to use CH_4 emission factors for petrochemical production from the IPCC 2006 guidelines rather than the IPCC 1996 guidelines. Further future improvements involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from petrochemical production. Beginning in 2010, all U.S. petrochemical production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. petrochemical production industry, for example using a Tier 2 methodology to calculate emissions from the production of methanol, ethylene, propylene, ethylene dichloride, and ethylene oxide. In addition, the planned improvements include assessing the data EPA obtains to update data sources for acrylonitrile production in the United States.

4.10. Titanium Dioxide Production (IPCC Source Category 2B5)

Titanium dioxide (TiO_2) is a metal oxide manufactured from titanium ore, and is principally used as a pigment. Titanium dioxide is a principal ingredient in white paint, and is also used as a pigment in the manufacture of white paper, foods, and other products. There are two processes for making TiO_2: the chloride process and the sulfate process. The chloride process uses petroleum coke and chlorine as raw materials and emits process-related CO_2. The sulfate process does not use petroleum coke or other forms of C as a raw material and does not emit CO_2.

The chloride process is based on the following chemical reactions:

$$2\ FeTiO_3 + 7\ Cl_2 + 3\ C \rightarrow 2\ TiCl_4 + 2\ FeCl_3 + 3\ CO_2$$

$$2\ TiCl_4 + 2\ O_2 \rightarrow 2\ TiO_2 + 4\ Cl_2$$

The C in the first chemical reaction is provided by petroleum coke, which is oxidized in the presence of the chlorine and $FeTiO_3$ (the Ti-containing ore) to form CO_2. The majority of U.S. TiO_2 was produced in the United States through the chloride process, and a special grade of “calcined” petroleum coke is manufactured specifically for this purpose.

Emissions of CO_2 in 2009 were 1.5 Tg CO_2 Eq. (1,541 Gg), which represents an increase of 29 percent since 1990 (see Table 4-38).

Table 4-38: CO_2 Emissions from Titanium Dioxide (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	1.2	1,195
2000	1.8	1,752
2005	1.8	1,755
2006	1.8	1,836
2007	1.9	1,930
2008	1.8	1,809
2009	1.5	1,541

Methodology

Emissions of CO_2 from TiO_2 production were calculated by multiplying annual TiO_2 production by chloride-process-specific emission factors.

Data were obtained for the total amount of TiO_2 produced each year. For years previous to 2004, it was assumed that TiO_2 was produced using the chloride process and the sulfate process in the same ratio as the ratio of the total U.S. production capacity for each process. As of 2004, the last remaining sulfate-process plant in the United States had closed; therefore, 100 percent of post-2004 production uses the chloride process (USGS 2005). An emission factor of 0.4 metric tons C/metric ton TiO2 was applied to the estimated chloride-process production. It was assumed that all TiO_2 produced using the chloride process was produced using petroleum coke, although some TiO_2 may have been produced with graphite or other C inputs. The amount of petroleum coke consumed annually in TiO_2 production was calculated based on the assumption that the calcined petroleum coke used in the process is 98.4 percent C and 1.6 percent inert materials (Nelson 1969).

The emission factor for the TiO_2 chloride process was taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). Titanium dioxide production data and the percentage of total TiO_2 production capacity that is chloride process for 1990 through 2008 (see Table 4-39) were obtained through the Minerals Yearbook: Titanium Annual Report (USGS 1991 through 2008). Production data in 2009 was obtained from the Minerals Commodity Summary: Titanium and Titanium Dioxide (USGS 2010). Due to lack of available 2009 capacity data at the time of publication, the 2008 capacity estimate is used as a proxy for 2009. Percentage chloride-process data were not available for 1990 through 1993, and data from the 1994 USGS Minerals Yearbook were used for these years. Because a sulfate-process plant closed in September 2001, the chloride-process percentage for 2001 was estimated based on a discussion with Joseph Gambogi (2002). By 2002, only one sulfate plant remained online in the United States and this plant closed in 2004 (USGS 2005).

Table 4-39: Titanium Dioxide Production (Gg)

Year	Gg
1990	979
2000	1,400
2005	1,310
2006	1,370
2007	1,440
2008	1,350
2009	1,150

Uncertainty and Time-Series Consistency

Although some TiO_2 may be produced using graphite or other C inputs, information and data regarding these practices were not available. Titanium dioxide produced using graphite inputs, for example, may generate differing amounts of CO_2 per unit of TiO_2 produced as compared to that generated through the use of petroleum coke in production. While the most accurate method to estimate emissions would be to base calculations on the amount of reducing agent used in each process rather than on the amount of TiO_2 produced, sufficient data were not available to do so.

Also, annual TiO_2 is not reported by USGS by the type of production process used (chloride or sulfate). Only the percentage of total production capacity by process is reported. The percent of total TiO_2 production capacity that was attributed to the chloride process was multiplied by total TiO_2 production to estimate the amount of TiO_2 produced using the chloride process (since, as of 2004, the last remaining sulfate-process plant in the United States closed). This assumes that the chloride-process plants and sulfate-process plants operate at the same level of utilization. Finally, the emission factor was applied uniformly to all chloride-process production, and no data were available to account for differences in production efficiency among chloride-process plants. In calculating the amount of petroleum coke consumed in chloride-process TiO_2 production, literature data were used for petroleum coke composition. Certain grades of petroleum coke are manufactured specifically for use in the TiO_2 chloride process; however, this composition information was not available.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-40. Titanium dioxide consumption CO_2 emissions were estimated to be between 1.4 and 1.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 13 percent below and 13 percent above the emission estimate of 1.5 Tg CO_2 Eq.

Table 4-40: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Titanium Dioxide Production (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**[a]			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Titanium Dioxide Production	CO_2	1.5	1.3	1.7	-13%	+13%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the titanium dioxide production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from titanium dioxide production. Beginning in 2010, all U.S. titanium dioxide production facilities using the chloride production process are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. titanium dioxide production industry, including improving the emission factors. In addition, the planned improvements include researching the significance of titanium-slag production in electric furnaces and synthetic-rutile production using the Becher process in the United States. Significant use of these production processes will be included in future estimates.

4.11. Carbon Dioxide Consumption (IPCC Source Category 2B5)

CO_2 is used for a variety of commercial applications, including food processing, chemical production, carbonated beverage production, and refrigeration, and is also used in petroleum production for enhanced oil recovery (EOR). CO_2 used for EOR is injected into the underground reservoirs to increase the reservoir pressure to enable additional petroleum to be produced.

For the most part, CO_2 used in non-EOR applications will eventually be released to the atmosphere, and for the purposes of this analysis CO_2 used in commercial applications other than EOR is assumed to be emitted to the atmosphere. CO_2 used in EOR applications is discussed in the Energy Chapter under “Carbon Capture and Storage, including Enhanced Oil Recovery” and is not discussed in this section.

CO_2 is produced from naturally occurring CO_2 reservoirs, as a by-product from the energy and industrial production processes (e.g., ammonia production, fossil fuel combustion, ethanol production), and as a by-product from the production of crude oil and natural gas, which contain naturally occurring CO_2 as a component. Only CO_2 produced from naturally occurring CO_2 reservoirs and used in industrial applications other than EOR is included in this analysis. Neither by-product CO_2 generated from energy nor industrial production processes nor CO_2 separated from crude oil and natural gas are included in this analysis for a number of reasons. CO_2 captured from biogenic sources (e.g., ethanol production plants) is not included in the inventory. CO_2 captured from crude oil and gas production is used in EOR applications and is therefore reported in the Energy Chapter. Any CO_2 captured from industrial or energy production processes (e.g., ammonia plants, fossil fuel combustion) and used in non-EOR applications is assumed to be emitted to the atmosphere. The CO_2 emissions from such capture and use are therefore accounted for under Ammonia Production, Fossil Fuel Combustion, or other appropriate source category.[114]

CO_2 is produced as a by-product of crude oil and natural gas production. This CO_2 is separated from the crude oil and natural gas using gas processing equipment, and may be emitted directly to the atmosphere, or captured and reinjected into underground formations, used for EOR, or sold for other commercial uses. A further discussion of CO_2 used in EOR is described in the Energy Chapter under the text box titled "Carbon Dioxide Transport, Injection, and Geological Storage." The only CO_2 consumption that is accounted for in this analysis is CO_2 produced from naturally-occurring CO_2 reservoirs that is used in commercial applications other than EOR.

There are currently two facilities, one in Mississippi and one in New Mexico, producing CO_2 from naturally occurring CO_2 reservoirs for use in both EOR and in other commercial applications (e.g., chemical manufacturing, food production). There are other naturally occurring CO_2 reservoirs, mostly located in the western UnitedStates. Facilities are producing CO_2 from these natural reservoirs, but they are only producing CO_2 for EOR applications, not for other commercial applications (Allis et al. 2000). CO_2 production from these facilities is discussed in the Energy Chapter.

In 2009, the amount of CO_2 produced by the Mississippi and New Mexico facilities for commercial applications and subsequently emitted to the atmosphere was 1.8 Tg CO_2 Eq. (1,763 Gg) (see Table 4-41). This amount represents a decrease of one percent from the previous year and an increase of 24 percent since 1990. This increase was due to an in increase in production at the Mississippi facility, despite the decrease in the percent of the facility's total reported production that was used for commercial applications.

Table 4-41: CO_2 Emissions from CO_2 Consumption (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	1.4	1,416
2000	1.4	1,421
2005	1.3	1,321
2006	1.7	1,709
2007	1.9	1,867
2008	1.8	1,780
2009	1.8	1,763

Methodology

CO_2 emission estimates for 1990 through 2009 were based on production data for the two facilities currently producing CO_2 from naturally-occurring CO_2 reservoirs for use in non-EOR applications. Some of the CO_2 produced by these facilities is used for EOR and some is used in other commercial applications (e.g., chemical manufacturing, food production). It is assumed that 100 percent of the CO_2 production used in commercial applications other than EOR is eventually released into the atmosphere.

CO_2 production data for the Jackson Dome, Mississippi facility and the percentage of total production that was used for EOR and in non-EOR applications were obtained from the Advanced Resources Institute (ARI 2006, 2007) for 1990 to 2000 and from the Annual Reports for Denbury Resources (Denbury Resources 2002 through 2010) for 2001 to 2009 (see Table 4-42). Denbury Resources reported the average CO_2 production in units of MMCF CO_2 per day for 2001 through 2009 and reported the percentage of the total average annual production that was used for EOR. CO_2 production data for the Bravo Dome, New Mexico facility were obtained from the Advanced Resources International, Inc. (ARI 1990 through 2010). The percentage of total production that was used for EOR and in non-EOR applications were obtained from the New Mexico Bureau of Geology and Mineral Resources (Broadhead 2003 and New Mexico Bureau of Geology and Mineral Resources 2006).

Table 4-42: CO_2 Production (Gg CO_2) and the Percent Used for Non-EOR Applications for Jackson Dome and

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[114] There are currently four known electric power plants operating in the U.S. that capture CO_2 for use as food-grade CO_2 or other industrial processes; however, insufficient data prevents estimating emissions from these activities as part of Carbon Dioxide Consumption.

Bravo Dome

Year	Jackson Dome CO_2 Production (Gg)	Jackson Dome % Used for Non-EOR	Bravo Dome CO_2 Production (Gg)	Bravo Dome % Used for Non-EOR
1990	1,353	100%	6,301	1%
2000	1,353	100%	6,834	1%
2005	4,678	27%	5,799	1%
2006	6,610	25%	5,613	1%
2007	9,529	19%	5,605	1%
2008	12,312	14%	5,605	1%
2009	13,201	13%	4,639	1%

Uncertainty and Time-Series Consistency

Uncertainty is associated with the number of facilities that are currently producing CO_2 from naturally occurring CO_2 reservoirs for commercial uses other than EOR, and for which the CO_2 emissions are not accounted for elsewhere. Research indicates that there are only two such facilities, which are in New Mexico and Mississippi; however, additional facilities may exist that have not been identified. In addition, it is possible that CO_2 recovery exists in particular production and end-use sectors that are not accounted for elsewhere. Such recovery may or may not affect the overall estimate of CO_2 emissions from that sector depending upon the end use to which the recovered CO_2 is applied. Further research is required to determine whether CO_2 is being recovered from other facilities for application to end uses that are not accounted for elsewhere.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-43. CO_2 consumption CO_2 emissions were estimated to be between 1.3 and 2.3 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 26 percent below to 30 percent above the emission estimate of 1.8 Tg CO_2 Eq.

Table 4-43: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from CO_2 Consumption (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
CO_2 Consumption	CO_2	1.8	1.3	2.3	-26%	+30%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the Carbon Dioxide Consumption source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from carbon dioxide consumption. Beginning in 2010, all U.S. CO_2 producers are required to monitor, calculate and report the quantity of CO_2 supplied to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 on CO_2 supplied from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from consumption of CO_2.

4.12. Phosphoric Acid Production (IPCC Source Category 2B5)

Phosphoric acid (H_3PO_4) is a basic raw material in the production of phosphate-based fertilizers. Phosphate rock is mined in Florida, North Carolina, Idaho, Utah, and other areas of the United States and is used primarily as a raw material for phosphoric acid production. The production of phosphoric acid from phosphate rock produces byproduct gypsum ($CaSO_4$-$2H_2O$), referred to as phosphogypsum.

The composition of natural phosphate rock varies depending upon the location where it is mined. Natural phosphate rock mined in the United States generally contains inorganic C in the form of calcium carbonate (limestone) and also may contain organic C. The chemical composition of phosphate rock (francolite) mined in Florida is:

$$Ca_{10-x-y}\,Na_x\,Mg_y\,(PO_4)_{6-x}(CO_3)_xF_{2+0.4x}$$

The calcium carbonate component of the phosphate rock is integral to the phosphate rock chemistry. Phosphate rock can also contain organic C that is physically incorporated into the mined rock but is not an integral component of the phosphate rock chemistry. Phosphoric acid production from natural phosphate rock is a source of CO_2 emissions, due to the chemical reaction of the inorganic C (calcium carbonate) component of the phosphate rock.

The phosphoric acid production process involves chemical reaction of the calcium phosphate ($Ca_3(PO_4)_2$) component of the phosphate rock with sulfuric acid (H_2SO_4) and recirculated phosphoric acid (H_3PO_4) (EFMA 2000). The primary chemical reactions for the production of phosphoric acid from phosphate rock are:

$$Ca_3(PO_4)_2 + 4H_3PO_4 \rightarrow 3Ca(H_2PO_4)_2$$

$$3Ca(H_2PO_4)_2 + 3H_2SO_4 + 6H_2O \rightarrow 3CaSO_4 \bullet 6H_2O + 6H_3PO_4$$

The limestone ($CaCO_3$) component of the phosphate rock reacts with the sulfuric acid in the phosphoric acid production process to produce calcium sulfate (phosphogypsum) and CO_2. The chemical reaction for the limestone-sulfuric acid reaction is:

$$CaCO_3 + H_2SO_4 + H_2O \rightarrow CaSO_4 \bullet 2H_2O + CO_2$$

Total marketable phosphate rock production in 2009 was 27.2 million metric tons (USGS 2010). Approximately 87 percent of domestic phosphate rock production was mined in Florida and North Carolina, while approximately 13 percent of production was mined in Idaho and Utah. Total imports of phosphate rock in 2009 were 1.8 million metric tons (USGS 2010). The vast majority, 99 percent, of imported phosphate rock is sourced from Morocco (USGS 2005). Marketable phosphate rock production, including domestic production and imports for consumption, decreased by 13.6 percent between 2008 and 2009. Over the 1990 to 2009 period, production has decreased by 34 percent. Total CO_2 emissions from phosphoric acid production were 1.0 Tg CO_2 Eq. (1,035 Gg) in 2009 (see Table 4-44). According to USGS 2010, the weak market conditions of phosphate rock in the U.S. in 2009 were a result of the global economic crisis that started in late 2008 and carried into 2009.

Table 4-44: CO_2 Emissions from Phosphoric Acid Production (Tg CO_2 Eq. and Gg)

Year	Tg CO2 Eq.	Gg
1990	1.5	1,529
2000	1.4	1,382
2005	1.4	1,386
2006	1.2	1,167
2007	1.2	1,166
2008	1.2	1,187
2009	1.0	1,035

Methodology

CO_2 emissions from production of phosphoric acid from phosphate rock are calculated by multiplying the average amount of calcium carbonate contained in the natural phosphate rock by the amount of phosphate rock that is used annually to produce phosphoric acid, accounting for domestic production and net imports for consumption.

The CO_2 emissions calculation methodology is based on the assumption that all of the inorganic C (calcium carbonate) content of the phosphate rock reacts to CO_2 in the phosphoric acid production process and is emitted with the stack gas. The methodology also assumes that none of the organic C content of the phosphate rock is converted to CO_2 and that all of the organic C content remains in the phosphoric acid product.

From 1993 to 2004, the *USGS Mineral Yearbook: Phosphate Rock* disaggregated phosphate rock mined annually in Florida and North Carolina from phosphate rock mined annually in Idaho and Utah, and reported the annual amounts of phosphate rock exported and imported for consumption (see Table 4-45). For the years 1990, 1991, 1992, 2005, 2006, and 2007 only nationally aggregated mining data was reported by USGS. For these years, the breakdown of phosphate rock mined in Florida and North Carolina, and the amount mined in Idaho and Utah, are approximated using 1993 to 2004 data. Data for domestic production of phosphate rock, exports of phosphate rock (primarily from Florida and North Carolina), and imports of phosphate rock for consumption for 1990 through 2008 were obtained from *USGS Minerals Yearbook: Phosphate Rock* (USGS 1994 through 2010). 2009 data were obtained from *USGS Minerals Commodity Summary: Phosphate Rock* (USGS 2010). From 2004 through 2009, the USGS reported no exports of phosphate rock from U.S. producers (USGS 2005 through 2010).

The carbonate content of phosphate rock varies depending upon where the material is mined. Composition data for domestically mined and imported phosphate rock were provided by the Florida Institute of Phosphate Research (FIPR 2003). Phosphate rock mined in Florida contains approximately 1 percent inorganic C, and phosphate rock imported from Morocco contains approximately 1.46 percent inorganic C. Calcined phosphate rock mined in North Carolina and Idaho contains approximately 0.41 percent and 0.27 percent inorganic C, respectively (see Table 4-46).

Carbonate content data for phosphate rock mined in Florida are used to calculate the CO_2 emissions from consumption of phosphate rock mined in Florida and North Carolina (87 percent of domestic production) and carbonate content data for phosphate rock mined in Morocco are used to calculate CO_2 emissions from consumption of imported phosphate rock. The CO_2 emissions calculation is based on the assumption that all of the domestic production of phosphate rock is used in uncalcined form. As of 2006, the USGS noted that one phosphate rock producer in Idaho produces calcined phosphate rock; however, no production data were available for this single producer (USGS 2006). Carbonate content data for uncalcined phosphate rock mined in Idaho and Utah (13 percent of domestic production) were not available, and carbonate content was therefore estimated from the carbonate content data for calcined phosphate rock mined in Idaho.

Table 4-45: Phosphate Rock Domestic Production, Exports, and Imports (Gg)

Location/Year	1990	2000	2005	2006	2007	2008	2009
U.S. Production[a]	49,800	37,370	36,100	30,100	29,700	30,200	27,200
FL & NC	42,494	31,900	31,227	26,037	25,691	26,123	23,528
ID & UT	7,306	5,470	4,874	4,064	4,010	4,077	3,672
Exports—FL & NC	6,240	299	-	-	-	-	-
Imports—Morocco	451	1,930	2,630	2,420	2,670	2,754	1,800
Total U.S. Consumption	**44,011**	**39,001**	**38,730**	**32,520**	**32,370**	**32,954**	**29,000**

[a] USGS does not disaggregate production data regionally (FL & NC and ID & UT) for 1990, 2005, 2006, and 2007. Data for those years are estimated based on the remaining time series distribution.

- Assumed equal to zero.

Table 4-46: Chemical Composition of Phosphate Rock (percent by weight)

Composition	Central Florida	North Florida	North Carolina (calcined)	Idaho (calcined)	Morocco
Total Carbon (as C)	1.60	1.76	0.76	0.60	1.56
Inorganic Carbon (as C)	1.00	0.93	0.41	0.27	1.46
Organic Carbon (as C)	0.60	0.83	0.35	-	0.10
Inorganic Carbon (as CO_2)	3.67	3.43	1.50	1.00	5.00

Source: FIPR 2003

- Assumed equal to zero.

Uncertainty and Time-Series Consistency

Phosphate rock production data used in the emission calculations were developed by the USGS through monthly and semiannual voluntary surveys of the active phosphate rock mines during 2009. For previous years in the time series, USGS provided the data disaggregated regionally; however, beginning in 2006 only total U.S. phosphate rock production were reported. Regional production for 2008 was estimated based on regional production data from previous years and multiplied by regionally-specific emission factors. There is uncertainty associated with the degree to which the estimated 2008 regional production data represents actual production in those regions. Total U.S. phosphate rock production data are not considered to be a significant source of uncertainty because all the domestic phosphate rock producers report their annual production to the USGS. Data for exports of phosphate rock used in the emission calculation are reported by phosphate rock producers and are not considered to be a significant source of uncertainty. Data for imports for consumption are based on international trade data collected by the U.S. Census Bureau. These U.S. government economic data are not considered to be a significant source of uncertainty.

An additional source of uncertainty in the calculation of CO_2 emissions from phosphoric acid production is the carbonate composition of phosphate rock; the composition of phosphate rock varies depending upon where the material is mined, and may also vary over time. Another source of uncertainty is the disposition of the organic C content of the phosphate rock. A representative of the FIPR indicated that in the phosphoric acid production process, the organic C content of the mined phosphate rock generally remains in the phosphoric acid product, which is what produces the color of the phosphoric acid product (FIPR 2003a). Organic C is therefore not included in the calculation of CO_2 emissions from phosphoric acid production.

A third source of uncertainty is the assumption that all domestically-produced phosphate rock is used in phosphoric acid production and used without first being calcined. Calcination of the phosphate rock would result in conversion of some of the organic C in the phosphate rock into CO_2. However, according to the USGS, only one producer in Idaho is currently calcining phosphate rock, and no data were available concerning the annual production of this single producer (USGS 2005). For available years, total production of phosphate rock in Utah and Idaho combined amounts to approximately 13 percent of total domestic production on average (USGS 1994 through 2005).

Finally, USGS indicated that approximately 7 percent of domestically-produced phosphate rock is used to manufacture elemental phosphorus and other phosphorus-based chemicals, rather than phosphoric acid (USGS 2006). According to USGS, there is only one domestic producer of elemental phosphorus, in Idaho, and no data were available concerning the annual production of this single producer. Elemental phosphorus is produced by reducing phosphate rock with coal coke, and it is therefore assumed that 100 percent of the carbonate content of the phosphate rock will be converted to CO_2 in the elemental phosphorus production process. The calculation for CO_2 emissions is based on the assumption that phosphate rock consumption, for purposes other than phosphoric acid production, results in CO_2 emissions from 100 percent of the inorganic C content in phosphate rock, but none from the organic C content.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-47. Phosphoric acid production CO_2 emissions were estimated to be between 0.9 and 1.2 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 18 percent below and 19 percent above the emission estimate of 1.0 Tg CO_2 Eq.

Table 4-47: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Phosphoric Acid Production (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**[a] **(Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Phosphoric Acid Production	CO_2	1.0	0.9	1.2	-18%	+19%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the phosphoric acid production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from phosphoric acid production. Beginning in 2010, all U.S. phosphoric acid producers are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from facilities based on use of higher tier methods and assess how this data could be used to improve the method for calculating emissions from the U.S. phosphoric acid production industry. Currently, data sources for the carbonate content of the phosphate rock are limited. If additional data sources are found, this information will be incorporated into future estimates. Additionally, as future improvement to the phosphoric acid uncertainty analysis, USGS Mineral Commodity Specialists will be contacted to verify uncertainty ranges associated with phosphate rock imports and exports.

4.13. Iron and Steel Production (IPCC Source Category 2C1) and Metallurgical Coke Production

The production of iron and steel is an energy-intensive activity that also generates process-related emissions of CO_2 and CH_4. Process emissions occur at each step of steel production from the production of raw materials to the refinement of iron to the making of crude steel. In the United States, steel is produced through both primary and secondary processes. Historically, primary production—using a basic oxygen furnace (BOF) with pig iron as the primary feedstock—has been the dominant method. But secondary production through the use scrap steel and electric arc furnaces (EAFs) has increased significantly in recent years due to the economic advantages of steel recycling, which has been driven by the increased availability of scrap steel. Total production of crude steel in the United States in the time period between 2001 and 2008 ranged from a low of 99,321,000 tons to a high of 109,879,000 tons (2001 and 2004, respectively). But due to the decrease in demand caused by the global economic downturn, crude steel production in the United States decreased to 65,460,000 tons in 2009 (AISI 2010).

Metallurgical coke is an important input in the production of iron and steel. Coke is used to produce iron or pig iron feedstock from raw iron ore. The production of metallurgical coke from coking coal occurs both on-site at "integrated" iron and steel plants and off-site at "merchant" coke plants. Metallurgical coke is produced by heating coking coal in a coke oven in a low-oxygen environment. The process drives off the volatile components of the coking coal and produces coal (metallurgical) coke. Carbon containing byproducts of the metallurgical coke manufacturing process include coke oven gas, coal tar, coke breeze (small-grade coke oven coke with particle size <5mm) and light oil. Coke oven gas is recovered and used for underfiring the coke ovens and within the iron and steel mill. Small amounts of coke oven gas are also sold as synthetic natural gas outside of iron and steel mills (and are accounted for in the Energy chapter). Coal tar is used as a raw material to produce anodes used for primary aluminum production, electric arc furnace (EAF) steel production, and other electrolytic processes, and also is used in the production of other coal tar products. Light oil is sold to petroleum refiners who use the material as an additive for gasoline. The metallurgical coke production process produces CO_2 emissions and fugitive CH_4 emissions.

Iron is produced by first reducing iron oxide (iron ore) with metallurgical coke in a blast furnace. Iron can be introduced into the blast furnace in the form of raw iron ore, taconite pellets (9-16mm iron-containing spheres), briquettes, or sinter. In addition to metallurgical coke and iron, other inputs to the blast furnace include natural gas, fuel oil, and coke oven gas. The carbon in the metallurgical coke used in the blast furnace combines with oxides in the iron ore in a reducing atmosphere to produce blast furnace gas containing carbon monoxide (CO) and CO_2. The CO is then converted and emitted as CO_2 when combusted to either pre-heat the blast air used in the blast furnace or for other purposes at the steel mill. This pig iron or crude iron that is produced from this process contains about 3 to 5 percent carbon by weight. The pig iron production process in a blast furnace produces CO_2 emissions and fugitive CH_4 emissions.

Iron can also be produced through the direct reduction process; wherein, iron ore is reduced to metallic iron in the solid state at process temperatures less than 1000°C. Direct reduced iron production results in process emissions of CO_2 and emissions of CH_4 through the consumption of natural gas used during the reduction process.

Sintering is a thermal process by which fine iron-bearing particles, such as air emission control system dust, are baked, which causes the material to agglomerate into roughly one-inch pellets that are then recharged into the blast furnace for pig iron production. Iron ore particles may also be formed into larger pellets or briquettes by mechanical means, and then agglomerated by heating. The agglomerate is then crushed and screened to produce an iron-bearing feed that is charged into the blast furnace. The sintering process produces CO_2 and fugitive CH_4 emissions through the consumption of carbonaceous inputs (e.g., coke breeze) during the sintering process.

Steel is produced from varying levels of pig iron and scrap steel in specialized BOF and EAF steel-making furnaces. Carbon inputs to BOF steel-making furnaces include pig iron and scrap steel as well as natural gas, fuel oil, and fluxes (e.g., limestone, dolomite). In a BOF, the carbon in iron and scrap steel combines with high-purity oxygen to reduce the carbon content of the metal to the amount desired for the specified grade of steel. EAFs use carbon electrodes, charge carbon and other materials (e.g., natural gas) to aid in melting metal inputs (primarily recycled scrap steel), which are refined and alloyed to produce the desired grade of steel. CO_2 emissions occur in BOFs through the reduction process. In EAFs, CO_2 emissions result primarily from the consumption of carbon electrodes and also from the consumption of supplemental materials used to augment the melting process.

In addition to the production processes mentioned above, CO_2 is also generated at iron and steel mills through the consumption of process by-products (e.g., blast furnace gas, coke oven gas) used for various purposes including heating, annealing, and electricity generation. Process by-products sold for use as synthetic natural gas are deducted and reported in the Energy chapter (emissions associated with natural gas and fuel oil consumption for these purposes are reported in the Energy chapter).

The majority of CO_2 emissions from the iron and steel production process come from the use of metallurgical coke in the production of pig iron and from the consumption of other process by-products at the iron and steel mill, with lesser amounts emitted from the use of flux and from the removal of carbon from pig iron used to produce steel. Some carbon is also stored in the finished iron and steel products.

According to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006), the production of metallurgical coke from coking coal is considered to be an energy use of fossil fuel and the use of coke in iron and steel production is considered to be an industrial process source. Therefore, the Guidelines suggest that emissions from the production of metallurgical coke should be reported separately in the Energy source, while emissions from coke consumption in iron and steel production should be reported in the industrial process source. However, the approaches and emission estimates for both metallurgical coke production and iron and steel production are both presented here because the activity data used to estimate emissions from metallurgical coke production have significant overlap with activity data used to estimate iron and steel production emissions. Further, some by-products (e.g., coke oven gas) of the metallurgical coke production process are consumed during iron and steel production, and some by-products of the iron and steel production process (e.g., blast furnace gas) are consumed during metallurgical coke production. Emissions associated with the consumption of these by-products are attributed to point of consumption. As an example, CO_2 emissions associated with the combustion of coke oven gas in the blast furnace during pig iron production are attributed to pig iron production. Emissions associated with the use of conventional fuels (e.g., natural gas and fuel oil) for electricity generation, heating and annealing, or other miscellaneous purposes downstream of the iron and steelmaking furnaces are reported in the Energy chapter.

Metallurgical Coke Production

Emissions of CO_2 and CH_4 from metallurgical coke production in 2009 were 1.0 Tg CO_2 Eq. (956 Gg) and less than 0.002 Tg CO_2 Eq. (less than 0.00003 Gg), respectively (see Table 4-48 and Table 4-49), totaling 1.0 Tg CO_2 Eq. Emissions decreased in 2009, and have decreased overall since 1990. In 2009, domestic coke production decreased by 29 percent and has decreased overall since 1990. Coke production in 2009 was 46 percent lower than in 2000 and 60 percent below 1990. Overall, emissions from metallurgical coke production have declined by 61 percent (1.5 Tg CO_2 Eq.) from 1990 to 2009.

Table 4-48: CO_2 and CH_4 Emissions from Metallurgical Coke Production (Tg CO_2 Eq.)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	2.5	2.2	2.0	1.9	2.1	2.3	1.0
CH_4	+	+	+	+	+	+	+
Total	**2.5**	**2.2**	**2.0**	**1.9**	**2.1**	**2.3**	**1.0**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 4-49: CO_2 and CH_4 Emissions from Metallurgical Coke Production (Gg)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	2,470	2,195	2,043	1,919	2,054	2,334	956
CH_4	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg

Iron and Steel Production

Emissions of CO_2 and CH_4 from iron and steel production in 2009 were 40.9 Tg CO_2 Eq. (40,914 Gg) and 0.4 Tg CO_2 Eq. (17.4 Gg), respectively (see Table 4-50 through Table 4-53), totaling approximately 41 Tg CO_2 Eq. Emissions decreased in 2009—largely due to decreased steel production associated with the global economic downturn—and have decreased overall since 1990 due to restructuring of the industry, technological improvements, and increased scrap steel utilization. CO_2 emission estimates include emissions from the consumption of carbonaceous materials in the blast furnace, EAF, and BOF as well as blast furnace gas and coke oven gas consumption for other activities at the steel mill.

In 2009, domestic production of pig iron decreased by 44 percent. Overall, domestic pig iron production has declined since the 1990s. Pig iron production in 2009 was 60 percent lower than in 2000 and 62 percent below 1990. CO_2 emissions from steel production have declined by 15 percent (1.1 Tg CO_2 Eq.) since 1990, while overall CO_2 emissions from iron and steel production have declined by 58 percent (56.1 Tg CO_2 Eq.) from 1990 to 2009.

Table 4-50: CO_2 Emissions from Iron and Steel Production (Tg CO_2 Eq.)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Sinter Production	2.4	2.2	1.7	1.4	1.4	1.3	0.8
Iron Production	47.9	33.8	19.6	23.9	27.3	25.7	15.9
Steel Production	7.5	7.9	8.5	8.9	9.4	7.5	6.4
Other Activities[a]	39.3	39.9	34.2	32.6	31.0	29.1	17.8
Total	**97.1**	**83.7**	**63.9**	**66.9**	**69.0**	**63.7**	**40.9**

Note: Totals may not sum due to independent rounding.

[a] Includes emissions from blast furnace gas and coke oven gas combustion for activities at the steel mill other than consumption in blast furnace, EAFs, or BOFs.

Table 4-51: CO_2 Emissions from Iron and Steel Production (Gg)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Sinter Production	2,448	2,158	1,663	1,418	1,383	1,299	763
Iron Production	47,880	33,818	19,570	23,928	27,262	25,696	15,948
Steel Production	7,475	7,887	8,489	8,924	9,382	7,541	6,389
Other Activities [a]	39,256	39,877	34,160	32,583	30,964	29,146	17,815
Total	**97,058**	**83,740**	**63,882**	**66,852**	**68,991**	**63,682**	**40,914**

Note: Totals may not sum due to independent rounding.

[a] Includes emissions from blast furnace gas and coke oven gas combustion for activities at the steel mill other than consumption in blast furnace, EAFs, or BOFs.

Table 4-52: CH_4 Emissions from Iron and Steel Production (Tg CO_2 Eq.)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Sinter Production	+	+	+	+	+	+	+
Iron Production	0.9	0.9	0.7	0.7	0.7	0.6	0.4
Total	**1.0**	**0.9**	**0.7**	**0.7**	**0.7**	**0.6**	**0.4**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 4-53: CH_4 Emissions from Iron and Steel Production (Gg)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Sinter Production	0.9	0.7	0.6	0.5	0.5	0.4	0.3
Iron Production	44.7	43.1	33.5	34.1	32.7	30.4	17.1
Total	**45.6**	**43.8**	**34.1**	**34.6**	**33.2**	**30.8**	**17.4**

Note: Totals may not sum due to independent rounding.

Methodology

Emission estimates presented in this chapter are based on the methodologies provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006), which call for a mass balance accounting of the carbonaceous inputs and outputs during the iron and steel production process and the metallurgical coke production process.

Metallurgical Coke Production

Coking coal is used to manufacture metallurgical (coal) coke that is used primarily as a reducing agent in the production of iron and steel, but is also used in the production of other metals including lead and zinc (see Lead

Production and Zinc Production in this chapter). Emissions associated with producing metallurgical coke from coking coal are estimated and reported separately from emissions that result from the iron and steel production process. To estimate emission from metallurgical coke production, a Tier 2 method provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) was utilized. The amount of carbon contained in materials produced during the metallurgical coke production process (i.e., coke, coke breeze, coke oven gas, and coal tar) is deducted from the amount of carbon contained in materials consumed during the metallurgical coke production process (i.e., natural gas, blast furnace gas, coking coal). Light oil, which is produced during the metallurgical coke production process, is excluded from the deductions due to data limitations. The amount of carbon contained in these materials is calculated by multiplying the material-specific carbon content by the amount of material consumed or produced (see Table 4-54). The amount of coal tar produced was approximated using a production factor of 0.03 tons of coal tar per ton of coking coal consumed. The amount of coke breeze produced was approximated using a production factor of 0.075 tons of coke breeze per ton of coking coal consumed. Data on the consumption of carbonaceous materials (other than coking coal) as well as coke oven gas production were available for integrated steel mills only (i.e., steel mills with co-located coke plants). Therefore, carbonaceous material (other than coking coal) consumption and coke oven gas production were excluded from emission estimates for merchant coke plants. Carbon contained in coke oven gas used for coke-oven underfiring was not included in the deductions to avoid double-counting.

Table 4-54: Material Carbon Contents for Metallurgical Coke Production

Material	kg C/kg
Coal Tar	0.62
Coke	0.83
Coke Breeze	0.83
Coking Coal	0.73
Material	**kg C/GJ**
Coke Oven Gas	12.1
Blast Furnace Gas	70.8

Source: IPCC 2006, Table 4.3. Coke Oven Gas and Blast Furnace Gas, Table 1.3.

The production processes for metallurgical coke production results in fugitive emissions of CH_4, which are emitted via leaks in the production equipment rather than through the emission stacks or vents of the production plants. The fugitive emissions were calculated by applying Tier 1 emission factors (0.1 g CH_4 per metric ton) taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) for metallurgical coke production.

Data relating to the mass of coking coal consumed at metallurgical coke plants and the mass of metallurgical coke produced at coke plants were taken from the Energy Information Administration (EIA), Quarterly Coal Report October through December (EIA 1998 through 2004) and January through March (EIA 2010a) (see Table 4-55). Data on the volume of natural gas consumption, blast furnace gas consumption, and coke oven gas production for metallurgical coke production at integrated steel mills were obtained from the American Iron and Steel Institute (AISI), *Annual Statistical Report* (AISI 2004 through 20010) and through personal communications with AISI (2008b) (see Table 4-56). The factor for the quantity of coal tar produced per ton of coking coal consumed was provided by AISI (2008b). The factor for the quantity of coke breeze produced per ton of coking coal consumed was obtained through Table 2-1 of the report *Energy and Environmental Profile of the U.S. Iron and Steel Industry* (DOE 2000). Data on natural gas consumption and coke oven gas production at merchant coke plants were not available and were excluded from the emission estimate. Carbon contents for coking coal, metallurgical coke, coal tar, coke oven gas, and blast furnace gas were provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The C content for coke breeze was assumed to equal the C content of coke.

Table 4-55: Production and Consumption Data for the Calculation of CO_2 and CH_4 Emissions from Metallurgical Coke Production (Thousand Metric Tons)

Source/Activity Data	1990	2000	2005	2006	2007	2008	2009
Metallurgical Coke Production							
Coking Coal Consumption at Coke Plants	35,269	26,254	21,259	20,827	20,607	20,022	13,904
Coke Production at Coke Plants	25,054	18,877	15,167	14,882	14,698	14,194	10,109
Coal Breeze Production	2,645	1,969	1,594	1,562	1,546	1,502	1,043
Coal Tar Production	1,058	788	638	625	618	601	417

Table 4-56: Production and Consumption Data for the Calculation of CO_2 Emissions from Metallurgical Coke Production (million ft^3)

Source/Activity Data	1990	2000	2005	2006	2007	2008	2009
Metallurgical Coke Production							
Coke Oven Gas Production[a]	250,767	149,477	114,213	114,386	109,912	103,191	66,155
Natural Gas Consumption	599	180	2,996	3,277	3,309	3,134	2,121
Blast Furnace Gas Consumption	24,602	26,075	4,460	5,505	5,144	4,829	2,435

[a] Includes coke oven gas used for purposes other than coke oven underfiring only.

Iron and Steel Production

Emissions of CO_2 from sinter production and direct reduced iron production were estimated by multiplying total national sinter production and the total national direct reduced iron production by Tier 1 CO_2 emission factors (see Table 4-57). Because estimates of sinter production and direct reduced iron production were not available, production was assumed to equal consumption.

Table 4-57: CO_2 Emission Factors for Sinter Production and Direct Reduced Iron Production

Material Produced	Metric Ton CO_2/Metric Ton
Sinter	0.2
Direct Reduced Iron	0.7

Source: IPCC 2006, Table 4.1.

To estimate emissions from pig iron production in the blast furnace, the amount of C contained in the produced pig iron and blast furnace gas were deducted from the amount of C contained in inputs (i.e., metallurgical coke, sinter, natural ore, pellets, natural gas, fuel oil, coke oven gas, direct coal injection). The C contained in the pig iron, blast furnace gas, and blast furnace inputs was estimated by multiplying the material-specific carbon content by each material type (see Table 4-58). Carbon in blast furnace gas used to pre-heat the blast furnace air is combusted to form CO_2 during this process.

Emissions from steel production in EAFs were estimated by deducting the C contained in the steel produced from the carbon contained in the EAF anode, charge carbon, and scrap steel added to the EAF. Small amounts of C from direct reduced iron, pig iron, and flux additions to the EAFs were also included in the EAF calculation. For BOFs, estimates of C contained in BOF steel were deducted from carbon contained in inputs such as natural gas, coke oven gas, fluxes, and pig iron. In each case, the C was calculated by multiplying material-specific carbon contents by each material type (see Table 4-58). For EAFs, the amount of EAF anode consumed was approximated by multiplying total EAF steel production by the amount of EAF anode consumed per metric ton of steel produced (0.002 metric tons EAF anode per metric ton steel produced (AISI 2008b)). The amount of flux (e.g., limestone and dolomite) used during steel manufacture was deducted from the Limestone and Dolomite Use source category to avoid double-counting.

CO_2 emissions from the consumption of blast furnace gas and coke oven gas for other activities occurring at the steel mill were estimated by multiplying the amount of these materials consumed for these purposes by the material-specific C content (see Table 4-58).

CO_2 emissions associated with the sinter production, direct reduced iron production, pig iron production, steel production, and other steel mill activities were summed to calculate the total CO_2 emissions from iron and steel production (see Table 4-50and Table 4-51).

Table 4-58: Material Carbon Contents for Iron and Steel Production

Material	kg C/kg
Coke	0.83
Direct Reduced Iron	0.02
Dolomite	0.13
EAF Carbon Electrodes	0.82
EAF Charge Carbon	0.83
Limestone	0.12
Pig Iron	0.04

Steel	0.01
Material	**kg C/GJ**
Coke Oven Gas	12.1
Blast Furnace Gas	70.8

Source: IPCC 2006, Table 4.3. Coke Oven Gas and Blast Furnace Gas, Table 1.3.

The production processes for sinter and pig iron result in fugitive emissions of CH_4, which are emitted via leaks in the production equipment rather than through the emission stacks or vents of the production plants. The fugitive emissions were calculated by applying Tier 1 emission factors taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) for sinter production and the 1995 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1995) (see Table 4-59) for pig iron production. The production of direct reduced iron also results in emissions of CH_4 through the consumption of fossil fuels (e.g., natural gas); however, these emissions estimates are excluded due to data limitations.

Table 4-59: CH_4 Emission Factors for Sinter and Pig Iron Production

Material Produced	Factor	Unit
Pig Iron	0.9	g CH_4/kg
Sinter	0.07	kg CH_4/metric ton

Source: Sinter (IPCC 2006, Table 4.2), Pig Iron (IPCC/UNEP/OECD/IEA 1995, Table 2.2)

Sinter consumption and direct reduced iron consumption data were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2008b) (see Table 4-60). Data on direct reduced iron consumed in EAFs were not available for the years 1990, 1991, 1999, 2006, 2007, 2008, and 2009. EAF direct reduced iron consumption in 1990 and 1991 were assumed to equal consumption in 1992, and consumption in 1999 was assumed to equal the average of 1998 and 2000. EAF consumption in 2006, 2007, 2008, and 2009 were calculated by multiplying the total DRI consumption for all furnaces as provided in the 2009 AISI Annual Statistical Report by the EAF share of total DRI consumption in 2005 (the most recent year that data was available for EAF vs. BOF consumption of DRI). Data on direct reduced iron consumed in BOFs were not available for the years 1990 through 1994, 1999, 2006, 2007, 2008, and 2009. BOF direct reduced iron consumption in 1990 through 1994 was assumed to equal consumption in 1995, and consumption in 1999 was assumed to equal the average of 1998 and 2000. BOF consumption in 2006, 2007, and 2008 were calculated by multiplying the total DRI consumption for all furnaces as provided in the 2009 AISI Annual Statistical Report by the BOF share of total DRI consumption in 2005 (the most recent year that data was available for EAF vs. BOF consumption of DRI). The Tier 1 CO_2 emission factors for sinter production and direct reduced iron production were obtained through the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). Data for pig iron production, coke, natural gas, fuel oil, sinter, and pellets consumed in the blast furnace; pig iron production; and blast furnace gas produced at the iron and steel mill and used in the metallurgical coke ovens and other steel mill activities were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2008b) (see Table 4-61). Data for EAF steel production, flux, EAF charge carbon, direct reduced iron, pig iron, scrap steel, and natural gas consumption as well as EAF steel production were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2011). The factor for the quantity of EAF anode consumed per ton of EAF steel produced was provided by AISI (AISI 2008b). Data for BOF steel production, flux, direct reduced iron, pig iron, scrap steel, natural gas, natural ore, pellet sinter consumption as well as BOF steel production were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2008b). Because data on pig iron consumption and scrap steel consumption in BOFs and EAFs were not available for 2006, 2007, and 2009, values for these years were calculated by multiplying the total pig iron and scrap steel consumption for all furnaces as provided in the 2009 AISI Annual Statistical Report by the BOF and EAF shares of total pig iron and scrap consumption in 2005 (the most recent year that data was available for EAF vs. BOF consumption of pig iron and scrap steel). Because pig iron consumption in EAFs was also not available in 2003 and 2004, the average of 2002 and 2005 pig iron consumption data were used. Data on coke oven gas and blast furnace gas consumed at the iron and steel mill other than in the EAF, BOF, or blast furnace were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2008b). Data on blast furnace gas and coke oven gas sold for use as synthetic natural gas were obtained through EIA's *Natural Gas Annual 2009* (EIA 2010b). C contents for direct reduced iron, EAF carbon electrodes, EAF charge carbon, limestone, dolomite, pig iron, and steel were provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The C contents for natural gas, fuel oil, and direct injection coal as well as the heat contents for the same fuels were provided by EIA (1992, 2010c). Heat contents for coke oven gas and blast furnace gas were provided in Table 2-2 of the report *Energy and Environmental Profile of the U.S. Iron and Steel Industry* (DOE 2000).

Table 4-60: Production and Consumption Data for the Calculation of CO_2 and CH_4 Emissions from Iron and Steel Production (Thousand Metric Tons)

Source/Activity Data	1990	2000	2005	2006	2007	2008	2009
Sinter Production							
Sinter Production	12,239	10,788	8,315	7,088	6,914	6,497	3,814
Direct Reduced Iron Production							
Direct Reduced Iron Production	936	1,914	1,633	1,497	2,087	1,769	1,243
Pig Iron Production							
Coke Consumption	24,946	19,215	13,832	14,684	15,039	14,251	8,572
Pig Iron Production	49,669	47,888	37,222	37,904	36,337	33,730	19,019
Direct Injection Coal Consumption	1,485	3,012	2,573	2,526	2,734	2,578	1,674
EAF Steel Production							
EAF Anode and Charge Carbon Consumption	67	96	1,127	1,245	1,214	1,109	845
Scrap Steel Consumption	35,743	43,001	37,558	38,033	40,845	40,824	35,472
Flux Consumption	319	654	695	671	567	680	476
EAF Steel Production	33,511	47,860	52,194	56,071	57,004	52,791	36,700
BOF Steel Production							
Pig Iron Consumption	46,564	46,993	32,115	32,638	33,773	29,322	23,134
Scrap Steel Consumption	14,548	14,969	11,612	11,759	12,628	8,029	6,641
Flux Consumption	576	978	582	610	408	431	318
BOF Steel Production	43,973	53,965	42,705	42,119	41,099	39,105	22,659

Table 4-61: Production and Consumption Data for the Calculation of CO_2 Emissions from Iron and Steel Production (million ft^3 unless otherwise specified)

Source/Activity Data	1990	2000	2005	2006	2007	2008	2009
Pig Iron Production							
Natural Gas Consumption	56,273	91,798	59,844	58,344	56,112	53,349	35,933
Fuel Oil Consumption (thousand gallons)	163,397	120,921	16,170	87,702	84,498	55,552	23,179
Coke Oven Gas Consumption	22,033	13,702	16,557	16,649	16,239	15,336	9,951
Blast Furnace Gas Production	1,439,380	1,524,891	1,299,980	1,236,526	1,173,588	1,104,674	672,486
EAF Steel Production							
Natural Gas Consumption	9,604	13,717	14,959	16,070	16,337	15,130	10,518
BOF Steel Production							
Natural Gas Consumption	6,301	6,143	5,026	5,827	11,740	-4,304[a]	-2,670[a]
Coke Oven Gas Consumption	3,851	640	524	559	525	528	373
Other Activities							
Coke Oven Gas Consumption	224,883	135,135	97,132	97,178	93,148	87,327	55,831
Blast Furnace Gas Consumption	1,414,778	1,498,816	1,295,520	1,231,021	1,168,444	1,099,845	670,051

[a] EPA is continuing to work with AISI to investigate why this value is negative.

Uncertainty and Time-Series Consistency

The estimates of CO_2 and CH_4 emissions from metallurgical coke production are based on material production and consumption data and average carbon contents. Uncertainty is associated with the total U.S. coking coal consumption, total U.S. coke production and materials consumed during this process. Data for coking coal consumption and metallurgical coke production are from different data sources (EIA) than data for other carbonaceous materials consumed at coke plants (AISI), which does not include data for merchant coke plants. There is uncertainty associated with the fact that coal tar and coke breeze production were estimated based on coke production because coal tar and coke breeze production data were not available. Since merchant coke plant data is not included in the estimate of other carbonaceous materials consumed at coke plants, the mass balance equation for CO_2 from metallurgical coke production cannot be reasonably completed. Therefore, for the purpose of this analysis, uncertainty parameters are applied to primary data inputs to the calculation (i.e, coking coal consumption and metallurgical coke production) only.

The estimates of CO_2 emissions from iron and steel production are based on material production and consumption data and average C contents. There is uncertainty associated with the assumption that direct reduced iron and sinter consumption are equal to production. There is uncertainty associated with the assumption that all coal used for purposes other than coking coal is for direct injection coal. Some of this coal may be used for electricity generation. There is also uncertainty associated with the C contents for pellets, sinter, and natural ore, which are assumed to equal the C contents of direct reduced iron. For EAF steel production there is uncertainty associated with the amount of EAF anode and charge C consumed due to inconsistent data throughout the time series. Uncertainty is also associated with the use of process gases such as blast furnace gas and coke oven gas. Data are not available to differentiate between the use of these gases for processes at the steel mill versus for energy generation (e.g., electricity and steam generation); therefore, all consumption is attributed to iron and steel production. These data and C contents produce a relatively accurate estimate of CO_2 emissions. However, there are uncertainties associated with each.

For the purposes of the CH_4 calculation from iron and steel production it is assumed that all of the CH_4 escapes as fugitive emissions and that none of the CH_4 is captured in stacks or vents. Additionally, the CO_2 emissions calculation is not corrected by subtracting the C content of the CH_4, which means there may be a slight double counting of C as both CO_2 and CH_4.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-62 for metallurgical coke production and iron and steel production. Total CO_2 emissions from metallurgical coke production and iron and steel production were estimated to be between 35.2 and 48.4 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 16 percent below and 16 percent above the emission estimate of 41.9 Tg CO_2 Eq. Total CH_4 emissions from metallurgical coke production and iron and steel production were estimated to be 0.4 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 21 percent below and 23 percent above the emission estimate of 0.4 Tg CO_2 Eq.

Table 4-62: Tier 2 Quantitative Uncertainty Estimates for CO_2 and CH_4 Emissions from Iron and Steel Production and Metallurgical Coke Production (Tg. CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Metallurgical Coke & Iron and Steel Production	CO_2	41.9	35.2	48.4	-16%	+16%
Metallurgical Coke & Iron and Steel Production	CH_4	0.4	0.3	0.4	-21%	+23%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the Iron and Steel production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from iron and steel production. Beginning in 2010, all U.S. iron and steel producing facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the method for calculating emissions from the U.S. iron and steel industry. Specifically, plans include attributing emissions estimates for the production of metallurgical coke to the Energy chapter as well as identifying the amount of carbonaceous materials, other than coking coal, consumed at merchant coke plants. Additional improvements include identifying the amount of coal used for direct injection and the amount of coke breeze, coal tar, and light oil produced during coke production. Efforts will also be made to identify inputs for preparing Tier 2 estimates for sinter and direct reduced iron production, as well as identifying information to better characterize emissions from the use of process gases and fuels within the Energy and Industrial Processes chapters.

Recalculations Discussion

In the previous Inventory, coal tar production and coke breeze production were incorrectly estimated by multiplying the respective production factors by U.S. coke production at coke plants rather than U.S. coking coal consumption at coke plants (to which the coal tar and coke breeze production factors should be applied). This issue has been corrected and decreased the 1990 through 2008 emissions from metallurgical coke production by an average of 53 percent per year relative to the previous Inventory. The total 1990 through 2008 emissions for metallurgical coke and iron and steel production decreased by an average of 3 percent per year relative to the previous Inventory.

4.14. Ferroalloy Production (IPCC Source Category 2C2)

CO_2 and CH_4 are emitted from the production of several ferroalloys. Ferroalloys are composites of iron and other elements such as silicon, manganese, and chromium. When incorporated in alloy steels, ferroalloys are used to alter the material properties of the steel. Estimates from two types of ferrosilicon (25 to 55 percent and 56 to 95 percent silicon), silicon metal (about 98 percent silicon), and miscellaneous alloys (36 to 65 percent silicon) have been calculated. Emissions from the production of ferrochromium and ferromanganese are not included here because of the small number of manufacturers of these materials in the United States. Subsequently, government information disclosure rules prevent the publication of production data for these production facilities.

Similar to emissions from the production of iron and steel, CO_2 is emitted when metallurgical coke is oxidized during a high-temperature reaction with iron and the selected alloying element. Due to the strong reducing environment, CO is initially produced, and eventually oxidized to CO_2. A representative reaction equation for the production of 50 percent ferrosilicon is given below:

$$Fe_2O_3 + 2SiO_2 + 7C \rightarrow 2FeSi + 7CO$$

While most of the C contained in the process materials is released to the atmosphere as CO_2, a percentage is also released as CH_4 and other volatiles. The amount of CH_4 that is released is dependent on furnace efficiency, operation technique, and control technology.

Emissions of CO_2 from ferroalloy production in 2009 were 1.5 Tg CO_2 Eq. (1,469 Gg) (see Table 4-63 and Table 4-64), which is a 32 percent reduction since 1990. Emissions of CH_4 from ferroalloy production in 2009 were 0.01 Tg CO_2 Eq. (0.406 Gg), which is a 40 percent decrease since 1990.

Table 4-63: CO_2 and CH_4 Emissions from Ferroalloy Production (Tg CO_2 Eq.)

Year	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	2.2		1.9		1.4	1.5	1.6	1.6	1.5
CH_4	+		+		+	+	+	+	+
Total	**2.2**		**1.9**		**1.4**	**1.5**	**1.6**	**1.6**	**1.6**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 4-64: CO_2 and CH_4 Emissions from Ferroalloy Production (Gg)

Year	1990		2000		2005	2006	2007	2008	2009
CO_2	2,152		1,893		1,392	1,505	1,552	1,599	1,469
CH_4	1		1		+	+	+	+	+

Methodology

Emissions of CO_2 and CH_4 from ferroalloy production were calculated by multiplying annual ferroalloy production by material-specific emission factors. Emission factors taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) were applied to ferroalloy production. For ferrosilicon alloys containing 25 to 55 percent silicon and miscellaneous alloys (including primarily magnesium-ferrosilicon, but also including other silicon alloys) containing 32 to 65 percent silicon, an emission factor for 45 percent silicon was applied for CO_2 (2.5 metric tons CO_2/metric ton of alloy produced) and an emission factor for 65 percent silicon was applied for CH_4 (1 kg CH_4/metric ton of alloy produced). Additionally, for ferrosilicon alloys containing 56 to 95 percent silicon, an emission factor for 75 percent silicon ferrosilicon was applied for both CO_2 and CH_4 (4 metric tons CO_2/metric ton alloy produced and 1 kg CH_4/metric ton of alloy produced, respectively). The emission factors for silicon metal equaled 5 metric tons CO_2/metric ton metal produced and 1.2 kg CH_4/metric ton metal produced. It was assumed that 100 percent of the ferroalloy production was produced using petroleum coke using an electric arc furnace process (IPCC 2006), although some ferroalloys may have been produced with coking coal, wood, other biomass, or graphite C inputs. The amount of petroleum coke consumed in ferroalloy production was calculated assuming that the petroleum coke used is 90 percent C and 10 percent inert material.

Ferroalloy production data for 1990 through 2009 (see Table 4-65) were obtained from the USGS through personal communications with the USGS Silicon Commodity Specialist (Corathers 2011) and through the *Minerals Yearbook: Silicon Annual Report* (USGS 1991 through 2010). Because USGS does not provide estimates of silicon metal production for 2006-2009, 2005 production data are used. Until 1999, the USGS reported production of ferrosilicon containing 25 to 55 percent silicon separately from production of miscellaneous alloys containing 32 to 65 percent silicon; beginning in 1999, the USGS reported these as a single category (see Table 4-65). The composition data for petroleum coke was obtained from Onder and Bagdoyan (1993).

Table 4-65: Production of Ferroalloys (Metric Tons)

Year	Ferrosilicon 25%-55%	Ferrosilicon 56%-95%	Silicon Metal	Misc. Alloys 32-65%
1990	321,385	109,566	145,744	72,442
2000	229,000	100,000	184,000	NA
2005	123,000	86,100	148,000	NA
2006	164,000	88,700	148,000	NA
2007	180,000	90,600	148,000	NA
2008	193,000	94,000	148,000	NA
2009	123,932	104,855	148,000	NA

NA (Not Available)

Uncertainty and Time-Series Consistency

Although some ferroalloys may be produced using wood or other biomass as a C source, information and data regarding these practices were not available. Emissions from ferroalloys produced with wood or other biomass would not be counted under this source because wood-based C is of biogenic origin.[115] Even though emissions from ferroalloys produced with coking coal or graphite inputs would be counted in national trends, they may be generated with varying amounts of CO_2 per unit of ferroalloy produced. The most accurate method for these estimates would be to base calculations on the amount of reducing agent used in the process, rather than the amount of ferroalloys produced. These data, however, were not available.

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[115] Emissions and sinks of biogenic carbon are accounted for in the Land Use, Land-Use Change, and Forestry chapter.

Emissions of CH_4 from ferroalloy production will vary depending on furnace specifics, such as type, operation technique, and control technology. Higher heating temperatures and techniques such as sprinkle charging will reduce CH_4 emissions; however, specific furnace information was not available or included in the CH_4 emission estimates.

Also, annual ferroalloy production is now reported by the USGS in three broad categories: ferroalloys containing 25 to 55 percent silicon (including miscellaneous alloys), ferroalloys containing 56 to 95 percent silicon, and silicon metal. It was assumed that the IPCC emission factors apply to all of the ferroalloy production processes, including miscellaneous alloys. Finally, production data for silvery pig iron (alloys containing less than 25 percent silicon) are not reported by the USGS to avoid disclosing company proprietary data. Emissions from this production category, therefore, were not estimated.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-66. Ferroalloy production CO_2 emissions were estimated to be between 1.3 and 1.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below and 13 percent above the emission estimate of 1.5 Tg CO_2 Eq. Ferroalloy production CH_4 emissions were estimated to be between a range of approximately 12 percent below and 12 percent above the emission estimate of 0.01 Tg CO_2 Eq.

Table 4-66: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Ferroalloy Production (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Ferroalloy Production	CO_2	1.5	1.3	1.7	-12%	+13%
Ferroalloy Production	CH_4	+	+	+	-12%	+12%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

+ Does not exceed 0.05 Tg CO_2 Eq.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the ferroalloy production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from ferroalloy production. Beginning in 2010, all U.S. ferroalloy producing facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. ferroalloy industry, in particular, including emission estimates from production of ferroalloys other than ferrosilicon and silicon metal. If data are available, emissions will be estimated for those ferroalloys. Additionally, research will be conducted to determine whether data are available concerning raw material consumption (e.g., coal coke, limestone and dolomite flux, etc.) for inclusion in ferroalloy production emission estimates.

4.15. Aluminum Production (IPCC Source Category 2C3)

Aluminum is a light-weight, malleable, and corrosion-resistant metal that is used in many manufactured products, including aircraft, automobiles, bicycles, and kitchen utensils. As of last reporting, the United States was the fourth largest producer of primary aluminum, with approximately seven percent of the world total (USGS 2009a). The United States was also a major importer of primary aluminum. The production of primary aluminum—in addition to consuming large quantities of electricity—results in process-related emissions of CO_2 and two perfluorocarbons (PFCs): perfluoromethane (CF_4) and perfluoroethane (C_2F_6).

CO_2 is emitted during the aluminum smelting process when alumina (aluminum oxide, Al_2O_3) is reduced to aluminum using the Hall-Heroult reduction process. The reduction of the alumina occurs through electrolysis in a molten bath of natural or synthetic cryolite (Na_3AlF_6). The reduction cells contain a carbon lining that serves as the cathode. Carbon is also contained in the anode, which can be a carbon mass of paste, coke briquettes, or prebaked carbon blocks from petroleum coke. During reduction, most of this carbon is oxidized and released to the atmosphere as CO_2.

Process emissions of CO_2 from aluminum production were estimated to be 3.0 Tg CO_2 Eq. (3,009 Gg) in 2009 (see Table 4-67). The carbon anodes consumed during aluminum production consist of petroleum coke and, to a minor extent, coal tar pitch. The petroleum coke portion of the total CO_2 process emissions from aluminum production is considered to be a non-energy use of petroleum coke, and is accounted for here and not under the CO_2 from Fossil Fuel Combustion source category of the Energy sector. Similarly, the coal tar pitch portion of these CO_2 process emissions is accounted for here.

Table 4-67: CO_2 Emissions from Aluminum Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	6.8	6,831
2000	6.1	6,086
2005	4.1	4,142
2006	3.8	3,801
2007	4.3	4,251
2008	4.5	4,477
2009	3.0	3,009

In addition to CO_2 emissions, the aluminum production industry is also a source of PFC emissions. During the smelting process, when the alumina ore content of the electrolytic bath falls below critical levels required for electrolysis, rapid voltage increases occur, which are termed “anode effects.” These anode effects cause carbon from the anode and fluorine from the dissociated molten cryolite bath to combine, thereby producing fugitive emissions of CF_4 and C_2F_6. In general, the magnitude of emissions for a given smelter and level of production depends on the frequency and duration of these anode effects. As the frequency and duration of the anode effects increase, emissions increase.

Since 1990, emissions of CF_4 and C_2F_6 have declined by 92 percent and 89 percent, respectively, to 1.3 Tg CO_2 Eq. of CF_4 (0.20 Gg) and 0.30 Tg CO_2 Eq. of C_2F_6 (0.032 Gg) in 2009, as shown in Table 4-68 and Table 4-69. This decline is due both to reductions in domestic aluminum production and to actions taken by aluminum smelting companies to reduce the frequency and duration of anode effects. Since 1990, aluminum production has declined by 57 percent, while the combined CF_4 and C_2F_6 emission rate (per metric ton of aluminum produced) has been reduced by 80 percent.

Table 4-68: PFC Emissions from Aluminum Production (Tg CO_2 Eq.)

Year	CF_4	C_2F_6	Total
1990	15.9	2.7	18.5
2000	7.8	0.8	8.6
2005	2.5	0.4	3.0
2006	2.1	0.4	2.5
2007	3.2	0.6	3.8
2008	2.2	0.5	2.7
2009	1.3	0.3	1.6

Note: Totals may not sum due to independent rounding.

Table 4-69: PFC Emissions from Aluminum Production (Gg)

Year	CF_4	C_2F_6
1990	2.4	0.3
2000	1.2	0.1
2005	0.4	+

2006	0.3	+
2007	0.5	0.1
2008	0.3	0.1
2009	0.2	+

+ Does not exceed 0.05 Gg.

In 2009, U.S. primary aluminum production totaled approximately 1.7 million metric tons, a 35 percent decrease from 2008 production levels (USAA 2010). In 2009, six companies managed production at 13 operational primary aluminum smelters. Four smelters were closed the entire year, and demolition of one smelter that had been idle since 2000 was completed in 2009. Of the operating smelters, three were temporarily idled during some fraction of 2009, and parts of four others were temporarily closed in 2009 (USGS 2010a). During 2009, U.S. primary aluminum production was less for every month when compared to the corresponding month in 2008 (USGS 2009b, USGS 2010b).

For 2010, total production during January through September was approximately 1.28 million metric tons, compared to 1.32 million metric tons for the same period in 2009, only a 3 percent decrease (USGS 2010c). Based on the similarity in production, process CO_2 and PFC emissions are likely to be similar over this period in 2009 given no significant changes in process controls at operational facilities.

Methodology

CO_2 emissions released during aluminum production were estimated by combining individual partner reported data with process-specific emissions modeling. These estimates are based on information gathered by EPA's Voluntary Aluminum Industrial Partnership (VAIP) program.

Most of the CO_2 emissions released during aluminum production occur during the electrolysis reaction of the carbon anode, as described by the following reaction:

$$2Al_2O_3 + 3C \rightarrow 4Al + 3CO_2$$

For prebake smelter technologies, CO_2 is also emitted during the anode baking process. These emissions can account for approximately 10 percent of total process CO_2 emissions from prebake smelters.

Depending on the availability of smelter-specific data, the CO_2 emitted from electrolysis at each smelter was estimated from: (1) the smelter's annual anode consumption, (2) the smelter's annual aluminum production and rate of anode consumption (per ton of aluminum produced) for previous and /or following years, or, (3) the smelter's annual aluminum production and IPCC default CO_2 emission factors. The first approach tracks the consumption and C content of the anode, assuming that all C in the anode is converted to CO_2. Sulfur, ash, and other impurities in the anode are subtracted from the anode consumption to arrive at total C consumption. This approach corresponds to either the IPCC Tier 2 or Tier 3 method, depending on whether smelter-specific data on anode impurities are used. The second approach interpolates smelter-specific anode consumption rates to estimate emissions during years for which anode consumption data are not available. This avoids substantial errors and discontinuities that could be introduced by reverting to Tier 1 methods for those years. The last approach corresponds to the IPCC Tier 1 method (2006) and is used in the absence of present or historic anode consumption data.

The equations used to estimate CO_2 emissions in the Tier 2 and 3 methods vary depending on smelter type (IPCC 2006). For Prebake cells, the process formula accounts for various parameters, including net anode consumption, and the sulfur, ash, and impurity content of the baked anode. For anode baking emissions, the formula accounts for packing coke consumption, the sulfur and ash content of the packing coke, as well as the pitch content and weight of baked anodes produced. For Søderberg cells, the process formula accounts for the weight of paste consumed per metric ton of aluminum produced, and pitch properties, including sulfur, hydrogen, and ash content.

Through the VAIP, anode consumption (and some anode impurity) data have been reported for 1990, 2000, 2003, 2004, 2005, 2006, 2007, 2008, and 2009. Where available, smelter-specific process data reported under the VAIP were used; however, if the data were incomplete or unavailable, information was supplemented using industry average values recommended by IPCC (2006). Smelter-specific CO_2 process data were provided by 18 of the 23 operating smelters in 1990 and 2000, by 14 out of 16 operating smelters in 2003 and 2004, 14 out of 15 operating smelters in 2005, 13 out of 14 operating smelters in 2006, 5 out of 14 operating smelters in, 2007 and 2008, and 3 out of 13 operating smelters in 2009. For years where CO_2 process data were not reported by these companies, estimates were developed through linear interpolation, and/or assuming industry default values.

In the absence of any previous smelter specific process data (i.e., 1 out of 13 smelters in 2009, 1 out of 14 smelters in 2006, 2007, and 2008, 1 out of 15 smelters in 2005, and 5 out of 23 smelters between 1990 and 2003), CO_2 emission estimates were estimated using Tier 1 Søderberg and/or Prebake emission factors (metric ton of CO_2 per metric ton of aluminum produced) from IPCC (2006).

Aluminum production data for 10 out of 13 operating smelters were reported under the VAIP in 2009. Between 1990 and 2008, production data were provided by 21 of the 23 U.S. smelters that operated during at least part of that period. For the non-reporting smelters, production was estimated based on the difference between reporting smelters and national aluminum production levels (USAA 2010), with allocation to specific smelters based on reported production capacities (USGS 2009a).

PFC emissions from aluminum production were estimated using a per-unit production emission factor that is expressed as a function of operating parameters (anode effect frequency and duration), as follows:

$$\text{PFC } (CF_4 \text{ or } C_2F_6) \text{ kg/metric ton Al} = S \times (\text{Anode Effect Minutes/Cell-Day})$$

where,

S = Slope coefficient ((kg PFC/metric ton Al)/(Anode Effect Minutes/Cell-Day))
Anode Effect Minutes/Cell-Day = Anode Effect Frequency/Cell-Day × Anode Effect Duration (minutes)

This approach corresponds to either the Tier 3 or the Tier 2 approach in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006), depending upon whether the slope-coefficient is smelter-specific (Tier 3) or technology-specific (Tier 2). For 1990 through 2009, smelter-specific slope coefficients were available and were used for smelters representing between 30 and 94 percent of U.S. primary aluminum production. The percentage changed from year to year as some smelters closed or changed hands and as the production at remaining smelters fluctuated. For smelters that did not report smelter-specific slope coefficients, IPCC technology-specific slope coefficients were applied (IPCC 2000, 2006). The slope coefficients were combined with smelter-specific anode effect data collected by aluminum companies and reported under the VAIP, to estimate emission factors over time. For 1990 through 2009, smelter-specific anode effect data were available for smelters representing between 80 and 100 percent of U.S. primary aluminum production. Where smelter-specific anode effect data were not available, industry averages were used.

For all smelters, emission factors were multiplied by annual production to estimate annual emissions at the smelter level. For 1990 through 2009, smelter-specific production data were available for smelters representing between 30 and 100 percent of U.S. primary aluminum production. (For the years after 2000, this percentage was near the high end of the range.) Production at non-reporting smelters was estimated by calculating the difference between the production reported under VAIP and the total U.S. production supplied by USGS or USAA and then allocating this difference to non-reporting smelters in proportion to their production capacity. Emissions were then aggregated across smelters to estimate national emissions.

National primary aluminum production data for 2009 were obtained via the United States Aluminum Association (USAA 2010). For 1990 through 2001, and 2006 (see Table 4-70) data were obtained from USGS, Mineral Industry Surveys: Aluminum Annual Report (USGS 1995, 1998, 2000, 2001, 2002, 2007). For 2002 through 2005, and 2007 through 2008 national aluminum production data were obtained from the USAA's Primary Aluminum Statistics (USAA 2004, 2005, 2006, 2008, 2009).

Table 4-70: Production of Primary Aluminum (Gg)

Year	Gg
1990	4,048
2000	3,668
2005	2,478
2006	2,284
2007	2,560
2008	2,659
2009	1,727

Uncertainty and Time Series Consistency

The overall uncertainties associated with the 2009 CO_2, CF_4, and C_2F_6 emission estimates were calculated using Approach 2, as defined by IPCC (2006). For CO_2, uncertainty was assigned to each of the parameters used to estimate CO_2 emissions. Uncertainty surrounding reported production data was assumed to be 1 percent (IPCC 2006). For additional variables, such as net C consumption, and sulfur and ash content in baked anodes, estimates for uncertainties associated with reported and default data were obtained from IPCC (2006). A Monte Carlo analysis was applied to estimate the overall uncertainty of the CO_2 emission estimate for the U.S. aluminum industry as a whole, and the results are provided below.

To estimate the uncertainty associated with emissions of CF_4 and C_2F_6, the uncertainties associated with three variables were estimated for each smelter: (1) the quantity of aluminum produced, (2) the anode effect minutes per cell day (which may be reported directly or calculated as the product of anode effect frequency and anode effect duration), and, (3) the smelter- or technology-specific slope coefficient. A Monte Carlo analysis was then applied to estimate the overall uncertainty of the emission estimate for each smelter and for the U.S. aluminum industry as a whole.

The results of this quantitative uncertainty analysis are summarized in Table 4-71. Aluminum production-related CO_2 emissions were estimated to be between 2.90 and 3.12 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 4 percent below to 4 percent above the emission estimate of 3.01 Tg CO_2 Eq. Also, production-related CF_4 emissions were estimated to be between 1.14 and 1.44 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below to 12 percent above the emission estimate of 1.29 Tg CO_2 Eq. Finally, aluminum production-related C_2F_6 emissions were estimated to be between 0.25 and 0.35 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 17 percent below to 19 percent above the emission estimate of 0.30 Tg CO_2 Eq.

Table 4-71: Tier 2 Quantitative Uncertainty Estimates for CO_2 and PFC Emissions from Aluminum Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to 2009 Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Aluminum Production	CO_2	3.0	2.9	3.1	−4%	+4%
Aluminum Production	CF_4	1.3	1.1	1.4	−12%	+12%
Aluminum Production	C_2F_6	0.3	0.2	0.4	−17%	+19%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

The 2009 emission estimate was developed using either company-wide or site-specific PFC slope coefficients for all but 1 of the 14 operating smelters where default IPCC (2006) slope data was used. In some cases, where smelters are owned by one company, data have been reported on a company-wide basis as totals or weighted averages. Consequently, in the Monte Carlo analysis, uncertainties in anode effect minutes per cell-day, slope coefficients, and aluminum production have been applied to the company as a whole and not to each smelter. This probably overestimates the uncertainty associated with the cumulative emissions from these smelters, because errors that were in fact independent were treated as if they were correlated. It is therefore likely that the uncertainties calculated above for the total U.S. 2009 emission estimates for CF_4 and C_2F_6 are also overestimated.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Beginning in 2010, all primary U.S. aluminum producing facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. primary aluminum production industry.

4.16. Magnesium Production and Processing (IPCC Source Category 2C4)

The magnesium metal production and casting industry uses sulfur hexafluoride (SF_6) as a cover gas to prevent the rapid oxidation of molten magnesium in the presence of air. Sulfur hexafluoride has been used in this application around the world for more than twenty-five years. A dilute gaseous mixture of SF_6 with dry air and/or CO_2 is blown over molten magnesium metal to induce and stabilize the formation of a protective crust. A small portion of the SF_6 reacts with the magnesium to form a thin molecular film of mostly magnesium oxide and magnesium fluoride. The amount of SF_6 reacting in magnesium production and processing is considered to be negligible, and thus all SF_6 used is assumed to be emitted into the atmosphere. Although alternative cover gases, such as AM-cover™ (containing HFC-134a), Novec™ 612 and dilute SO_2 systems can be used, many facilities in the United States are still using traditional SF_6 cover gas systems.

The magnesium industry emitted 1.1 Tg CO_2 Eq. (0.04 Gg) of SF_6 in 2009, representing a decrease of approximately 45 percent from 2008 emissions (See Table 4-72). The decrease can be attributed to die casting facilities in the United States closing or halting production due to reduced demand from the American auto industry and other industrial sectors (USGS 2010a). Production associated with primary and secondary facilities also dropped in 2009. The significant reduction in emissions can also be attributed to industry efforts to switch to cover gas alternatives, such as sulfur dioxide, as part of the EPA's SF_6 Emission Reduction Partnership for the Magnesium Industry.

Table 4-72: SF_6 Emissions from Magnesium Production and Processing (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	5.4	0.2
2000	3.0	0.1
2005	2.9	0.1
2006	2.9	0.1
2007	2.6	0.1
2008	1.9	0.1
2009	1.1	0.04

Methodology

Emission estimates for the magnesium industry incorporate information provided by industry participants in EPA's SF_6 Emission Reduction Partnership for the Magnesium Industry. The Partnership started in 1999 and, currently, participating companies represent 100 percent of U.S. primary and secondary production and 90 percent of the casting sector production (i.e., die, sand, permanent mold, wrought, and anode casting). Absolute emissions for 1999 through 2009 from primary production, secondary production (i.e., recycling), and die casting were generally reported by Partnership participants. Partners reported their SF_6 consumption, which was assumed to be equivalent to emissions. When a partner did not report emissions, they were estimated based on the metal processed and emission rate reported by that partner in previous and (if available) subsequent years. Where data for subsequent years was not available, metal production and emissions rates were extrapolated based on the trend shown by partners reporting in the current and previous years. When it was determined a Partner is no longer in production, their metal production and emissions rates were set to zero if no activity information was available; in one case a partner that closed mid-year was estimated to have produced 50 percent of the metal from the prior year.

Emission factors for 2002 to 2006 for sand casting activities were also acquired through the Partnership. For 2007, 2008 and 2009, the sand casting partner did not report and the reported emission factor from 2005 was utilized as being representative of the industry. The 1999 through 2009 emissions from casting operations (other than die) were estimated by multiplying emission factors (kg SF_6 per metric ton of metal produced or processed) by the amount of metal produced or consumed. The emission factors for casting activities are provided below in Table 4-73. The emission factors for primary production, secondary production and sand casting are withheld to protect company-specific production information. However, the emission factor for primary production has not risen above the average 1995 partner value of 1.1 kg SF_6 per metric ton. The emission factors for the other industry sectors (i.e., permanent mold, wrought, and anode casting) were based on discussions with industry representatives. U.S. magnesium consumption (casting) data from 1990 through 2009 were available from the USGS (USGS 2002, 2003, 2005, 2006, 2007, 2008, 2010).

Table 4-73: SF_6 Emission Factors (kg SF_6 per metric ton of magnesium)

Year	Die Casting	Permanent Mold	Wrought	Anodes
1999	2.14[a]	2	1	1
2000	0.72	2	1	1
2001	0.72	2	1	1
2002	0.71	2	1	1
2003	0.81	2	1	1
2004	0.81	2	1	1
2005	0.79	2	1	1
2006	0.86	2	1	1
2007	0.67	2	1	1
2008	1.15[b]	2	1	1
2009	1.77[b]	2	1	1

[a] This is a weighted average that includes an estimated emission factor of 5.2 kg SF_6 per metric ton of magnesium for die casters that did not participate in the Partnership in 1999. These die casters were assumed to be similar to partners that cast small parts. Due to process requirements, these casters consume larger quantities of SF_6 per metric ton of processed magnesium than casters that process large parts. In later years, die casters participating in the Partnership accounted for all U.S. die casting tracked by USGS.

[b] The emission factor for die casting increased significantly between 2007 and 2008, and again between 2008 and 2009. These increases occurred for two reasons. First, one of the die casters with a significant share of U.S. production that had used SF_6 as a cover gas and that had maintained a relatively low emission rate began using an alternative cover gas in 2008. Since the SF_6 emission factor provided here is based only on die casting operations that use SF_6 as a cover gas, the removal of the low-emitting die caster from the SF_6-using group increased the weighted average emission rate of that group. Second, one SF_6-using die caster experienced a significant leak in its cover gas distribution system in 2009 that resulted in an abnormally high SF_6 emission rate.

To estimate emissions for 1990 through 1998, industry emission factors were multiplied by the corresponding metal production and consumption (casting) statistics from USGS. The primary production emission factors were 1.2 kg per metric ton for 1990 through 1993, and 1.1 kg per metric ton for 1994 through 1997. These factors were based on information provided by U.S. primary producers. For die casting, an emission factor of 4.1 kg per metric ton was used for the period 1990 through 1996. This factor was drawn from an international survey of die casters (Gjestland & Magers 1996). For 1996 through 1998, the emission factors for primary production and die casting were assumed to decline linearly to the level estimated based on partner reports in 1999. This assumption is consistent with the trend in SF_6 sales to the magnesium sector that is reported in the RAND survey of major SF_6 manufacturers, which shows a decline of 70 percent from 1996 to 1999 (RAND 2002). Sand casting emission factors for 2002 through 2009 were provided by the Magnesium Partnership participants, and 1990 through 2001 emission factors for this process were assumed to have been the same as the 2002 emission factor. The emission factor for secondary production from 1990 through 1998 was assumed to be constant at the 1999 average partner value. The emission factors for the other processes (i.e., permanent mold, wrought, and anode casting), about which less is known, were assumed to remain constant at levels defined in Table 4-73.

Uncertainty

To estimate the uncertainty surrounding the estimated 2009 SF_6 emissions from magnesium production and processing, the uncertainties associated with three variables were estimated (1) emissions reported by magnesium producers and processors that participate in the Magnesium Partnership, (2) emissions estimated for magnesium producers and processors that participate in the Partnership but did not report this year, and (3) emissions estimated for magnesium producers and processors that do not participate in the Partnership. An uncertainty of 5 percent was assigned to the data reported by each participant in the Partnership. If partners did not report emissions data during the current reporting year, SF_6 emissions data were estimated using available emission factor and production information reported in prior years; the extrapolation was based on the average trend for partners reporting in the current reporting year and the year prior. The uncertainty associated with the SF_6 usage estimate generated from the extrapolated emission factor and production information was estimated to be 30 percent for each year of extrapolation. The lone sand casting partner did not report in the past two reporting years and its activity and emission factor were held constant at 2005 levels due to a reporting anomaly in 2006 because of malfunctions at the facility. The uncertainty associated with the SF_6 usage for the sand casting partner was 52 percent. For those industry processes that are not represented in Partnership, such as permanent mold and wrought casting, SF_6 emissions were estimated using production and consumption statistics reported by USGS and estimated process-specific emission factors (see Table 4-73). The uncertainties associated with the emission factors and USGS-reported statistics were assumed to be 75 percent and 25 percent, respectively. Emissions associated with sand casting activities utilized a partner-reported emission factor with an uncertainty of 75 percent. In general, where precise quantitative information was not available on the uncertainty of a parameter, a conservative (upper-bound) value was used.

Additional uncertainties exist in these estimates that are not addressed in this methodology, such as the basic assumption that SF_6 neither reacts nor decomposes during use. The melt surface reactions and high temperatures associated with molten magnesium could potentially cause some gas degradation. Recent measurement studies have identified SF_6 cover gas degradation in die casting applications on the order of 20 percent (Bartos et al. 2007). Sulfur hexafluoride may also be used as a cover gas for the casting of molten aluminum with high magnesium content; however, the extent to which this technique is used in the United States is unknown.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 4-74. SF_6 emissions associated with magnesium production and processing were estimated to be between 1.01 and 1.10 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 6 percent below to 5 percent above the 2008 emission estimate of 1.05 Tg CO_2 Eq.

Table 4-74: Tier 2 Quantitative Uncertainty Estimates for SF_6 Emissions from Magnesium Production and Processing (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a]**			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Magnesium Production	SF_6	1.05	1.01	1.10	-4%	+4%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Recalculations Discussion

The uncertainty estimates for 2009 are lower relative to the previous inventory uncertainty estimate for 2008 emissions, which is likely due to the fact that emission estimates for 2009 are based more on actual reported data than emission estimates for 2008 were in the 1990-2008 inventory, with two emission sources using projected (highly uncertain) estimates.

Planned Improvements

Cover gas research conducted by the EPA over the last decade has found that SF_6 used for magnesium melt protection can have degradation rates on the order of 20 percent in die casting applications (Bartos et al. 2007). Current emission estimates assume (per the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006)) that all SF_6 utilized is emitted to the atmosphere. Additional research may lead to a revision of IPCC Guidelines to reflect this phenomenon and until such time, developments in this sector will be monitored for possible application to the inventory methodology. Another issue that will be addressed in future inventories is the likely adoption of alternate cover gases by U.S. magnesium producers and processors. These cover gases, which include AM-cover™ (containing HFC-134a) and Novec™ 612, have lower GWPs than SF_6, and tend to quickly degrade during their exposure to the molten metal. Magnesium producers and processors have already begun using these cover gases for 2006 through 2009 in a limited fashion; because the amounts being used by companies on the whole are low enough that they have a minor effect on the overall emissions from the industry, these emissions are only being monitored and recorded at this time.

4.17. Zinc Production (IPCC Source Category 2C5)

Zinc production in the United States consists of both primary and secondary processes. Primary production in the United States is conducted through the electrolytic process while secondary techniques used in the United States include the electrothermic and Waelz kiln processes as well as a range of other metallurgical, hydrometallurgical, and pyrometallurgical processes. Worldwide primary zinc production also employs a pyrometallurgical process using the Imperial Smelting Furnace process; however, this process is not used in the United States (Sjardin 2003). Of the primary and secondary processes used in the United States, only the electrothermic and Waelz kiln secondary processes result in non-energy CO_2 emissions (Viklund-White 2000).

During the electrothermic zinc production process, roasted zinc concentrate and secondary zinc products enter a sinter feed where they are burned to remove impurities before entering an electric retort furnace. Metallurgical coke added to the electric retort furnace reduces the zinc oxides and produces vaporized zinc, which is then captured in a vacuum condenser. This reduction process produces non-energy CO_2 emissions (Sjardin 2003).

In the Waelz kiln process, EAF dust, which is captured during the recycling of galvanized steel, enters a kiln along with a reducing agent—often metallurgical coke. When kiln temperatures reach approximately 1100–1200°C, zinc fumes are produced, which are combusted with air entering the kiln. This combustion forms zinc oxide, which is collected in a baghouse or electrostatic precipitator, and is then leached to remove chloride and fluoride. Through this process, approximately 0.33 metric ton of zinc is produced for every metric ton of EAF dust treated (Viklund-White 2000).

In 2009, U.S. primary and secondary zinc production was estimated to total 286,000 metric tons (USGS 2010). Since reported activity data for 2009 were not available for all necessary inputs in time for this publication, production values in 2009 were assumed to equal 2008 values in some cases. The resulting emissions of CO_2 from zinc production in 2009 were estimated to be 0.97 Tg CO_2 Eq. (966 Gg) (see Table 4-75). All 2009 CO_2 emissions resulted from secondary zinc production.

Table 4-75: CO_2 Emissions from Zinc Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	0.7	667
2000	1.0	997
2005	1.1	1088
2006	1.1	1088
2007	1.1	1081
2008	1.2	1230
2009	1.0	966

Emissions from zinc production in the U.S. have increased overall due to a gradual shift from non-emissive primary production to emissive secondary production. In 2009, emissions were estimated to be 45 percent higher than they were in 1990.

Methodology

Non-energy CO_2 emissions from zinc production result from the electrothermic and Waelz kiln secondary production processes, which both use metallurgical coke or other C-based materials as reductants. Sjardin (2003) provides an emission factor of 0.43 metric tons CO_2/metric ton zinc produced for emissive zinc production processes; however, this emission factor is based on the Imperial Smelting Furnace production process. Because the Imperial Smelting Furnace production process is not used in the United States, emission factors specific to electrothermic and Waelz kiln processes were needed. Due to the limited amount of information available for these electrothermic processes, only Waelz kiln process-specific emission factors were developed. These emission factors were applied to both the Waelz kiln and electrothermic secondary zinc production processes.

A Waelz kiln emission factor based on the amount of zinc produced was developed based on the amount of metallurgical coke consumed for non-energy purposes per ton of zinc produced, 1.19 metric tons coke/metric ton zinc produced (Viklund-White 2000), and the following equation:

$$EF_{\text{Waelz Kiln}} = \frac{1.19\ \mathit{metric\ tons\ coke}}{\mathit{metric\ tons\ zinc}} \times \frac{0.85\ \mathit{metric\ tons\ C}}{\mathit{metric\ tons\ coke}} \times \frac{3.67\ \mathit{metric\ tons\ CO_2}}{\mathit{metric\ tons\ C}} = \frac{3.70\ \mathit{metric\ tons\ CO_2}}{\mathit{metric\ tons\ zinc}}$$

In addition, a Waelz kiln emission factor based on the amount of EAF dust consumed was developed based on the amount of metallurgical coke consumed per ton of EAF dust consumed, 0.4 metric tons coke/metric ton EAF dust consumed (Viklund-White 2000), and the following equation:[116]

$$EF_{\text{EAF Dust}} = \frac{0.4\,metric\,tons\,coke}{metric\,tons\,EAF\,dust} \times \frac{0.85\,metric\,tons\,C}{metric\,tons\,coke} \times \frac{3.67\,metric\,tons\,CO_2}{metric\,tons\,C} = \frac{1.24\,metric\,tons\,CO_2}{metric\,tons\,EAF\,Dust}$$

The only companies in the United States that use emissive technology to produce secondary zinc products are Horsehead Corp and Steel Dust Recycling. For Horsehead Corp, EAF dust is recycled in Waelz kilns at their Beaumont, TX; Calumet, IL; Palmerton, PA; and Rockwood, TN facilities (and soon to be performed at their new South Carolina facility). These Waelz kiln facilities produce intermediate zinc products (crude zinc oxide or calcine), most of which is transported to their Monaca, PA facility where the products are smelted into refined zinc using electrothermic technology. Some of Horsehead's intermediate zinc products that are not smelted at Monaca are instead exported to other countries around the world (Horsehead Corp 2010). Steel Dust Recycling recycles EAF dust into intermediate zinc products using Waelz kilns, and then sells the intermediate products to companies who smelt it into refined products.

The total amount of EAF dust consumed by Horsehead Corp at their Waelz kilns was available from Horsehead financial reports for years 2006 through 2009 (Horsehead 2010). Consumption levels for 1990 through 2005 were extrapolated using the percentage change in annual refined zinc production at secondary smelters in the United States as provided by USGS Minerals Yearbook: Zinc (USGS 1994 through 2010). The EAF dust consumption values for each year were then multiplied by the 1.24 metric tons CO_2/metric ton EAF dust consumed emission factor to develop CO_2 emission estimates for Horsehead's Waelz kiln facilities.

The amount of EAF dust consumed by the Steel Dust Recycling facility for 2008 and 2009 (the only two years it has been in operation) was not publically available. Therefore, these consumption values were estimated by calculating the 2008 and 2009 capacity utilization of Horsehead's Waelz kilns and multiplying this utilization ratio by the capacity of Steel Dust Recycling's facility, which were available from the company (Steel Dust Recycling LLC 2010). The 1.24 metric tons CO_2/metric ton EAF dust consumed emission factor was then applied to Steel Dust Recycling's estimated EAF dust consumption to develop CO_2 emission estimates for its Waelz kiln facility.

Refined zinc production levels for Horsehead's Monaca, PA facility (utilizing electrothermic technology) were available from the company for years 2005 through 2009 (Horsehead Corp 2010, Horsehead Corp 2008). Production levels for 1990 through 2004 were extrapolated using the percentage changes in annual refined zinc production at secondary smelters in the United States as provided by USGS Minerals Yearbook: Zinc (USGS 1994 through 2010). The 3.70 metric tons CO_2/metric ton zinc emission factor was then applied to the Monaca facility's production levels to estimate CO_2 emissions for the facility. The Waelz kiln production emission factor was applied in this case rather than the EAF dust consumption emission factor since Horsehead's Monaca facility did not consume EAF dust.

Table 4-76: Zinc Production (Metric Tons)

Year	Primary	Secondary
1990	262,704	95,708
2000	227,800	143,000
2005	191,120	156,000
2006	113,000	156,000
2007	121,000	157,000
2008	125,000	161,000
2009	125,000	161,000

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[116] For Waelz kiln based secondary zinc production, IPCC recommends the use of emission factors based on EAF dust consumption rather than the amount of zinc produced since the amount of reduction materials used is more directly dependent on the amount of EAF dust consumed (IPCC 2006).

Uncertainty and Time-Series Consistency

The uncertainties contained in these estimates are two-fold, relating to activity data and emission factors used.

First, there is uncertainty associated with the amount of EAF dust consumed in the United States to produce secondary zinc using emission-intensive Waelz kilns. The estimate for the total amount of EAF dust consumed in Waelz kilns is based on (1) an EAF dust consumption value reported annually by Horsehead Corporation as part of its financial reporting to the Securities and Exchange Commission (SEC), and (2) an estimate of the amount of EAF dust consumed at a Waelz kiln facility operated in Alabama by Steel Dust Recycling LLC. Since actual EAF dust consumption information is not available for the Steel Dust Recycling LLC facility, the amount is estimated by multiplying the EAF dust recycling capacity of the facility (available from the company's Web site) by the capacity utilization factor for Horsehead Corporation (which is available from Horsehead's financial reports). Therefore, there is uncertainty associated with the assumption that the capacity utilization of Steel Dust Recycling LLC's Waelz kiln facility is equal to the capacity utilization of Horsehead's Waelz kiln facility. Second, there are uncertainties associated with the emission factors used to estimate CO_2 emissions from secondary zinc production processes. The Waelz kiln emission factors are based on materials balances for metallurgical coke and EAF dust consumed as provided by Viklund-White (2000). Therefore, the accuracy of these emission factors depend upon the accuracy of these materials balances. Data limitations prevented the development of emission factors for the electrothermic process. Therefore, emission factors for the Waelz kiln process were applied to both electrothermic and Waelz kiln production processes. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-77. Zinc production CO_2 emissions were estimated to be between 0.8 and 1.1 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 17 percent below and 18 percent above the emission estimate of 1.0 Tg CO_2 Eq.

Table 4-77: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Zinc Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Zinc Production	CO_2	1.0	0.8	1.1	-17%	+18%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the zinc production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from zinc production. Beginning in 2010, all U.S. zinc producing facilities (both primary and secondary) that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. zinc production industry.

Recalculations Discussion

The methodology for estimating CO_2 emissions from zinc production was revised for the current Inventory based on the availability of new data regarding secondary zinc production in the United States. The previous Inventory methodology assumed that two facilities had produced zinc in the United States using emissive processes since 1990: Horsehead Corporation's Monaca, PA facility (electrothermic) and Horsehead Corporation's Palmerton, PA facility (Waelz kiln). The 3.70 metric tons CO_2/metric ton zinc emission factor was applied to the estimated refined zinc production at the Monaca, PA electrothermic facility, and the 1.24 metric tons CO_2/metric ton EAF dust consumed emission factor was applied to the estimated EAF dust consumption at the Palmerton, PA Waelz kiln facility. The annual zinc production (for the Monaca facility) and EAF dust consumption (for the Palmerton facility) were estimated using historic values that were published in articles for select years (extrapolation techniques were used for years in which published data was not available). The Monaca, PA facility was assumed to have closed in 2003 and not operated since.

New data for the industry showed that there were emissive zinc-producing facilities not being captured by the previous Inventory methodology. The facilities that were not captured included three Horsehead Corp Waelz kiln facilities in Beaumont, TX; Calumet, IL; and Rockwood, TN as well as a Waelz kiln facility commissioned in 2008 in Millport, AL by Steel Dust Recycling LLC. Also, research showed that the Monaca, PA facility only closed temporarily in 2003 and has been operating every year since (the Monaca, PA facility produces refined zinc from intermediary zinc products produced at Horsehead's other facilities). The updated methodology utilizes EAF dust consumption values and secondary zinc production values released annually by the main secondary zinc producer in the United States (Horsehead Corp.), and also includes the previously overlooked secondary zinc producing facilities in the emission estimates.

As a result of the revised methodology, historical emission estimates decreased by an average of 11 percent between 1990 and 2002, while emission estimates increased by an average of 140 percent between 2003 and 2009. The significant changes in emission estimates for years 2005 through 2008 were largely driven by Horsehead Corp's Monaca, PA facility being captured in the emission calculations for these years.

4.18. Lead Production (IPCC Source Category 2C5)

Lead production in the United States consists of both primary and secondary processes—both of which emit CO_2 (Sjardin 2003). Primary lead production, in the form of direct smelting, occurs at a just a single plant in Missouri. Secondary production largely involves the recycling of lead acid batteries at approximately 21 separate smelters in the United States. Fifteen of those secondary smelters have annual capacities of 15,000 tons or more and were collectively responsible for 99 percent of secondary lead production in 2009 (USGS 2010). Secondary lead production has increased in the United States over the past decade while primary lead production has decreased. In 2009, secondary lead production accounted for approximately 92 percent of total lead production (USGS 2011).

Primary production of lead through the direct smelting of lead concentrate produces CO_2 emissions as the lead concentrates are reduced in a furnace using metallurgical coke (Sjardin 2003). U.S. primary lead production decreased by 24 percent from 2008 to 2009, and has decreased by 75 percent since 1990 (USGS 2011, USGS 1995).

Similar to primary lead production, CO_2 emissions from secondary production result when a reducing agent, usually metallurgical coke, is added to the smelter to aid in the reduction process. CO_2 emissions from secondary production also occur through the treatment of secondary raw materials (Sjardin 2003). U.S. secondary lead production decreased from 2008 to 2009 by 3 percent, and has increased by 20 percent since 1990 (USGS 2011, USGS 1995).

At last reporting, the United States was the third largest mine producer of lead in the world, behind China and Australia, accounting for 11 percent of world production in 2009 (USGS 2011). In 2009, U.S. primary and secondary lead production totaled 1,213,000 metric tons (USGS 2011). The resulting emissions of CO_2 from 2009 production were estimated to be 0.5 Tg CO_2 Eq. (525 Gg) (see Table 4-78). The majority of 2009 lead production is from secondary processes, which accounted for 95 percent of total 2009 CO_2 emissions.

Table 4-78: CO_2 Emissions from Lead Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	0.5	516
2000	0.6	594
2005	0.6	553
2006	0.6	560
2007	0.6	562
2008	0.6	551
2009	0.5	525

After a gradual decrease in total emissions from 1990 to 1995, total emissions have gradually increased since 1995 and emissions in 2009 were two percent greater than in 1990. Although primary production has decreased significantly (75 percent since 1990), secondary production has increased by about 20 percent over the same time period. Since secondary production is more emissions-intensive, the increase in secondary production since 1990 has resulted in a net increase in emissions despite the sharp decrease in primary production (USGS 2011, USGS 1994).

Methodology

Non-energy CO_2 emissions from lead production result from primary and secondary production processes that use metallurgical coke or other C-based materials as reductants. For primary lead production using direct smelting, Sjardin (2003) and the IPCC (2006) provide an emission factor of 0.25 metric tons CO_2/metric ton lead. For secondary lead production, Sjardin (2003) and IPCC (2006) provide an emission factor of 0.25 metric tons CO_2/metric ton lead for direct smelting as well as an emission factor of 0.2 metric tons CO_2/metric ton lead produced for the treatment of secondary raw materials (i.e., pretreatment of lead acid batteries). The direct smelting factor (0.25) and the sum of the direct smelting and pretreatment emission factors (0.45) are multiplied by total U.S. primary and secondary lead production, respectively, to estimate CO_2 emissions.

The 1990 through 2009 activity data for primary and secondary lead production (see Table 4-79) were obtained through the USGS Mineral Yearbook: Lead (USGS 1994 through 2011).

Table 4-79: Lead Production (Metric Tons)

Year	Primary	Secondary
1990	404,000	922,000
2000	341,000	1,130,000
2005	143,000	1,150,000
2006	153,000	1,160,000
2007	123,000	1,180,000
2008	135,000	1,150,000
2009	103,000	1,110,000

Uncertainty and Time-Series Consistency

Uncertainty associated with lead production relates to the emission factors and activity data used. The direct smelting emission factor used in primary production is taken from Sjardin (2003) who averages the values provided by three other studies (Dutrizac et al. 2000, Morris et al. 1983, Ullman 1997). For secondary production, Sjardin (2003) adds a CO_2 emission factor associated with battery treatment. The applicability of these emission factors to plants in the United States is uncertain. There is also a smaller level of uncertainty associated with the accuracy of primary and secondary production data provided by the USGS.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-80. Lead production CO_2 emissions were estimated to be between 0.5 and 0.6 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 14 percent below and 15 percent above the emission estimate of 0.5 Tg CO_2 Eq.

Table 4-80: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Lead Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Lead Production	CO_2	0.5	0.5	0.6	-14%	+15%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the lead production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emission calculations from lead production. Beginning in 2010, all U.S. lead producing facilities (primary and secondary) that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the Program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. lead production industry.

Recalculations Discussion

In previous Inventory reports, CO_2 emissions from secondary lead production were estimated by multiplying secondary lead production values from USGS by an emission factor of 0.2 metric tons CO_2/metric ton lead produced. This emission factor is provided by Sjardin (2003) and IPCC (2006) for the treatment of secondary raw materials (i.e., pretreatment of lead acid batteries). Due to a misinterpretation of language in Sjardin (2003) and IPCC (2006), this was the only emission factor applied to secondary lead production even though an emission factor of 0.25 metric tons CO_2/metric ton lead for direct smelting should have been applied as well. This issue has been corrected for the current Inventory, and increased 1990 through 2008 emissions from lead production by an average of 95 percent per year relative to the previous Inventory.

4.19. HCFC-22 Production (IPCC Source Category 2E1)

Trifluoromethane (HFC-23 or CHF_3) is generated as a by-product during the manufacture of chlorodifluoromethane (HCFC-22), which is primarily employed in refrigeration and air conditioning systems and as a chemical feedstock for manufacturing synthetic polymers. Between 1990 and 2000, U.S. production of HCFC-22 increased significantly as HCFC-22 replaced chlorofluorocarbons (CFCs) in many applications. Between 2000 and 2007, U.S. production fluctuated but generally remained above 1990 levels. In 2008 and 2009, U.S. production declined markedly. Because HCFC-22 depletes stratospheric ozone, its production for non-feedstock uses is scheduled to be phased out by 2020 under the U.S. Clean Air Act.[117] Feedstock production, however, is permitted to continue indefinitely.

HCFC-22 is produced by the reaction of chloroform ($CHCl_3$) and hydrogen fluoride (HF) in the presence of a catalyst, $SbCl_5$. The reaction of the catalyst and HF produces $SbCl_xF_y$, (where x + y = 5), which reacts with chlorinated hydrocarbons to replace chlorine atoms with fluorine. The HF and chloroform are introduced by submerged piping into a continuous-flow reactor that contains the catalyst in a hydrocarbon mixture of chloroform and partially fluorinated intermediates. The vapors leaving the reactor contain HCFC-21 ($CHCl_2F$), HCFC-22 ($CHClF_2$), HFC-23 (CHF_3), HCl, chloroform, and HF. The under-fluorinated intermediates (HCFC-21) and chloroform are then condensed and returned to the reactor, along with residual catalyst, to undergo further fluorination. The final vapors leaving the condenser are primarily HCFC-22, HFC-23, HCl and residual HF. The HCl is recovered as a useful byproduct, and the HF is removed. Once separated from HCFC-22, the HFC-23 may be released to the atmosphere, recaptured for use in a limited number of applications, or destroyed.

Emissions of HFC-23 in 2009 were estimated to be 5.4 Tg CO_2 Eq. (0.5 Gg) (Table 4-81). This quantity represents a 60 percent decrease from 2008 emissions and a 85 percent decline from 1990 emissions. The decrease from 2008 emissions was caused by a 27 percent decrease in HCFC-22 production and a 46 percent decrease in the HFC-23 emission rate. The decline from 1990 emissions is due to a 34 percent decrease in HCFC-22 production and a 78 percent decrease in the HFC-23 emission rate since 1990. The decrease in the emission rate is primarily attributable to five factors: (a) five plants that did not capture and destroy the HFC-23 generated have ceased production of HCFC-22 since 1990, (b) one plant that captures and destroys the HFC-23 generated began to produce HCFC-22, (c) one plant implemented and documented a process change that reduced the amount of HFC-23 generated, and (d) the same plant began recovering HFC-23, primarily for destruction and secondarily for sale, and (e) another plant began destroying HFC-23. All three HCFC-22 production plants operating in the United States in 2009 used thermal oxidation to significantly lower their HFC-23 emissions.

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[117] As construed, interpreted, and applied in the terms and conditions of the *Montreal Protocol on Substances that Deplete the Ozone Layer*. [42 U.S.C. §7671m(b), CAA §614]

Table 4-81: HFC-23 Emissions from HCFC-22 Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	36.4	3
2000	28.6	2
2005	15.8	1
2006	13.8	1
2007	17.0	1
2008	13.6	1
2009	5.4	0.46

Methodology

To estimate HFC-23 emissions for five of the eight HCFC-22 plants that have operated in the United States since 1990, methods comparable to the Tier 3 methods in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) were used. For the other three plants, the last of which closed in 1993, methods comparable to the Tier 1 method in the 2006 IPCC Guidelines were used. Emissions from these three plants have been calculated using the recommended emission factor for unoptimized plants operating before 1995 (0.04 kg HCFC-23/kg HCFC-22 produced).

The five plants that have operated since 1994 measured concentrations of HFC-23 to estimate their emissions of HFC-23. Plants using thermal oxidation to abate their HFC-23 emissions monitor the performance of their oxidizers to verify that the HFC-23 is almost completely destroyed. Plants that release (or historically have released) some of their byproduct HFC-23 periodically measure HFC-23 concentrations in the output stream using gas chromatography. This information is combined with information on quantities of products (e.g., HCFC-22) to estimate HFC-23 emissions.

In most years, including 2010, an industry association aggregates and reports to EPA country-level estimates of HCFC-22 production and HFC-23 emissions (ARAP 1997, 1999, 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010). However, in 1997 and 2008, EPA (through a contractor) performed comprehensive reviews of plant-level estimates of HFC-23 emissions and HCFC-22 production (RTI 1997; RTI 2008). These reviews enabled EPA to review, update, and where necessary, correct U.S. totals, and also to perform plant-level uncertainty analyses (Monte-Carlo simulations) for 1990, 1995, 2000, 2005, and 2006. Estimates of annual U.S. HCFC-22 production are presented in Table 4-82.

Table 4-82: HCFC-22 Production (Gg)

Year	Gg
1990	139
2000	186
2005	156
2006	154
2007	162
2008	126
2009	91

Uncertainty and Time Series Consistency

The uncertainty analysis presented in this section was based on a plant-level Monte Carlo simulation for 2006. The Monte Carlo analysis used estimates of the uncertainties in the individual variables in each plant's estimating procedure. This analysis was based on the generation of 10,000 random samples of model inputs from the probability density functions for each input. A normal probability density function was assumed for all measurements and biases except the equipment leak estimates for one plant; a log-normal probability density function was used for this plant's equipment leak estimates. The simulation for 2006 yielded a 95-percent confidence interval for U.S. emissions of 6.8 percent below to 9.6 percent above the reported total.

Because plant-level emissions data for 2009 were not available, the relative errors yielded by the Monte Carlo simulation for 2006 were applied to the U.S. emission estimate for 2009. The resulting estimates of absolute uncertainty are likely to be accurate because (1) the methods used by the three plants to estimate their emissions are not believed to have changed significantly since 2006, and (2) although the distribution of emissions among the plants may have changed between 2008 and 2009 (because both HCFC-22 production and the HFC-23 emission rate declined significantly), the two plants that contribute significantly to emissions were estimated to have similar relative uncertainties in their 2006 (as well as 2005) emission estimates. Thus, changes in the relative contributions of these two plants to total emissions are not likely to have a large impact on the uncertainty of the national emission estimate.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-83. HFC-23 emissions from HCFC-22 production were estimated to be between 5.0 and 5.9 Tg CO_2 Eq. at the 95percent confidence level. This indicates a range of approximately 7 percent below and 10 percent above the emission estimate of 5.4 Tg CO_2 Eq.

Table 4-83: Quantitative Uncertainty Estimates for HFC-23 Emissions from HCFC-22 Production (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**[a] **(Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
HCFC-22 Production	HFC-23	5.4	5.0	5.9	-7%	+10%

[a] Range of emissions reflects a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Beginning in 2010, all U.S. HCFC-22 production facilities are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Data collected under this program will be used in future inventories to improve the calculation of national emissions from HCFC-22 production

4.20. Substitution of Ozone Depleting Substances (IPCC Source Category 2F)

Hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) are used as alternatives to several classes of ozone-depleting substances (ODSs) that are being phased out under the terms of the Montreal Protocol and the Clean Air Act Amendments of 1990.[118] Ozone depleting substances—chlorofluorocarbons (CFCs), halons, carbon tetrachloride, methyl chloroform, and hydrochlorofluorocarbons (HCFCs)—are used in a variety of industrial applications including refrigeration and air conditioning equipment, solvent cleaning, foam production, sterilization, fire extinguishing, and aerosols. Although HFCs and PFCs are not harmful to the stratospheric ozone layer, they are potent greenhouse gases. Emission estimates for HFCs and PFCs used as substitutes for ODSs are provided in Table 4-84 and Table 4-85.

Table 4-84: Emissions of HFCs and PFCs from ODS Substitutes (Tg CO_2 Eq.)

Gas	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
HFC-23	+	+	+	+	+	+	+
HFC-32	+	+	0.3	0.6	1.0	1.3	1.7
HFC-125	+	5.2	10.1	12.5	15.1	18.2	21.6
HFC-134a	+	60.4	75.1	75.0	72.3	69.3	66.7
HFC-143a	+	4.1	12.2	14.4	16.7	19.2	22.0
HFC-236fa	+	0.5	0.8	0.8	0.9	0.9	0.9

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[118] [42 U.S.C § 7671, CAA § 601]

CF_4	+	+	+	+	+	+	+
Others*	0.3	4.0	5.6	6.0	6.3	6.7	7.0
Total	**0.3**	**74.3**	**104.2**	**109.4**	**112.3**	**115.5**	**120.0**

+ Does not exceed 0.05 Tg CO_2 Eq.

* Others include HFC-152a, HFC-227ea, HFC-245fa, HFC-4310mee, C_4F_{10}, and PFC/PFPEs, the latter being a proxy for a diverse collection of PFCs and perfluoropolyethers (PFPEs) employed for solvent applications. For estimating purposes, the GWP value used for PFC/PFPEs was based upon C_6F_{14}.

Note: Totals may not sum due to independent rounding.

Table 4-85: Emissions of HFCs and PFCs from ODS Substitution (Mg)

Gas	1990	2000	2005	2006	2007	2008	2009
HFC-23	+	1	1	1	1	2	2
HFC-32	+	26	505	971	1,465	1,977	2,540
HFC-125	+	1,855	3,619	4,453	5,393	6,486	7,730
HFC-134a	+	46,465	57,777	57,728	55,603	53,294	51,281
HFC-143a	+	1,089	3,200	3,782	4,402	5,044	5,798
HFC-236fa	+	85	125	131	136	141	144
CF_4	+	1	2	2	2	2	2
Others*	M	M	M	M	M	M	M

M (Mixture of Gases)

+ Does not exceed 0.5 Mg

* Others include HFC-152a, HFC-227ea, HFC-245fa, HFC-4310mee, C_4F_{10}, and PFC/PFPEs, the latter being a proxy for a diverse collection of PFCs and perfluoropolyethers (PFPEs) employed for solvent applications.

In 1990 and 1991, the only significant emissions of HFCs and PFCs as substitutes to ODSs were relatively small amounts of HFC-152a—used as an aerosol propellant and also a component of the refrigerant blend R-500 used in chillers—and HFC-134a in refrigeration end-uses. Beginning in 1992, HFC-134a was used in growing amounts as a refrigerant in motor vehicle air-conditioners and in refrigerant blends such as R-404A.[119] In 1993, the use of HFCs in foam production began, and in 1994 these compounds also found applications as solvents. In 1995, ODS substitutes for halons entered widespread use in the United States as halon production was phased-out.

The use and subsequent emissions of HFCs and PFCs as ODS substitutes has been increasing from small amounts in 1990 to 120.0 Tg CO_2 Eq. in 2009. This increase was in large part the result of efforts to phase out CFCs and other ODSs in the United States. In the short term, this trend is expected to continue, and will likely accelerate over the next decade as HCFCs, which are interim substitutes in many applications, are themselves phased-out under the provisions of the Copenhagen Amendments to the Montreal Protocol. Improvements in the technologies associated with the use of these gases and the introduction of alternative gases and technologies, however, may help to offset this anticipated increase in emissions.

Table 4-86 presents emissions of HFCs and PFCs as ODS substitutes by end-use sector for 1990 through 2009. The end-use sectors that contributed the most toward emissions of HFCs and PFCs as ODS substitutes in 2009 include refrigeration and air-conditioning (104.9 Tg CO_2 Eq., or approximately 87 percent), aerosols (9.1 Tg CO_2 Eq., or approximately 8 percent), and foams (3.9 Tg CO_2 Eq., or approximately 3 percent). Within the refrigeration and air-conditioning end-use sector, motor vehicle air-conditioning was the highest emitting end-use (45.9 Tg CO_2 Eq.), followed by refrigerated retail food and transport. Each of the end-use sectors is described in more detail below.

Table 4-86: Emissions of HFCs and PFCs from ODS Substitutes (Tg CO_2 Eq.) by Sector

Gas	1990	2000	2005	2006	2007	2008	2009
Refrigeration/Air Conditioning	+	61.6	93.1	97.6	99.8	102.3	104.9
Aerosols	0.3	10.1	7.3	7.7	8.2	8.6	9.1
Foams	+	0.3	1.9	2.1	2.3	2.5	3.9
Solvents	+	2.1	1.3	1.3	1.3	1.3	1.3
Fire Protection	+	0.2	0.5	0.6	0.7	0.7	0.8
Total	**0.3**	**74.3**	**104.2**	**109.4**	**112.3**	**115.5**	**120.0**

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[119] R-404A contains HFC-125, HFC-143a, and HFC-134a.

Refrigeration/Air Conditioning

The refrigeration and air-conditioning sector includes a wide variety of equipment types that have historically used CFCs or HCFCs. End-uses within this sector include motor vehicle air-conditioning, retail food refrigeration, refrigerated transport (e.g., ship holds, truck trailers, railway freight cars), household refrigeration, residential and small commercial air-conditioning/and heat pumps, chillers (large comfort cooling), cold storage facilities, and industrial process refrigeration (e.g., systems used in food processing, chemical, petrochemical, pharmaceutical, oil and gas, and metallurgical industries). As the ODS phaseout is taking effect, most equipment is being or will eventually be retrofitted or replaced to use HFC-based substitutes. Common HFCs in use today in refrigeration/air-conditioning equipment are HFC-134a, R-410A[120], R-404A, and R-507A[121]. These HFCs are emitted to the atmosphere during equipment manufacture and operation (as a result of component failure, leaks, and purges), as well as at servicing and disposal events.

Aerosols

Aerosol propellants are used in metered dose inhalers (MDIs) and a variety of personal care products and technical/specialty products (e.g., duster sprays and safety horns). Many pharmaceutical companies that produce MDIs—a type of inhaled therapy used to treat asthma and chronic obstructive pulmonary disease—have committed to replace the use of CFCs with HFC-propellant alternatives. The earliest ozone-friendly MDIs were produced with HFC-134a, but the industry has started to use HFC-227ea as well. Conversely, since the use of CFC propellants was banned in 1978, most consumer aerosol products have not transitioned to HFCs, but to “not-in-kind” technologies, such as solid roll-on deodorants and finger-pump sprays. The transition away from ODS in specialty aerosol products has also led to the introduction of non-fluorocarbon alternatives (e.g., hydrocarbon propellants) in certain applications, in addition to HFC-134a or HFC-152a. These propellants are released into the atmosphere as the aerosol products are used.

Foams

CFCs and HCFCs have traditionally been used as foam blowing agents to produce polyurethane (PU), polystyrene, polyolefin, and phenolic foams, which are used in a wide variety of products and applications. Since the Montreal Protocol, flexible PU foams as well as other types of foam, such as polystyrene sheet, polyolefin, and phenolic foam, have transitioned almost completely away from fluorocompounds, into alternatives such as CO_2, methylene chloride, and hydrocarbons. The majority of rigid PU foams have transitioned to HFCs—primarily HFC-134a and HFC-245fa. Today, these HFCs are used to produce polyurethane appliance, PU commercial refrigeration, PU spray, and PU panel foams—used in refrigerators, vending machines, roofing, wall insulation, garage doors, and cold storage applications. In addition, HFC-152a is used to produce polystyrene sheet/board foam, which is used in food packaging and building insulation. Emissions of blowing agents occur when the foam is manufactured as well as during the foam lifetime and at foam disposal, depending on the particular foam type.

Solvents

CFCs, methyl chloroform (1,1,1-trichloroethane or TCA), and to a lesser extent carbon tetrachloride (CCl_4) were historically used as solvents in a wide range of cleaning applications, including precision, electronics, and metal cleaning. Since their phaseout, metal cleaning end-use applications have primarily transitioned to non-fluorocarbon solvents and not-in-kind processes. The precision and electronics cleaning end-uses have transitioned in part to high-GWP gases, due to their high reliability, excellent compatibility, good stability, low toxicity, and selective solvency. These applications rely on HFC-4310mee, HFC-365mfc, HFC-245fa, and to a lesser extent, PFCs. Electronics cleaning involves removing flux residue that remains after a soldering operation for printed circuit boards and other contamination-sensitive electronics applications. Precision cleaning may apply to either electronic components or to metal surfaces, and is characterized by products, such as disk drives, gyroscopes, and optical components, that require a high level of cleanliness and generally have complex shapes, small clearances, and other cleaning

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[120] R-410A contains HFC-32 and HFC-125.

[121] R-507A, also called R-507, contains HFC-125 and HFC-143a.

challenges. The use of solvents yields fugitive emissions of these HFCs and PFCs.

Fire Protection

Fire protection applications include portable fire extinguishers (“streaming” applications) that originally used halon 1211, and total flooding applications that originally used halon 1301, as well as some halon 2402. Since the production and sale of halons were banned in the United States in 1994, the halon replacement agent of choice in the streaming sector has been dry chemical, although HFC-236ea is also used to a limited extent. In the total flooding sector, HFC-227ea has emerged as the primary replacement for halon 1301 in applications that require clean agents. Other HFCs, such as HFC-23, HFC-236fa, and HFC-125, are used in smaller amounts. The majority of HFC-227ea in total flooding systems is used to protect essential electronics, as well as in civil aviation, military mobile weapons systems, oil/gas/other process industries, and merchant shipping. As fire protection equipment is tested or deployed, emissions of these HFCs occur.

Methodology

A detailed Vintaging Model of ODS-containing equipment and products was used to estimate the actual—versus potential—emissions of various ODS substitutes, including HFCs and PFCs. The name of the model refers to the fact that it tracks the use and emissions of various compounds for the annual “vintages” of new equipment that enter service in each end-use. The Vintaging Model predicts ODS and ODS substitute use in the United States based on modeled estimates of the quantity of equipment or products sold each year containing these chemicals and the amount of the chemical required to manufacture and/or maintain equipment and products over time. Emissions for each end-use were estimated by applying annual leak rates and release profiles, which account for the lag in emissions from equipment as they leak over time. By aggregating the data for nearly 60 different end-uses, the model produces estimates of annual use and emissions of each compound. Further information on the Vintaging Model is contained in Annex 3.8.

Uncertainty

Given that emissions of ODS substitutes occur from thousands of different kinds of equipment and from millions of point and mobile sources throughout the United States, emission estimates must be made using analytical tools such as the Vintaging Model or the methods outlined in IPCC (2006). Though the model is more comprehensive than the IPCC default methodology, significant uncertainties still exist with regard to the levels of equipment sales, equipment characteristics, and end-use emissions profiles that were used to estimate annual emissions for the various compounds.

The Vintaging Model estimates emissions from nearly 60 end-uses. The uncertainty analysis, however, quantifies the level of uncertainty associated with the aggregate emissions resulting from the top 21 end-uses, comprising over 95 percent of the total emissions, and 5 other end-uses. These 26 end-uses comprise 97 percent of the total emissions. In an effort to improve the uncertainty analysis, additional end-uses are added annually, with the intention that over time uncertainty for all emissions from the Vintaging Model will be fully characterized. Any end-uses included in previous years’ uncertainty analysis were included in the current uncertainty analysis, whether or not those end-uses were included in the top 95 percent of emissions from ODS Substitutes.

In order to calculate uncertainty, functional forms were developed to simplify some of the complex “vintaging” aspects of some end-use sectors, especially with respect to refrigeration and air-conditioning, and to a lesser degree, fire extinguishing. These sectors calculate emissions based on the entire lifetime of equipment, not just equipment put into commission in the current year, thereby necessitating simplifying equations. The functional forms used variables that included growth rates, emission factors, transition from ODSs, change in charge size as a result of the transition, disposal quantities, disposal emission rates, and either stock for the current year or original ODS consumption. Uncertainty was estimated around each variable within the functional forms based on expert judgment, and a Monte Carlo analysis was performed. The most significant sources of uncertainty for this source category include the emission factors for retail food equipment and refrigerated transport, as well as the percent of non-MDI aerosol propellant that is HFC-152a.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-87. Substitution of ozone depleting substances HFC and PFC emissions were estimated to be between 111.8 and 129.3 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below to 8 percent above the emission estimate of 120.0 Tg CO_2 Eq.

Table 4-87: Tier 2 Quantitative Uncertainty Estimates for HFC and PFC Emissions from ODS Substitutes (Tg CO_2 Eq. and Percent)

Source	**Gases**	**2009 Emission Estimate (Tg CO_2 Eq.)**[a]	**Uncertainty Range Relative to Emission Estimate**[b] **(Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Substitution of Ozone Depleting Substances	HFCs and PFCs	117.1	109.0	126.5	-7%	+8%

[a] 2009 emission estimates and the uncertainty range presented in this table correspond to selected end-uses within the aerosols, foams, solvents, fire extinguishing agents, and refrigerants sectors, but not for other remaining categories. Therefore, because the uncertainty associated with emissions from "other" ODS substitutes was not estimated, they were excluded in the estimates reported in this table.

[b] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Recalculations Discussion

An extensive review of the MDI aerosol, unitary air-conditioning, and domestic refrigerator foams markets resulted in revisions to the Vintaging Model since the previous Inventory. For MDI aerosols, the charge size for both the CFC and HFC propellants was revised. Based on research on substitutes and growth in the market, the percent of the CFC market that transitions to HFCs over the time series and the overall size of the MDI market decreased. For unitary air-conditioning, a review of air conditioner sales data reduced the quantity of air-conditioning equipment introduced into the market for 1990 through1993 and 2008, while increasing the quantity of equipment sold into the market for 1994 through 2009. A review of the domestic refrigerator foams market increased the quantity of blowing agent consumed in the foam and decreased the quantity of blowing agent emitted during the foam manufacturing process. Overall, these changes to the Vintaging Model increased greenhouse gas emissions on average by 0.5 percent across the time series.

4.21. Semiconductor Manufacture (IPCC Source Category 2F6)

The semiconductor industry uses multiple long-lived fluorinated gases in plasma etching and plasma enhanced chemical vapor deposition (PECVD) processes to produce semiconductor products. The gases most commonly employed are trifluoromethane (HFC-23 or CHF_3), perfluoromethane (CF_4), perfluoroethane (C_2F_6), nitrogen trifluoride (NF_3), and sulfur hexafluoride (SF_6), although other compounds such as perfluoropropane (C_3F_8) and perfluorocyclobutane (c-C_4F_8) are also used. The exact combination of compounds is specific to the process employed.

A single 300 mm silicon wafer that yields between 400 to 500 semiconductor products (devices or chips) may require as many as 100 distinct fluorinated-gas-using process steps, principally to deposit and pattern dielectric films. Plasma etching (or patterning) of dielectric films, such as silicon dioxide and silicon nitride, is performed to provide pathways for conducting material to connect individual circuit components in each device. The patterning process uses plasma-generated fluorine atoms, which chemically react with exposed dielectric film to selectively remove the desired portions of the film. The material removed as well as undissociated fluorinated gases flow into waste streams and, unless emission abatement systems are employed, into the atmosphere. PECVD chambers, used for depositing dielectric films, are cleaned periodically using fluorinated and other gases. During the cleaning cycle the gas is converted to fluorine atoms in plasma, which etches away residual material from chamber walls, electrodes, and chamber hardware. Undissociated fluorinated gases and other products pass from the chamber to waste streams and, unless abatement systems are employed, into the atmosphere. In addition to emissions of unreacted gases, some fluorinated compounds can also be transformed in the plasma processes into different fluorinated compounds which are then exhausted, unless abated, into the atmosphere. For example, when C_2F_6 is used in cleaning or etching, CF_4 is generated and emitted as a process by-product. Besides dielectric film etching and PECVD chamber cleaning, much smaller quantities of fluorinated gases are used to etch polysilicon films and refractory metal films like tungsten.

For 2009, total weighted emissions of all fluorinated greenhouse gases by the U.S. semiconductor industry were estimated to be 5.3 Tg CO_2 Eq. Combined emissions of all fluorinated greenhouse gases are presented in Table 4-88 and Table 4-89 below for years 1990, 2000 and the period 2005 to 2009. The rapid growth of this industry and the increasing complexity (growing number of layers)[122] of semiconductor products led to an increase in emissions of 148 percent between 1990 and 1999, when emissions peaked at 7.2 Tg CO_2 Eq. The emissions growth rate began to slow after 1998, and emissions declined by 26 percent between 1999 and 2009. Together, industrial growth and adoption of emissions reduction technologies, including but not limited to abatement technologies, resulted in a net increase in emissions of 83 percent between 1990 and 2009.

Table 4-88: PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture (Tg CO_2 Eq.)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CF_4	0.7	1.8	1.1	1.2	1.3	1.4	1.5
C_2F_6	1.5	3.0	2.0	2.2	2.3	2.4	2.5
C_3F_8	0.0	0.1	0.0	0.0	0.0	0.1	0.0
C_4F_8	0.0	0.0	0.1	0.1	0.1	0.1	0.0
HFC-23	0.2	0.3	0.2	0.3	0.3	0.3	0.3
SF_6	0.5	1.1	1.0	1.0	0.8	0.9	1.0
NF_3*	0.0	0.2	0.4	0.7	0.5	0.6	0.5
Total	**2.9**	**6.2**	**4.4**	**4.7**	**4.8**	**5.1**	**5.3**

Note: Totals may not sum due to independent rounding.
* NF_3 emissions are presented for informational purposes, using the AR4 GWP of 17,200, and are not included in totals.

Table 4-89: PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture (Mg)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CF_4	115	281	168	181	198	216	227
C_2F_6	160	321	216	240	249	261	271
C_3F_8	0	18	5	5	6	13	5
C_4F_8	0	0	13	13	7	7	4
HFC-23	15	23	18	22	23	25	28
SF_6	22	45	40	40	34	36	40
NF_3	3	11	26	40	30	33	30

Methodology

Emissions are based on Partner reported emissions data received through the EPA's PFC Reduction/Climate Partnership and the EPA's PFC Emissions Vintage Model (PEVM), a model which estimates industry emissions in the absence of emission control strategies (Burton and Beizaie 2001).[123] The availability and applicability of Partner data differs across the 1990 through 2009 time series. Consequently, emissions from semiconductor manufacturing were estimated using four distinct methods, one each for the periods 1990 through 1994, 1995 through 1999, 2000 through 2006, and 2007 through 2009.

1990 through 1994

From 1990 through 1994, Partnership data was unavailable and emissions were modeled using the PEVM (Burton

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[122] Complexity is a term denoting the circuit required to connect the active circuit elements (transistors) on a chip. Increasing miniaturization, for the same chip size, leads to increasing transistor density, which, in turn, requires more complex interconnections between those transistors. This increasing complexity is manifested by increasing the levels (i.e., layers) of wiring, with each wiring layer requiring fluorinated gas usage for its manufacture.

[123] A Partner refers to a participant in the U.S. EPA PFC Reduction/Climate Partnership for the Semiconductor Industry. Through a Memorandum of Understanding (MoU) with the EPA, Partners voluntarily report their PFC emissions to the EPA by way of a third party, which aggregates the emissions.

and Beizaie 2001).[124] 1990 to 1994 emissions are assumed to be uncontrolled, since reduction strategies such as chemical substitution and abatement were yet to be developed.

PEVM is based on the recognition that PFC emissions from semiconductor manufacturing vary with: (1) the number of layers that comprise different kinds of semiconductor devices, including both silicon wafer and metal interconnect layers, and (2) silicon consumption (i.e., the area of semiconductors produced) for each kind of device. The product of these two quantities, Total Manufactured Layer Area (TMLA), constitutes the activity data for semiconductor manufacturing. PEVM also incorporates an emission factor that expresses emissions per unit of layer-area. Emissions are estimated by multiplying TMLA by this emission factor.

PEVM incorporates information on the two attributes of semiconductor devices that affect the number of layers: (1) linewidth technology (the smallest manufactured feature size), [125] and (2) product type (discrete, memory or logic).[126] For each linewidth technology, a weighted average number of layers is estimated using VLSI product-specific worldwide silicon demand data in conjunction with complexity factors (i.e., the number of layers per Integrated Circuit (IC)) specific to product type (Burton and Beizaie 2001, ITRS 2007). PEVM derives historical consumption of silicon (i.e., square inches) by linewidth technology from published data on annual wafer starts and average wafer size (VLSI Research, Inc. 2010).

The emission factor in PEVM is the average of four historical emission factors, each derived by dividing the total annual emissions reported by the Partners for each of the four years between 1996 and 1999 by the total TMLA estimated for the Partners in each of those years. Over this period, the emission factors varied relatively little (i.e., the relative standard deviation for the average was 5 percent). Since Partners are believed not to have applied significant emission reduction measures before 2000, the resulting average emission factor reflects uncontrolled emissions. The emission factor is used to estimate world uncontrolled emissions using publicly available data on world silicon consumption.

1995 through 1999

For 1995 through 1999, total U.S. emissions were extrapolated from the total annual emissions reported by the Partners (1995 through 1999). Partner-reported emissions are considered more representative (e.g., in terms of capacity utilization in a given year) than PEVM estimated emissions, and are used to generate total U.S. emissions when applicable. The emissions reported by the Partners were divided by the ratio of the total capacity of the plants operated by the Partners and the total capacity of all of the semiconductor plants in the United States; this ratio represents the share of capacity attributable to the Partnership. This method assumes that Partners and non-Partners have identical capacity utilizations and distributions of manufacturing technologies. Plant capacity data is contained in the World Fab Forecast (WFF) database and its predecessors, which is updated quarterly (Semiconductor Equipment and Materials Industry 2010).

2000 through 2006

The emission estimate for the years 2000 through 2006—the period during which Partners began the consequential application of PFC-reduction measures—was estimated using a combination of Partner reported emissions and PEVM modeled emissions. The emissions reported by Partners for each year were accepted as the quantity emitted from the share of the industry represented by those Partners. Remaining emissions, those from non-Partners, were

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[124] Various versions of the PEVM exist to reflect changing industrial practices. From 1990 to 1994 emissions estimates are from PEVM v1.0, completed in September 1998. The emission factor used to estimate 1990 to 1994 emissions is an average of the 1995 and 1996 emissions factors, which were derived from Partner reported data for those years.

[125] By decreasing features of Integrated Circuit components, more components can be manufactured per device, which increases its functionality. However, as those individual components shrink it requires more layers to interconnect them to achieve the functionality. For example, a microprocessor manufactured with the smallest feature sizes (65 nm) might contain as many as 1 billion transistors and require as many as 11 layers of component interconnects to achieve functionality while a device manufactured with 130 nm feature size might contain a few hundred million transistors and require 8 layers of component interconnects (ITRS 2007).

[126] Memory devices manufactured with the same feature sizes as microprocessors (a logic device) require approximately one-half the number of interconnect layers, whereas discrete devices require only a silicon base layer and no interconnect layers (ITRS 2007). Since discrete devices did not start using PFCs appreciably until 2004, they are only accounted for in the PEVM emissions estimates from 2004 onwards.

estimated using PEVM and the method described above. This is because non-Partners are assumed not to have implemented any PFC-reduction measures, and PEVM models emissions without such measures. The portion of the U.S. total attributed to non-Partners is obtained by multiplying PEVM's total U.S. emissions figure by the non-Partner share of U. S. total silicon capacity for each year as described above.[127,128] Annual updates to PEVM reflect published figures for actual silicon consumption from VLSI Research, Inc., revisions and additions to the world population of semiconductor manufacturing plants, and changes in IC fabrication practices within the semiconductor industry (see ITRS 2007 and Semiconductor Equipment and Materials Industry 2010).[129,130,131]

2007 through 2009

For the years 2007 through 2009, emissions were also estimated using a combination of Partner reported emissions and PEVM modeled emissions; however, two improvements were made to the estimation method employed for the previous years in the time series. First, the 2007 through 2009 emission estimates account for the fact that Partners and non-Partners employ different distributions of manufacturing technologies, with the Partners using manufacturing technologies with greater transistor densities and therefore greater numbers of layers.[132] Second, the scope of the 2007 through 2009 estimates is expanded relative to the estimates for the years 2000 through 2006 to include emissions from Research and Development (R&D) fabs. This was feasible through the use of more detailed data published in the World Fab Forecast. PEVM databases are updated annually as described above. The published world average capacity utilization for 2007 and 2008 was used for production fabs while in 2008 for R&D fabs a 20 percent figure was assumed (SIA 2009).

In addition, publicly available actual utilization data was used to account for differences in fab utilization for manufacturers of discrete and IC products for the emissions in 2009 for non-partners. PEVM estimates were adjusted using technology weighted capacity shares that reflect relative influence of different utilization.

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[127] This approach assumes that the distribution of linewidth technologies is the same between Partners and non-Partners. As discussed in the description of the method used to estimate 2007 emissions, this is not always the case.

[128] Generally 5 percent or less of the fields needed to estimate TMLA shares are missing values in the World Fab Watch databases. In the 2007 World Fab Watch database used to generate the 2006 non-Partner TMLA capacity share, these missing values were replaced with the corresponding mean TMLA across fabs manufacturing similar classes of products. However, the impact of replacing missing values on the non-Partner TMLA capacity share was inconsequential.

[129] Special attention was given to the manufacturing capacity of plants that use wafers with 300 mm diameters because the actual capacity of these plants is ramped up to design capacity, typically over a 2–3 year period. To prevent overstating estimates of partner-capacity shares from plants using 300 mm wafers, *design* capacities contained in WFW were replaced with estimates of *actual installed* capacities for 2004 published by Citigroup Smith Barney (2005). Without this correction, the partner share of capacity would be overstated, by approximately 5 percent. For perspective, approximately 95 percent of all new capacity additions in 2004 used 300 mm wafers, and by year-end those plants, on average, could operate at approximately 70 percent of the design capacity. For 2005, actual installed capacities were estimated using an entry in the World Fab Watch database (April 2006 Edition) called "wafers/month, 8-inch equivalent," which denoted the actual installed capacity instead of the fully-ramped capacity. For 2006, actual installed capacities of new fabs were estimated using an average monthly ramp rate of 1100 wafer starts per month (wspm) derived from various sources such as semiconductor fabtech, industry analysts, and articles in the trade press. The monthly ramp rate was applied from the first-quarter of silicon volume (FQSV) to determine the average design capacity over the 2006 period.

[130] In 2006, the industry trend in co-ownership of manufacturing facilities continued. Several manufacturers, who are Partners, now operate fabs with other manufacturers, who in some cases are also Partners and in other cases are not Partners. Special attention was given to this occurrence when estimating the Partner and non-Partner shares of U.S. manufacturing capacity.

[131] Two versions of PEVM are used to model non-Partner emissions during this period. For the years 2000 to 2003 PEVM v3.2.0506.0507 was used to estimate non-Partner emissions. During this time, discrete devices did not use PFCs during manufacturing and therefore only memory and logic devices were modeled in the PEVM v3.2.0506.0507. From 2004 onwards, discrete device fabrication started to use PFCs, hence PEVM v4.0.0701.0701, the first version of PEVM to account for PFC emissions from discrete devices, was used to estimate non-Partner emissions for this time period.

[132] EPA considered applying this change to years before 2007, but found that it would be difficult due to the large amount of data (i.e., technology-specific global and non-Partner TMLA) that would have to be examined and manipulated for each year. This effort did not appear to be justified given the relatively small impact of the improvement on the total estimate for 2007 and the fact that the impact of the improvement would likely be lower for earlier years because the estimated share of emissions accounted for by non-Partners is growing as Partners continue to implement emission-reduction efforts.

Gas-Specific Emissions

Two different approaches were also used to estimate the distribution of emissions of specific fluorinated gases. Before 1999, when there was no consequential adoption of fluorinated-gas-reducing measures, a fixed distribution of fluorinated-gas use was assumed to apply to the entire U.S. industry. This distribution was based upon the average fluorinated-gas purchases made by semiconductor manufacturers during this period and the application of IPCC default emission factors for each gas (Burton and Beizaie 2001). For the 2000 through 2009 period, the 1990 through 1999 distribution was assumed to apply to the non-Partners. Partners, however, began reporting gas-specific emissions during this period. Thus, gas-specific emissions for 2000 through 2009 were estimated by adding the emissions reported by the Partners to those estimated for the non-Partners.

Data Sources

Partners estimate their emissions using a range of methods. For 2009, it is assumed that most Partners used a method at least as accurate as the IPCC's Tier 2a Methodology, recommended in the 2006 IPCC Guidelines for National Greenhouse Inventories (IPCC 2006). Data used to develop emission estimates are attributed in part to estimates provided by the members of the Partnership, and in part from data obtained from PEVM estimates. Estimates of operating plant capacities and characteristics for Partners and non-Partners were derived from the Semiconductor Equipment and Materials Industry (SEMI) World Fab Forecast (formerly World Fab Watch) database (1996 through 2009) (e.g., Semiconductor Materials and Equipment Industry, 2010). Actual world capacity utilizations for 2009 were obtained from Semiconductor International Capacity Statistics (SICAS) (SIA, 2009). Estimates of silicon consumed by linewidth from 1990 through 2009 were derived from information from VLSI Research, Inc. (2010), and the number of layers per linewidth was obtained from International Technology Roadmap for Semiconductors: 2006 Update (Burton and Beizaie 2001, ITRS 2007, ITRS 2008).

Uncertainty and Time Series Consistency

A quantitative uncertainty analysis of this source category was performed using the IPCC-recommended Tier 2 uncertainty estimation methodology, the Monte Carlo Stochastic Simulation technique. The equation used to estimate uncertainty is:

$$\text{U.S. emissions} = \sum\text{Partnership gas-specific submittals} + [(\text{non-Partner share of World TMLA}) \times (\text{PEVM Emission Factor} \times \text{World TMLA})]$$

The Monte Carlo analysis results presented below relied on estimates of uncertainty attributed to the four quantities on the right side of the equation. Estimates of uncertainty for the four quantities were in turn developed using the estimated uncertainties associated with the individual inputs to each quantity, error propagation analysis, Monte Carlo simulation, and expert judgment. The relative uncertainty associated with World TMLA estimate in 2009 is about ±10 percent, based on the uncertainty estimate obtained from discussions with VLSI, Inc. For the share of World layer-weighted silicon capacity accounted for by non-Partners, a relative uncertainty of ±8 percent was estimated based on a separate Monte Carlo simulation to account for the random occurrence of missing data in the World Fab Watch database. For the aggregate PFC emissions data supplied to the partnership, a relative uncertainty of ±50 percent was estimated for each gas-specific PFC emissions value reported by an individual Partner, and error propagation techniques were used to estimate uncertainty for total Partnership gas-specific submittals.[133] A relative uncertainty of approximately ±10 percent was estimated for the PEVM emission factor, based on the standard deviation of the 1996 to 1999 emission factors.[134] All estimates of uncertainties are given at 95-percent confidence intervals.

In developing estimates of uncertainty, consideration was also given to the nature and magnitude of the potential bias that World activity data (i.e., World TMLA) might have in its estimates of the number of layers associated with devices manufactured at each technology node. The result of a brief analysis indicated that U.S. TMLA overstates the average number of layers across all product categories and all manufacturing technologies for 2004 by 0.12 layers or 2.9 percent. The same upward bias is assumed for World TMLA, and is represented in the uncertainty analysis by deducting the absolute bias value from the World activity estimate when it is incorporated into the

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[133] Error propagation resulted in Partnership gas-specific uncertainties ranging from 17 to 27 percent·

[134] The average of 1996 to 1999 emission factor is used to derive the PEVM emission factor.

Monte Carlo analysis.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-90. The emissions estimate for total U.S. PFC emissions from semiconductor manufacturing were estimated to be between 4.8 and 5.9 Tg CO_2 Eq. at a 95 percent confidence level. This range represents 10 percent below to 11 percent above the 2009 emission estimate of 5.3 Tg CO_2 Eq. This range and the associated percentages apply to the estimate of total emissions rather than those of individual gases. Uncertainties associated with individual gases will be somewhat higher than the aggregate, but were not explicitly modeled.

Table 4-90: Tier 2 Quantitative Uncertainty Estimates for HFC, PFC, and SF_6 Emissions from Semiconductor Manufacture (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate[a] (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[b] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound[c]	**Upper Bound[c]**	**Lower Bound**	**Upper Bound**
Semiconductor Manufacture	HFC, PFC, and SF_6	5.3	4.8	5.9	−10%	+11%

[a] Because the uncertainty analysis covered all emissions (including NF_3), the emission estimate presented here does not match that shown in Table 4-88.

[b] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

[c] Absolute lower and upper bounds were calculated using the corresponding lower and upper bounds in percentages.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

With the exception of possible future updates to emission factors, the method to estimate non-Partner related emissions (i.e., PEVM) is not expected to change. Future improvements to the national emission estimates will primarily be associated with determining the portion of national emissions to attribute to Partner report totals (about 80 percent in recent years) and improvements in estimates of non-Partner totals. As the nature of the Partner reports change through time and industry-wide reduction efforts increase, consideration will be given to what emission reduction efforts—if any—are likely to be occurring at non-Partner facilities. Currently, none are assumed to occur.

Another point of consideration for future national emissions estimates is the inclusion of PFC emissions from heat transfer fluid (HTF) loss to the atmosphere and the production of photovoltaic cells (PVs). Heat transfer fluids, of which some are liquid perfluorinated compounds, are used during testing of semiconductor devices and, increasingly, are used to manage heat during the manufacture of semiconductor devices. Evaporation of these fluids is a source of emissions (EPA 2006). PFCs are also used during manufacture of PV cells that use silicon technology, specifically, crystalline, polycrystalline, and amorphous silicon technologies. PV manufacture is growing in the United States, and therefore may be expected to constitute a growing share of U.S. PFC emissions from the electronics sector.

4.22. Electrical Transmission and Distribution (IPCC Source Category 2F7)

The largest use of SF_6, both in the United States and internationally, is as an electrical insulator and interrupter in equipment that transmits and distributes electricity (RAND 2004). The gas has been employed by the electric power industry in the United States since the 1950s because of its dielectric strength and arc-quenching characteristics. It is used in gas-insulated substations, circuit breakers, and other switchgear. Sulfur hexafluoride has replaced flammable insulating oils in many applications and allows for more compact substations in dense urban areas.

Fugitive emissions of SF_6 can escape from gas-insulated substations and switchgear through seals, especially from older equipment. The gas can also be released during equipment manufacturing, installation, servicing, and disposal. Emissions of SF_6 from equipment manufacturing and from electrical transmission and distribution systems were estimated to be 12.8 Tg CO_2 Eq. (0.5 Gg) in 2009. This quantity represents a 55 percent decrease from the estimate for 1990 (see Table 4-91 and Table 4-92). This decrease is believed to have two causes: a sharp increase in the price of SF_6 during the 1990s and a growing awareness of the environmental impact of SF_6 emissions through programs such as EPA's SF_6 Emission Reduction Partnership for Electric Power Systems.

Table 4-91: SF_6 Emissions from Electric Power Systems and Electrical Equipment Manufacturers (Tg CO_2 Eq.)

Year	Electric Power Systems	Electrical Equipment Manufacturers	Total
1990	28.1	0.3	28.4
2000	15.4	0.7	16.0
2005	14.1	1.1	15.1
2006	13.1	1.0	14.1
2007	12.4	0.8	13.2
2008	12.1	1.3	13.3
2009	12.1	0.7	12.8

Note: Totals may not sum due to independent rounding.

Table 4-92: SF_6 Emissions from Electric Power Systems and Electrical Equipment Manufacturers (Gg)

Year	Emissions
1990	1.2
2000	0.7
2005	0.6
2006	0.6
2007	0.6
2008	0.6
2009	0.5

Methodology

The estimates of emissions from Electric Transmission and Distribution are comprised of emissions from electric power systems and emissions from the manufacture of electrical equipment. The methodologies for estimating both sets of emissions are described below.

1999 through 2009 Emissions from Electric Power Systems

Emissions from electric power systems from 1999 to 2009 were estimated based on: (1) reporting from utilities participating in EPA's SF_6 Emission Reduction Partnership for Electric Power Systems (Partners), which began in 1999; and, (2) the relationship between emissions and utilities' transmission miles as reported in the 2001, 2004, 2007, and 2010 Utility Data Institute (UDI) Directories of Electric Power Producers and Distributors (UDI 2001, 2004, 2007, 2010). (Transmission miles are defined as the miles of lines carrying voltages above 34.5 kV.) Over the period from 1999 to 2009, Partner utilities, which for inventory purposes are defined as utilities that either currently are or previously have been part of the Partnership, represented between 42 percent and 47 percent of total U.S. transmission miles. For each year, the emissions reported by or estimated for Partner utilities were added to the emissions estimated for utilities that have never participated in the Partnership (i.e., non-Partners).[135]

Partner utilities estimated their emissions using a Tier 3 utility-level mass balance approach (IPCC 2006). If a Partner utility did not provide data for a particular year, emissions were interpolated between years for which data were available or extrapolated based on Partner-specific transmission mile growth rates. In 2009, non-reporting Partners accounted for approximately 8 percent of the total emissions attributed to Partner utilities.

Emissions from non-Partners in every year since 1999 were estimated using the results of a regression analysis that showed that the emissions from reporting utilities were most strongly correlated with their transmission miles. The results of this analysis are not surprising given that, in the United States, SF_6 is contained primarily in transmission

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[135] Partners in EPA's SF_6 Emission Reduction Partnership reduced their emissions by approximately 61% from 1999 to 2008.

equipment rated above 34.5 kV. The equations were developed based on the 1999 SF_6 emissions reported by a subset of 42 Partner utilities (representing approximately 23 percent of U.S. transmission miles) and 2000 transmission mileage data obtained from the 2001 UDI Directory of Electric Power Producers and Distributors (UDI 2001). Two equations were developed, one for small and one for large utilities (i.e., with fewer or more than 10,000 transmission miles, respectively). The distinction between utility sizes was made because the regression analysis showed that the relationship between emissions and transmission miles differed for small and large transmission networks. The same equations were used to estimate non-Partner emissions in 1999 and every year thereafter because non-Partners were assumed not to have implemented any changes that would have resulted in reduced emissions since 1999.

The regression equations are:

Non-Partner small utilities (fewer than 10,000 transmission miles, in kilograms):

$$\text{Emissions (kg)} = 1.001 \times \text{Transmission Miles}$$

Non-Partner large utilities (more than 10,000 transmission miles, in kilograms):

$$\text{Emissions (kg)} = 0.58 \times \text{Transmission Miles}$$

Data on transmission miles for each non-Partner utility for the years 2000, 2003, 2006, and 2009 were obtained from the 2001, 2004, 2007, and 2010 UDI Directories of Electric Power Producers and Distributors, respectively (UDI 2001, 2004, 2007, 2010). The U.S. transmission system grew by over 25,000 miles between 2000 and 2003 and by over 52,000 miles between 2003 and 2006. These periodic increases are assumed to have occurred gradually. Therefore, transmission mileage was assumed to increase at an annual rate of 1.3 percent between 2000 and 2003 and 2.6 percent between 2003 and 2006. This growth rate slowed to 0.2% from 2006 to 2009 as transmission miles increased by just 4,400 miles (approximately).

As a final step, total electric power system emissions were determined for each year by summing the Partner reported and estimated emissions (reported data was available through the EPA's SF_6 Emission Reduction Partnership for Electric Power Systems) and the non-Partner emissions (determined using the 1999 regression equations).

1990 through 1998 Emissions from Electric Power Systems

Because most participating utilities reported emissions only for 1999 through 2009, modeling was used to estimate SF_6 emissions from electric power systems for the years 1990 through 1998. To perform this modeling, U.S. emissions were assumed to follow the same trajectory as global emissions from this source during the 1990 to 1999 period. To estimate global emissions, the RAND survey of global SF_6 sales were used, together with the following equation for estimating emissions, which is derived from the mass-balance equation for chemical emissions (Volume 3, Equation 7.3) in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006).[136] (Although equation 7.3 of the IPCC Guidelines appears in the discussion of substitutes for ozone-depleting substances, it is applicable to emissions from any long-lived pressurized equipment that is periodically serviced during its lifetime.)

$$\text{Emissions (kilograms } SF_6) = SF_6 \text{ purchased to refill existing equipment (kilograms)} + \text{nameplate capacity of retiring equipment (kilograms)}$$[137]

Note that the above equation holds whether the gas from retiring equipment is released or recaptured; if the gas is recaptured, it is used to refill existing equipment, thereby lowering the amount of SF_6 purchased by utilities for this purpose.

Gas purchases by utilities and equipment manufacturers from 1961 through 2003 are available from the RAND (2004) survey. To estimate the quantity of SF_6 released or recovered from retiring equipment, the nameplate capacity of retiring equipment in a given year was assumed to equal 81.2 percent of the amount of gas purchased by

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[136] Ideally, sales to utilities in the U.S. between 1990 and 1999 would be used as a model. However, this information was not available. There were only two U.S. manufacturers of SF_6 during this time period, so it would not have been possible to conceal sensitive sales information by aggregation.

[137] Nameplate capacity is defined as the amount of SF_6 within fully charged electrical equipment.

electrical equipment manufacturers 40 years previous (e.g., in 2000, the nameplate capacity of retiring equipment was assumed to equal 81.2 percent of the gas purchased in 1960). The remaining 18.8 percent was assumed to have been emitted at the time of manufacture. The 18.8 percent emission factor is an average of IPCC default SF_6 emission rates for Europe and Japan for 1995 (IPCC 2006). The 40-year lifetime for electrical equipment is also based on IPCC (2006). The results of the two components of the above equation were then summed to yield estimates of global SF_6 emissions from 1990 through 1999.

U.S. emissions between 1990 and 1999 are assumed to follow the same trajectory as global emissions during this period. To estimate U.S. emissions, global emissions for each year from 1990 through 1998 were divided by the estimated global emissions from 1999. The result was a time series of factors that express each year's global emissions as a multiple of 1999 global emissions. Historical U.S. emissions were estimated by multiplying the factor for each respective year by the estimated U.S. emissions of SF_6 from electric power systems in 1999 (estimated to be 15.0 Tg CO_2 Eq.).

Two factors may affect the relationship between the RAND sales trends and actual global emission trends. One is utilities' inventories of SF_6 in storage containers. When SF_6 prices rise, utilities are likely to deplete internal inventories before purchasing new SF_6 at the higher price, in which case SF_6 sales will fall more quickly than emissions. On the other hand, when SF_6 prices fall, utilities are likely to purchase more SF_6 to rebuild inventories, in which case sales will rise more quickly than emissions. This effect was accounted for by applying 3-year smoothing to utility SF_6 sales data. The other factor that may affect the relationship between the RAND sales trends and actual global emissions is the level of imports from and exports to Russia and China. SF_6 production in these countries is not included in the RAND survey and is not accounted for in any another manner by RAND. However, atmospheric studies confirm that the downward trend in estimated global emissions between 1995 and 1998 was real (see the Uncertainty discussion below).

1990 through 2009 Emissions from Manufacture of Electrical Equipment

The 1990 to 2009 emission estimates for original equipment manufacturers (OEMs) were derived by assuming that manufacturing emissions equal 10 percent of the quantity of SF_6 provided with new equipment. The quantity of SF_6 provided with new equipment was estimated based on statistics compiled by the National Electrical Manufacturers Association (NEMA). These statistics were provided for 1990 to 2000; the quantities of SF_6 provided with new equipment for 2001 to 2009 were estimated using Partner reported data and the total industry SF_6 nameplate capacity estimate (137.4 Tg CO_2 Eq. in 2009). Specifically, the ratio of new nameplate capacity to total nameplate capacity of a subset of Partners for which new nameplate capacity data was available from 1999 to 2009 was calculated. This ratio was then multiplied by the total industry nameplate capacity estimate to derive the amount of SF_6 provided with new equipment for the entire industry. The 10 percent emission rate is the average of the "ideal" and "realistic" manufacturing emission rates (4 percent and 17 percent, respectively) identified in a paper prepared under the auspices of the International Council on Large Electric Systems (CIGRE) in February 2002 (O'Connell et al. 2002).

Uncertainty

To estimate the uncertainty associated with emissions of SF_6 from Electric Transmission and Distribution, uncertainties associated with three quantities were estimated: (1) emissions from Partners, (2) emissions from non-Partners, and (3) emissions from manufacturers of electrical equipment. A Monte Carlo analysis was then applied to estimate the overall uncertainty of the emissions estimate.

Total emissions from the SF_6 Emission Reduction Partnership include emissions from both reporting and non-reporting Partners. For reporting Partners, individual Partner-reported SF_6 data was assumed to have an uncertainty of 10 percent. Based on a Monte Carlo analysis, the cumulative uncertainty of all Partner reported data was estimated to be 5.3 percent. The uncertainty associated with extrapolated or interpolated emissions from non-reporting Partners was assumed to be 20 percent.

There are two sources of uncertainty associated with the regression equations used to estimate emissions in 2009 from non-Partners: (1) uncertainty in the coefficients (as defined by the regression standard error estimate), and (2) the uncertainty in total transmission miles for non-Partners. In addition, there is uncertainty associated with the assumption that the emission factor used for non-Partner utilities (which accounted for approximately 57 percent of U.S. transmission miles in 2009) will remain at levels defined by Partners who reported in 1999. However, the last source of uncertainty was not modeled.

Uncertainties were also estimated regarding (1) the quantity of SF_6 supplied with equipment by equipment manufacturers, which is projected from Partner provided nameplate capacity data and industry SF_6 nameplate capacity estimates, and (2) the manufacturers' SF_6 emissions rate.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-93. Electrical Transmission and Distribution SF_6 emissions were estimated to be between 10.2 and 15.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 21 percent below and 22 percent above the emission estimate of 12.8 Tg CO_2 Eq.

Table 4-93: Tier 2 Quantitative Uncertainty Estimates for SF_6 Emissions from Electrical Transmission and Distribution (Tg CO_2 Eq. and percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to 2009 Emission Estimate[a]**			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Electrical Transmission and Distribution	SF_6	12.8	10.2	15.7	-21%	+22%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

In addition to the uncertainty quantified above, there is uncertainty associated with using global SF_6 sales data to estimate U.S. emission trends from 1990 through 1999. However, the trend in global emissions implied by sales of SF_6 appears to reflect the trend in global emissions implied by changing SF_6 concentrations in the atmosphere. That is, emissions based on global sales declined by 29 percent between 1995 and 1998, and emissions based on atmospheric measurements declined by 27 percent over the same period.

Several pieces of evidence indicate that U.S. SF_6 emissions were reduced as global emissions were reduced. First, the decreases in sales and emissions coincided with a sharp increase in the price of SF_6 that occurred in the mid-1990s and that affected the United States as well as the rest of the world. A representative from DILO, a major manufacturer of SF_6 recycling equipment, stated that most U.S. utilities began recycling rather than venting SF_6 within two years of the price rise. Finally, the emissions reported by the one U.S. utility that reported 1990 through 1999 emissions to EPA showed a downward trend beginning in the mid-1990s.

Recalculations Discussion

SF_6 emission estimates for the period 1990 through 2008 were updated based on (1) new data from EPA's SF_6 Emission Reduction Partnership; (2) revisions to interpolated and extrapolated non-reported Partner data; and (3) a correction made to 2004 transmission mile data for a large Partnership utility that had been interpreted incorrectly from the UDI database in previous years. Updating the 2004 transmission mile data for the Partner changed the annual transmission mile growth rates used to extrapolate total U.S. transmission mile values for years in which a UDI database was not purchased (including 1999). This recalculation impacted emission estimates in two ways. First, the regression coefficients used to estimate emissions for non-Partners are based on 1999 transmission miles and emissions for Partners that reported emissions in 1999, so the change in 1999 transmission miles affected the regression coefficients. The result was that the regression coefficient for utilities with fewer than 10,000 transmission miles increased from 0.89 to 1.001 kg of emissions per transmission mile, while the regression coefficient for utilities with more than 10,000 transmission miles increased very slightly from 0.577 to 0.578 kg of emissions per transmission mile. The second impact of the updated annual transmission mile growth rates was that the total non-Partner transmission miles that the regression coefficients are applied to were also affected. Based on the revisions listed above, SF_6 emissions from electric transmission and distribution increased between 4 to 9 percent for each year from 1990 through 2008.

In addition, the method for estimating potential emissions from the sector was updated for the 1990-2009 Inventory. In previous years, potential emissions were assumed to equal total industry SF_6 purchases, which were developed from two components: (1) purchases by Partner utilities from bulk gas distributors, and (2) purchases by electrical equipment manufacturers from bulk gas distributors. This previous method led to concerns of double-counting since Partners sometimes were recording all SF_6 received in cylinders from any source (including equipment manufacturers) as gas received from bulk distributors. Therefore, SF_6 that was purchased by a utility from an equipment manufacturer was sometimes counted as a purchase by both the equipment manufacturer and the utility. The new method still assumes that potential emissions are equal to industry purchases, but estimates total purchases for the industry by adding the total amount of gas purchased by all U.S. utilities from any source (bulk distributor or equipment manufacturer) to estimated emissions from equipment manufacturers. It is assumed that all SF_6 purchased by equipment manufacturers is either emitted or sent to utilities.

4.23. Industrial Sources of Indirect Greenhouse Gases

In addition to the main greenhouse gases addressed above, many industrial processes generate emissions of indirect greenhouse gases. Total emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs) from non-energy industrial processes from 1990 to 2009 are reported in Table 4-94.

Table 4-94: NO_x, CO, and NMVOC Emissions from Industrial Processes (Gg)

Gas/Source	1990	1995	2000	2005	2006	2007	2008	2009
NO_x	**591**	**607**	**626**	**569**	**553**	**537**	**520**	**568**
Other Industrial Processes	343	362	435	437	418	398	379	436
Chemical & Allied Product Manufacturing	152	143	95	55	57	59	61	55
Metals Processing	88	89	81	60	61	62	62	60
Storage and Transport	3	5	14	15	15	16	16	15
Miscellaneous*	5	8	2	2	2	2	2	2
CO	**4,125**	**3,959**	**2,216**	**1,555**	**1,597**	**1,640**	**1,682**	**1,549**
Metals Processing	2,395	2,159	1,175	752	788	824	859	752
Other Industrial Processes	487	566	537	484	474	464	454	484
Chemical & Allied Product Manufacturing	1,073	1,110	327	189	206	223	240	187
Storage and Transport	69	23	153	97	100	103	104	97
Miscellaneous*	101	102	23	32	30	27	25	29
NMVOCs	**2,422**	**2,642**	**1,773**	**1,997**	**1,933**	**1,869**	**1,804**	**1,322**
Storage and Transport	1,352	1,499	1,067	1,308	1,266	1,224	1,182	662
Other Industrial Processes	364	408	412	415	398	383	367	395
Chemical & Allied Product Manufacturing	575	599	230	213	211	210	207	206
Metals Processing	111	113	61	44	44	43	42	44
Miscellaneous*	20	23	3	17	14	10	7	15

* Miscellaneous includes the following categories: catastrophic/accidental release, other combustion, health services, cooling towers, and fugitive dust. It does not include agricultural fires or slash/prescribed burning, which are accounted for under the Field Burning of Agricultural Residues source.

Note: Totals may not sum due to independent rounding.

Methodology

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual categories from various agencies. Depending on the category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

Activity data were used in conjunction with emission factors, which together relate the quantity of emissions to the activity. Emission factors are generally available from the EPA's Compilation of Air Pollutant Emission Factors, AP-42 (EPA 1997). The EPA currently derives the overall emission control efficiency of a source category from a variety of information sources, including published reports, the 1985 National Acid Precipitation and Assessment Program emissions inventory, and other EPA databases.

Uncertainty and Time-Series Consistency

Uncertainties in these estimates are partly due to the accuracy of the emission factors used and accurate estimates of activity data. A quantitative uncertainty analysis was not performed.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2008. Details on the emission trends through time are described in more detail in the Methodology section, above.

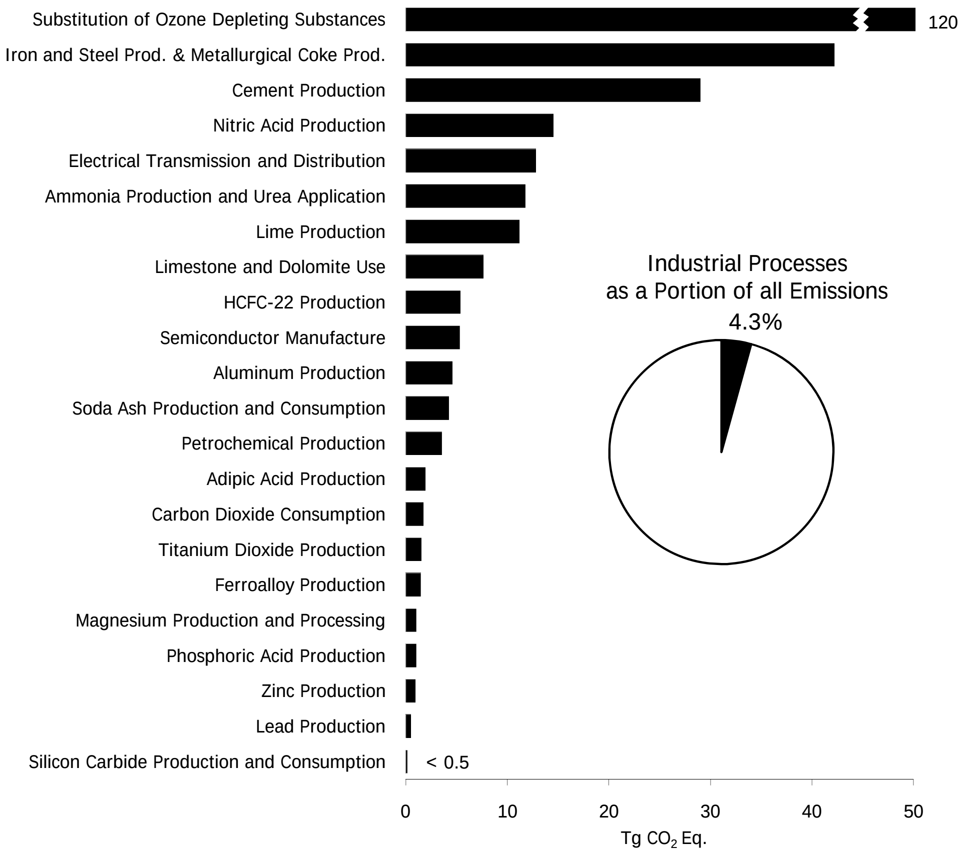

Figure 4-1: 2009 Industrial Processes Chapter Greenhouse Gas Sources

5. Solvent and Other Product Use

Greenhouse gas emissions are produced as a by-product of various solvent and other product uses. In the United States, emissions from Nitrous Oxide (N_2O) Product Uses, the only source of greenhouse gas emissions from this sector, accounted for less than 0.1 percent of total U.S. anthropogenic greenhouse gas emissions on a CO_2 equivalent basis in 2009 (see Table 5-1). Indirect greenhouse gas emissions also result from solvent and other product use, and are presented in Table 5-5 in gigagrams (Gg).

Table 5-1: N_2O Emissions from Solvent and Other Product Use (Tg CO_2 Eq. and Gg)

Gas/Source	1990		2000		2005	2006	2007	2008	2009
N_2O from Product Uses									
Tg CO_2 Eq.	4.4		4.9		4.4	4.4	4.4	4.4	4.4
Gg	14		16		14	14	14	14	14

5.1. Nitrous Oxide from Product Uses (IPCC Source Category 3D)

N_2O is a clear, colorless, oxidizing liquefied gas, with a slightly sweet odor. Two companies operate a total of five N_2O production facilities in the United States (Airgas 2007; FTC 2001). N_2O is primarily used in carrier gases with oxygen to administer more potent inhalation anesthetics for general anesthesia, and as an anesthetic in various dental and veterinary applications. As such, it is used to treat short-term pain, for sedation in minor elective surgeries, and as an induction anesthetic. The second main use of N_2O is as a propellant in pressure and aerosol products, the largest application being pressure-packaged whipped cream. Small quantities of N_2O also are used in the following applications:

- Oxidizing agent and etchant used in semiconductor manufacturing;
- Oxidizing agent used, with acetylene, in atomic absorption spectrometry;
- Production of sodium azide, which is used to inflate airbags;
- Fuel oxidant in auto racing; and
- Oxidizing agent in blowtorches used by jewelers and others (Heydorn 1997).

Production of N_2O in 2009 was approximately 15 Gg (Table 5-2).

Table 5-2: N_2O Production (Gg)

Year	Gg
1990	16
2000	17
2005	15
2006	15
2007	15
2008	15
2009	15

N_2O emissions were 4.4 Tg CO_2 Eq. (14 Gg) in 2009 (Table 5-3). Production of N_2O stabilized during the 1990s because medical markets had found other substitutes for anesthetics, and more medical procedures were being performed on an outpatient basis using local anesthetics that do not require N_2O. The use of N_2O as a propellant for whipped cream has also stabilized due to the increased popularity of cream products packaged in reusable plastic tubs (Heydorn 1997).

Table 5-3: N_2O Emissions from N_2O Product Usage (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	4.4	14

2000	4.9	16
2005	4.4	14
2006	4.4	14
2007	4.4	14
2008	4.4	14
2009	4.4	14

Methodology

Emissions from N_2O product usage were calculated by first multiplying the total amount of N_2O produced in the United States by the share of the total quantity of N_2O attributed to each end use. This value was then multiplied by the associated emission rate for each end use. After the emissions were calculated for each end use, they were added together to obtain a total estimate of N_2O product usage emissions. Emissions were determined using the following equation:

$$N_2O \text{ Product Usage Emissions} = \sum i \text{ [Total U.S. Production of } N_2O] \times \text{[Share of Total Quantity of } N_2O \text{ Usage by Sector i]} \times \text{[Emissions Rate for Sector i]}$$

where,

i = Sector.

The share of total quantity of N_2O usage by end use represents the share of national N_2O produced that is used by the specific subcategory (i.e., anesthesia, food processing, etc.). In 2009, the medical/dental industry used an estimated 89.5 percent of total N_2O produced, followed by food processing propellants at 6.5 percent. All other categories combined used the remainder of the N_2O produced. This subcategory breakdown has changed only slightly over the past decade. For instance, the small share of N_2O usage in the production of sodium azide has declined significantly during the 1990s. Due to the lack of information on the specific time period of the phase-out in this market subcategory, most of the N_2O usage for sodium azide production is assumed to have ceased after 1996, with the majority of its small share of the market assigned to the larger medical/dental consumption subcategory (Heydorn 1997). The N_2O was allocated across the following categories: medical applications, food processing propellant, and sodium azide production (pre-1996). A usage emissions rate was then applied for each sector to estimate the amount of N_2O emitted.

Only the medical/dental and food propellant subcategories were estimated to release emissions into the atmosphere, and therefore these subcategories were the only usage subcategories with emission rates. For the medical/dental subcategory, due to the poor solubility of N_2O in blood and other tissues, none of the N_2O is assumed to be metabolized during anesthesia and quickly leaves the body in exhaled breath. Therefore, an emission factor of 100 percent was used for this subcategory (IPCC 2006). For N_2O used as a propellant in pressurized and aerosol food products, none of the N_2O is reacted during the process and all of the N_2O is emitted to the atmosphere, resulting in an emission factor of 100 percent for this subcategory (IPCC 2006). For the remaining subcategories, all of the N_2O is consumed/reacted during the process, and therefore the emission rate was considered to be zero percent (Tupman 2002).

The 1990 through 1992 N_2O production data were obtained from SRI Consulting's Nitrous Oxide, North America report (Heydorn 1997). N_2O production data for 1993 through 1995 were not available. Production data for 1996 was specified as a range in two data sources (Heydorn 1997, Tupman 2002). In particular, for 1996, Heydorn (1997) estimates N_2O production to range between 13.6 and 18.1 thousand metric tons. Tupman (2003) provided a narrower range (15.9 to 18.1 thousand metric tons) for 1996 that falls within the production bounds described by Heydorn (1997). Tupman (2003) data are considered more industry-specific and current. Therefore, the midpoint of the narrower production range was used to estimate N_2O emissions for years 1993 through 2001 (Tupman 2003). The 2002 and 2003 N_2O production data were obtained from the Compressed Gas Association Nitrous Oxide Fact Sheet and Nitrous Oxide Abuse Hotline (CGA 2002, 2003). These data were also provided as a range. For example, in 2003, CGA (2003) estimates N_2O production to range between 13.6 and 15.9 thousand metric tons. Due to unavailable data, production estimates for years 2004 through 2009 were held at the 2003 value.

The 1996 share of the total quantity of N_2O used by each subcategory was obtained from SRI Consulting's Nitrous

Oxide, North America report (Heydorn 1997). The 1990 through 1995 share of total quantity of N_2O used by each subcategory was kept the same as the 1996 number provided by SRI Consulting. The 1997 through 2001share of total quantity of N_2O usage by sector was obtained from communication with a N_2O industry expert (Tupman 2002). The 2002 and 2003 share of total quantity of N_2O usage by sector was obtained from CGA (2002, 2003). Due to unavailable data, the share of total quantity of N_2O usage data for years 2004 through 2009 was assumed to equal the 2003 value. The emissions rate for the food processing propellant industry was obtained from SRI Consulting's Nitrous Oxide, North America report (Heydorn 1997), and confirmed by a N_2O industry expert (Tupman 2002). The emissions rate for all other subcategories was obtained from communication with a N_2O industry expert (Tupman 2002). The emissions rate for the medical/dental subcategory was obtained from the 2006 IPCC Guidelines.

Uncertainty and Time-Series Consistency

The overall uncertainty associated with the 2009 N_2O emission estimate from N_2O product usage was calculated using the IPCC Guidelines for National Greenhouse Gas Inventories (2006) Tier 2 methodology. Uncertainty associated with the parameters used to estimate N_2O emissions include production data, total market share of each end use, and the emission factors applied to each end use, respectively.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 5-4. N_2O emissions from N_2O product usage were estimated to be between 4.1 and 4.7 Tg CO_2 Eq. at the 95 percent confidence level (or in 19 out of 20 Monte Carlo Stochastic Simulations). This indicates a range of approximately 8 percent below to 8 percent above the 2009 emissions estimate of 4.4 Tg CO_2 Eq.

Table 5-4: Tier 2 Quantitative Uncertainty Estimates for N_2O Emissions from N_2O Product Usage (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**[a]			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
N_2O Product Usage	N_2O	4.4	4.1	4.7	-8%	+8%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Note that this uncertainty range (±8 percent) has increased by 12 percent compared to the uncertainty range in last year's Inventory (±2 percent), due to a correction to the uncertainty input parameters. Furthermore, methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time-series are described in more detail in the Methodology section, above.

Planned Improvements

Planned improvements include a continued evaluation of alternative production statistics for cross verification, a reassessment of N_2O product use subcategories to accurately represent trends, investigation of production and use cycles, and the potential need to incorporate a time lag between production and ultimate product use and resulting release of N_2O. Additionally, planned improvements include considering imports and exports of N_2O for product uses.

5.2. Indirect Greenhouse Gas Emissions from Solvent Use

The use of solvents and other chemical products can result in emissions of various ozone precursors (i.e., indirect greenhouse gases).[138] Non-CH_4 volatile organic compounds (NMVOCs), commonly referred to as "hydrocarbons," are the primary gases emitted from most processes employing organic or petroleum based solvents. As some of industrial applications also employ thermal incineration as a control technology, combustion by-products, such as carbon monoxide (CO) and nitrogen oxides (NO_x), are also reported with this source category. In the United States,

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[138] Solvent usage in the United States also results in the emission of small amounts of hydrofluorocarbons (HFCs) and hydrofluoroethers (HFEs), which are included under Substitution of Ozone Depleting Substances in the Industrial Processes chapter.

emissions from solvents are primarily the result of solvent evaporation, whereby the lighter hydrocarbon molecules in the solvents escape into the atmosphere. The evaporation process varies depending on different solvent uses and solvent types. The major categories of solvent uses include: degreasing, graphic arts, surface coating, other industrial uses of solvents (i.e., electronics, etc.), dry cleaning, and non-industrial uses (i.e., uses of paint thinner, etc.).

Total emissions of NO_x, NMVOCs, and CO from 1990 to 2009 are reported in Table 5-5.

Table 5-5: Emissions of NO_x, CO, and NMVOC from Solvent Use (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
NO_x	**1**	**3**	**3**	**4**	**4**	**4**	**3**
Surface Coating	1	3	3	4	4	4	3
Graphic Arts	+	+	+	+	+	+	+
Degreasing	+	+	+	+	+	+	+
Dry Cleaning	+	+	+	+	+	+	+
Other Industrial Processes[a]	+	+	+	+	+	+	+
Non-Industrial Processes[b]	+	+	+	+	+	+	+
Other	NA	+	+	+	+	+	+
CO	**5**	**45**	**2**	**2**	**2**	**2**	**2**
Surface Coating	+	45	2	2	2	2	2
Other Industrial Processes[a]	4	+	+	+	+	+	+
Dry Cleaning	+	+	+	+	+	+	+
Degreasing	+	+	+	+	+	+	+
Graphic Arts	+	+	+	+	+	+	+
Non-Industrial Processes[b]	+	+	+	+	+	+	+
Other	NA	+	+	+	+	+	+
NMVOCs	**5,216**	**4,384**	**3,851**	**3,846**	**3,839**	**3,834**	**2,583**
Surface Coating	2,289	1,766	1,578	1,575	1,573	1,571	1,058
Non-Industrial Processes[b]	1,724	1,676	1,446	1,444	1,441	1,439	970
Degreasing	675	316	280	280	280	279	188
Dry Cleaning	195	265	230	230	229	229	154
Graphic Arts	249	222	194	193	193	193	130
Other Industrial Processes[a]	85	98	88	88	87	87	59
Other	+	40	36	36	36	36	24

[a] Includes rubber and plastics manufacturing, and other miscellaneous applications.

[b] Includes cutback asphalt, pesticide application adhesives, consumer solvents, and other miscellaneous applications.

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.5 Gg.

Methodology

Emissions were calculated by aggregating solvent use data based on information relating to solvent uses from different applications such as degreasing, graphic arts, etc. Emission factors for each consumption category were then applied to the data to estimate emissions. For example, emissions from surface coatings were mostly due to solvent evaporation as the coatings solidify. By applying the appropriate solvent-specific emission factors to the amount of solvents used for surface coatings, an estimate of emissions was obtained. Emissions of CO and NO_x result primarily from thermal and catalytic incineration of solvent-laden gas streams from painting booths, printing operations, and oven exhaust.

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of solvent purchased) as an indicator of emissions. National activity data were collected for individual applications from various agencies.

Activity data were used in conjunction with emission factors, which together relate the quantity of emissions to the activity. Emission factors are generally available from the EPA's Compilation of Air Pollutant Emission Factors, AP-42 (EPA 1997). The EPA currently derives the overall emission control efficiency of a source category from a variety of information sources, including published reports, the 1985 National Acid Precipitation and Assessment Program emissions inventory, and other EPA databases.

Uncertainty and Time-Series Consistency

Uncertainties in these estimates are partly due to the accuracy of the emission factors used and the reliability of correlations between activity data and actual emissions.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

6. Agriculture

Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes. This chapter provides an assessment of non-carbon-dioxide emissions from the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues (see Figure 6-1). Carbon dioxide (CO_2) emissions and removals from agriculture-related land-use activities, such as liming of agricultural soils and conversion of grassland to cultivated land, are presented in the Land Use, Land-Use Change, and Forestry chapter. Carbon dioxide emissions from on-farm energy use are accounted for in the Energy chapter.

Figure 6-1: 2009 Agriculture Chapter Greenhouse Gas Emission Sources

In 2009, the Agriculture sector was responsible for emissions of 419.3 teragrams of CO_2 equivalents (Tg CO_2 Eq.), or 6.3 percent of total U.S. greenhouse gas emissions. Methane (CH_4) and nitrous oxide (N_2O) were the primary greenhouse gases emitted by agricultural activities. Methane emissions from enteric fermentation and manure management represent about 20 percent and 7 percent of total CH_4 emissions from anthropogenic activities, respectively. Of all domestic animal types, beef and dairy cattle were by far the largest emitters of CH_4. Rice cultivation and field burning of agricultural residues were minor sources of CH_4. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N_2O emissions, accounting for 69 percent. Manure management and field burning of agricultural residues were also small sources of N_2O emissions.

Table 6-1 and Table 6-2 present emission estimates for the Agriculture sector. Between 1990 and 2009, CH_4 emissions from agricultural activities increased by 14.9 percent, while N_2O emissions fluctuated from year to year, but overall increased by 4.8 percent.

Table 6-1: Emissions from Agriculture (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH_4	**171.2**	**186.7**	**190.1**	**191.7**	**198.2**	**197.5**	**196.8**
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Field Burning of Agricultural Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
N_2O	**212.4**	**224.0**	**228.7**	**227.1**	**227.6**	**228.8**	**222.5**
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**383.6**	**410.6**	**418.8**	**418.8**	**425.8**	**426.3**	**419.3**

Note: Totals may not sum due to independent rounding.

Table 6-2: Emissions from Agriculture (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH_4	**8,153**	**8,890**	**9,052**	**9,129**	**9,437**	**9,405**	**9,372**
Enteric Fermentation	6,290	6,502	6,500	6,611	6,715	6,696	6,655
Manure Management	1,511	2,019	2,217	2,226	2,416	2,353	2,356
Rice Cultivation	339	357	326	282	295	343	349
Field Burning of Agricultural Residues	13	12	9	11	11	13	12
N_2O	**685**	**722**	**738**	**732**	**734**	**738**	**718**
Agricultural Soil Management	638	667	682	674	675	680	660

Manure Management	47	55	56	58	58	58	58
Field Burning of Agricultural Residues	+	+	+	+	+	+	+

+ Less than 0.5 Gg.
Note: Totals may not sum due to independent rounding.

6.1. Enteric Fermentation (IPCC Source Category 4A)

Methane is produced as part of normal digestive processes in animals. During digestion, microbes resident in an animal's digestive system ferment food consumed by the animal. This microbial fermentation process, referred to as enteric fermentation, produces CH_4 as a byproduct, which can be exhaled or eructated by the animal. The amount of CH_4 produced and emitted by an individual animal depends primarily upon the animal's digestive system, and the amount and type of feed it consumes.

Ruminant animals (e.g., cattle, buffalo, sheep, goats, and camels) are the major emitters of CH_4 because of their unique digestive system. Ruminants possess a rumen, or large "fore-stomach," in which microbial fermentation breaks down the feed they consume into products that can be absorbed and metabolized. The microbial fermentation that occurs in the rumen enables them to digest coarse plant material that non-ruminant animals cannot. Ruminant animals, consequently, have the highest CH_4 emissions among all animal types.

Non-ruminant animals (e.g., swine, horses, and mules) also produce CH_4 emissions through enteric fermentation, although this microbial fermentation occurs in the large intestine. These non-ruminants emit significantly less CH_4 on a per-animal basis than ruminants because the capacity of the large intestine to produce CH_4 is lower.

In addition to the type of digestive system, an animal's feed quality and feed intake also affect CH_4 emissions. In general, lower feed quality and/or higher feed intake leads to higher CH_4 emissions. Feed intake is positively correlated to animal size, growth rate, and production (e.g., milk production, wool growth, pregnancy, or work). Therefore, feed intake varies among animal types as well as among different management practices for individual animal types (e.g., animals in feedlots or grazing on pasture).

Methane emission estimates from enteric fermentation are provided in Table 6-3 and Table 6-4. Total livestock CH_4 emissions in 2009 were 139.8 Tg CO_2 Eq. (6,655 Gg). Beef cattle remain the largest contributor of CH_4 emissions from enteric fermentation, accounting for 71 percent in 2009. Emissions from dairy cattle in 2009 accounted for 24 percent, and the remaining emissions were from horses, sheep, swine, and goats.

From 1990 to 2009, emissions from enteric fermentation have increased by 5.8 percent. Generally, emissions decreased from 1996 to 2003, though with a slight increase in 2002. This trend was mainly due to decreasing populations of both beef and dairy cattle and increased digestibility of feed for feedlot cattle. Emissions increased from 2004 through 2007, as both dairy and beef populations have undergone increases and the literature for dairy cow diets indicated a trend toward a decrease in feed digestibility for those years. Emissions decreased again in 2008 and 2009 as beef cattle populations again decreased. During the timeframe of this analysis, populations of sheep have decreased 49 percent while horse populations have increased over 87 percent, mostly since 1999. Goat and swine populations have increased 25 percent and 23 percent, respectively, during this timeframe.

Table 6-3: CH_4 Emissions from Enteric Fermentation (Tg CO_2 Eq.)

Livestock Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Beef Cattle	94.5	100.6	99.3	100.9	101.6	100.7	99.6
Dairy Cattle	31.8	30.7	30.4	31.1	32.4	32.9	33.2
Horses	1.9	2.0	3.5	3.6	3.6	3.6	3.6
Sheep	1.9	1.2	1.0	1.0	1.0	1.0	1.0
Swine	1.7	1.9	1.9	1.9	2.1	2.1	2.1
Goats	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**132.1**	**136.5**	**136.5**	**138.8**	**141.0**	**140.6**	**139.8**

Note: Totals may not sum due to independent rounding.

Table 6-4: CH_4 Emissions from Enteric Fermentation (Gg)

Livestock Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Beef Cattle	4,502	4,790	4,731	4,803	4,837	4,796	4,742
Dairy Cattle	1,513	1,460	1,449	1,479	1,544	1,564	1,581

Horses	91		94		166	171	171	171	171
Sheep	91		56		49	50	49	48	46
Swine	81		88		92	93	98	101	99
Goats	13		12		14	15	16	16	16
Total	**6,290**		**6,502**		**6,500**	**6,611**	**6,715**	**6,696**	**6,655**

Note: Totals may not sum due to independent rounding.

Methodology

Livestock emission estimate methodologies fall into two categories: cattle and other domesticated animals. Cattle, due to their large population, large size, and particular digestive characteristics, account for the majority of CH_4 emissions from livestock in the United States. A more detailed methodology (i.e., IPCC Tier 2) was therefore applied to estimate emissions for all cattle except for bulls. Emission estimates for other domesticated animals (horses, sheep, swine, goats, and bulls) were handled using a less detailed approach (i.e., IPCC Tier 1).

While the large diversity of animal management practices cannot be precisely characterized and evaluated, significant scientific literature exists that provides the necessary data to estimate cattle emissions using the IPCC Tier 2 approach. The Cattle Enteric Fermentation Model (CEFM), developed by EPA and used to estimate cattle CH_4 emissions from enteric fermentation, incorporates this information and other analyses of livestock population, feeding practices, and production characteristics.

National cattle population statistics were disaggregated into the following cattle sub-populations:

- Dairy Cattle
    - Calves
    - Heifer Replacements
    - Cows
- Beef Cattle
    - Calves
    - Heifer Replacements
    - Heifer and Steer Stockers
    - Animals in Feedlots (Heifers and Steers)
    - Cows
    - Bulls

Calf birth rates, end-of-year population statistics, detailed feedlot placement information, and slaughter weight data were used to create a transition matrix that models cohorts of individual animal types and their specific emission profiles. The key variables tracked for each of the cattle population categories are described in Annex 3.9. These variables include performance factors such as pregnancy and lactation as well as average weights and weight gain. Annual cattle population data were obtained from the U.S. Department of Agriculture's (USDA) National Agricultural Statistics Service (NASS) QuickStats database (USDA 2010).

Diet characteristics were estimated by region for U.S. dairy, beef, and feedlot cattle. These estimates were used to calculate Digestible Energy (DE) values (expressed as the percent of gross energy intake digested by the animal) and CH_4 conversion rates (Y_m) (expressed as the fraction of gross energy converted to CH_4) for each population category. The IPCC recommends Y_m values of 3.0±1.0 percent for feedlot cattle and 6.5±1.0 percent for other well-fed cattle consuming temperate-climate feed types (IPCC 2006). Given the availability of detailed diet information for different regions and animal types in the United States, DE and Y_m values unique to the United States were developed, rather than using the recommended IPCC values. The diet characterizations and estimation of DE and Y_m values were based on information from state agricultural extension specialists, a review of published forage quality studies and scientific literature, expert opinion, and modeling of animal physiology. The diet characteristics for dairy cattle were based on Donovan (1999) and an extensive review of nearly 20 years of literature. Dairy replacement heifer diet assumptions were based on the observed relationship in the literature between dairy cow and dairy heifer diet characteristics. The diet assumptions for beef cattle were derived from NRC (2000). For feedlot animals, the DE and Y_m values used for 1990 were recommended by Johnson (1999). Values for DE and Y_m for 1991 through 1999 were linearly extrapolated based on the 1990 and 2000 data. DE and Y_m values for 2000 onwards were based on survey data in Galyean and Gleghorn (2001) and Vasconcelos and Galyean (2007). For grazing beef cattle, DE values were based on diet information in NRC (2000) and Y_m values were based on Johnson (2002). Weight and weight gains for cattle were estimated from Holstein Association USA (2010), Enns (2008), Lippke et al. (2000), Pinchack et al., (2004), Platter et al. (2003), Skogerboe et al. (2000), and expert opinion. See Annex 3.9 for more details on the method used to characterize cattle diets and weights in the United States.

To estimate CH_4 emissions from all cattle types except bulls and calves younger than 7 months,[139] the population was divided into state, age, sub-type (i.e., dairy cows and replacements, beef cows and replacements, heifer and steer stockers, and heifers and steers in feedlots), and production (i.e., pregnant, lactating) groupings to more fully capture differences in CH_4 emissions from these animal types. The transition matrix was used to simulate the age and weight structure of each sub-type on a monthly basis, to more accurately reflect the fluctuations that occur throughout the year. Cattle diet characteristics were then used in conjunction with Tier 2 equations from IPCC (2006) to produce CH_4 emission factors for the following cattle types: dairy cows, beef cows, dairy replacements, beef replacements, steer stockers, heifer stockers, steer feedlot animals, and heifer feedlot animals. To estimate emissions from cattle, population data from the transition matrix were multiplied by the calculated emission factor for each cattle type. More details are provided in Annex 3.9.

Emission estimates for other animal types were based on average emission factors representative of entire populations of each animal type. Methane emissions from these animals accounted for a minor portion of total CH_4 emissions from livestock in the United States from 1990 through 2009. Also, the variability in emission factors for each of these other animal types (e.g., variability by age, production system, and feeding practice within each animal type) is less than that for cattle. Annual livestock population data for these other livestock types, except horses and goats, as well as feedlot placement information, were obtained for all years from USDA NASS (USDA 2010). Horse population data were obtained from the Food and Agriculture Organization of the United Nations (FAO) FAOSTAT database (FAO 2010), because USDA does not estimate U.S. horse populations annually. Goat population data were obtained for 1992, 1997, 2002, and 2007 (USDA 2010); these data were interpolated and extrapolated to derive estimates for the other years. Methane emissions from sheep, goats, swine, and horses were estimated by using emission factors utilized in Crutzen et al. (1986, cited in IPCC 2006). These emission factors are representative of typical animal sizes, feed intakes, and feed characteristics in developed countries. The methodology is the same as that recommended by IPCC (2006).

See Annex 3.9 for more detailed information on the methodology and data used to calculate CH_4 emissions from enteric fermentation.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis for this source category was performed through the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique as described in ICF (2003). These uncertainty estimates were developed for the 1990 through 2001 Inventory report. No significant changes occurred in the method of data collection, data estimation methodology, or other factors that influence the uncertainty ranges around the 2009 activity data and emission factor input variables used in the current submission. Consequently, these uncertainty estimates were directly applied to the 2009 emission estimates.

A total of 185 primary input variables (177 for cattle and 8 for non-cattle) were identified as key input variables for the uncertainty analysis. A normal distribution was assumed for almost all activity- and emission factor-related input variables. Triangular distributions were assigned to three input variables (specifically, cow-birth ratios for the three most recent years included in the 2001 model run) to capture the fact that these variables cannot be negative. For some key input variables, the uncertainty ranges around their estimates (used for inventory estimation) were collected from published documents and other public sources; others were based on expert opinion and best estimates. In addition, both endogenous and exogenous correlations between selected primary input variables were

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[139] Emissions from bulls are estimated using a Tier 1 approach because it is assumed there is minimal variation in population and diets. Because calves younger than 7 months consume mainly milk and the IPCC recommends the use of methane conversion factor of zero for all juveniles consuming only milk, this results in no methane emissions from this subcategory of cattle.

modeled. The exogenous correlation coefficients between the probability distributions of selected activity-related variables were developed through expert judgment.

The uncertainty ranges associated with the activity data-related input variables were plus or minus 10 percent or lower. However, for many emission factor-related input variables, the lower- and/or the upper-bound uncertainty estimates were over 20 percent. The results of the quantitative uncertainty analysis are summarized in Table 6-5. Enteric fermentation CH_4 emissions in 2009 were estimated to be between 124.4 and 165.0 Tg CO_2 Eq. at a 95 percent confidence level, which indicates a range of 11 percent below to 18 percent above the 2009 emission estimate of 139.8 Tg CO_2 Eq. Among the individual cattle sub-source categories, beef cattle account for the largest amount of CH_4 emissions as well as the largest degree of uncertainty in the inventory emission estimates. Among non-cattle, horses account for the largest degree of uncertainty in the inventory emission estimates because there is a higher degree of uncertainty among the FAO population estimates used for horses than for the USDA population estimates used for swine, goats, and sheep.

Table 6-5: Quantitative Uncertainty Estimates for CH_4 Emissions from Enteric Fermentation (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate**	**Uncertainty Range Relative to Emission Estimate**[a, b]			
		(Tg CO_2 Eq.)	**(Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Enteric Fermentation	CH_4	139.8	124.4	165.0	-11%	+18%

[a] Range of emissions estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

[b] Note that the relative uncertainty range was estimated with respect to the 2001 emission estimates submitted in 2003 and applied to the 2009 estimates.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section.

QA/QC and Verification

In order to ensure the quality of the emission estimates from enteric fermentation, the IPCC Tier 1 and Tier 2 Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. QA/QC plan. Tier 2 QA procedures included independent peer review of emission estimates. Because there were no major modifications to the CEFM for 2009, QA/QC emphasis for the current Inventory was placed on cleaning up documentation and references within the model, and review of external data sources. For example, during the course of the QA/QC activities for this source category, it was noted that the U.S. total for 2009 Cattle On Feed data provided via USDA's Quickstats database did not match the total calculated from summing all individual states. The appropriate party was contacted at USDA, and it was determined that data for New Mexico and North Carolina were included individually, as well as within the "Other States" aggregate number, so they were being double counted in the U.S. total. This issue was quickly resolved.

In addition, over the past few years, particular importance has been placed on harmonizing the data exchange between the enteric fermentation and manure management source categories. The current inventory submission now utilizes the transition matrix from the CEFM for estimating cattle populations and weights for both source categories, and the CEFM is used to output volatile solids and nitrogen (N) excretion estimates using the diet assumptions in the model in conjunction with the energy balance equations from the IPCC (2006). This approach should complete the resolution of the discrepancies noted in previous reviews of these sectors, and facilitate the QA/QC process for both of these source categories.

Recalculations Discussion

There were several modifications to the estimates relative to the previous Inventory that had an effect on emission estimates, including the following:

- The average weight assumed for mature dairy cows has changed from the 1,550 pounds used in previous inventories to 1,500 pounds (Johnson 2010; Holstein Association 2010).
- The USDA published revised estimates in several categories that affected historical emissions estimated for

cattle and swine for 2008. Calves, beef replacements, and feedlot cattle all saw slight modifications to their 2008 populations, while swine population categories were modified so that the categories "<60 pounds" and "60-119 pounds" were replaced with "<50 pounds" and "50-119" pounds. Additionally, 2008 lactation estimates for Arkansas, Connecticut, Indiana, Nebraska, New Jersey, Oklahoma, South Carolina, and Vermont were updated by USDA.

- For the 1990 through 2009 inventory, goat population data were taken from the 2007 *Census of Agriculture*. For 2007 population values, the Census's 2007 "Total Goat" population for each state was used. Using the 2002 and 2007 data points, the population for the intervening years was interpolated, and the population for 2008 and 2009 were set equal to the population for 2007. The updated Census data resulted in a change in population values from 2003 through 2008 as populations for these years were previously set equal to the 2002 population.

As a result of these changes, dairy cattle emissions decreased an average of 11.5 Gg (0.8 percent) per year and beef cattle emissions decreased an average of 0.13 Gg (less than 0.01 percent) per year over the entire time series relative to the previous Inventory. Historical emission estimates for 2008 increased by 1.3 percent for goats as a result of the USDA population revisions described above.

Planned Improvements

Continued research and regular updates are necessary to maintain a current model of cattle diet characterization, feedlot placement data, rates of weight gain and calving, among other data inputs. Ongoing revisions could include some of the following options:

- Reviewing and updating the diet assumptions for foraging beef cattle;
- Estimating bull emissions using the IPCC Tier 2 approach;
- Updating input variables that are from older data sources, such as beef births by month and beef cow lactation rates;
- The possible breakout of other animal types (i.e., sheep, swine, goats, horses) from national estimates to state-level estimates; and
- Including bison in the estimates for other domesticated animals.

In addition, recent changes that have been implemented to the CEFM warrant an assessment of the current uncertainty analysis; therefore, a revision of the quantitative uncertainty surrounding emission estimates from this source category will be initiated.

6.2. Manure Management (IPCC Source Category 4B)

The management of livestock manure can produce anthropogenic CH_4 and N_2O emissions. Methane is produced by the anaerobic decomposition of manure. Direct N_2O emissions are produced as part of the N cycle through the nitrification and denitrification of the organic N in livestock dung and urine.[140] Indirect N_2O emissions are produced as result of the volatilization of N as NH_3 and NO_x and runoff and leaching of N during treatment, storage and transportation.

When livestock or poultry manure are stored or treated in systems that promote anaerobic conditions (e.g., as a liquid/slurry in lagoons, ponds, tanks, or pits), the decomposition of materials in the manure tends to produce CH_4. When manure is handled as a solid (e.g., in stacks or drylots) or deposited on pasture, range, or paddock lands, it tends to decompose aerobically and produce little or no CH_4. Ambient temperature, moisture, and manure storage or residency time affect the amount of CH_4 produced because they influence the growth of the bacteria responsible for CH_4 formation. For non-liquid-based manure systems, moist conditions (which are a function of rainfall and

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[140] Direct and indirect N_2O emissions from dung and urine spread onto fields either directly as daily spread or after it is removed from manure management systems (e.g., lagoon, pit, etc.) and from livestock dung and urine deposited on pasture, range, or paddock lands are accounted for and discussed in the Agricultural Soil Management source category within the Agriculture sector.

humidity) can promote CH_4 production. Manure composition, which varies by animal diet, growth rate, and type, including the animal's digestive system, also affects the amount of CH_4 produced. In general, the greater the energy content of the feed, the greater the potential for CH_4 emissions. However, some higher-energy feeds also are more digestible than lower quality forages, which can result in less overall waste excreted from the animal.

The production of direct N_2O emissions from livestock manure depends on the composition of the manure and urine, the type of bacteria involved in the process, and the amount of oxygen and liquid in the manure system. For direct N_2O emissions to occur, the manure must first be handled aerobically where ammonia (NH_3) or organic N is converted to nitrates and nitrites (nitrification), and then handled anaerobically where the nitrates and nitrites are reduced to dinitrogen gas (N_2), with intermediate production of N_2O and nitric oxide (NO) (denitrification) (Groffman et al. 2000). These emissions are most likely to occur in dry manure handling systems that have aerobic conditions, but that also contain pockets of anaerobic conditions due to saturation. A very small portion of the total N excreted is expected to convert to N_2O in the waste management system (WMS). Indirect N_2O emissions are produced when nitrogen is lost from the system through volatilization (as NH_3 or NO_x) or through runoff and leaching. The vast majority of volatilization losses from these operations are NH_3. Although there are also some small losses of NO_x, there are no quantified estimates available for use, so losses due to volatilization are only based on NH_3 loss factors. Runoff losses would be expected from operations that house animals or store manure in a manner that is exposed to weather. Runoff losses are also specific to the type of animal housed on the operation due to differences in manure characteristics. Little information is known about leaching from manure management systems as most research focuses on leaching from land application systems. Since leaching losses are expected to be minimal, leaching losses are coupled with runoff losses and the runoff/leaching estimate does not include any leaching losses.

Estimates of CH_4 emissions in 2009 were 49.5 Tg CO_2 Eq. (2,356 Gg), 56 percent higher than in 1990. Emissions increased on average by 0.9 Tg CO_2 Eq. (2.5 percent) annually over this period. The majority of this increase was from swine and dairy cow manure, where emissions increased 45 and 95 percent, respectively. Although the majority of manure in the United States is handled as a solid, producing little CH_4, the general trend in manure management, particularly for dairy and swine (which are both shifting towards larger facilities), is one of increasing use of liquid systems. Also, new regulations limiting the application of manure nutrients have shifted manure management practices at smaller dairies from daily spread to manure managed and stored on site. Although national dairy animal populations have been generally decreasing, some states have seen increases in their dairy populations as the industry becomes more concentrated in certain areas of the country. These areas of concentration, such as California, New Mexico, and Idaho, tend to utilize more liquid-based systems to manage (flush or scrape) and store manure. Thus the shift toward larger facilities is translated into an increasing use of liquid manure management systems, which have higher potential CH_4 emissions than dry systems. This shift was accounted for by incorporating state and WMS-specific CH_4 conversion factor (MCF) values in combination with the 1992, 1997, and 2002 farm-size distribution data reported in the *Census of Agriculture* (USDA 2009a). Methane emissions from sheep have decreased significantly since 1990 (a 54 percent decrease from 1990 to 2009); however, this is mainly due to population changes. Overall, sheep contribute less than one percent of CH_4 emissions from animal manure management. From 2008 to 2009, there was a less than 1 percent increase in total CH_4 emissions, due to minor shifts in the animal populations and the resultant effects on manure management system allocations.

In 2009, total N_2O emissions were estimated to be 17.9 Tg CO_2 Eq. (58 Gg); in 1990, emissions were 14.5 Tg CO_2 Eq. (47 Gg). These values include both direct and indirect N_2O emissions from manure management. Nitrous oxide emissions have remained fairly steady since 1990. Small changes in N_2O emissions from individual animal groups exhibit the same trends as the animal group populations, with the overall net effect that N_2O emissions showed a 23 percent increase from 1990 to 2009 and a less than 1 percent decrease from 2008 through 2009.

Table 6-6 and Table 6-7 provide estimates of CH_4 and N_2O emissions from manure management by animal category.

Table 6-6: CH_4 and N_2O Emissions from Manure Management (Tg CO_2 Eq.)

Gas/Animal Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CH_4[a]	**31.7**	**42.4**	**46.6**	**46.7**	**50.7**	**49.4**	**49.5**
Dairy Cattle	12.6	18.9	21.4	21.7	24.2	24.1	24.5
Beef Cattle	2.7	2.8	2.8	2.9	2.9	2.8	2.7
Swine	13.1	17.5	19.0	18.7	20.3	19.3	19.0
Sheep	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Goats	+	+	+	+	+	+	+
Poultry	2.8	2.7	2.7	2.7	2.8	2.7	2.7
Horses	0.5	0.4	0.6	0.6	0.6	0.5	0.5
N_2O^b	**14.5**	**17.1**	**17.3**	**18.0**	**18.1**	**17.9**	**17.9**
Dairy Cattle	5.3	5.6	5.6	5.8	5.8	5.7	5.8
Beef Cattle	6.1	7.8	7.5	8.0	7.9	7.8	7.8
Swine	1.2	1.6	1.8	1.8	1.9	2.0	2.0
Sheep	0.1	0.3	0.4	0.4	0.4	0.4	0.3
Goats	+	+	+	+	+	+	+
Poultry	1.5	1.6	1.7	1.7	1.7	1.7	1.6
Horses	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Total	**46.2**	**59.5**	**63.8**	**64.8**	**68.9**	**67.3**	**67.3**

+ Less than 0.05 Tg CO_2 Eq.

[a] Accounts for CH_4 reductions due to capture and destruction of CH_4 at facilities using anaerobic digesters.

[b] Includes both direct and indirect N_2O emissions.

Note: Totals may not sum due to independent rounding.

Table 6-7: CH_4 and N_2O Emissions from Manure Management (Gg)

Gas/Animal Type	1990	2000	2005	2006	2007	2008	2009
CH_4^a	**1,511**	**2,019**	**2,217**	**2,226**	**2,416**	**2,353**	**2,356**
Dairy Cattle	599	900	1,018	1,034	1,151	1,147	1,168
Beef Cattle	128	133	132	139	136	131	130
Swine	624	834	905	889	965	918	903
Sheep	7	4	3	3	3	3	3
Goats	1	1	1	1	1	1	1
Poultry	131	127	129	131	134	129	127
Horses	22	20	28	28	27	24	24
N_2O^b	**47**	**55**	**56**	**58**	**58**	**58**	**58**
Dairy Cattle	17	18	18	19	19	18	19
Beef Cattle	20	25	24	26	26	25	25
Swine	4	5	6	6	6	6	6
Sheep	+	1	1	1	1	1	1
Goats	+	+	+	+	+	+	+
Poultry	5	5	5	5	5	5	5
Horses	1	1	1	1	1	1	1

+ Less than 0.5 Gg.

[a] Accounts for CH_4 reductions due to capture and destruction of CH_4 at facilities using anaerobic digesters.

[b] Includes both direct and indirect N_2O emissions.

Note: Totals may not sum due to independent rounding.

Methodology

The methodologies presented in IPCC (2006) form the basis of the CH_4 and N_2O emission estimates for each animal type. This section presents a summary of the methodologies used to estimate CH_4 and N_2O emissions from manure management for this Inventory. See Annex 3.10 for more detailed information on the methodology and data used to calculate CH_4 and N_2O emissions from manure management.

Methane Calculation Methods

The following inputs were used in the calculation of CH_4 emissions:

- Animal population data (by animal type and state);
- Typical animal mass (TAM) data (by animal type);
- Portion of manure managed in each waste management system (WMS), by state and animal type;
- Volatile solids (VS) production rate (by animal type and state or United States);
- Methane producing potential (B_o) of the volatile solids (by animal type); and

- Methane conversion factors (MCF), the extent to which the CH_4 producing potential is realized for each type of WMS (by state and manure management system, including the impacts of any biogas collection efforts).

Methane emissions were estimated by first determining activity data, including animal population, TAM, WMS usage, and waste characteristics. The activity data sources are described below:

- Annual animal population data for 1990 through 2009 for all livestock types, except horses and goats were obtained from USDA NASS. For cattle, the USDA populations were utilized in conjunction with birth rates, detailed feedlot placement information, and slaughter weight data to create the transition matrix in the CEFM that models cohorts of individual animal types and their specific emission profiles. The key variables tracked for each of the cattle population categories are described in Section 6.1 and in more detail in Annex 3.9. Horse population data were obtained from the FAOSTAT database (FAO 2010). Goat population data for 1992, 1997, 2002, and 2007 were obtained from the *Census of Agriculture* (USDA 2009a).
- The TAM is an annual average weight which was obtained for animal types other than cattle from information in USDA's *Agricultural Waste Management Field Handbook* (USDA 1996a), the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1999) and others (EPA 1992, Safley 2000, ERG 2010a). For a description of the TAM used for cattle, please see section 6.1, Enteric Fermentation.
- WMS usage was estimated for swine and dairy cattle for different farm size categories using data from USDA (USDA 1996b, 1998b, 2000a) and EPA (ERG 2000a, EPA 2002a, 2002b). For beef cattle and poultry, manure management system usage data were not tied to farm size but were based on other data sources (ERG 2000a, USDA 2000b, UEP 1999). For other animal types, manure management system usage was based on previous estimates (EPA 1992).
- VS production rates for all cattle except for bulls and calves were calculated by head for each state and animal type in the CEFM. VS production rates by animal mass for all other animals were determined using data from USDA's *Agricultural Waste Management Field Handbook* (USDA 1996a, 2008) and data from the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1998).
- The maximum CH_4 producing capacity of the VS (B_o) was determined for each animal type based on literature values (Morris 1976, Bryant et al, 1976, Hashimoto 1981, Hashimoto 1984, EPA 1992, Hill 1982, and Hill 1984).
- MCFs for dry systems were set equal to default IPCC factors based on state climate for each year (IPCC 2006). MCFs for liquid/slurry, anaerobic lagoon, and deep pit systems were calculated based on the forecast performance of biological systems relative to temperature changes as predicted in the van't Hoff-Arrhenius equation which is consistent with IPCC (2006) Tier 2 methodology.
- Anaerobic digestion system data were obtained from the EPA AgSTAR Program, including information presented in the *AgSTAR Digest* (EPA 2000, 2003, 2006). Anearobic digester emissions were calculated based on estimated methane production and collection and destruction efficiency assumptions (ERG 2008).

To estimate CH_4 emissions for cattle, the estimated amount of VS (kg per animal-year) managed in each WMS for each animal type, state, and year were taken from the CEFM. For animals other than cattle, the annual amount of VS (kg per year) from manure excreted in each WMS was calculated for each animal type, state, and year. This calculation multiplied the animal population (head) by the VS excretion rate (kg VS per 1,000 kg animal mass per day), the TAM (kg animal mass per head) divided by 1,000, the WMS distribution (percent), and the number of days per year (365.25).

The estimated amount of VS managed in each WMS was used to estimate the CH_4 emissions (kg CH_4 per year) from each WMS. The amount of VS (kg per year) were multiplied by the maximum CH_4 producing capacity of the VS (B_o) (m^3 CH_4 per kg VS), the MCF for that WMS (percent), and the density of CH_4 (kg CH_4 per m^3 CH_4). The CH_4 emissions for each WMS, state, and animal type were summed to determine the total U.S. CH_4 emissions.

Nitrous Oxide Calculation Methods

The following inputs were used in the calculation of direct and indirect N_2O emissions:

- Animal population data (by animal type and state);

- TAM data (by animal type);
- Portion of manure managed in each WMS (by state and animal type);
- Total Kjeldahl N excretion rate (Nex);
- Direct N_2O emission factor (EF_{WMS});
- Indirect N_2O emission factor for volitalization ($EF_{volitalization}$);
- Indirect N_2O emission factor for runoff and leaching ($EF_{runoff/leach}$);
- Fraction of nitrogen loss from volitalization of NH_3 and NO_x ($Frac_{gas}$); and
- Fraction of nitrogen loss from runoff and leaching ($Frac_{runoff/leach}$).

N_2O emissions were estimated by first determining activity data, including animal population, TAM, WMS usage, and waste characteristics. The activity data sources (except for population, TAM, and WMS, which were described above) are described below:

- Nex rates for all cattle except for bulls and calves were calculated by head for each state and animal type in the CEFM. Nex rates by animal mass for all other animals were determined using data from USDA's *Agricultural Waste Management Field Handbook* (USDA 1996a, 2008) and data from the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1998).
- All N_2O emission factors (direct and indirect) were taken from IPCC (2006).
- Country-specific estimates for the fraction of N loss from volatilization ($Frac_{gas}$) and runoff and leaching ($Frac_{runoff/leach}$) were developed. $Frac_{gas}$ values were based on WMS-specific volatilization values as estimated from EPA's *National Emission Inventory - Ammonia Emissions from Animal Agriculture Operations* (EPA 2005). $Frac_{runoff/leaching}$ values were based on regional cattle runoff data from EPA's Office of Water (EPA 2002b; see Annex 3.1).

To estimate N_2O emissions for cattle, the estimated amount of N excreted (kg per animal-year) managed in each WMS for each animal type, state, and year were taken from the CEFM. For animals other than cattle, the amount of N excreted (kg per year) in manure in each WMS for each animal type, state, and year was calculated. The population (head) for each state and animal was multiplied by TAM (kg animal mass per head) divided by 1,000, the nitrogen excretion rate (Nex, in kg N per 1000 kg animal mass per day), WMS distribution (percent), and the number of days per year.

Direct N_2O emissions were calculated by multiplying the amount of N excreted (kg per year) in each WMS by the N_2O direct emission factor for that WMS (EF_{WMS}, in kg N_2O-N per kg N) and the conversion factor of N_2O-N to N_2O. These emissions were summed over state, animal, and WMS to determine the total direct N_2O emissions (kg of N_2O per year).

Next, indirect N_2O emissions from volatilization (kg N_2O per year) were calculated by multiplying the amount of N excreted (kg per year) in each WMS by the fraction of N lost through volatilization ($Frac_{tas}$) divided by 100, and the emission factor for volatilization ($EF_{volatilization}$, in kg N_2O per kg N), and the conversion factor of N_2O-N to N_2O. Indirect N_2O emissions from runoff and leaching (kg N_2O per year) were then calculated by multiplying the amount of N excreted (kg per year) in each WMS by the fraction of N lost through runoff and leaching ($Frac_{runoff/leach}$) divided by 100, and the emission factor for runoff and leaching ($EF_{runoff/leach}$, in kg N_2O per kg N), and the conversion factor of N_2O-N to N_2O. The indirect N_2O emissions from volatilization and runoff and leaching were summed to determine the total indirect N_2O emissions.

The direct and indirect N_2O emissions were summed to determine total N_2O emissions (kg N_2O per year).

Uncertainty and Time-Series Consistency

An analysis (ERG 2003) was conducted for the manure management emission estimates presented in the 1990 through 2001 Inventory report to determine the uncertainty associated with estimating CH_4 and N_2O emissions from livestock manure management. The quantitative uncertainty analysis for this source category was performed in 2002 through the IPCC-recommended Tier 2 uncertainty estimation methodology, the Monte Carlo Stochastic Simulation technique. The uncertainty analysis was developed based on the methods used to estimate CH_4 and N_2O emissions from manure management systems. A normal probability distribution was assumed for each source data category. The series of equations used were condensed into a single equation for each animal type and state. The equations for each animal group contained four to five variables around which the uncertainty analysis was performed for each state. These uncertainty estimates were directly applied to the 2009 emission estimates.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 6-8. Manure management CH_4 emissions in 2009 were estimated to be between 40.6 and 59.4 Tg CO_2 Eq. at a 95 percent confidence level, which indicates a range of 18 percent below to 20 percent above the actual 2009 emission estimate of 49.5 Tg CO_2 Eq. At the 95 percent confidence level, N_2O emissions were estimated to be between 15.0 and 22.1 Tg CO_2 Eq. (or approximately 16 percent below and 24 percent above the actual 2009 emission estimate of 17.9 Tg CO_2 Eq.).

Table 6-8: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O (Direct and Indirect) Emissions from Manure Management (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Manure Management	CH_4	49.5	40.6	59.4	-18%	+20%
Manure Management	N_2O	17.9	15.0	22.1	-16%	+24%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

QA/QC and Verification

Tier 1 and Tier 2 QA/QC activities were conducted consistent with the U.S. QA/QC plan. Tier 2 activities focused on comparing estimates for the previous and current inventories for N_2O emissions from managed systems and CH_4 emissions from livestock manure. All errors identified were corrected. Order of magnitude checks were also conducted, and corrections made where needed. Manure N data were checked by comparing state-level data with bottom up estimates derived at the county level and summed to the state level. Similarly, a comparison was made by animal and WMS type for the full time series, between national level estimates for nitrogen excreted and the sum of county estimates for the full time series.

Recalculations Discussion

The CEFM produces VS and Nex data for cattle that are used in the manure management inventory. As a result, all changes to the CEFM described in Section 6.1 Enteric Fermentation contributed to changes in the VS and Nex data utilized for calculating CH_4 and N_2O emissions from manure management. In addition, to standardize the estimates of TAM between the CEFM and the manure management source category, the total VS and Nex estimates in units of kg per head per year from the CEFM were used in the manure management calculations in the current Inventory. With these changes, CH_4 and N_2O emission estimates from manure management systems are higher than reported in the previous Inventory for both beef and dairy cattle. Methane emissions from beef and dairy cattle were higher by 7 and 24 percent, respectively, while N_2O emissions were higher by 1 and 5 percent for beef and dairy cattle, respectively, averaged over the 1990 to 2008 time series.

In addition to changes in cattle Nex and VS data, the VS and Nex for other animal types were updated using data from USDA's updated *Agricultural Waste Management Field Handbook* (USDA 2008). Data from both the previous *Handbook* and the updated the *Handbook* were used to create a time series of VS and Nex data across all inventory years for all animals (ERG 2010b). The VS and Nex updates for all animals contributed to an average emission increase of 9.5 percent for CH_4 and 2.7 percent for N_2O across the time series.

For the current Inventory, USDA population data were used that included updated market swine categories. USDA changed the "market swine under 60 lbs." category to "market swine under 50 lbs." for years 2008 and 2009. In addition, USDA changed the "market swine from 60-119 lbs." to "market swine from 50-119 lbs." for the same years. This update resulted in a change in TAM estimates for those two swine categories which contributed to an overall decrease in CH_4 emissions from swine of 1.6 percent and an overall increase in N_2O emissions from swine of 20.9 percent in 2008.

The goat population was updated to reflect the USDA 2007 Census of Agriculture. This change resulted in an increase in both $CH_4$and N_2O emissions for goats from the years 2003 through 2008 by 13 percent and 16 percent on average, respectively.

Planned Improvements

A recent journal article (Lory et al., 2010) criticized the IPCC and EPA methodology used to estimate greenhouse gas emissions from manure management. After review of the methodologies, EPA does not feel that any changes to the IPCC inventory methodologies are required as a result of this article; for more specific information, please see EPA's detailed response to the article (Bartram et al., 2010). EPA will continue to investigate any new or additional data sources identified that contain updated information that can be used to improve the inventory emission estimates. Also, EPA will continue to seek empirical data to compare inventory estimates to specific systems, in order to improve the methodology used to estimate greenhouse gas emissions from manure management.

USDA's 2007 *Census of Agriculture* data are finalized and available. These data will be incorporated into the county-level population estimates used for the Agricultural Soils source category and the estimates of MCF and utilize it to update the WMS distributions for swine and dairy animals.

Due to time constraints, the temperature data used to estimate MCFs were not updated for the current Inventory. Updated temperature data will be obtained and applied for subsequent Inventory reports.

The uncertainty analysis will be updated in the future to more accurately assess uncertainty of emission calculations. This update is necessary due to the extensive changes in emission calculation methodology that was made in the 1990 through 2006 Inventory, including estimation of emissions at the WMS level and the use of new calculations and variables for indirect N_2O emissions.

6.3. Rice Cultivation (IPCC Source Category 4C)

Most of the world's rice, and all rice in the United States, is grown on flooded fields. When fields are flooded, aerobic decomposition of organic material gradually depletes most of the oxygen present in the soil, causing anaerobic soil conditions. Once the environment becomes anaerobic, CH_4 is produced through anaerobic decomposition of soil organic matter by methanogenic bacteria. As much as 60 to 90 percent of the CH_4 produced is oxidized by aerobic methanotrophic bacteria in the soil (some oxygen remains at the interfaces of soil and water, and soil and root system) (Holzapfel-Pschorn et al. 1985, Sass et al. 1990). Some of the CH_4 is also leached away as dissolved CH_4 in floodwater that percolates from the field. The remaining un-oxidized CH_4 is transported from the submerged soil to the atmosphere primarily by diffusive transport through the rice plants. Minor amounts of CH_4 also escape from the soil via diffusion and bubbling through floodwaters.

The water management system under which rice is grown is one of the most important factors affecting CH_4 emissions. Upland rice fields are not flooded, and therefore are not believed to produce CH_4. In deepwater rice fields (i.e., fields with flooding depths greater than one meter), the lower stems and roots of the rice plants are dead, so the primary CH_4 transport pathway to the atmosphere is blocked. The quantities of CH_4 released from deepwater fields, therefore, are believed to be significantly less than the quantities released from areas with shallower flooding depths. Some flooded fields are drained periodically during the growing season, either intentionally or accidentally. If water is drained and soils are allowed to dry sufficiently, CH_4 emissions decrease or stop entirely. This is due to soil aeration, which not only causes existing soil CH_4 to oxidize but also inhibits further CH_4 production in soils. All rice in the United States is grown under continuously flooded conditions; none is grown under deepwater conditions. Mid-season drainage does not occur except by accident (e.g., due to levee breach).

Other factors that influence CH_4 emissions from flooded rice fields include fertilization practices (especially the use of organic fertilizers), soil temperature, soil type, rice variety, and cultivation practices (e.g., tillage, seeding, and weeding practices). The factors that determine the amount of organic material available to decompose (i.e., organic fertilizer use, soil type, rice variety,[141] and cultivation practices) are the most important variables influencing the amount of CH_4 emitted over the growing season; the total amount of CH_4 released depends primarily on the amount of organic substrate available. Soil temperature is known to be an important factor regulating the activity of methanogenic bacteria, and therefore the rate of CH_4 production. However, although temperature controls the amount of time it takes to convert a given amount of organic material to CH_4, that time is short relative to a growing season, so the dependence of total emissions over an entire growing season on soil temperature is weak. The application of synthetic fertilizers has also been found to influence CH_4 emissions; in particular, both nitrate and

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[141] The roots of rice plants shed organic material, which is referred to as "root exudate." The amount of root exudate produced by a rice plant over a growing season varies among rice varieties.

sulfate fertilizers (e.g., ammonium nitrate and ammonium sulfate) appear to inhibit CH_4 formation.

Rice is cultivated in eight states: Arkansas, California, Florida, Louisiana, Mississippi, Missouri, Oklahoma, and Texas.[142] Soil types, rice varieties, and cultivation practices for rice vary from state to state, and even from farm to farm. However, most rice farmers apply organic fertilizers in the form of residue from the previous rice crop, which is left standing, disked, or rolled into the fields. Most farmers also apply synthetic fertilizer to their fields, usually urea. Nitrate and sulfate fertilizers are not commonly used in rice cultivation in the United States. In addition, the climatic conditions of southwest Louisiana, Texas, and Florida often allow for a second, or ratoon, rice crop. Ratoon crops are much less common or non-existent in Arkansas, California, Mississippi, Missouri, Oklahoma, and northern areas of Louisiana. Methane emissions from ratoon crops have been found to be considerably higher than those from the primary crop. This second rice crop is produced from regrowth of the stubble after the first crop has been harvested. Because the first crop's stubble is left behind in ratooned fields, and there is no time delay between cropping seasons (which would allow the stubble to decay aerobically), the amount of organic material that is available for anaerobic decomposition is considerably higher than with the first (i.e., primary) crop.

Rice cultivation is a small source of CH_4 in the United States (Table 6-9 and Table 6-10). In 2009, CH_4 emissions from rice cultivation were 7.3 Tg CO_2 Eq. (349 Gg). Annual emissions fluctuated unevenly between the years 1990 and 2009, ranging from an annual decrease of 14 percent to an annual increase of 17 percent. There was an overall decrease of 17 percent between 1990 and 2006, due to an overall decrease in primary crop area.[143] However, emission levels increased again by 24 percent between 2006 and 2009 due to a slight increase in rice crop area in all states. The factors that affect the rice acreage in any year vary from state to state, although the price of rice relative to competing crops is the primary controlling variable in most states.

Table 6-9: CH_4 Emissions from Rice Cultivation (Tg CO_2 Eq.)

State	1990	2000	2005	2006	2007	2008	2009
Primary	**5.1**	**5.5**	**6.0**	**5.1**	**4.9**	**5.3**	**5.6**
Arkansas	2.1	2.5	2.9	2.5	2.4	2.5	2.6
California	0.7	1.0	0.9	0.9	1.0	0.9	1.0
Florida	+	+	+	+	+	+	+
Louisiana	1.0	0.9	0.9	0.6	0.7	0.8	0.8
Mississippi	0.4	0.4	0.5	0.3	0.3	0.4	0.4
Missouri	0.1	0.3	0.4	0.4	0.3	0.4	0.4
Oklahoma	+	+	+	+	0.0	0.0	0.0
Texas	0.6	0.4	0.4	0.3	0.3	0.3	0.3
Ratoon	**2.1**	**2.0**	**0.8**	**0.9**	**1.3**	**1.9**	**1.8**
Arkansas	+	+	+	+	+	+	+
Florida	+	0.1	+	+	+	+	+
Louisiana	1.1	1.3	0.5	0.5	0.9	1.2	1.1
Texas	0.9	0.7	0.4	0.4	0.3	0.6	0.7
Total	**7.1**	**7.5**	**6.8**	**5.9**	**6.2**	**7.2**	**7.3**

+ Less than 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 6-10: CH_4 Emissions from Rice Cultivation (Gg)

State	1990	2000	2005	2006	2007	2008	2009
Primary	**241**	**260**	**287**	**241**	**235**	**254**	**265**
Arkansas	102	120	139	119	113	119	125
California	34	47	45	44	45	44	47
Florida	1	2	1	1	1	1	1
Louisiana	46	41	45	29	32	39	39

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[142] A very small amount of rice is grown on about 20 acres in South Carolina; however, this amount was determined to be too insignificant to warrant inclusion in national emission estimates.

[143] The 14 percent decrease occurred between 2005 and 2006; the 17 percent increase happened between 1993 and 1994.

Mississippi	21	19	22	16	16	19	21
Missouri	7	14	18	18	15	17	17
Oklahoma	+	+	+	+	0	+	+
Texas	30	18	17	13	12	15	14
Ratoon	**98**	**97**	**39**	**41**	**60**	**89**	**84**
Arkansas	+	+	1	+	+	+	+
Florida	2	2	+	1	1	1	2
Louisiana	52	61	22	22	42	59	51
Texas	45	34	17	18	16	29	31
Total	**339**	**357**	**326**	**282**	**295**	**343**	**349**

+ Less than 0.5 Gg
Note: Totals may not sum due to independent rounding.

Methodology

IPCC (2006) recommends using harvested rice areas, area-based daily emission factors (i.e., amount of CH_4 emitted per day per unit harvested area), and length of growing season to estimate annual CH_4 emissions from rice cultivation. This Inventory uses the recommended methodology and employs Tier 2 U.S.-specific emission factors derived from rice field measurements. State-specific and daily emission factors were not available, however, so average U.S. seasonal emission factors were used. Seasonal emissions have been found to be much higher for ratooned crops than for primary crops, so emissions from ratooned and primary areas are estimated separately using emission factors that are representative of the particular growing season. This approach is consistent with IPCC (2006).

The harvested rice areas for the primary and ratoon crops in each state are presented in Table 6-11, and the area of ratoon crop area as a percent of primary crop area is shown in Table 6-12. Primary crop areas for 1990 through 2009 for all states except Florida and Oklahoma were taken from U.S. Department of Agriculture's Field Crops Final Estimates 1987–1992 (USDA 1994), Field Crops Final Estimates 1992–1997 (USDA 1998), Field Crops Final Estimates 1997–2002 (USDA 2003), and Crop Production Summary (USDA 2005 through 2010). Source data for non-USDA sources of primary and ratoon harvest areas are shown in Table 6-13. California, Mississippi, Missouri, and Oklahoma have not ratooned rice over the period 1990 through 2009 (Guethle 1999 through 2010; Lee 2003 through 2007; Mutters 2002 through 2005; Street 1999 through 2003; Walker 2005, 2007 through 2008; Buehring 2009 through 2010).

Table 6-11: Rice Areas Harvested (Hectares)

State/Crop	1990	2000	2005	2006	2007	2008	2009
Arkansas							
Primary	485,633	570,619	661,675	566,572	536,220	564,549	594,901
Ratoon[a]	-	-	662	6	5	6	6
California	159,854	221,773	212,869	211,655	215,702	209,227	225,010
Florida							
Primary	4,978	7,801	4,565	4,575	6,242	5,463	5,664
Ratoon	2,489	3,193	0	1,295	1,873	1,639	2,266
Louisiana							
Primary	220,558	194,253	212,465	139,620	152,975	187,778	187,778
Ratoon	66,168	77,701	27,620	27,924	53,541	75,111	65,722
Mississippi	101,174	88,223	106,435	76,487	76,487	92,675	98,341
Missouri	32,376	68,393	86,605	86,605	72,036	80,534	80,939
Oklahoma	617	283	271	17	0	77	0
Texas							
Primary	142,857	86,605	81,344	60,704	58,681	69,607	68,798
Ratoon	57,143	43,302	21,963	23,675	21,125	36,892	39,903
Total Primary	***1,148,047***	***1,237,951***	***1,366,228***	***1,146,235***	***1,118,343***	***1,209,911***	***1,261,431***

Total Ratoon	*125,799*		*124,197*		*50,245*	*52,899*	*76,544*	*113,648*	*107,897*
Total	**1,273,847**		**1,362,148**		**1,416,473**	**1,199,135**	**1,194,887**	**1,323,559**	**1,369,328**

[a] Arkansas ratooning occurred only in 1998, 1999, and 2005 through 2009.

Note: Totals may not sum due to independent rounding.

Table 6-12: Ratooned Area as Percent of Primary Growth Area

State	1990		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Arkansas	0%			+	+	0%					0.1%	+	+	+	+
Florida	50%				65%	41%	60%	54%	100%	77%	0%	28%	30%	30%	40%
Louisiana	30%					40%	30%	15%	35%	30%	13%	20%	35%	40%	35%
Texas	40%					50%	40%	37%	38%	35%	27%	39%	36%	53%	58%

+ Indicates ratooning rate less than 0.1 percent.

Table 6-13: Non-USDA Data Sources for Rice Harvest Information

State/Crop	1990		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Arkansas												
Ratoon	Wilson (2002 – 2007, 2009 – 2010)											
Florida												
Primary	Scheuneman (1999 – 2001)			Deren (2002)	Kirstein (2003, 2006)			Gonzales (2006 – 2010)				
Ratoon	Scheuneman (1999)			Deren (2002)	Kirstein (2003-2004)		Cantens (2005)	Gonzales (2006 – 2010)				
Louisiana												
Ratoon	Bollich (2000)		Linscombe (1999, 2001 – 2010)									
Oklahoma												
Primary	Lee (2003-2007)									Anderson (2008 – 2010)		
Texas												
Ratoon	Klosterboer (1999 – 2003)					Stansel (2004 – 2005)		Texas Ag Experiment Station (2006 – 2010)				

To determine what CH_4 emission factors should be used for the primary and ratoon crops, CH_4 flux information from rice field measurements in the United States was collected. Experiments that involved atypical or nonrepresentative management practices (e.g., the application of nitrate or sulfate fertilizers, or other substances believed to suppress CH_4 formation), as well as experiments in which measurements were not made over an entire flooding season or floodwaters were drained mid-season, were excluded from the analysis. The remaining experimental results[144] were then sorted by season (i.e., primary and ratoon) and type of fertilizer amendment (i.e., no fertilizer added, organic fertilizer added, and synthetic and organic fertilizer added). The experimental results from primary crops with added synthetic and organic fertilizer (Bossio et al. 1999; Cicerone et al. 1992; Sass et al. 1991a, 1991b) were averaged to derive an emission factor for the primary crop, and the experimental results from ratoon crops with added synthetic fertilizer (Lindau and Bollich 1993, Lindau et al. 1995) were averaged to derive an emission factor for the ratoon crop. The resultant emission factor for the primary crop is 210 kg CH_4/hectare-season, and the resultant emission factor for the ratoon crop is 780 kg CH_4/hectare-season.

Uncertainty and Time-Series Consistency

The largest uncertainty in the calculation of CH_4 emissions from rice cultivation is associated with the emission factors. Seasonal emissions, derived from field measurements in the United States, vary by more than one order of

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[144] In some of these remaining experiments, measurements from individual plots were excluded from the analysis because of the aforementioned reasons. In addition, one measurement from the ratooned fields (i.e., the flux of 1,490 kg CH_4/hectare-season in Lindau and Bollich 1993) was excluded, because this emission rate is unusually high compared to other flux measurements in the United States, as well as IPCC (2006) default emission factors.

magnitude. This inherent variability is due to differences in cultivation practices, particularly fertilizer type, amount, and mode of application; differences in cultivar type; and differences in soil and climatic conditions. A portion of this variability is accounted for by separating primary from ratooned areas. However, even within a cropping season or a given management regime, measured emissions may vary significantly. Of the experiments used to derive the emission factors applied here, primary emissions ranged from 22 to 479 kg CH_4/hectare-season and ratoon emissions ranged from 481 to 1,490 kg CH_4/hectare-season. The uncertainty distributions around the primary and ratoon emission factors were derived using the distributions of the relevant primary or ratoon emission factors available in the literature and described above. Variability about the rice emission factor means was not normally distributed for either primary or ratooned crops, but rather skewed, with a tail trailing to the right of the mean. A lognormal statistical distribution was, therefore, applied in the Tier 2 Monte Carlo analysis.

Other sources of uncertainty include the primary rice-cropped area for each state, percent of rice-cropped area that is ratooned, and the extent to which flooding outside of the normal rice season is practiced. Expert judgment was used to estimate the uncertainty associated with primary rice-cropped area for each state at 1 to 5 percent, and a normal distribution was assumed. Uncertainties were applied to ratooned area by state, based on the level of reporting performed by the state. No uncertainties were calculated for the practice of flooding outside of the normal rice season because CH_4 flux measurements have not been undertaken over a sufficient geographic range or under a broad enough range of representative conditions to account for this source in the emission estimates or its associated uncertainty.

To quantify the uncertainties for emissions from rice cultivation, a Monte Carlo (Tier 2) uncertainty analysis was performed using the information provided above. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 6-14. Rice cultivation CH_4 emissions in 2009 were estimated to be between 2.5 and 18.0 Tg CO_2 Eq. at a 95 percent confidence level, which indicates a range of 65 percent below to 146 percent above the actual 2009 emission estimate of 7.3 Tg CO_2 Eq.

Table 6-14: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Rice Cultivation (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate**	**Uncertainty Range Relative to Emission Estimate**[a]			
		(Tg CO_2 Eq.)	**(Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Rice Cultivation	CH_4	7.3	2.5	18.0	-65%	+146%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for rice cultivation was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on comparing trends across years, states, and cropping seasons to attempt to identify any outliers or inconsistencies. No problems were found.

Planned Improvements

A possible future improvement is to create region-specific emission factors for rice cultivation. The current methodology uses a nationwide average emission factor, derived from several studies done in a number of states. The prospective improvement would take the same studies and average them by region, presumably resulting in more spatially specific emission factors.

6.4. Agricultural Soil Management (IPCC Source Category 4D)

Nitrous oxide is produced naturally in soils through the microbial processes of nitrification and denitrification.[145] A number of agricultural activities increase mineral N availability in soils, thereby increasing the amount available for nitrification and denitrification, and ultimately the amount of N_2O emitted. These activities increase soil mineral N either directly or indirectly (see Figure 6-2). Direct increases occur through a variety of management practices that add or lead to greater release of mineral N to the soil, including fertilization; application of managed livestock manure and other organic materials such as sewage sludge; deposition of manure on soils by domesticated animals in pastures, rangelands, and paddocks (PRP) (i.e., by grazing animals and other animals whose manure is not managed); production of N-fixing crops and forages; retention of crop residues; and drainage and cultivation of organic cropland soils (i.e., soils with a high organic matter content, otherwise known as histosols).[146] Other agricultural soil management activities, including irrigation, drainage, tillage practices, and fallowing of land, can influence N mineralization in soils and thereby affect direct emissions. Mineral N is also made available in soils through decomposition of soil organic matter and plant litter, as well as asymbiotic fixation of N from the atmosphere,[147] and these processes are influenced by agricultural management through impacts on moisture and temperature regimes in soils. These additional sources of mineral N are included at the recommendation of IPCC (2006) for complete accounting of management impacts on greenhouse gas emissions, as discussed in the Methodology section. Indirect emissions of N_2O occur through two pathways: (1) volatilization and subsequent atmospheric deposition of applied/mineralized N,[148] and (2) surface runoff and leaching of applied/mineralized N into groundwater and surface water. Direct emissions from agricultural lands (i.e., cropland and grassland) are included in this section, while direct emissions from forest lands and settlements are presented in the Land Use, Land-Use Change, and Forestry chapter. However, indirect N_2O emissions from all land-uses (cropland, grassland, forest lands, and settlements) are reported in this section.

Figure 6-2: Sources and Pathways of N that Result in N_2O Emissions from Agricultural Soil Management

Agricultural soils produce the majority of N_2O emissions in the United States. Estimated emissions from this source in 2009 were 204.6 Tg CO_2 Eq. (660 Gg N_2O) (see Table 6-15 and Table 6-16). Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2009, although overall emissions were 3 percent higher in 2009 than in 1990. Year-to-year fluctuations are largely a reflection of annual variation in weather patterns, synthetic fertilizer use, and crop production. On average, cropland accounted for approximately 70 percent of total direct emissions, while grassland accounted for approximately 30 percent. These percentages are about the same for indirect emissions since forest lands and settlements account for such a small percentage of total indirect emissions. Estimated direct and indirect N_2O emissions by sub-source category are shown in Table 6-17 and Table 6-18.

Table 6-15: N_2O Emissions from Agricultural Soils (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Direct	**153.8**	**162.6**	**167.5**	**163.7**	**165.1**	**166.6**	**160.2**
Cropland	102.9	115.6	118.1	115.6	117.8	117.9	112.0
Grassland	50.9	47.1	49.4	48.1	47.3	48.7	48.2
Indirect (All Land-Use Types)	**44.0**	**44.1**	**43.9**	**45.2**	**44.3**	**44.1**	**44.4**

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[145] Nitrification and denitrification are driven by the activity of microorganisms in soils. Nitrification is the aerobic microbial oxidation of ammonium (NH_4^+) to nitrate (NO_3^-), and denitrification is the anaerobic microbial reduction of nitrate to N_2. Nitrous oxide is a gaseous intermediate product in the reaction sequence of denitrification, which leaks from microbial cells into the soil and then into the atmosphere. Nitrous oxide is also produced during nitrification, although by a less well-understood mechanism (Nevison 2000).

[146] Drainage and cultivation of organic soils in former wetlands enhances mineralization of N-rich organic matter, thereby increasing N_2O emissions from these soils.

[147] Asymbiotic N fixation is the fixation of atmospheric N_2 by bacteria living in soils that do not have a direct relationship with plants.

[148] These processes entail volatilization of applied or mineralized N as NH_3 and NO_x, transformation of these gases within the atmosphere (or upon deposition), and deposition of the N primarily in the form of particulate NH_4^+, nitric acid (HNO_3), and NO_x.

Cropland	37.5	37.7	36.8	38.6	37.6	37.5	37.5
Grassland	6.1	5.8	6.3	5.9	5.9	5.9	6.2
Forest Land	+	0.1	0.1	0.1	0.1	0.1	0.1
Settlements	0.3	0.4	0.6	0.6	0.6	0.6	0.6
Total	**197.8**	**206.8**	**211.3**	**208.9**	**209.4**	**210.7**	**204.6**

+ Less than 0.05 Tg CO_2 Eq.

Table 6-16: N_2O Emissions from Agricultural Soils (Gg)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Direct	**496**	**525**	**540**	**528**	**533**	**538**	**517**
Cropland	332	373	381	373	380	380	361
Grassland	164	152	159	155	152	157	155
Indirect (All Land-Use Types)	**142**	**142**	**142**	**146**	**143**	**142**	**143**
Cropland	121	122	119	125	121	121	121
Grassland	20	19	20	19	19	19	20
Forest Land	0	+	+	+	+	+	+
Settlements	1	1	2	2	2	2	2
Total	**638**	**667**	**682**	**674**	**675**	**680**	**660**

+ Less than 0.5 Gg N_2O

Table 6-17: Direct N_2O Emissions from Agricultural Soils by Land Use Type and N Input Type (Tg CO_2 Eq.)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Cropland	**102.9**	**115.6**	**118.1**	**115.6**	**117.8**	**117.9**	**112.0**
Mineral Soils	100.1	112.7	115.2	112.7	114.9	115.0	109.1
Mineralization and Asymbiotic Fixation	*44.6*	*50.6*	*50.5*	*49.7*	*50.9*	*50.9*	*47.1*
Synthetic Fertilizer	*32.3*	*36.0*	*38.6*	*36.7*	*37.4*	*37.3*	*36.9*
Residue N[a]	*12.4*	*14.3*	*13.7*	*13.8*	*13.9*	*14.3*	*13.1*
Organic Amendments[b]	*10.8*	*11.8*	*12.3*	*12.5*	*12.8*	*12.5*	*12.1*
Organic Soils	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Grassland	**50.9**	**47.1**	**49.4**	**48.1**	**47.3**	**48.7**	**48.2**
Residue N[c]	15.6	13.8	14.6	14.2	13.9	14.4	14.1
PRP Manure	8.1	7.9	8.2	8.1	8.0	8.2	7.9
Synthetic Fertilizer	3.9	3.9	4.1	4.0	3.9	4.0	3.9
Managed Manure[d]	1.5	1.6	1.6	1.6	1.6	1.6	1.6
Sewage Sludge	0.3	0.4	0.5	0.5	0.5	0.5	0.5
Mineralization and Asymbiotic Fixation	21.5	19.5	20.4	19.7	19.3	20.0	20.1
Total	**153.8**	**162.6**	**167.5**	**163.7**	**165.1**	**166.6**	**160.2**

[a] Cropland residue N inputs include N in unharvested legumes as well as crop residue N.

[b] Organic amendment inputs include managed manure amendments, daily spread manure amendments, and commercial organic fertilizers (i.e., dried blood, dried manure, tankage, compost, and other).

[c] Grassland residue N inputs include N in ungrazed legumes as well as ungrazed grass residue N

[d] Accounts for managed manure and daily spread manure amendments that are applied to grassland soils.

Table 6-18: Indirect N_2O Emissions from all Land-Use Types (Tg CO_2 Eq.)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Cropland	**37.5**	**37.7**	**36.8**	**38.6**	**37.6**	**37.5**	**37.5**
Volatilization & Atm. Deposition	11.6	12.7	13.1	14.2	12.8	12.9	13.4
Surface Leaching & Run-Off	25.8	25.0	23.7	24.4	24.9	24.5	24.1
Grassland	**6.1**	**5.8**	**6.3**	**5.9**	**5.9**	**5.9**	**6.2**
Volatilization & Atm. Deposition	5.1	4.7	4.8	4.8	4.7	4.7	4.7

Surface Leaching & Run-Off	1.0	1.2	1.5	1.1	1.2	1.2	1.5
Forest Land	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Volatilization & Atm. Deposition	+	+	+	+	+	+	+
Surface Leaching & Run-Off	+	0.1	0.1	0.1	0.1	0.1	0.1
Settlements	**0.3**	**0.4**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**
Volatilization & Atm. Deposition	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Surface Leaching & Run-Off	0.2	0.3	0.4	0.4	0.4	0.4	0.4
Total	**44.0**	**44.1**	**43.9**	**45.2**	**44.3**	**44.1**	**44.4**

+ Less than 0.05 Tg CO_2 Eq.

Figure 6-3 through Figure 6-6 show regional patterns in direct N_2O emissions, and also show N losses from volatilization, leaching, and runoff that lead to indirect N_2O emissions. Average annual emissions and N losses are shown for croplands that produce major crops and from grasslands in each state. Direct N_2O emissions from croplands tend to be high in the Corn Belt (Illinois, Iowa, Indiana, Ohio, southern Minnesota, southern Wisconsin, and eastern Nebraska), where a large portion of the land is used for growing highly fertilized corn and N-fixing soybean crops. Direct emissions are also high in Missouri, Kansas, and Texas, primarily from irrigated cropping in western Texas, dryland wheat in Kansas, and hay cropping in eastern Texas and Missouri. Direct emissions are low in many parts of the eastern United States because a small portion of land is cultivated, and also low in many western states where rainfall and access to irrigation water are limited.

Direct emissions (Tg CO_2 Eq./state/year) from grasslands are highest in the central and western United States (Figure 6-4) where a high proportion of the land is used for cattle grazing. Some areas in the Great Lake states, the Northeast, and Southeast have moderate to low emissions even though emissions from these areas tend to be high on a per unit area basis, because the total amount of grassland is much lower than in the central and western United States.

Indirect emissions from croplands and grasslands (Figure 6-5 and Figure 6-6) show patterns similar to direct emissions, because the factors that control direct emissions (N inputs, weather, soil type) also influence indirect emissions. However, there are some exceptions, because the processes that contribute to indirect emissions (NO_3^- leaching, N volatilization) do not respond in exactly the same manner as the processes that control direct emissions (nitrification and denitrification). For example, coarser-textured soils facilitate relatively high indirect emissions in Florida grasslands due to high rates of N volatilization and NO_3^- leaching, even though they have only moderate rates of direct N_2O emissions.

Figure 6-3: Major Crops, Average Annual Direct N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Tg CO_2 Eq./year)
[Figure will be provided in public review]

Figure 6-4: Grasslands, Average Annual Direct N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Tg CO_2 Eq./year)
[Figure will be provided in public review]

Figure 6-5: Major Crops, Average Annual N Losses Leading to Indirect N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Gg N/year)
[Figure will be provided in public review]

Figure 6-6: Grasslands, Average Annual N Losses Leading to Indirect N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Gg N/year)
[Figure will be provided in public review]

Methodology

The *2006 IPCC Guidelines* (IPCC 2006) divide the Agricultural Soil Management source category into four components: (1) direct emissions due to N additions to cropland and grassland mineral soils, including synthetic fertilizers, sewage sludge applications, crop residues, organic amendments, and biological N fixation associated with planting of legumes on cropland and grassland soils; (2) direct emissions from drainage and cultivation of organic cropland soils; (3) direct emissions from soils due to the deposition of manure by livestock on PRP grasslands; and (4) indirect emissions from soils and water due to N additions and manure deposition to soils that lead to volatilization, leaching, or runoff of N and subsequent conversion to N_2O.

The United States has adopted recommendations from IPCC (2006) on methods for agricultural soil management. These recommendations include (1) estimating the contribution of N from crop residues to indirect soil N_2O emissions; (2) adopting a revised emission factor for direct N_2O emissions to the extent that Tier 1 methods are used in the Inventory (described later in this section); (3) removing double counting of emissions from N-fixing crops associated with the biological N fixation and crop residue N input categories; (4) using revised crop residue statistics to compute N inputs to soils based on harvest yield data to the extent that Tier 1 methods are used in the Inventory; (5) accounting for indirect as well as direct emissions from N made available via mineralization of soil organic matter and litter, in addition to asymbiotic fixation[149] (i.e., computing total emissions from managed land); and (6) reporting all emissions from managed lands, largely because management affects all processes leading to soil N_2O emissions. One recommendation from IPCC (2006) that has not been adopted is the accounting of emissions from pasture renewal, which involves occasional plowing to improve forage production. This practice is not common in the United States, and is not estimated.

The methodology used to estimate emissions from agricultural soil management in the United States is based on a combination of IPCC Tier 1 and 3 approaches. A Tier 3, process-based model (DAYCENT) was used to estimate direct emissions from major crops on mineral (i.e., non-organic) soils; as well as most of the direct emissions from grasslands. The Tier 3 approach has been specifically designed and tested to estimate N_2O emissions in the United States, accounting for more of the environmental and management influences on soil N_2O emissions than the IPCC Tier 1 method (see Box 6-1 for further elaboration). The Tier 1 IPCC (2006) methodology was used to estimate (1) direct emissions from non-major crops on mineral soils (e.g., barley, oats, vegetables, and other crops); (2) the portion of the grassland direct emissions that were not estimated with the Tier 3 DAYCENT model (i.e., federal grasslands); and (3) direct emissions from drainage and cultivation of organic cropland soils. Indirect emissions were also estimated with a combination of DAYCENT and the IPCC Tier 1 method.

In past Inventories, attempts were made to subtract "background" emissions that would presumably occur if the lands were not managed. However, this approach is likely to be inaccurate for estimating the anthropogenic influence on soil N_2O emissions. Moreover, if background emissions could be measured or modeled based on processes unaffected by anthropogenic activity, they would be a very small portion of the total emissions, due to the high inputs of N to agricultural soils from fertilization and legume cropping. Given the recommendation from IPCC (2006) and the influence of management on all processes leading to N_2O emissions from soils in agricultural systems, the decision was made to report total emissions from managed lands for this source category. Annex 3.11 provides more detailed information on the methodologies and data used to calculate N_2O emissions from each component.

[BEGIN BOX]

Box 6-1. Tier 1 vs. Tier 3 Approach for Estimating N_2O Emissions

The IPCC (2006) Tier 1 approach is based on multiplying activity data on different N inputs (e.g., synthetic fertilizer, manure, N fixation, etc.) by the appropriate default IPCC emission factors to estimate N_2O emissions on an input-by-input basis. The Tier 1 approach requires a minimal amount of activity data, readily available in most countries (e.g., total N applied to crops); calculations are simple; and the methodology is highly transparent. In contrast, the Tier 3 approach developed for this Inventory employs a process-based model (i.e., DAYCENT) that represents the interaction of N inputs and the environmental conditions at specific locations. Consequently, the Tier

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[149] N inputs from asymbiotic N fixation are not directly addressed in *2006 IPCC Guidelines*, but are a component of the total emissions from managed lands and are included in the Tier 3 approach developed for this source.

3 approach is likely to produce more accurate estimates; it accounts more comprehensively for land-use and management impacts and their interaction with environmental factors (i.e., weather patterns and soil characteristics), which will enhance or dampen anthropogenic influences. However, the Tier 3 approach requires more detailed activity data (e.g., crop-specific N amendment rates), additional data inputs (e.g., daily weather, soil types, etc.), and considerable computational resources and programming expertise. The Tier 3 methodology is less transparent, and thus it is critical to evaluate the output of Tier 3 methods against measured data in order to demonstrate the adequacy of the method for estimating emissions (IPCC 2006). Another important difference between the Tier 1 and Tier 3 approaches relates to assumptions regarding N cycling. Tier 1 assumes that N added to a system is subject to N_2O emissions only during that year and cannot be stored in soils and contribute to N_2O emissions in subsequent years. This is a simplifying assumption that is likely to create bias in estimated N_2O emissions for a specific year. In contrast, the process-based model used in the Tier 3 approach includes such legacy effects when N added to soils is re-mineralized from soil organic matter and emitted as N_2O during subsequent years.

[END BOX]

Direct N_2O Emissions from Cropland Soils

Major Crop Types on Mineral Cropland Soils

The DAYCENT ecosystem model (Del Grosso et al. 2001, Parton et al. 1998) was used to estimate direct N_2O emissions from mineral cropland soils that are managed for production of major crops—specifically corn, soybeans, wheat, alfalfa hay, other hay, sorghum, and cotton—representing approximately 90 percent of total croplands in the United States. For these croplands, DAYCENT was used to simulate crop growth, soil organic matter decomposition, greenhouse gas fluxes, and key biogeochemical processes affecting N_2O emissions, and the simulations were driven by model input data generated from daily weather records (Thornton et al. 1997, 2000; Thornton and Running 1999), land management surveys (see citations below), and soil physical properties determined from national soil surveys (Soil Survey Staff 2005). Note that the influence of land-use change on soil N_2O emissions was not addressed in this analysis, but is a planned improvement.

DAYCENT simulations were conducted for each major crop at the county scale in the United States. Simulating N_2O emissions at the county scale was facilitated by soil and weather data that were available for every county with more than 100 acres of agricultural land, and by land management data (e.g., timing of planting, harvesting, and intensity of cultivation) that were available at the agricultural-region level as defined by the Agricultural Sector Model (McCarl et al. 1993). ASM has 63 agricultural regions in the contiguous United States. Most regions correspond to one state, except for those states with greater heterogeneity in agricultural practices; in such cases, more than one region is assigned to a state. While cropping systems were simulated for each county, the results best represent emissions at regional (i.e., state) and national levels due to the regional scale of management data, which include model parameters that determined the influence of management activities on soil N_2O emissions (e.g., when crops were planted/harvested).

Nitrous oxide emissions from managed agricultural lands are the result of interactions among anthropogenic activities (e.g., N fertilization, manure application, tillage) and other driving variables, such as weather and soil characteristics. These factors influence key processes associated with N dynamics in the soil profile, including immobilization of N by soil microbial organisms, decomposition of organic matter, plant uptake, leaching, runoff, and volatilization, as well as the processes leading to N_2O production (nitrification and denitrification). It is not possible to partition N_2O emissions into each anthropogenic activity directly from model outputs due to the complexity of the interactions (e.g., N_2O emissions from synthetic fertilizer applications cannot be distinguished from those resulting from manure applications). To approximate emissions by activity, the amount of mineral N added to the soil for each of these sources was determined and then divided by the total amount of mineral N that was made available in the soil according to the DAYCENT model. The percentages were then multiplied by the total of direct N_2O emissions in order to approximate the portion attributed to key practices. This approach is only an approximation because it assumes that all N made available in soil has an equal probability of being released as N_2O, regardless of its source, which is unlikely to be the case (Delgado et al., 2009). However, this approach allows for further disaggregation of emissions by source of N, which is valuable for reporting purposes and is analogous to the reporting associated with the IPCC (2006) Tier 1 method, in that it associates portions of the total soil N_2O

emissions with individual sources of N.

DAYCENT was used to estimate direct N_2O emissions due to mineral N available from: (1) the application of synthetic fertilizers; (2) the application of livestock manure; (3) the retention of crop residues (i.e., leaving residues in the field after harvest instead of burning or collecting residues); and (4) mineralization of soil organic matter and litter, in addition to asymbiotic fixation. Note that commercial organic fertilizers are addressed with the Tier 1 method because county-level application data would be needed to simulate applications in DAYCENT, and currently data are only available at the national scale. The third and fourth sources are generated internally by the DAYCENT model. For the first two practices, annual changes in soil mineral N due to anthropogenic activity were obtained or derived from the following sources:

- Crop-specific N-fertilization rates: Data sources for fertilization rates include Alexander and Smith (1990), Anonymous (1924), Battaglin and Goolsby (1994), Engle and Makela (1947), ERS (1994, 2003), Fraps and Asbury (1931), Ibach and Adams (1967), Ibach et al. (1964), NFA (1946), NRIAI (2003), Ross and Mehring (1938), Skinner (1931), Smalley et al. (1939), Taylor (1994), and USDA (1966, 1957, 1954, 1946). Information on fertilizer use and rates by crop type for different regions of the United States were obtained primarily from the USDA *Economic Research Service Cropping Practices Survey* (ERS 1997) with additional data from other sources, including the National Agricultural Statistics Service (NASS 1992, 1999, 2004).
- Managed manure production and application to croplands and grasslands: Manure N amendments and daily spread manure N amendments applied to croplands and grasslands (not including PRP manure) were determined using USDA Manure N Management Databases for 1997 (Kellogg et al. 2000; Edmonds et al. 2003). Amendment data for 1997 were scaled to estimate values for other years based on the availability of managed manure N for application to soils in 1997 relative to other years. The amount of available N from managed manure for each livestock type was calculated as described in the Manure Management section (Section 6.2) and Annex 3.10.
- Retention of crop residue, N mineralization from soil organic matter, and asymbiotic N fixation from the atmosphere: The IPCC approach considers crop residue N and N mineralized from soil organic matter as activity data. However, they are not treated as activity data in DAYCENT simulations because residue production, N fixation, mineralization of N from soil organic matter, and asymbiotic fixation are internally generated by the model as part of the simulation. In other words, DAYCENT accounts for the influence of N fixation, mineralization of N from soil organic matter, and retention of crop residue on N_2O emissions, but these are not model inputs. The DAYCENT simulations also accounted for the approximately 3 percent of grain crop residues that were assumed to be burned based on state inventory data (ILENR 1993, Oregon Department of Energy 1995, Noller 1996, Wisconsin Department of Natural Resources 1993, and Cibrowski 1996), and therefore did not contribute to soil N_2O emissions.
- Historical and modern crop rotation and management information (e.g., timing and type of cultivation, timing of planting/harvest, etc.): These activity data were derived from Hurd (1930, 1929), Latta (1938), Iowa State College Staff Members (1946), Bogue (1963), Hurt (1994), USDA (2000a) as extracted by Eve (2001) and revised by Ogle (2002), CTIC (1998), Piper et al. (1924), Hardies and Hume (1927), Holmes (1902, 1929), Spillman (1902, 1905, 1907, 1908), Chilcott (1910), Smith (1911), Kezer (ca. 1917), Hargreaves (1993), ERS (2002), Warren (1911), Langston et al. (1922), Russell et al. (1922), Elliott and Tapp (1928), Elliott (1933), Ellsworth (1929), Garey (1929), Hodges et al. (1930), Bonnen and Elliott (1931), Brenner et al. (2002, 2001), and Smith et al. (2002).

DAYCENT simulations produced per-area estimates of N_2O emissions (g N_2O-N/m^2) for major crops in each county, which were multiplied by the cropland areas in each county to obtain county-scale emission estimates. Cropland area data were from NASS (USDA 2010a, 2010b). The emission estimates by reported crop areas in the county were scaled to the regions (and states for mapping purposes when there was more than one region in a state), and the national estimate was calculated by summing results across all regions. DAYCENT is sensitive to interannual variability in weather patterns and other controlling variables, so emissions associated with individual activities vary through time even if the management practices remain the same (e.g., if N fertilization remains the same for two years). In contrast, Tier 1 methods do not capture this variability and rather have a linear, monotonic response that depends solely on management practices. DAYCENT's ability to capture these interactions between management and environmental conditions produces more accurate estimates of N_2O emissions than the Tier 1 method.

Non-Major Crop Types on Mineral Cropland Soils

The IPCC (2006) Tier 1 methodology was used to estimate direct N_2O emissions for mineral cropland soils that are managed for production of non-major crop types, including barley, oats, tobacco, sugarcane, sugar beets, sunflowers, millet, rice, peanuts, and other crops that were not included in the DAYCENT simulations. Estimates of direct N_2O emissions from N applications to non-major crop types were based on mineral soil N that was made available from the following practices: (1) the application of synthetic commercial fertilizers; (2) application of managed manure and non-manure commercial organic fertilizers;[150] and (3) the retention of above- and below-ground crop residues in agricultural fields (i.e., crop biomass that is not harvested). Non-manure organic amendments were not included in the DAYCENT simulations because county-level data were not available. Consequently, non-manure organic amendments, as well as additional manure that was not added to major crops in the DAYCENT simulations, were included in the Tier 1 analysis. The influence of land-use change on soil N_2O emissions from non-major crops has not been addressed in this analysis, but is a planned improvement. The following sources were used to derive activity data:

- A process-of-elimination approach was used to estimate synthetic N fertilizer additions for non-major crops, because little information exists on their fertilizer application rates. The total amount of fertilizer used on farms has been estimated by the USGS from sales records (Ruddy et al. 2006), and these data were aggregated to obtain state-level N additions to farms. After subtracting the portion of fertilizer applied to major crops and grasslands (see sections on Major Crops and Grasslands for information on data sources), the remainder of the total fertilizer used on farms was assumed to be applied to non-major crops.
- A process-of-elimination approach was used to estimate manure N additions for non-major crops, because little information exists on application rates for these crops. The amount of manure N applied to major crops and grasslands was subtracted from total manure N available for land application (see sections on Major Crops and Grasslands for information on data sources), and this difference was assumed to be applied to non-major crops.
- Non-manure, non-sewage-sludge commercial organic fertilizer additions were based on organic fertilizer consumption statistics, which were converted to units of N using average organic fertilizer N content (TVA 1991 through 1994; AAPFCO 1995 through 2010). Manure and sewage sludge components were subtracted from total commercial organic fertilizers to avoid double counting.
- Crop residue N was derived by combining amounts of above- and below-ground biomass, which were determined based on crop production yield statistics (USDA 1994, 1998, 2003, 2005, 2006, 2008, 2009, 2010a), dry matter fractions (IPCC 2006), linear equations to estimate above-ground biomass given dry matter crop yields from harvest (IPCC 2006), ratios of below-to-above-ground biomass (IPCC 2006), and N contents of the residues (IPCC 2006). Approximately 3 percent of the crop residues were burned and therefore did not contribute to soil N_2O emissions, based on state inventory data (ILENR 1993, Oregon Department of Energy 1995, Noller 1996, Wisconsin Department of Natural Resources 1993, and Cibrowski 1996).

The total increase in soil mineral N from applied fertilizers and crop residues was multiplied by the IPCC (2006) default emission factor to derive an estimate of direct N_2O emissions from non-major crop types.

Drainage and Cultivation of Organic Cropland Soils

The IPCC (2006) Tier 1 methods were used to estimate direct N_2O emissions due to drainage and cultivation of organic soils at a state scale. State-scale estimates of the total area of drained and cultivated organic soils were obtained from the *National Resources Inventory* (NRI) (USDA 2000a, as extracted by Eve 2001 and amended by Ogle 2002). Temperature data from Daly et al. (1994, 1998) were used to subdivide areas into temperate and sub-tropical climates using the climate classification from IPCC (2006). Data were available for 1982, 1992 and 1997. To estimate annual emissions, the total temperate area was multiplied by the IPCC default emission factor for temperate regions, and the total sub-tropical area was multiplied by the average of the IPCC default emission factors for temperate and tropical regions (IPCC 2006).

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[150] Commercial organic fertilizers include dried blood, tankage, compost, and other; dried manure and sewage sludge that are used as commercial fertilizer have been excluded to avoid double counting. The dried manure N is counted with the non-commercial manure applications, and sewage sludge is assumed to be applied only to grasslands.

Direct N_2O Emissions from Grassland Soils

As with N_2O from croplands, the Tier 3 process-based DAYCENT model and Tier 1 method described in IPCC (2006) were combined to estimate emissions from grasslands. Grasslands include pastures and rangelands used for grass forage production, where the primary use is livestock grazing. Rangelands are typically extensive areas of native grasslands that are not intensively managed, while pastures are often seeded grasslands, possibly following tree removal, which may or may not be improved with practices such as irrigation and interseeding legumes.

DAYCENT was used to simulate county-scale N_2O emissions from non-federal grasslands resulting from manure deposited by livestock directly onto pastures and rangelands (i.e., PRP manure), N fixation from legume seeding, managed manure amendments (i.e., manure other than PRP manure), and synthetic fertilizer application. Other N inputs were simulated within the DAYCENT framework, including N input from mineralization due to decomposition of soil organic matter and N inputs from senesced grass litter, as well as asymbiotic fixation of N from the atmosphere. The simulations used the same weather, soil, and synthetic N fertilizer data as discussed under the section for Major Crop Types on Mineral Cropland Soils. Managed manure N amendments to grasslands were estimated from Edmonds et al. (2003) and adjusted for annual variation using data on the availability of managed manure N for application to soils, according to methods described in the Manure Management section (Section 6.2) and Annex 3.10. Biological N fixation is simulated within DAYCENT and therefore was not an input to the model.

Manure N deposition from grazing animals (i.e., PRP manure) is another key input of N to grasslands. The amounts of PRP manure N applied on non-federal and federal grasslands in each county were based on the proportion of non-federal to federal grassland area (See below for more information on area data). The amount of PRP manure applied on non-federal grasslands was an input to the DAYCENT model (see Annex 3.10), and included approximately 91 percent of total PRP manure. The remainder of the PRP manure N excretions in each county was assumed to be excreted on federal grasslands (i.e., DAYCENT simulations were only conducted for non-federal grasslands), and the N_2O emissions were estimated using the IPCC (2006) Tier 1 method with IPCC default emission factors. Sewage sludge was assumed to be applied on grasslands because of the heavy metal content and other pollutants in human waste that limit its use as an amendment to croplands. Sewage sludge application was estimated from data compiled by EPA (1993, 1999, 2003), McFarland (2001), and NEBRA (2007). Sewage sludge data on soil amendments to agricultural lands were only available at the national scale, and it was not possible to associate application with specific soil conditions and weather at the county scale. Therefore, DAYCENT could not be used to simulate the influence of sewage sludge amendments on N_2O emissions from grassland soils, and consequently, emissions from sewage sludge were estimated using the IPCC (2006) Tier 1 method.

Grassland area data were consistent with the Land Representation reported in Section 7.1. Data were obtained from the U.S. Department of Agriculture *National Resources Inventory* (USDA 2000a, Nusser and Goebel 1997, http://www.ncgc.nrcs.usda.gov/products/nri/index.htm) and the U.S. Geological Survey (USGS) National Land Cover Dataset (NLCD, Vogelman et al. 2001, http://www.mrlc.gov), which were reconciled with the Forest Inventory and Analysis Data (http://fia.fs.us/tools-data/data). The area data for pastures and rangeland were aggregated to the county level to estimate non-federal and federal grassland areas.

DAYCENT simulations produced per-area estimates of N_2O emissions (g N_2O-N/m^2) for pasture and rangelands, which were multiplied by the non-federal grassland areas in each county. The county-scale N_2O emission estimates for non-federal grasslands were scaled to the 63 agricultural regions (and to the state level for mapping purposes if there was more than one region in a state), and the national estimate was calculated by summing results across all regions. Tier 1 estimates of N_2O emissions for the PRP manure N deposited on federal grasslands and applied sewage sludge N were produced by multiplying the N input by the appropriate emission factor. Tier 1 estimates for emissions from manure N were calculated at the state level and aggregated to the entire country but emission from sewage sludge N were calculated exclusively at the national scale.

Total Direct N_2O Emissions from Cropland and Grassland Soils

Annual direct emissions from major and non-major crops on mineral cropland soils, from drainage and cultivation of organic cropland soils, and from grassland soils were summed to obtain the total direct N_2O emissions from agricultural soil management (see Table 6-15 and Table 6-16).

Indirect N_2O Emissions from Managed Soils of all Land-Use Types

This section describes the methods used for estimating indirect soil N_2O emissions from all land-use types (i.e., croplands, grasslands, forest lands, and settlements). Indirect N_2O emissions occur when mineral N made available through anthropogenic activity is transported from the soil either in gaseous or aqueous forms and later converted into N_2O. There are two pathways leading to indirect emissions. The first pathway results from volatilization of N as NO_x and NH_3 following application of synthetic fertilizer, organic amendments (e.g., manure, sewage sludge), and deposition of PRP manure. N made available from mineralization of soil organic matter and asymbiotic fixation also contributes to volatilized N emissions. Volatilized N can be returned to soils through atmospheric deposition, and a portion of the deposited N is emitted to the atmosphere as N_2O. The second pathway occurs via leaching and runoff of soil N (primarily in the form of NO_3^-) that was made available through anthropogenic activity on managed lands, mineralization of soil organic matter, and asymbiotic fixation. The NO_3^- is subject to denitrification in water bodies, which leads to N_2O emissions. Regardless of the eventual location of the indirect N_2O emissions, the emissions are assigned to the original source of the N for reporting purposes, which here includes croplands, grasslands, forest lands, and settlements.

Indirect N_2O Emissions from Atmospheric Deposition of Volatilized N from Managed Soils

As in the direct emissions calculation, the Tier 3 DAYCENT model and IPCC (2006) Tier 1 methods were combined to estimate the amount of N that was volatilized and eventually emitted as N_2O. DAYCENT was used to estimate N volatilization for land areas whose direct emissions were simulated with DAYCENT (i.e., major croplands and most grasslands). The N inputs included are the same as described for direct N_2O emissions in the sections on major crops and grasslands. Nitrogen volatilization for all other areas was estimated using the Tier 1 method and default IPCC fractions for N subject to volatilization (i.e., N inputs on non-major croplands, PRP manure N excretion on federal grasslands, sewage sludge application on grasslands). The Tier 1 method and default fractions were also used to estimate N subject to volatilization from N inputs on settlements and forest lands (see the Land Use, Land-Use Change, and Forestry chapter). For the volatilization data generated from both the DAYCENT and Tier 1 approaches, the IPCC (2006) default emission factor was used to estimate indirect N_2O emissions occurring due to re-deposition of the volatilized N (Table 6-18).

Indirect N_2O Emissions from Leaching/Runoff

As with the calculations of indirect emissions from volatilized N, the Tier 3 DAYCENT model and IPCC (2006) Tier 1 method were combined to estimate the amount of N that was subject to leaching and surface runoff into water bodies, and eventually emitted as N_2O. DAYCENT was used to simulate the amount of N transported from lands used to produce major crops and most grasslands. N transport from all other areas was estimated using the Tier 1 method and the IPCC (2006) default factor for the proportion of N subject to leaching and runoff. This N transport estimate includes N applications on croplands that produce non-major crops, sewage sludge amendments on grasslands, PRP manure N excreted on federal grasslands, and N inputs on settlements and forest lands. For both the DAYCENT and IPCC (2006) Tier 1 methods, nitrate leaching was assumed to be an insignificant source of indirect N_2O in cropland and grassland systems in arid regions as discussed in IPCC (2006). In the United States, the threshold for significant nitrate leaching is based on the potential evapotranspiration (PET) and rainfall amount, similar to IPCC (2006), and is assumed to be negligible in regions where the amount of precipitation plus irrigation does not exceed 80 percent of PET. For leaching and runoff data estimated by the DAYCENT and Tier 1 approaches, the IPCC (2006) default emission factor was used to estimate indirect N_2O emissions that occur in groundwater and waterways (Table 6-18).

Uncertainty and Time-Series Consistency

Uncertainty was estimated for each of the following five components of N_2O emissions from agricultural soil management: (1) direct emissions calculated by DAYCENT; (2) the components of indirect emissions (N volatilized and leached or runoff) calculated by DAYCENT; (3) direct emissions calculated with the IPCC (2006) Tier 1 method; (4) the components of indirect emissions (N volatilized and leached or runoff) calculated with the IPCC (2006) Tier 1 method; and (5) indirect emissions calculated with the IPCC (2006) Tier 1 method. Uncertainty in direct emissions, which account for the majority of N_2O emissions from agricultural management, as well as the components of indirect emissions calculated by DAYCENT were estimated with a Monte Carlo Analysis, addressing uncertainties in model inputs and structure (i.e., algorithms and parameterization) (Del Grosso et al., 2010). Uncertainties in direct emissions calculated with the IPCC (2006) Tier 1 method, the proportion of volatilization and leaching or runoff estimated with the IPCC (2006) Tier 1 method, and indirect N_2O emissions were estimated with a simple error propagation approach (IPCC 2006). Additional details on the uncertainty methods are provided in Annex 3.11.

Uncertainties from the Tier 1 and Tier 3 (i.e., DAYCENT) estimates were combined using simple error propagation (IPCC 2006), and the results are summarized in Table 6-19. Agricultural direct soil N_2O emissions in 2009 were estimated to be between 118.3 and 250.6 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 26 percent below and 56 percent above the 2009 emission estimate of 160.2 Tg CO_2 Eq. The indirect soil N_2O emissions in 2009 were estimated to range from 22.4 to 111.6 Tg CO_2 Eq. at a 95 percent confidence level, indicating an uncertainty of 50 percent below and 151 percent above the 2009 emission estimate of 44.4 Tg CO_2 Eq.

Table 6-19: Quantitative Uncertainty Estimates of N_2O Emissions from Agricultural Soil Management in 2009 (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate (Tg CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Direct Soil N_2O Emissions	N_2O	160.2	118.3	250.6	-26%	+56%
Indirect Soil N_2O Emissions	N_2O	44.4	22.4	111.6	-50%	+151%

Note: Due to lack of data, uncertainties in areas for major crops, managed manure N production, PRP manure N production, other organic fertilizer amendments, indirect losses of N in the DAYCENT simulations, and sewage sludge amendments to soils are currently treated as certain; these sources of uncertainty will be included in future Inventories.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

For quality control, DAYCENT results for N_2O emissions and NO_3^- leaching were compared with field data representing various cropland and grassland systems, soil types, and climate patterns (Del Grosso et al. 2005, Del Grosso et al. 2008), and further evaluated by comparing to emission estimates produced using the IPCC (2006) Tier 1 method for the same sites. Nitrous oxide measurement data were available for 11 sites in the United States and one in Canada, representing 30 different combinations of fertilizer treatments and cultivation practices. DAYCENT estimates of N_2O emissions were closer to measured values at all sites compared to the IPCC Tier 1 estimate, except for Colorado dryland cropping (Figure 6-7). In general, IPCC Tier 1 methodology tends to over-estimate emissions when observed values are low and under-estimate emissions when observed values are high, while DAYCENT estimates are less biased. This is not surprising because DAYCENT accounts for site-level factors (weather, soil type) that influence N_2O emissions. Nitrate leaching data were available for three sites in the United States representing nine different combinations of fertilizer amendments. Linear regressions of simulated vs. observed emission and leaching data yielded correlation coefficients of 0.89 and 0.94 for annual N_2O emissions and NO_3^- leaching, respectively. This comparison demonstrates that DAYCENT provides relatively high predictive capability for N_2O emissions and NO_3^- leaching, and is an improvement over the IPCC Tier 1 method (see additional information in Annex 3.11).

Figure 6-7: Comparison of Measured Emissions at Field Sites and Modeled Emissions Using the DAYCENT Simulation Model

Spreadsheets containing input data and probability distribution functions required for DAYCENT simulations of major croplands and grasslands and unit conversion factors were checked, as were the program scripts that were used to run the Monte Carlo uncertainty analysis. Several errors were identified following re-organization of the calculation spreadsheets, and corrective actions have been taken. In particular, some of the links between spreadsheets were missing or needed to be modified. Spreadsheets containing input data, emission factors, and calculations required for the Tier 1 approach were checked and no errors were found.

Recalculations Discussion

Two major revisions were made in the Agricultural Soil Management section for the current Inventory.

First, the methodology used to estimate grassland areas was updated and revised to be consistent with the Land Representation used in the Land Use, Land Use Change and Forestry sector (see Section 7.1). This led to an overall decrease in grassland area, and lower emissions than reported in the prior Inventory. Second, the methodology used to calculate livestock manure N was changed such that total manure N added to soils increased by approximately 11 percent (see Section 6.2 for details).

The recalculations had opposite impacts on the emissions, with less grassland area tending to decrease emissions and higher manure N inputs tending to increase emissions. In some years emissions were higher overall, but on average, these changes led to a lower amount of N_2O emissions from agricultural soil management by about 1.5 percent over the time series relative to the previous Inventory.

Planned Improvements

A key improvement is underway for Agricultural Soil Management to incorporate more land-use survey data from the NRI (USDA 2000a) into the DAYCENT simulation analysis, beyond the area estimates for rangeland and pasture that are currently used to estimate emissions from grasslands. NRI has a record of land-use activities since 1979 for all U.S. agricultural land, which is estimated at about 386 Mha. NASS is used as the basis for land-use records in the current Inventory, and there are three major disadvantages to this dataset. First, most crops are grown in rotation with other crops (e.g., corn-soybean), but NASS data provide no information regarding rotation histories. In contrast, NRI is designed to track rotation histories, which is important because emissions from any particular year can be influenced by the crop that was grown the previous year. Second, NASS does not conduct a complete survey of cropland area each year, leading to gaps in the land base. NRI provides a complete history of cropland areas for four out of every five years from 1979 to 1997, and then every year after 1998. Third, the current inventory based on NASS does not quantify the influence of land-use change on emissions, which can be addressed using the NRI survey records. NRI also provides additional information on pasture land management that can be incorporated into the analysis (particularly the use of irrigation). Using NRI data will also make the Agricultural Soil Management methods more consistent with the methods used to estimate C stock changes for agricultural soils. The structure of model input files that contain land management data are currently being extensively revised to facilitate use of the annualized NRI data. This improvement is planned for completion by the next Inventory.

Another improvement is to reconcile the amount of crop residues burned with the Field Burning of Agricultural Residues source category (Section 6.5). This year the methodology for Field Burning of Agricultural Residues was significantly updated, but the changes were implemented too late for the new estimates of crop residues burned to be incorporated into the DAYCENT runs for the Agricultural Soil Management source. Next year the estimates will be reconciled; meanwhile the estimates presented in this section use the previous year’s methodology for determining crop residues burned.

Other planned improvements are minor but will lead to more accurate estimates, including updating DAYMET weather data for more recent years following the release of new data, and using a rice-crop-specific emission factor for N amendments to rice areas.

6.5. Field Burning of Agricultural Residues (IPCC Source Category 4F)

Farming activities produce large quantities of agricultural crop residues, and farmers use or dispose of these residues in a variety of ways. For example, agricultural residues can be left on or plowed into the field; composted and then applied to soils; landfilled; or burned in the field. Alternatively, they can be collected and used as fuel, animal bedding material, supplemental animal feed, or construction material. Field burning of crop residues is not considered a net source of CO_2, because the C released to the atmosphere as CO_2 during burning is assumed to be reabsorbed during the next growing season. Crop residue burning is, however, a net source of CH_4, N_2O, CO, and NO_x, which are released during combustion.

Field burning is not a common method of agricultural residue disposal in the United States. The primary crop types whose residues are typically burned in the United States are corn, cotton, lentils, rice, soybeans, sugarcane, and wheat (McCarty 2009). In 2009, CH_4 and N_2O emissions from field burning were 0.2 Tg CO_2 Eq. (12 Gg) and 0.1 Tg. CO_2 Eq. (0.3 Gg), respectively. Annual emissions from this source over the period 1990 to 2009 have remained relatively constant, averaging approximately 0.2 Tg CO_2 Eq. (1 Gg) of CH_4 and 0.1 Tg CO_2 Eq. (0.3 Gg) of N_2O (see Table 6-20 and Table 6-21).

Table 6-20: CH_4 and N_2O Emissions from Field Burning of Agricultural Residues (Tg CO_2 Eq.)

Gas/Crop Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CH_4	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.3**	**0.2**
Corn	+	+	+	+	+	+	+
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	+	+	+	+	0.1	+	+
Soybeans	+	+	+	+	+	+	+
Sugarcane	0.1	0.1	+	0.1	+	+	+
Wheat	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Corn	+	+	+	+	+	+	+
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	+	+	+	+	+	+	+
Soybeans	+	+	+	+	+	+	+
Sugarcane	+	+	+	+	+	+	+
Wheat	+	+	+	+	+	+	+
Total	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.4**	**0.4**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 6-21: CH_4, N_2O, CO, and NO_x Emissions from Field Burning of Agricultural Residues (Gg)

Gas/Crop Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CH_4	**13**	**12**	**9**	**11**	**11**	**13**	**12**
Corn	1	1	1	2	1	1	2
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	2	2	2	2	3	2	2
Soybeans	1	1	1	1	1	1	1
Sugarcane	3	2	1	3	1	2	2
Wheat	6	6	4	4	5	6	5
N_2O	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Corn	+	+	+	+	+	+	+
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	+	+	+	+	+	+	+
Soybeans	+	+	+	+	+	+	+
Sugarcane	+	+	+	+	+	+	+
Wheat	+	+	+	+	+	+	+
CO	**268**	**259**	**184**	**233**	**237**	**270**	**247**
NO_x	**8**	**8**	**6**	**7**	**8**	**8**	**8**

+ Less than 0.5 Gg

Note: Totals may not sum due to independent rounding.

Methodology

The Tier 2 methodology used for estimating greenhouse gas emissions from field burning of agricultural residues in the United States is consistent with IPCC (2006) (for more details, see Box 6-2). In order to estimate the amounts of C and N released during burning, the following equation was used:

C or N released = Σ over all crop types and states (Area Burned ÷ Crop Area Harvested × Crop Production ×

Residue/Crop Ratio × Dry Matter Fraction × Burning Efficiency × Combustion Efficiency × Fraction of C or N)

where,

Area Burned = Total area of crop burned, by state
Crop Area Harvested = Total area of crop harvested, by state
Crop Production = Annual production of crop in Gg, by state
Residue/Crop Ratio = Amount of residue produced per unit of crop production, by state
Dry Matter Fraction = Amount of dry matter per unit of biomass for a crop
Fraction of C or N = Amount of C or N per unit of dry matter for a crop
Burning Efficiency = The proportion of prefire fuel biomass consumed[151]
Combustion Efficiency = The proportion of C or N released with respect to the total amount of C or N available in the burned material, respectively[151]

Crop production and area harvested were available by state and year from USDA (2010) for all crops (except rice in Florida and Oklahoma, as detailed below). The amount C or N released was used in the following equation to determine the CH_4, CO, N_2O and NO_x emissions from the field burning of agricultural residues:

CH_4 and CO, or N_2O and NO_x Emissions from Field Burning of Agricultural Residues = (C or N Released) × (Emissions Ratio for C or N) × (Conversion Factor)

where,

Emissions Ratio = g CH_4-C or CO-C/g C released, or g N_2O-N or NO_x-N/g N released
Conversion Factor = conversion, by molecular weight ratio, of CH_4-C to C (16/12), or CO-C to C (28/12), or N_2O-N to N (44/28), or NO_x-N to N (30/14)

[BEGIN BOX]

Box 6-2: Comparison of Tier 2 U.S. Inventory Approach and IPCC (2006) Default Approach

This Inventory calculates emissions from Burning of Agricultural Residues using a Tier 2 methodology that is based on IPCC/UNEP/OECD/IEA (1997) and incorporates crop- and country-specific emission factors and variables. The equation used in this Inventory varies slightly in form from the one presented in the IPCC (2006) guidelines, but both equations rely on the same underlying variables. The IPCC (2006) equation was developed to be broadly applicable to all types of biomass burning, and, thus, is not specific to agricultural residues. IPCC (2006) default factors are provided only for four crops (wheat, corn, rice, and sugarcane), while this Inventory analyzes emissions from seven crops. A comparison of the methods and factors used in (1) the current Inventory and (2) the default IPCC (2006) approach was undertaken to determine the magnitude of the difference in overall estimates resulting from the two approaches. The IPCC (2006) approach was not used because crop-specific emission factors for N_2O were not available for all crops. In order to maintain consistency of methodology, the IPCC/UNEP/OECD/IEA (1997) approach presented in the Methodology section was used.

The IPCC (2006) default approach resulted in 12 percent higher emissions of CH_4 and 25 percent higher emissions of N_2O than the current estimates in this Inventory. It is reasonable to maintain the current methodology, since the IPCC (2006) defaults are only available for four crops and are worldwide average estimates, while current inventory estimates are based on U.S.-specific, crop-specific, published data.

[END BOX]

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[151] In IPCC/UNEP/OECD/IEA (1997), the equation for C or N released contains the variable 'fraction oxidized in burning.' This variable is equivalent to (burning efficiency × combustion efficiency).

Crop production data for all crops except rice in Florida and Oklahoma were taken from USDA's QuickStats service (USDA 2010). Rice production and area data for Florida and Oklahoma, which are not collected by USDA, were estimated separately. Average primary and ratoon crop yields for Florida (Schueneman and Deren 2002) were applied to Florida acreages (Schueneman 1999, 2001; Deren 2002; Kirstein 2003, 2004; Cantens 2004, 2005; Gonzalez 2007 through 2010), and crop yields for Arkansas (USDA 2010) were applied to Oklahoma acreages[152] (Lee 2003 through 2006; Anderson 2008 through 2010). The production data for the crop types whose residues are burned are presented in Table 6-22. Crop weight by bushel was obtained from Murphy (1993).

The fraction of crop area burned was calculated using data on area burned by crop type and state[153] from McCarty (2010) for corn, cotton, lentils, rice, soybeans, sugarcane, and wheat.[154] McCarty (2010) used remote sensing data from Moderate Resolution Imaging Spectroradiometer (MODIS) to estimate area burned by crop. For the inventory analysis, the state-level area burned data were divided by state-level crop area harvested data to estimate the percent of crop area burned by crop and by state. The average fraction of area burned by crop across all states is shown in Table 6-23. All crop area harvested data were from USDA (2010), except for rice acreage in Florida and Oklahoma, which is not measured by USDA (Schueneman 1999, 2001; Deren 2002; Kirstein 2003, 2004; Cantens 2004, 2005; Gonzalez 2007 through 2010; Lee 2003 through 2006; Anderson 2008 through 2010). Data on crop area burned were only available from McCarty (2010) for the years 2003 through 2007. For other years in the time series, the percent area burned was assumed to be equal to the average percent area burned from the 5 years for which data were available. This average was taken at the crop and state level. Table 6-23 shows these percent area estimates aggregated for the United States as a whole, at the crop level.

All residue/crop product mass ratios except sugarcane and cotton were obtained from Strehler and Stützle (1987). The datum for sugarcane is from Kinoshita (1988) and that of cotton from Huang et al. (2007). The residue/crop ratio for lentils was assumed to be equal to the average of the values for peas and beans. Residue dry matter fractions for all crops except soybeans, lentils, and cotton were obtained from Turn et al. (1997). Soybean and lentil dry matter fractions were obtained from Strehler and Stützle (1987); the value for lentil residue was assumed to equal the value for bean straw. The cotton dry matter fraction was taken from Huang et al. (2007). The residue C contents and N contents for all crops except soybeans and cotton are from Turn et al. (1997). The residue C content for soybeans is the IPCC default (IPCC/UNEP/OECD/IEA 1997). The N content of soybeans is from Barnard and Kristoferson (1985). The C and N contents of lentils were assumed to equal those of soybeans. The C and N contents of cotton are from Lachnicht et al. (2004). These data are listed in Table 6-24. The burning efficiency was assumed to be 93 percent, and the combustion efficiency was assumed to be 88 percent, for all crop types, except sugarcane (EPA 1994). For sugarcane, the burning efficiency was assumed to be 81 percent (Kinoshita 1988) and the combustion efficiency was assumed to be 68 percent (Turn et al. 1997). Emission ratios and conversion factors for all gases (see Table 6-25) were taken from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997).

Table 6-22: Agricultural Crop Production (Gg of Product)

Crop	1990	2000	2005	2006	2007	2008	2009
Corn[a]	201,534	251,854	282,263	267,503	331,177	307,142	333,011
Cotton	3,376	3,742	5,201	4,700	4,182	2,790	2,654
Lentils	40	137	238	147	166	109	266
Rice	7,114	8,705	10,132	8,843	9,033	9,272	9,972
Soybeans	52,416	75,055	83,507	87,001	72,859	80,749	91,417
Sugarcane	25,525	32,763	24,137	26,820	27,188	25,041	27,608
Wheat	74,292	60,641	57,243	49,217	55,821	68,016	60,366

[a] Corn for grain (i.e., excludes corn for silage).

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[152] Rice production yield data are not available for Oklahoma, so the Arkansas values are used as a proxy.

[153] Alaska and Hawaii were excluded.

[154] McCarty (2009) also examined emissions from burning of Kentucky bluegrass and a general "other crops/fallow" category, but USDA crop area and production data were insufficient to estimate emissions from these crops using the methodology employed in the Inventory. McCarty (2009) estimates that approximately 18 percent of crop residue emissions result from burning of the Kentucky bluegrass and "other" categories.

Table 6-23: U.S. Average Percent Crop Area Burned by Crop (Percent)

State	1990	2000	2005	2006	2007	2008	2009
Corn	+	+	+	+	+	+	+
Cotton	1	1	1	1	1	2	1
Lentils	3	2	+	2	1	1	1
Rice	10	10	6	8	12	9	9
Soybeans	+	+	+	+	+	+	+
Sugarcane	59	40	26	56	26	39	37
Wheat	3	3	2	3	3	3	3

+ Less than 0.5 percent

Table 6-24: Key Assumptions for Estimating Emissions from Field Burning of Agricultural Residues

Crop	Residue/Crop Ratio	Dry Matter Fraction	C Fraction	N Fraction	Burning Efficiency (Fraction)	Combustion Efficiency (Fraction)
Corn	1.0	0.91	0.448	0.006	0.93	0.88
Cotton	1.6	0.90	0.445	0.012	0.93	0.88
Lentils	2.0	0.85	0.450	0.023	0.93	0.88
Rice	1.4	0.91	0.381	0.007	0.93	0.88
Soybeans	2.1	0.87	0.450	0.023	0.93	0.88
Sugarcane	0.2	0.62	0.424	0.004	0.81	0.68
Wheat	1.3	0.93	0.443	0.006	0.93	0.88

Table 6-25: Greenhouse Gas Emission Ratios and Conversion Factors

Gas	Emission Ratio	Conversion Factor
CH_4:C	0.005[a]	16/12
CO:C	0.060[a]	28/12
N_2O:N	0.007[b]	44/28
NO_x:N	0.121[b]	30/14

[a] Mass of C compound released (units of C) relative to mass of total C released from burning (units of C).

[b] Mass of N compound released (units of N) relative to mass of total N released from burning (units of N).

Uncertainty and Time-Series Consistency

Due to data and time limitations, uncertainty resulting from the fact that emissions from burning of Kentucky bluegrass and "other" residues are not included in the emissions estimates was not incorporated into the uncertainty analysis. The results of the Tier 2 Monte Carlo uncertainty analysis are summarized in Table 6-26. Methane emissions from field burning of agricultural residues in 2009 were estimated to be between 0.15 and 0.35 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 40 percent below and 42 percent above the 2009 emission estimate of 0.25 Tg CO_2 Eq. Also at the 95 percent confidence level, N_2O emissions were estimated to be between 0.07 and 0.14 Tg CO_2 Eq. (or approximately 30 percent below and 31 percent above the 2009 emission estimate of 0.10 Tg CO_2 Eq.).

Table 6-26: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Field Burning of Agricultural Residues (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Field Burning of Agricultural Residues	CH_4	0.25	0.15	0.35	-40%	+42%
Field Burning of Agricultural Residues	N_2O	0.10	0.07	0.14	-30%	+31%

[a]Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990

through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for field burning of agricultural residues was implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on comparing trends across years, states, and crops to attempt to identify any outliers or inconsistencies. For some crops and years in Florida and Oklahoma, the total area burned as measured by McCarty (2010) was greater than the area estimated for that crop, year, and state by USDA (2010), leading to a percent area burned estimate of greater than 100 percent. In such cases, it was assumed that the percent crop area burned for that state was 100 percent.

Recalculations Discussion

The methodology over the entire time series was revised relative to the previous Inventory to incorporate state- and crop-level data on area burned from McCarty (2010). (1) Cotton and lentils were added as crops; peanuts and barley were removed, because McCarty (2009) indicated that their residues are not burned in significant quantities in the United States; (2) fraction of residue burned was calculated at the state and crop level based on McCarty (2010) and USDA (2010) data, rather than a blanket application of 3 percent burned for all crops except rice and sugarcane, as was used in the previous Inventory; (3) since data from McCarty (2010) were only available for 5 years, the percent area burned for those 5 years was averaged by crop and state and used as an estimate for the remaining years in the time series. Because the percent area burned was lower than previously assumed for almost all crops, these recalculations have resulted in an average decrease in CH_4 emissions of 71 percent and an average decrease in N_2O emissions of 79 percent across the time series, relative to the previous Inventory.

Planned Improvements

Further investigation will be made into inconsistent data from Florida and Oklahoma as mentioned in the QA/QC and verification section, and attempts will be made to revise or further justify the assumption of 100 percent of area burned for those crops and years where the estimated percent area burned exceeded 100 percent. The availability of useable area harvested and other data for bluegrass and the “other crops” category in McCarty (2010) will also be investigated, in order to try to incorporate these emissions into the Inventory.

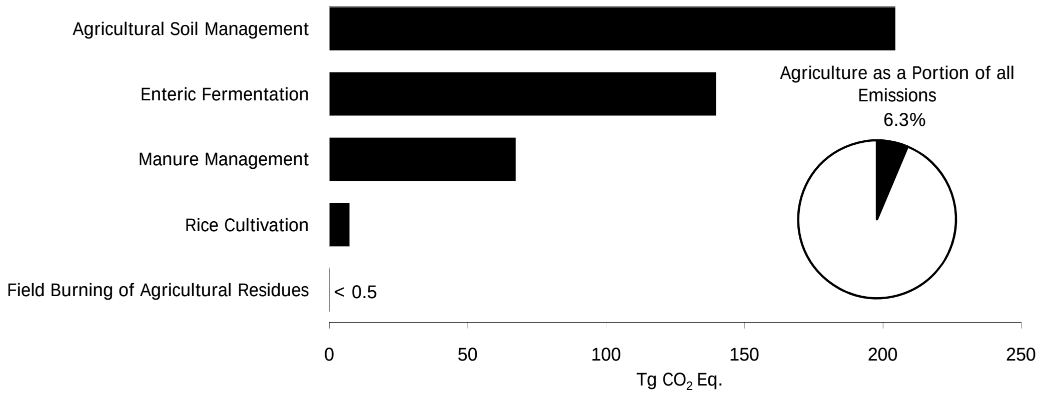
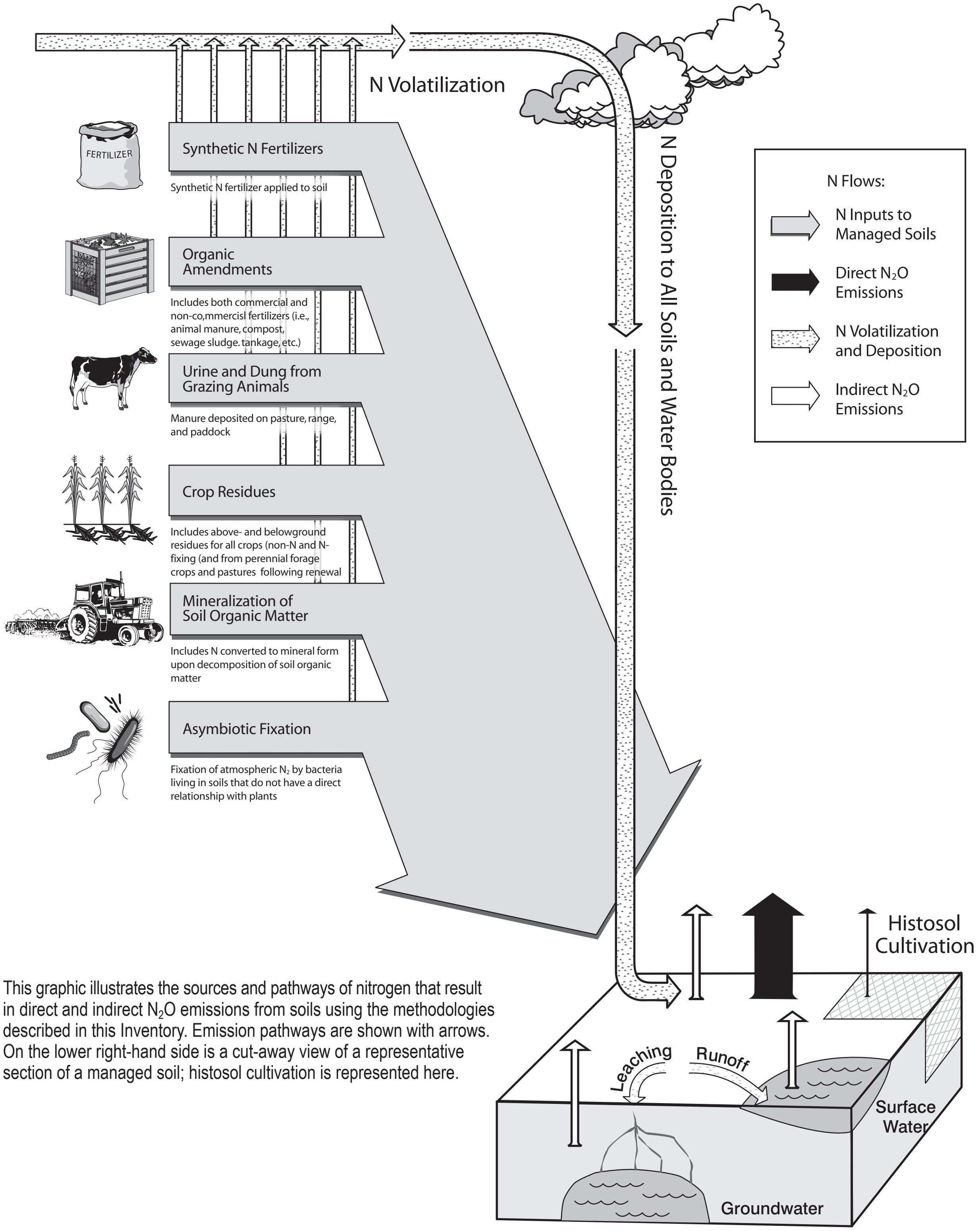


Figure 6-1: 2009 Agriculture Chapter Greenhouse Gas Sources

Figure 6-2

Sources and Pathways of N that Result in N_2O Emissions from Agricultural Soil Management



This graphic illustrates the sources and pathways of nitrogen that result in direct and indirect N_2O emissions from soils using the methodologies described in this Inventory. Emission pathways are shown with arrows. On the lower right-hand side is a cut-away view of a representative section of a managed soil; histosol cultivation is represented here.

Figure 6-3

Major Crops, Average Annual Direct N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Tg CO_2 Eq/year)

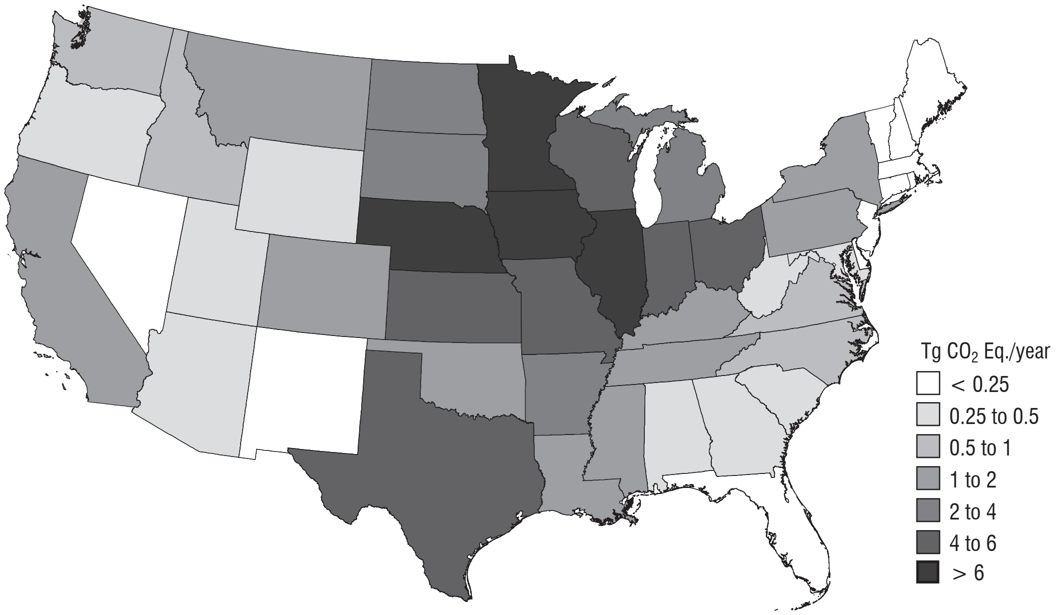


Figure 6-4

Grasslands, Average Annual Direct N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009
(Tg CO_2 Eq./year)

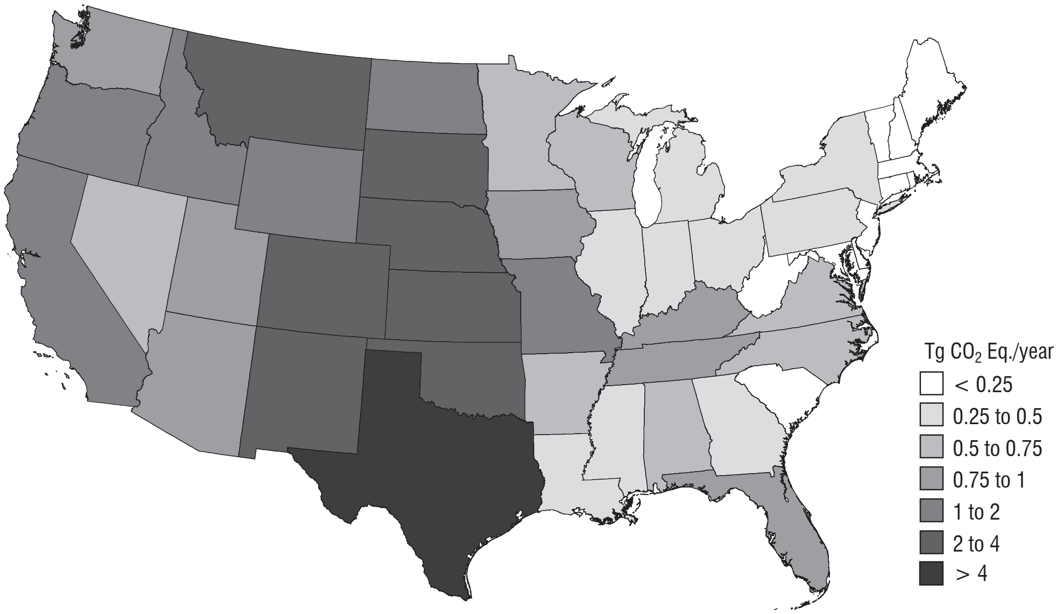


Figure 6-5

Major Crops, Average Annual N Losses Leading to Indirect N_2O Emissions Using the DAYCENT Model, 1990–2009 (Gg N/year)

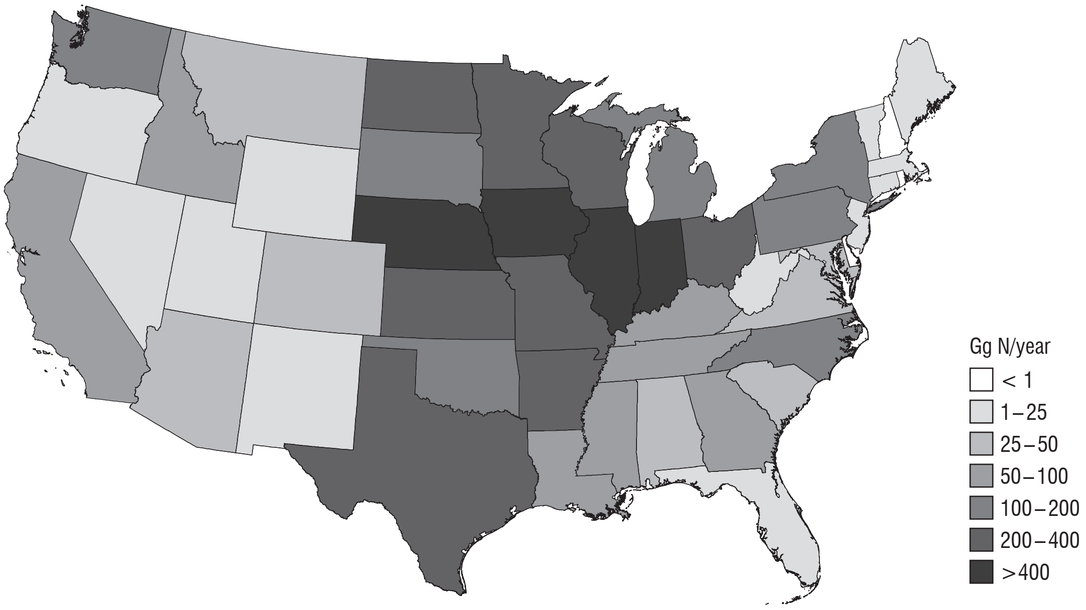


Figure 6-6

Grasslands, Average Annual N Losses Leading to Indirect N_2O Emissions Using the DAYCENT Model, 1990–2009 (Gg N/year)

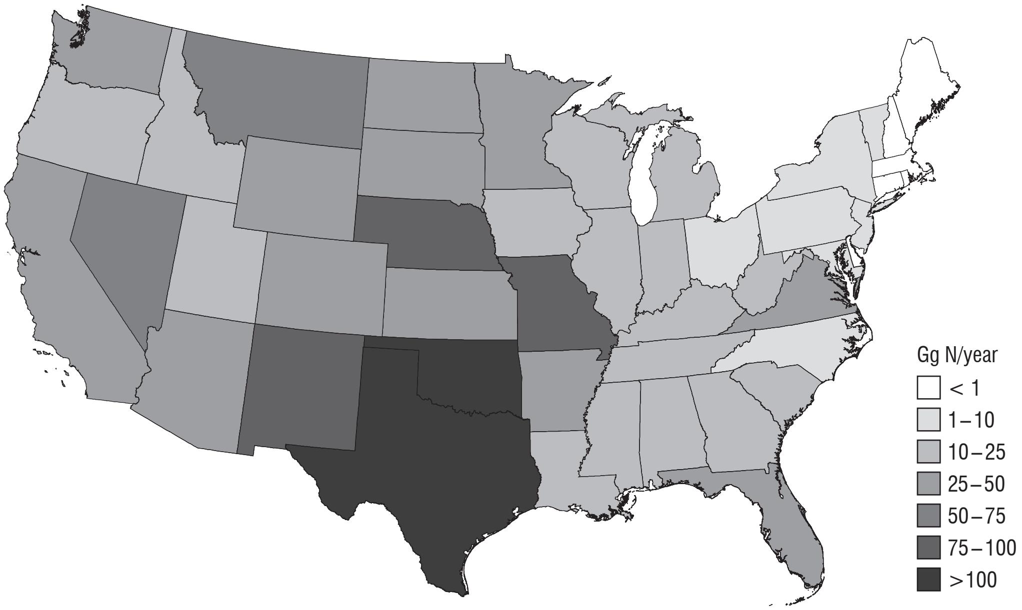
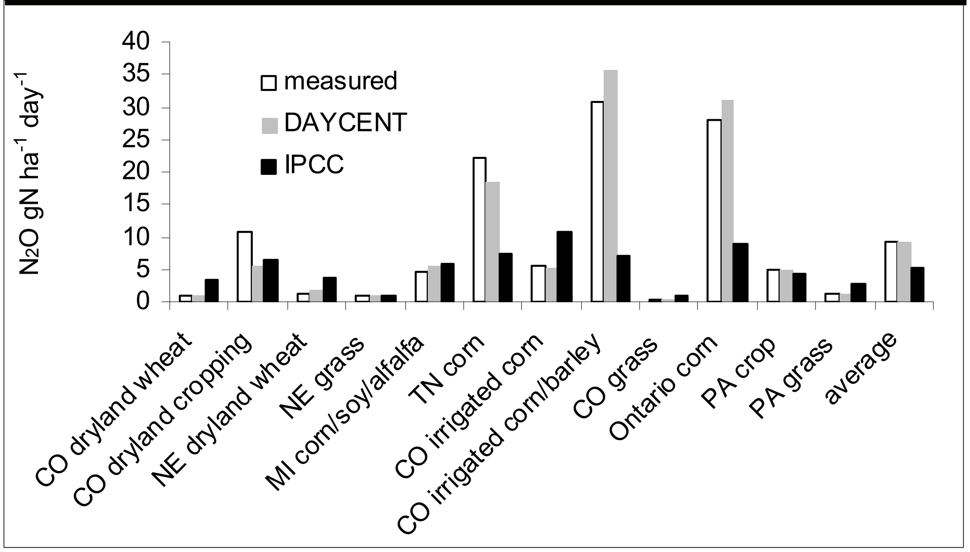


Figure 6-7

Comparison of Measured Emissions at Field Sites with Modeled Emissions Using the DAYCENT Simulation Model



7. Land Use, Land-Use Change, and Forestry

This chapter provides an assessment of the net greenhouse gas flux[155] resulting from the uses and changes in land types and forests in the United States. The Intergovernmental Panel on Climate Change *2006 Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) recommends reporting fluxes according to changes within and conversions between certain land-use types termed forest land, cropland, grassland, and settlements (as well as wetlands). The greenhouse gas flux from *Forest Land Remaining Forest Land* is reported using estimates of changes in forest carbon (C) stocks, non-carbon dioxide (CO_2) emissions from forest fires, and the application of synthetic fertilizers to forest soils. The greenhouse gas flux reported in this chapter from agricultural lands (i.e., cropland and grassland) includes changes in organic C stocks in mineral and organic soils due to land use and management, and emissions of CO_2 due to the application of crushed limestone and dolomite to managed land (i.e., soil liming) and urea fertilization. Fluxes are reported for four agricultural land use/land-use change categories: *Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland*, and *Land Converted to Grassland*. Fluxes resulting from *Settlements Remaining Settlements* include those from urban trees and soil fertilization. Landfilled yard trimmings and food scraps are accounted for separately under *Other*.

The estimates in this chapter, with the exception of CO_2 fluxes from wood products and urban trees, and CO_2 emissions from liming and urea fertilization, are based on activity data collected at multiple-year intervals, which are in the form of forest, land-use, and municipal solid waste surveys. CO_2 fluxes from forest C stocks (except the wood product components) and from agricultural soils (except the liming component) are calculated on an average annual basis from data collected in intervals ranging from 1 to 10 years. The resulting annual averages are applied to years between surveys. Calculations of non-CO_2 emissions from forest fires are based on forest CO_2 flux data. For the landfilled yard trimmings and food scraps source, periodic solid waste survey data were interpolated so that annual storage estimates could be derived. This flux has been applied to the entire time series, and periodic U.S. census data on changes in urban area have been used to develop annual estimates of CO_2 flux.

Land use, land-use change, and forestry activities in 2009 resulted in a net C sequestration of 1,015.1 Tg CO_2 Eq. (276.8 Tg C) (Table 7-1 and Table 7-2). This represents an offset of approximately 15.3 percent of total U.S. CO_2 emissions. Total land use, land-use change, and forestry net C sequestration[156] increased by approximately 17.8 percent between 1990 and 2009. This increase was primarily due to an increase in the rate of net C accumulation in forest C stocks. Net C accumulation in *Forest Land Remaining Forest Land, Land Converted to Grassland*, and *Settlements Remaining Settlements* increased, while net C accumulation in *Cropland Remaining Cropland, Grassland Remaining Grassland*, and landfilled yard trimmings and food scraps slowed over this period. Emissions from *Land Converted to Cropland* increased between 1990 and 2009.

Table 7-1: Net CO_2 Flux from Carbon Stock Changes in Land Use, Land-Use Change, and Forestry (Tg CO_2 Eq.)

Sink Category	1990	2000	2005	2006	2007	2008	2009
Forest Land Remaining Forest Land[1]	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)
Cropland Remaining Cropland	(29.4)	(30.2)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)
Land Converted to Cropland	2.2	2.4	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)	(52.6)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)
Land Converted to Grassland	(19.8)	(27.2)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)
Settlements Remaining Settlements[2]	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)
Total	**(861.5)**	**(576.6)**	**(1,056.5)**	**(1,064.3)**	**(1,060.9)**	**(1,040.5)**	**(1,015.1)**

Note: Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

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[155] The term "flux" is used here to encompass both emissions of greenhouse gases to the atmosphere, and removal of C from the atmosphere. Removal of C from the atmosphere is also referred to as "carbon sequestration."

[156] Carbon sequestration estimates are net figures. The C stock in a given pool fluctuates due to both gains and losses. When losses exceed gains, the C stock decreases, and the pool acts as a source. When gains exceed losses, the C stock increases, and the pool acts as a sink. This is also referred to as net C sequestration.

[1] Estimates include C stock changes on both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*.
[2] Estimates include C stock changes on both *Settlements Remaining Settlements* and *Land Converted to Settlements*.

Table 7-2: Net CO_2 Flux from Carbon Stock Changes in Land Use, Land-Use Change, and Forestry (Tg C)

Sink Category	1990	2000	2005	2006	2007	2008	2009
Forest Land Remaining Forest Land[1]	(185.7)	(103.2)	(248.6)	(250.2)	(248.7)	(243.0)	(235.4)
Cropland Remaining Cropland	(8.0)	(8.2)	(5.0)	(5.2)	(5.4)	(4.9)	(4.7)
Land Converted to Cropland	0.6	0.6	1.6	1.6	1.6	1.6	1.6
Grassland Remaining Grassland	(14.2)	(14.3)	(2.4)	(2.4)	(2.3)	(2.3)	(2.3)
Land Converted to Grassland	(5.4)	(7.4)	(6.7)	(6.6)	(6.5)	(6.5)	(6.4)
Settlements Remaining Settlements[2]	(15.6)	(21.1)	(23.9)	(24.5)	(25.1)	(25.6)	(26.2)
Other (Landfilled Yard Trimmings and Food Scraps)	(6.6)	(3.6)	(3.1)	(3.0)	(3.0)	(3.1)	(3.4)
Total	**(235.0)**	**(157.3)**	**(288.1)**	**(290.3)**	**(289.3)**	**(283.8)**	**(276.8)**

Note: 1 Tg C = 1 teragram C = 1 million metric tons C. Parentheses indicate net sequestration. Totals may not sum due to independent rounding.
[1] Estimates include C stock changes on both *Forest Land Remaining Forest Land and Land Converted to Forest Land*.
[2] Estimates include C stock changes on both *Settlements Remaining Settlements* and *Land Converted to Settlements*.

Emissions from Land Use, Land-Use Change, and Forestry are shown in Table 7-3 and Table 7-4. Liming of agricultural soils and urea fertilization in 2009 resulted in CO_2 emissions of 4.2 Tg CO_2 Eq. (4,221 Gg) and 3.6 Tg CO_2 Eq. (3,612 Gg), respectively. Lands undergoing peat extraction (i.e., *Peatlands Remaining Peatlands*) resulted in CO_2 emissions of 1.1 Tg CO_2 Eq. (1,090 Gg), and nitrous oxide (N_2O) emissions of less than 0.05 Tg CO_2 Eq. The application of synthetic fertilizers to forest soils in 2009 resulted in direct N_2O emissions of 0.4 Tg CO_2 Eq. (1 Gg). Direct N_2O emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, direct N_2O emissions from fertilizer application to settlement soils in 2009 accounted for 1.5 Tg CO_2 Eq. (5 Gg) in 2009. This represents an increase of 55 percent since 1990. Forest fires in 2009 resulted in methane (CH_4) emissions of 7.8 Tg CO_2 Eq. (372 Gg), and in N_2O emissions of 6.4 Tg CO_2 Eq. (21 Gg).

Table 7-3: Emissions from Land Use, Land-Use Change, and Forestry (Tg CO_2 Eq.)

Source Category	1990	2000	2005	2006	2007	2008	2009
CO_2	**8.1**	**8.8**	**8.9**	**8.8**	**9.2**	**9.6**	**8.9**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2
Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
CH_4	**3.2**	**14.3**	**9.8**	**21.6**	**20.0**	**11.9**	**7.8**
Forest Land Remaining Forest Land: Forest Fires	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N_2O	**3.7**	**13.2**	**9.8**	**19.5**	**18.3**	**11.6**	**8.3**
Forest Land Remaining Forest Land: Forest Fires	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Forest Land Remaining Forest Land: Forest Soils[1]	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils[2]	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**15.0**	**36.3**	**28.6**	**49.8**	**47.5**	**33.2**	**25.0**

+ Less than 0.05 Tg CO_2 Eq.
Note: These estimates include direct emissions only. Indirect N_2O emissions are reported in the Agriculture chapter. Totals may

not sum due to independent rounding.
[1] Estimates include emissions from N fertilizer additions on both *Forest Land Remaining Forest Land*, and *Land Converted to Forest Land*, but not from land-use conversion.
[2] Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements*, and *Land Converted to Settlements*, but not from land-use conversion.

Table 7-4: Emissions from Land Use, Land-Use Change, and Forestry (Gg)

Source Category	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**8,117**	**8,768**	**8,933**	**8,754**	**9,214**	**9,646**	**8,922**
Cropland Remaining Cropland: Liming of Agricultural Soils	4,667	4,328	4,349	4,220	4,464	5,042	4,221
Urea Fertilization	2,417	3,214	3,504	3,656	3,738	3,612	3,612
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1,033	1,227	1,079	879	1,012	992	1,090
CH_4	**152**	**682**	**467**	**1,027**	**953**	**569**	**372**
Forest Land Remaining Forest Land: Forest Fires	152	682	467	1,027	953	569	372
N_2O	**12**	**43**	**32**	**63**	**59**	**37**	**27**
Forest Land Remaining Forest Land: Forest Fires	8	38	26	57	53	31	21
Forest Land Remaining Forest Land: Forest Soils[1]	+	1	1	1	1	1	1
Settlements Remaining Settlements: Settlement Soils[2]	3	4	5	5	5	5	5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+

+ Less than 0.5 Gg
Note: These estimates include direct emissions only. Indirect N_2O emissions are reported in the Agriculture chapter. Totals may not sum due to independent rounding.
[1] Estimates include emissions from N fertilizer additions on both *Forest Land Remaining Forest Land*, and *Land Converted to Forest Land*, but not from land-use conversion.
[2] Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements*, and *Land Converted to Settlements*, but not from land-use conversion.

[BEGIN BOX]

Box 7-1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the Intergovernmental Panel on Climate Change (IPCC).[157] Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[158] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

[END BOX]

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[157] See http://www.ipcc-nggip.iges.or.jp/public/index.html.

[158] See http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php.

7.1. Representation of the U.S. Land Base

A national land-use categorization system that is consistent and complete both temporally and spatially is needed in order to assess land use and land-use change status and the associated greenhouse gas fluxes over the inventory time series. This system should be consistent with IPCC (2006), such that all countries reporting on national greenhouse gas fluxes to the UNFCCC should (1) describe the methods and definitions used to determine areas of managed and unmanaged lands in the country, (2) describe and apply a consistent set of definitions for land-use categories over the entire national land base and time series associated with the greenhouse gas inventory, such that increases in the land areas within particular land-use categories are balanced by decreases in the land areas of other categories, and (3) account for greenhouse gas fluxes on all managed lands. The implementation of such a system helps to ensure that estimates of greenhouse gas fluxes are as accurate as possible. This section of the Inventory has been developed in order to comply with this guidance.

Multiple databases are used to track land management in the United States, which are also used as the basis to classify U.S. land area into the six IPCC land-use categories (i.e., *Forest Land Remaining Forest Land*, *Cropland Remaining Cropland*, *Grassland Remaining Grassland*, *Wetlands Remaining Wetlands*, *Settlements Remaining Settlements* and *Other Land Remaining Other Land*) and thirty land-use change categories (e.g., *Cropland Converted to Forest Land*, *Grassland Converted to Forest Land*, *Wetlands Converted to Forest Land*, *Settlements Converted to Forest Land*, *Other Land Converted to Forest Lands*)[159] (IPCC 2006). The primary databases are the U.S. Department of Agriculture (USDA) National Resources Inventory (NRI)[160] and the USDA Forest Service (USFS) Forest Inventory and Analysis (FIA)[161] Database. The U.S. Geological Survey (USGS) National Land Cover Dataset (NLCD)[162] is also used to identify land uses in regions that were not included in the NRI or FIA. The total land area included in the U.S. Inventory is 786 million hectares, and this entire land base is considered managed.[163] In 2009, the United States had a total of 274 million hectares of Forest Land (a 4 percent increase since 1990), 163 million hectares of Cropland (down 4.4 percent since 1990), 258 million hectares of Grassland (down 4.2 percent since 1990), 26 million hectares of Wetlands (down 4.9 percent since 1990), 49 million hectares of Settlements (up 24.5 percent since 1990), and 14 million hectares of Other Land. It is important to note that the land base formally classified for the Inventory (see Table 7-5) is considered managed. Alaska is not formally included in the current land representation, but there is a planned improvement underway to include this portion of the United States in future inventories. In addition, wetlands are not differentiated between managed and unmanaged, although some wetlands would be unmanaged according to the U.S. definition (see definition later in this section). Future improvements will include a differentiation between managed and unmanaged wetlands. In addition, carbon stock changes are not currently estimated for the entire land base, which leads to discrepancies between the area data presented here and in the subsequent sections of the NIR. Planned improvements are underway or in development phases to conduct an inventory of carbon stock changes on all managed land (e.g., federal grasslands).

Dominant land uses vary by region, largely due to climate patterns, soil types, geology, proximity to coastal regions, and historical settlement patterns, although all land-uses occur within each of the fifty states (Figure 7-1). Forest Land tends to be more common in the eastern states, mountainous regions of the western United States, and Alaska. Cropland is concentrated in the mid-continent region of the United States, and Grassland is more common in the western United States. Wetlands are fairly ubiquitous throughout the United States, though they are more common in the upper Midwest and eastern portions of the country. Settlements are more concentrated along the coastal margins and in the eastern states.

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[159] Land-use category definitions are provided in the Methodology section.

[160] NRI data is available at <http://www.ncgc.nrcs.usda.gov/products/nri/index.html>.

[161] FIA data is available at <http://fia.fs.fed .us/tools-data/data/>.

[162] NLCD data is available at <http://www.mrlc.gov/>.

[163] The current land representation does not include areas from Alaska or U.S. territories, but there are planned improvements to include these regions in future reports.

Table 7-5: Size of Land Use and Land-Use Change Categories on Managed Land Area by Land Use and Land Use Change Categories (thousands of hectares)

Land Use & Land-Use Change Categories[a]	1990	2000	2005	2006	2007	2008	2009
Total Forest Land	**263,878**	**268,790**	**271,322**	**272,107**	**272,891**	**273,677**	**274,462**
FF	257,180	253,080	255,444	256,181	256,917	257,655	258,392
CF	1,266	2,793	2,976	2,983	2,991	2,998	3,006
GF	4,879	11,347	11,122	11,157	11,193	11,229	11,264
WF	63	201	205	205	206	207	207
SF	101	268	303	304	305	306	307
OF	389	1,102	1,273	1,276	1,279	1,282	1,285
Total Cropland	**170,632**	**164,401**	**163,192**	**163,178**	**163,164**	**163,151**	**163,137**
CC	155,433	144,004	145,531	145,518	145,506	145,493	145,481
FC	1,105	1,101	805	804	803	802	802
GC	13,298	17,834	15,513	15,513	15,513	15,512	15,512
WC	163	264	234	234	234	234	234
SC	470	886	825	825	825	825	825
OC	162	311	283	283	283	283	283
Total Grassland	**269,643**	**263,092**	**260,565**	**260,012**	**259,458**	**258,904**	**258,350**
GG	260,064	245,460	243,839	243,395	242,951	242,506	242,061
FG	1,463	3,048	2,787	2,773	2,759	2,745	2,730
CG	7,502	13,303	12,632	12,541	12,451	12,360	12,270
WG	230	373	339	338	338	337	336
SG	129	255	255	253	252	250	249
OG	255	653	714	712	709	706	704
Total Wetlands	**27,788**	**27,560**	**27,173**	**26,983**	**26,793**	**26,603**	**26,412**
WW	27,179	26,155	25,701	25,519	25,338	25,157	24,976
FW	138	378	401	398	395	393	390
CW	134	348	351	348	344	341	338
GW	286	633	675	672	670	668	665
SW	<1	3	3	3	3	3	3
OW	51	43	43	42	42	42	42
Total Settlements	**39,518**	**47,558**	**49,247**	**49,238**	**49,229**	**49,220**	**49,212**
SS	34,742	34,055	34,975	34,966	34,958	34,949	34,941
FS	1,842	5,480	5,872	5,872	5,872	5,871	5,871
CS	1,373	3,599	3,673	3,672	3,672	3,672	3,672
GS	1,498	4,183	4,479	4,479	4,479	4,479	4,479
WS	3	29	32	32	32	32	32
OS	60	212	217	217	217	217	217
Total Other Land	**14,385**	**14,443**	**14,346**	**14,327**	**14,309**	**14,290**	**14,272**
OO	13,397	12,286	12,104	12,087	12,069	12,051	12,033
FO	193	506	559	559	559	559	559
CO	279	440	499	499	499	499	499
GO	458	1,085	1,058	1,057	1,057	1,056	1,056
WO	55	115	114	114	114	114	113
SO	3	11	12	12	12	12	12
Grand Total	**785,845**	**785,845**	**785,845**	**785,845**	**785,845**	**785,845**	**785,845**

[a] The abbreviations are "F" for Forest Land, "C" for Cropland, "G" for Grassland, "W" for Wetlands, "S" for Settlements, and "O" for Other Lands. Lands remaining in the same land use category are identified with the land use abbreviation given twice (e.g., "FF" is Forest Land Remaining Forest Land), and land use change categories are identified with the previous land use abbreviation followed by the new land use abbreviation (e.g., "CF" is Cropland Converted to Forest Land).

Notes: All land areas reported in this table are considered managed. A planned improvement is underway to deal with an exception for wetlands which includes both managed and unmanaged lands based on the definitions for the current U.S. Land Representation Assessment. In addition, U.S. Territories have not been classified into land uses and are not included in the U.S. Land Representation Assessment. See Planned Improvements for discussion on plans to include Alaska and territories in future Inventories.

Figure 7-1. Percent of Total Land Area in the General Land-Use Categories for 2009

Methodology

IPCC Approaches for Representing Land Areas

IPCC (2006) describes three approaches for representing land areas. Approach 1 provides data on the total area for each individual land-use category, but does not provide detailed information on changes of area between categories and is not spatially explicit other than at the national or regional level. With Approach 1, total net conversions between categories can be detected, but not the individual changes between the land-use categories that led to those net changes. Approach 2 introduces tracking of individual land-use changes between the categories (e.g., Forest Land to Cropland, Cropland to Forest Land, Grassland to Cropland, etc.), using surveys or other forms of data that do not provide location data on specific parcels of land. Approach 3 extends Approach 2 by providing location data on specific parcels of land, such as maps, along with the land-use history. The three approaches are not presented as hierarchical tiers and are not mutually exclusive.

According to IPCC (2006), the approach or mix of approaches selected by an inventory agency should reflect calculation needs and national circumstances. For this analysis, the NRI, FIA, and the NLCD have been combined to provide a complete representation of land use for managed lands. These data sources are described in more detail later in this section. All of these datasets have a spatially-explicit time series of land-use data, and therefore Approach 3 is used to provide a full representation of land use in the U.S. Inventory. Lands are treated as remaining in the same category (e.g., *Cropland Remaining Cropland*) if a land-use change has not occurred in the last 20 years. Otherwise, the land is classified in a land-use-change category based on the current use and most recent use before conversion to the current use (e.g., *Cropland Converted to Forest Land*).

Definitions of Land Use in the United States

Managed and Unmanaged Land

The U.S. definitions of managed and unmanaged lands are similar to the basic IPCC (2006) definition of managed land, but with some additional elaboration to reflect national circumstances. Based on the following definitions, most lands in the United States are classified as managed:

- *Managed Land*: Land is considered managed if direct human intervention has influenced its condition. Direct intervention includes altering or maintaining the condition of the land to produce commercial or non-commercial products or services; to serve as transportation corridors or locations for buildings, landfills, or other developed areas for commercial or non-commercial purposes; to extract resources or facilitate acquisition of resources; or to provide social functions for personal, community or societal objectives. Managed land also includes legal protection of lands (e.g., wilderness, preserves, parks, etc.) for conservation purposes (i.e., meets societal objectives).[164]
- *Unmanaged Land*: All other land is considered unmanaged. Unmanaged land is largely comprised of areas inaccessible to human intervention due to the remoteness of the locations, or lands with essentially no development interest or protection due to limited personal, commercial or social value. Though these lands may be influenced indirectly by human actions such as atmospheric deposition of chemical species

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[164] Wetlands are an exception to this general definition, because these lands, as specified by IPCC (2006), are only considered managed if they are created through human activity, such as dam construction, or the water level is artificially altered by human activity. Distinguishing between managed and unmanaged wetlands is difficult, however, due to limited data availability. Wetlands are not characterized by use within the NRI. Therefore, unless wetlands are managed for cropland or grassland, it is not possible to know if they are artificially created or if the water table is managed based on the use of NRI data. See the Planned Improvements section of the Inventory for work being done to refine the Wetland area estimates.

produced in industry, they are not influenced by a direct human intervention.[165]

Land-Use Categories

As with the definition of managed lands, IPCC (2006) provides general non-prescriptive definitions for the six main land-use categories: Forest Land, Cropland, Grassland, Wetlands, Settlements and Other Land. In order to reflect U.S. circumstances, country-specific definitions have been developed, based predominantly on criteria used in the land-use surveys for the United States. Specifically, the definition of Forest Land is based on the FIA definition of forest,[166] while definitions of Cropland, Grassland, and Settlements are based on the NRI.[167] The definitions for Other Land and Wetlands are based on the IPCC (2006) definitions for these categories.

- *Forest Land*: A land-use category that includes areas at least 36.6 m wide and 0.4 ha in size with at least 10 percent cover (or equivalent stocking) by live trees of any size, including land that formerly had such tree cover and that will be naturally or artificially regenerated. Forest land includes transition zones, such as areas between forest and non-forest lands that have at least 10 percent cover (or equivalent stocking) with live trees and forest areas adjacent to urban and built-up lands. Roadside, streamside, and shelterbelt strips of trees must have a crown width of at least 36.6 m and continuous length of at least 110.6 m to qualify as forest land. Unimproved roads and trails, streams, and clearings in forest areas are classified as forest if they are less than 36.6 m wide or 0.4 ha in size, otherwise they are excluded from Forest Land and classified as Settlements. Tree-covered areas in agricultural production settings, such as fruit orchards, or tree-covered areas in urban settings, such as city parks, are not considered forest land (Smith et al. 2009). NOTE: This definition applies to all U.S. lands and territories. However, at this time, data availability is limited for remote or inaccessible areas such as interior Alaska
- *Cropland*: A land-use category that includes areas used for the production of adapted crops for harvest; this category includes both cultivated and non-cultivated lands.[168] Cultivated crops include row crops or close-grown crops and also hay or pasture in rotation with cultivated crops. Non-cultivated cropland includes continuous hay, perennial crops (e.g., orchards) and horticultural cropland. Cropland also includes land with alley cropping and windbreaks,[169] as well as lands in temporary fallow or enrolled in conservation reserve programs (i.e., set-asides[170]). Roads through Cropland, including interstate highways, state highways, other paved roads, gravel roads, dirt roads, and railroads are excluded from Cropland area estimates and are, instead, classified as Settlements.
- *Grassland*: A land-use category on which the plant cover is composed principally of grasses, grass-like plants, forbs, or shrubs suitable for grazing and browsing, and includes both pastures and native rangelands.[171] This includes areas where practices such as clearing, burning, chaining, and/or chemicals are applied to maintain the grass vegetation. Savannas, some wetlands and deserts, in addition to tundra are considered Grassland.[172] Woody plant communities of low forbs and shrubs, such as mesquite, chaparral, mountain shrub, and pinyon-juniper, are also classified as Grassland if they do not meet the criteria for Forest Land. Grassland includes land managed with agroforestry practices such as silvipasture and windbreaks, assuming the stand or woodlot does not meet the criteria for Forest Land. Roads through

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[165] There will be some areas that qualify as Forest Land or Grassland according to the land use criteria, but are classified as unmanaged land due to the remoteness of their location.

[166] See <http://socrates.lv-hrc.nevada.edu/fia/ab/issues/pending/glossary/Glossary_5_30_06.pdf>.

[167] See <http://www.nrcs.usda.gov/technical/land/nri01/glossary.html>.

[168] A minor portion of Cropland occurs on federal lands, and is not currently included in the C stock change inventory. A planned improvement is underway to include these areas in future C inventories.

[169] Currently, there is no data source to account for biomass C stock change associated with woody plant growth and losses in alley cropping systems and windbreaks in cropping systems, although these areas are included in the cropland land base.

[170] A set-aside is cropland that has been taken out of active cropping and converted to some type of vegetative cover, including, for example, native grasses or trees.

[171] Grasslands on federal lands are included in the managed land base, but C stock changes are not estimated on these lands. Federal grassland areas have been assumed to have negligible changes in C due to limited land use and management change, but planned improvements are underway to further investigate this issue and include these areas in future C inventories.

[172] IPCC (2006) guidelines do not include provisions to separate desert and tundra as land categories.

Grassland, including interstate highways, state highways, other paved roads, gravel roads, dirt roads, and railroads are excluded from Grassland area estimates and are, instead, classified as Settlements.

- *Wetlands*: A land-use category that includes land covered or saturated by water for all or part of the year. Managed Wetlands are those where the water level is artificially changed, or were created by human activity. Certain areas that fall under the managed Wetlands definition are covered in other areas of the IPCC guidance and/or the inventory, including Cropland (e.g., rice cultivation), Grassland, and Forest Land (including drained or undrained forested wetlands).
- *Settlements*: A land-use category representing developed areas consisting of units of 0.25 acres (0.1 ha) or more that includes residential, industrial, commercial, and institutional land; construction sites; public administrative sites; railroad yards; cemeteries; airports; golf courses; sanitary landfills; sewage treatment plants; water control structures and spillways; parks within urban and built-up areas; and highways, railroads, and other transportation facilities. Also included are tracts of less than 10 acres (4.05 ha) that may meet the definitions for Forest Land, Cropland, Grassland, or Other Land but are completely surrounded by urban or built-up land, and so are included in the settlement category. Rural transportation corridors located within other land uses (e.g., Forest Land, Cropland) are also included in Settlements.
- *Other Land*: A land-use category that includes bare soil, rock, ice, non-settlement transportation corridors, and all land areas that do not fall into any of the other five land-use categories. It allows the total of identified land areas to match the managed national area.

Land-Use Data Sources: Description and Application to U.S. Land Area Classification

U.S. Land-Use Data Sources

The three main data sources for land area and use data in the United States are the NRI, FIA, and the NLCD. For the Inventory, the NRI is the official source of data on all land uses on non-federal lands (except forest land), and is also used as the resource to determine the total land base for the conterminous United States and Hawaii. The NRI is conducted by the USDA Natural Resources Conservation Service and is designed to assess soil, water, and related environmental resources on non-federal lands. The NRI has a stratified multi-stage sampling design, where primary sample units are stratified on the basis of county and township boundaries defined by the U.S. Public Land Survey (Nusser and Goebel 1997). Within a primary sample unit (typically a 160-acre [64.75 ha] square quarter-section), three sample points are selected according to a restricted randomization procedure. Each point in the survey is assigned an area weight (expansion factor) based on other known areas and land-use information (Nusser and Goebel 1997). The NRI survey utilizes data derived from remote sensing imagery and site visits in order to provide detailed information on land use and management, particularly for croplands and grasslands, and is used as the basis to account for C stock changes in agricultural lands (except federal Grasslands). The NRI survey was conducted every 5 years between 1982 and 1997, but shifted to annualized data collection in 1998. This Inventory incorporates data through 2003 from the NRI.

The FIA program, conducted by the USFS, is the official source of data on Forest Land area and management data for the Inventory. FIA engages in a hierarchical system of sampling, with sampling categorized as Phases 1 through 3, in which sample points for phases are subsets of the previous phase. Phase 1 refers to collection of remotely-sensed data (either aerial photographs or satellite imagery) primarily to classify land into forest or non-forest and to identify landscape patterns like fragmentation and urbanization. Phase 2 is the collection of field data on a network of ground plots that enable classification and summarization of area, tree, and other attributes associated with forest land uses. Phase 3 plots are a subset of Phase 2 plots where data on indicators of forest health are measured. Data from all three phases are also used to estimate C stock changes for forest land. Historically, FIA inventory surveys had been conducted periodically, with all plots in a state being measured at a frequency of every 5 to 14 years. A new national plot design and annual sampling design was introduced by FIA about ten years ago. Most states, though, have only recently been brought into this system. Annualized sampling means that a portion of plots throughout each state is sampled each year, with the goal of measuring all plots once every 5 years. See Annex 3.12 to see the specific survey data available by state. The most recent year of available data varies state by state (2002 through 2009).

Though NRI provides land-area data for both federal and non-federal lands, it only includes land-use data on non-federal lands, and FIA only records data for forest land.[173] Consequently, major gaps exist when the datasets are combined, such as federal grassland operated by the Bureau of Land Management (BLM), USDA, and National Park Service, as well as most of Alaska.[174] The NLCD is used as a supplementary database to account for land use on federal lands that are not included in the NRI and FIA databases. The NLCD land-cover classification scheme, available for 1992 and 2001, has been applied over the conterminous United States (Homer et al. 2007). The 2001 product also provides land use data that has been used for Hawaii federal lands. For this analysis, the NLCD Retrofit Land Cover Change Product was used in order to represent both land use and land-use change for federal lands in the conterminous U.S. (Homer et al. 2007). It is based primarily on Landsat Thematic Mapper imagery. The NLCD contains 21 categories of land-cover information, which have been aggregated into the IPCC land-use categories, and the data are available at a spatial resolution of 30 meters. The federal land portion of the NLCD was extracted from the dataset using the federal land area boundary map from the National Atlas (2005). This map represents federal land boundaries in 2005, so as part of the analysis, the federal land area was adjusted annually based on the NRI federal land area estimates (i.e., land is periodically transferred between federal and non-federal ownership). Consequently, the portion of the land base categorized with NLCD data varied from year to year, corresponding to an increase or decrease in the federal land base. The NLCD is strictly a source of land-cover information, however, and does not provide the necessary site conditions, crop types, and management information from which to estimate C stock changes on those lands.

Another step in the analysis is to address gaps as well as overlaps in the representation of the U.S. land base between the Agricultural Carbon Stock Inventory (*Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland*) and Forest Land Carbon Stock Inventory (*Forest Land Remaining Forest Land* and *Land Converted to Forest Land*), which are based on the NRI and FIA databases, respectively. NRI and FIA have different criteria for classifying forest land and sampling designs, leading to discrepancies in the resulting estimates of Forest Land area on non-federal land. Similarly, there are discrepancies between the NLCD and FIA data for defining and classifying Forest Land on federal lands. Moreover, dependence exists between the Forest Land area and the amount of land designated as other land uses in both the NRI and the NLCD, such as the amount of Grassland, Cropland, and Wetlands, relative to the Forest Land area. This results in inconsistencies among the three databases for estimated Forest Land area, as well as for the area estimates for other land-use categories. FIA is the main database for forest statistics, and consequently, the NRI and NLCD were adjusted to achieve consistency with FIA estimates of Forest Land. The adjustments were made at a state-scale, and it was assumed that the majority of the discrepancy in forest area was associated with an under- or over-prediction of Grassland and Wetland area in the NRI and NLCD due to differences in Forest Land definitions. Specifically, the Forest Land area for a given state according to the NRI and NLCD was adjusted to match the FIA estimates of Forest Land for non-federal and federal land, respectively. In a second step, corresponding increases or decreases were made in the area estimates of Grassland and Wetland from the NRI and NLCD, in order to balance the change in forest area, and therefore not change the overall amount of managed land within an individual state. The adjustments were based on the proportion of land within each of these land-use categories at the state-level. (i.e., a higher proportion of Grassland led to a larger adjustment in Grassland area).

As part of Quality Assurance /Quality Control (QA/QC), the land base derived from the NRI, FIA and NLCD was compared to the Topologically Integrated Geographic Encoding and Referencing (TIGER) survey (U.S. Census Bureau 2010). The U.S. Census Bureau gathers data on the U.S. population and economy, and has a database of land areas for the country. The land area estimates from the U.S. Census Bureau differ from those provided by the land-use surveys used in the Inventory because of discrepancies in the reporting approach for the census and the methods used in the NRI, FIA, and NLCD. The area estimates of land-use categories, based on NRI, FIA, and NLCD, are derived from remote sensing data instead of the land survey approach used by the U.S. Census Survey. More importantly, the U.S. Census Survey does not provide a time series of land-use change data or land management information, which is critical for conducting emission inventories and is provided from the NRI and FIA surveys. Consequently, the U.S. Census Survey was not adopted as the official land area estimate for the Inventory. Rather, the NRI data were adopted because this database provides full coverage of land area and land use

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[173] FIA does collect some data on non-forest land use, but these are held in regional databases versus the national database. The status of these data is being investigated.

[174] The survey programs also do not include U.S. Territories with the exception of non-federal lands in Puerto Rico, which are included in the NRI survey. Furthermore, NLCD does not include coverage for U.S. Territories.

for the conterminous United States and Hawaii. Regardless, the total difference between the U.S. Census Survey and the data sources used in the Inventory is about 25 million hectares for the total land base of about 786 million hectares currently included in the Inventory, or a 3.1 percent difference. Much of this difference is associated with open waters in coastal regions and the Great Lakes. NRI does not include as much of the area of open waters in these regions as the U.S. Census Survey.

Approach for Combining Data Sources

The managed land base in the United States has been classified into the six IPCC land-use categories using definitions[175] developed to meet national circumstances, while adhering to IPCC (2006). In practice, the land was initially classified into a variety of land-use categories using the NRI, FIA and NLCD, and then aggregated into the thirty-six broad land use and land-use-change categories identified in IPCC (2006). Details on the approach used to combine data sources for each land use are described below as are the gaps that will be reconciled as part of ongoing planned improvements:

- *Forest Land*: Both non-federal and federal forest lands in both the continental United States and coastal Alaska are covered by FIA. FIA is used as the basis for both Forest Land area data as well as to estimate C stocks and fluxes on Forest Land. Interior Alaska is not currently surveyed by FIA, but NLCD has a new product for Alaska that will be incorporated into the assessment as a planned improvement for future reports. Forest Lands in U.S. territories are currently excluded from the analysis, but FIA surveys are currently being conducted on U.S. territories and will become available in the future. NRI is being used in the current report to provide Forest Land areas on non-federal lands in Hawaii. Currently, federal forest land in Hawaii is evaluated with the 2001 NLCD, but FIA data will be collected in Hawaii in the future.

- *Cropland*: Cropland is classified using the NRI, which covers all non-federal lands within 49 states (excluding Alaska), including state and local government-owned land as well as tribal lands. NRI is used as the basis for both Cropland area data as well as to estimate C stocks and fluxes on Cropland. Croplands in U.S. territories are excluded from both NRI data collection and the NLCD. NLCD has a new product for Alaska that will be incorporated into the assessment as a planned improvement for future reports.

- *Grassland*: Grassland on non-federal lands is classified using the NRI within 49 states (excluding Alaska), including state and local government-owned land as well as tribal lands. NRI is used as the basis for both Grassland area data as well as to estimate C stocks and fluxes on Grassland. U.S. territories are excluded from both NRI data collection and the current release of the NLCD product. Grassland on federal Bureau of Land Management lands, Department of Defense lands, National Parks and within USFS lands are covered by the NLCD. In addition, federal and non-federal grasslands in Alaska are currently excluded from the analysis, but NLCD has a new product for Alaska that will be incorporated into the assessment for future reports.

- *Wetlands*: NRI captures wetlands on non-federal lands within 49 states (excluding Alaska), while federal wetlands are covered by the NLCD. Alaska and U.S. territories are excluded. This currently includes both managed and unmanaged wetlands as no database has yet been applied to make this distinction. See Planned Improvements for details.

- *Settlements*: The NRI captures non-federal settlement area in 49 states (excluding Alaska). If areas of Forest Land or Grassland under 10 acres (4.05 ha) are contained within settlements or urban areas, they are classified as Settlements (urban) in the NRI database. If these parcels exceed the 10 acre (4.05 ha) threshold and are Grassland, they will be classified as such by NRI. Regardless of size, a forested area is classified as non-forest by FIA if it is located within an urban area. Settlements on federal lands are covered by NLCD. Settlements in U.S. territories are currently excluded from NRI and NLCD. NLCD has a new product for Alaska that will be incorporated into the assessment as a planned improvement for future reports.

- *Other Land*: Any land not falling into the other five land categories and, therefore, categorized as Other Land is classified using the NRI for non-federal areas in the 49 states (excluding Alaska) and NLCD for the federal lands. Other land in U.S. territories is excluded from the NLCD. NLCD has a new product for

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[175] Definitions are provided in the previous section.

Alaska that will be incorporated into the assessment as a planned improvement for future reports.

Some lands can be classified into one or more categories due to multiple uses that meet the criteria of more than one definition. However, a ranking has been developed for assignment priority in these cases. The ranking process is initiated by distinguishing between managed and unmanaged lands. The managed lands are then assigned, from highest to lowest priority, in the following manner:

Settlements > Cropland > Forest Land > Grassland > Wetlands > Other Land

Settlements are given the highest assignment priority because they are extremely heterogeneous with a mosaic of patches that include buildings, infrastructure and travel corridors, but also open grass areas, forest patches, riparian areas, and gardens. The latter examples could be classified as Grassland, Forest Land, Wetlands, and Cropland, respectively, but when located in close proximity to settlement areas they tend to be managed in a unique manner compared to non-settlement areas. Consequently, these areas are assigned to the Settlements land-use category. Cropland is given the second assignment priority, because cropping practices tend to dominate management activities on areas used to produce food, forage or fiber. The consequence of this ranking is that crops in rotation with grass will be classified as Cropland, and land with woody plant cover that is used to produce crops (e.g., orchards) is classified as Cropland, even though these areas may meet the definitions of Grassland or Forest Land, respectively. Similarly, Wetlands are considered Croplands if they are used for crop production, such as rice or cranberries. Forest Land occurs next in the priority assignment because traditional forestry practices tend to be the focus of the management activity in areas with woody plant cover that are not croplands (e.g., orchards) or settlements (e.g., housing subdivisions with significant tree cover). Grassland occurs next in the ranking, while Wetlands and Other Land complete the list.

The assignment priority does not reflect the level of importance for reporting greenhouse gas emissions and removals on managed land, but is intended to classify all areas into a single land use. Currently, the IPCC does not make provisions in the guidelines for assigning land to multiple uses. For example, a Wetland is classified as Forest Land if the area has sufficient tree cover to meet the stocking and stand size requirements. Similarly, Wetlands are classified as Cropland if they are used for crop production, such as rice or cranberries. In either case, emissions from Wetlands are included in the Inventory if human interventions are influencing emissions from Wetlands, in accordance with the guidance provided in IPCC (2006).

Recalculations Discussion

No major revisions were made to the time series for the current Inventory. However, new data were incorporated from FIA on forestland areas, which was used to make minor adjustments to the time series. FIA conducts a survey of plots annually so that each plot is visited every 5 years (Note: some states have not initiated the annual sampling regime, as discussed previously). Consequently, the time series is updated each year as new data are collected over the 5 year cycles.

Planned Improvements

Area data by land-use category are not estimated for major portions of Alaska or any of the U.S. territories. A key planned improvement is to incorporate land-use data from these areas into the Inventory. For Alaska, a new NLCD 2001 data product will be used to cover those land areas presently omitted. Fortunately, most of the managed land in the United States is included in the current land-use statistics, but a complete accounting is a key goal for the near future. Data sources will also be evaluated for representing land use on federal and non-federal lands in U.S. territories.

Additional work will be conducted to reconcile differences in Forest Land estimates between the NRI and FIA, evaluating the assumption that the majority of discrepancies in Forest Land areas are associated with an over- or under-estimation of Grassland and Wetland area. In some regions of the United States, a discrepancy in Forest Land areas between NRI and FIA may be associated with an over- or under-prediction of other land uses, and an analysis is planned to develop region-specific adjustments.

There are also other databases that may need to be reconciled with the NRI and NLCD datasets, particularly for Settlements and Wetlands. Urban area estimates, used to produce C stock and flux estimates from urban trees, are currently based on population data (1990 and 2000 U.S. Census data). Using the population statistics, “urban clusters” are defined as areas with more than 500 people per square mile. The USFS is currently moving ahead with an urban forest inventory program so that urban forest area estimates will be consistent with FIA forest area estimates outside of urban areas, which would be expected to reduce omissions and overlap of forest area estimates along urban boundary areas.

7.2. Forest Land Remaining Forest Land

Changes in Forest Carbon Stocks (IPCC Source Category 5A1)

For estimating C stocks or stock change (flux), C in forest ecosystems can be divided into the following five storage pools (IPCC 2003):

- Aboveground biomass, which includes all living biomass above the soil including stem, stump, branches, bark, seeds, and foliage. This category includes live understory.
- Belowground biomass, which includes all living biomass of coarse living roots greater than 2 mm diameter.
- Dead wood, which includes all non-living woody biomass either standing, lying on the ground (but not including litter), or in the soil.
- Litter, which includes the litter, fumic, and humic layers, and all non-living biomass with a diameter less than 7.5 cm at transect intersection, lying on the ground.
- Soil organic C (SOC), including all organic material in soil to a depth of 1 meter but excluding the coarse roots of the aboveground pools.

In addition, there are two harvested wood pools necessary for estimating C flux:

- Harvested wood products (HWP) in use.
- HWP in solid waste disposal sites (SWDS).

C is continuously cycled among these storage pools and between forest ecosystems and the atmosphere as a result of biological processes in forests (e.g., photosynthesis, respiration, growth, mortality, decomposition, and disturbances such as fires or pest outbreaks) and anthropogenic activities (e.g., harvesting, thinning, clearing, and replanting). As trees photosynthesize and grow, C is removed from the atmosphere and stored in living tree biomass. As trees die and otherwise deposit litter and debris on the forest floor, C is released to the atmosphere or transferred to the soil by organisms that facilitate decomposition.

The net change in forest C is not equivalent to the net flux between forests and the atmosphere because timber harvests do not cause an immediate flux of C of all vegetation C to the atmosphere. Instead, harvesting transfers a portion of the C stored in wood to a "product pool." Once in a product pool, the C is emitted over time as CO_2 when the wood product combusts or decays. The rate of emission varies considerably among different product pools. For example, if timber is harvested to produce energy, combustion releases C immediately. Conversely, if timber is harvested and used as lumber in a house, it may be many decades or even centuries before the lumber decays and C is released to the atmosphere. If wood products are disposed of in SWDS, the C contained in the wood may be released many years or decades later, or may be stored almost permanently in the SWDS.

This section quantifies the net changes in C stocks in the five forest C pools and two harvested wood pools. The net change in stocks for each pool is estimated, and then the changes in stocks are summed over all pools to estimate total net flux. The focus on C implies that all C-based greenhouse gases are included, and the focus on stock change suggests that specific ecosystem fluxes do not need to be separately itemized in this report. Disturbances from forest fires and pest outbreaks are implicitly included in the net changes. For instance, an inventory conducted after fire counts only the trees that are left. The change between inventories thus accounts for the C changes due to fires; however, it may not be possible to attribute the changes to the disturbance specifically. The IPCC (2003) recommends reporting C stocks according to several land-use types and conversions, specifically *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*. Currently, consistent datasets are just becoming available for the conterminous United States to allow forest land conversions and forest land remaining forest land to be identified, and research is ongoing to properly use that information based on research results. Thus, net changes in all forest-related land, including non-forest land converted to forest and forests converted to non-forest, are reported here.

Forest C storage pools, and the flows between them via emissions, sequestration, and transfers, are shown in Figure 7-2. In the figure, boxes represent forest C storage pools and arrows represent flows between storage pools or between storage pools and the atmosphere. Note that the boxes are not identical to the storage pools identified in this chapter. The storage pools identified in this chapter have been refined in this graphic to better illustrate the processes that result in transfers of C from one pool to another, and emissions to as well as uptake from the atmosphere.

Figure 7-2: Forest Sector Carbon Pools and Flows

Approximately 33 percent (304 million hectares) of the U.S. land area is forested (Smith et al. 2009). The current forest carbon inventory includes 271 million hectares in the conterminous 48 states (USDA Forest Service 2010a, 2010b) that are considered managed and are included in this inventory. An additional 6.1 million hectares of southeast and south central Alaskan forest are inventoried and are included here. Three notable differences exist in forest land defined in Smith et al. (2009) and the forest land included in this report, which is based on USDA Forest Service (2010b). Survey data are not yet available from Hawaii and a large portion of interior Alaska, but estimates of these areas are included in Smith et al. (2009). Alternately, survey data for west Texas has only recently become available, and these forests contribute to overall carbon stock reported below. While Hawaii and U.S. territories have relatively small areas of forest land and will thus probably not influence the overall C budget substantially, these regions will be added to the C budget as sufficient data become available. Agroforestry systems are also not currently accounted for in the inventory, since they are not explicitly inventoried by either the Forest Inventory and Analysis (FIA) program of the U.S. Department of Agriculture (USDA) Forest Service or the National Resources Inventory (NRI) of the USDA Natural Resources Conservation Service (Perry et al. 2005).

Sixty-eight percent of U.S. forests (208 million hectares) are classified as timberland, meaning they meet minimum levels of productivity. Nine percent of Alaska forests overall and 81 percent of forests in the conterminous United States are classified as timberlands. Of the remaining nontimberland forests, 30 million hectares are reserved forest lands (withdrawn by law from management for production of wood products) and 66 million hectares are lower productivity forest lands (Smith et al. 2009). Historically, the timberlands in the conterminous 48 states have been more frequently or intensively surveyed than other forest lands.

Forest land area declined by approximately 10 million hectares over the period from the early 1960s to the late 1980s. Since then, forest area has increased by about 12 million hectares. Current trends in forest area represent average annual change of less than 0.2 percent. Given the low rate of change in U.S. forest land area, the major influences on the current net C flux from forest land are management activities and the ongoing impacts of previous land-use changes. These activities affect the net flux of C by altering the amount of C stored in forest ecosystems. For example, intensified management of forests that leads to an increased rate of growth increases the eventual biomass density of the forest, thereby increasing the uptake of C.[176] Though harvesting forests removes much of the aboveground C, on average the volume of annual net growth nationwide is about 72 percent higher than the volume of annual removals on timberlands (Smith et al. 2009). The reversion of cropland to forest land increases C storage in biomass, forest floor, and soils. The net effects of forest management and the effects of land-use change involving forest land are captured in the estimates of C stocks and fluxes presented in this chapter.

In the United States, improved forest management practices, the regeneration of previously cleared forest areas, and timber harvesting and use have resulted in net uptake (i.e., net sequestration) of C each year from 1990 through 2009. The rate of forest clearing begun in the 17th century following European settlement had slowed by the late 19th century. Through the later part of the 20th century many areas of previously forested land in the United States were allowed to revert to forests or were actively reforested. The impacts of these land-use changes still influence C fluxes from these forest lands. More recently, the 1970s and 1980s saw a resurgence of federally-sponsored forest management programs (e.g., the Forestry Incentive Program) and soil conservation programs (e.g., the Conservation Reserve Program), which have focused on tree planting, improving timber management activities, combating soil erosion, and converting marginal cropland to forests. In addition to forest regeneration and management, forest

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[176] The term “biomass density” refers to the mass of live vegetation per unit area. It is usually measured on a dry-weight basis. Dry biomass is 50 percent C by weight.

harvests have also affected net C fluxes. Because most of the timber harvested from U.S. forests is used in wood products, and many discarded wood products are disposed of in SWDS rather than by incineration, significant quantities of C in harvested wood are transferred to long-term storage pools rather than being released rapidly to the atmosphere (Skog and Nicholson 1998, Skog 2008). The size of these long-term C storage pools has increased during the last century.

Changes in C stocks in U.S. forests and harvested wood were estimated to account for net sequestration of 863 Tg CO_2 Eq. (235 Tg C) in 2009 (Table 7-6, Table 7-7, and Table 7-8). In addition to the net accumulation of C in harvested wood pools, sequestration is a reflection of net forest growth and increasing forest area over this period. Overall, average C in forest ecosystem biomass (aboveground and belowground) increased from 67 to 73 Mg C/ha between 1990 and 2010 (see Annex 3-12 for average C densities by specific regions and forest types). Continuous, regular annual surveys are not available over the period for each state; therefore, estimates for non-survey years were derived by interpolation between known data points. Survey years vary from state to state, and national estimates are a composite of individual state surveys. Therefore, changes in sequestration over the interval 1990 to 2009 are the result of the sequences of new inventories for each state. C in forest ecosystem biomass had the greatest effect on total change through increases in C density and total forest land. Management practices that increase C stocks on forest land, as well as afforestation and reforestation efforts, influence the trends of increased C densities in forests and increased forest land in the United States.

The decline in net additions to HWP carbon stocks continued though 2009 from the recent high point in 2006. This is due to sharp declines in U.S. production of solidwood and paper products in 2009 primarily due to the decline in housing construction. The low level of gross additions to solidwood and paper products in use in 2009 was exceeded by discards from uses. The result is a net reduction in the amount of HWP carbon that is held in products in use during 2009. For 2009, additions to landfills still exceeded emissions from landfills and the net additions to landfills have remained relatively stable. Overall, there were net carbon additions to HWP in use and in landfills combined in 2009.

Table 7-6: Net Annual Changes in C Stocks (Tg CO_2/yr) in Forest and Harvested Wood Pools

Carbon Pool	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Forest	**(549.3)**	**(265.4)**	**(806.1)**	**(808.9)**	**(808.9)**	**(808.9)**	**(808.9)**
Aboveground Biomass	(360.0)	(287.0)	(447.9)	(447.9)	(447.9)	(447.9)	(447.9)
Belowground Biomass	(70.9)	(57.5)	(88.4)	(88.4)	(88.4)	(88.4)	(88.4)
Dead Wood	(31.6)	(12.9)	(30.8)	(33.5)	(33.5)	(33.5)	(33.5)
Litter	(32.2)	27.5	(41.9)	(41.9)	(41.9)	(41.9)	(41.9)
Soil Organic Carbon	(54.7)	64.6	(197.2)	(197.2)	(197.2)	(197.2)	(197.2)
Harvested Wood	**(131.8)**	**(112.9)**	**(105.4)**	**(108.6)**	**(103.0)**	**(82.1)**	**(54.3)**
Products in Use	(64.8)	(47.0)	(45.4)	(45.1)	(39.1)	(19.1)	6.8
SWDS	(67.0)	(65.9)	(59.9)	(63.4)	(63.8)	(63.0)	(61.1)
Total Net Flux	**(681.1)**	**(378.3)**	**(911.5)**	**(917.5)**	**(911.9)**	**(891.0)**	**(863.1)**

Note: Forest C stocks do not include forest stocks in U.S. territories, Hawaii, a portion of managed forests in Alaska, or trees on non-forest land (e.g., urban trees, agroforestry systems). Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere). Total net flux is an estimate of the actual net flux between the total forest C pool and the atmosphere. Forest area estimates are based on interpolation and extrapolation of inventory data as described in the text and in Annex 3.12. Harvested wood estimates are based on results from annual surveys and models. Totals may not sum due to independent rounding.

Table 7-7: Net Annual Changes in C Stocks (Tg C/yr) in Forest and Harvested Wood Pools

Carbon Pool	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Forest	**(149.8)**	**(72.4)**	**(219.9)**	**(220.6)**	**(220.6)**	**(220.6)**	**(220.6)**
Aboveground Biomass	(98.2)	(78.3)	(122.1)	(122.1)	(122.1)	(122.1)	(122.1)
Belowground Biomass	(19.3)	(15.7)	(24.1)	(24.1)	(24.1)	(24.1)	(24.1)
Dead Wood	(8.6)	(3.5)	(8.4)	(9.1)	(9.1)	(9.1)	(9.1)

Litter	(8.8)	7.5	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)
Soil Organic C	(14.9)	17.6	(53.8)	(53.8)	(53.8)	(53.8)	(53.8)
Harvested Wood	**(35.9)**	**(30.8)**	**(28.7)**	**(29.6)**	**(28.1)**	**(22.4)**	**(14.8)**
Products in Use	(17.7)	(12.8)	(12.4)	(12.3)	(10.7)	(5.2)	1.9
SWDS	(18.3)	(18.0)	(16.3)	(17.3)	(17.4)	(17.2)	(16.7)
Total Net Flux	**(185.7)**	**(103.2)**	**(248.6)**	**(250.2)**	**(248.7)**	**(243.0)**	**(235.4)**

Note: Forest C stocks do not include forest stocks in U.S. territories, Hawaii, a portion of managed lands in Alaska, or trees on non-forest land (e.g., urban trees, agroforestry systems). Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere). Total net flux is an estimate of the actual net flux between the total forest C pool and the atmosphere. Harvested wood estimates are based on results from annual surveys and models. Totals may not sum due to independent rounding.

Stock estimates for forest and harvested wood C storage pools are presented in Table 7-8. Together, the aboveground live and forest soil pools account for a large proportion of total forest C stocks. C stocks in all non-soil pools increased over time. Therefore, C sequestration was greater than C emissions from forests, as discussed above. Figure 7-4 shows county-average C densities for live trees on forest land, including both above- and belowground biomass.

Table 7-8: Forest area (1000 ha) and C Stocks (Tg C) in Forest and Harvested Wood Pools

	1990	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Forest Area (1000 ha)	**269,137**	**274,183**	**276,769**	**277,561**	**278,354**	**279,147**	**279,939**	**280,732**
Carbon Pools (Tg C)								
Forest	**42,783**	**44,108**	**44,886**	**45,105**	**45,326**	**45,547**	**45,767**	**45,988**
Aboveground Biomass	15,072	16,024	16,536	16,658	16,780	16,902	17,024	17,147
Belowground Biomass	2,995	3,183	3,285	3,309	3,333	3,357	3,381	3,405
Dead Wood	2,960	3,031	3,060	3,068	3,077	3,086	3,096	3,105
Litter	4,791	4,845	4,862	4,873	4,885	4,896	4,908	4,919
Soil Organic C	16,96	17,025	17,143	17,197	17,251	17,304	17,358	17,412
Harvested Wood	**1,859**	**2,187**	**2,325**	**2,354**	**2,383**	**2,412**	**2,434**	**2,449**
Products in Use	1,231	1,382	1,436	1,448	1,460	1,471	1,476	1,474
SWDS	628	805	890	906	923	941	958	974
Total C Stock	**44,643**	**46,296**	**47,211**	**47,459**	**47,710**	**47,958**	**48,201**	**48,437**

Note: Forest area estimates include portions of managed forests in Alaska for which survey data are available. Forest C stocks do not include forest stocks in U.S. territories, Hawaii, a large portion of Alaska, or trees on non-forest land (e.g., urban trees, agroforestry systems). Wood product stocks include exports, even if the logs are processed in other countries, and exclude imports. Forest area estimates are based on interpolation and extrapolation of inventory data as described in Smith et al. (2010) and in Annex 3.12. Harvested wood estimates are based on results from annual surveys and models. Totals may not sum due to independent rounding. Inventories are assumed to represent stocks as of January 1 of the inventory year. Flux is the net annual change in stock. Thus, an estimate of flux for 2006 requires estimates of C stocks for 2006 and 2007.

Figure 7-3: Estimates of Net Annual Changes in C Stocks for Major C Pools

Figure 7-4: Average C Density in the Forest Tree Pool in the Conterminous United States, 2009

[BEGIN BOX]

Box 7-2: CO_2 Emissions from Forest Fires

As stated previously, the forest inventory approach implicitly accounts for emissions due to disturbances such as forest fires, because only C remaining in the forest is estimated. Net C stock change is estimated by subtracting consecutive C stock estimates. A disturbance removes C from the forest. The inventory data on which net C stock estimates are based already reflect this C loss. Therefore, estimates of net annual changes in C stocks for U.S. forestland already account for CO_2 emissions from forest fires occurring in the lower 48 states as well as in the proportion of Alaska's managed forest land captured in this inventory. Because it is of interest to quantify the magnitude of CO_2 emissions from fire disturbance, these estimates are being highlighted here, using the full extent of available data. Non-CO_2 greenhouse gas emissions from forest fires are also quantified in a separate section below.

The IPCC (2003) methodology and IPCC (2006) default combustion factor for wildfire were employed to estimate CO_2 emissions from forest fires. CO_2 emissions for wildfires and prescribed fires in the lower 48 states and wildfires in Alaska in 2009 were estimated to be 124.3 Tg CO_2/yr. This amount is masked in the estimate of net annual forest carbon stock change for 2009, however, because this net estimate accounts for the amount sequestered minus any emissions.

Table 7-9: Estimates of CO_2 (Tg/yr) emissions for the lower 48 states and Alaska[1]

Year	CO_2 emitted from Wildfires in Lower 48 States (Tg/yr)	CO_2 emitted from Prescribed Fires in Lower 48 States (Tg/yr)	CO_2 emitted from Wildfires in Alaska (Tg/yr)	Total CO_2 emitted (Tg/yr)
1990	42.1	8.5	+	50.7
2000	225.1	2.1	+	227.3
2005	131.0	24.8	+	155.9
2006	313.6	29.3	+	342.9
2007	284.1	34.0	+	318.1
2008	169.0	20.8	+	189.8
2009	97.1	27.3	+	124.3

+ Does not exceed 0.05 Tg CO_2 Eq.

[1] Note that these emissions have already been accounted for in the estimates of net annual changes in C stocks, which account for the amount sequestered minus any emissions.

[END BOX]

Methodology and Data Sources

The methodology described herein is consistent with IPCC (2003, 2006) and IPCC/UNEP/OECD/IEA (1997). Forest ecosystem C stocks and net annual C stock change are determined according to stock-difference methods, which involve applying C estimation factors to forest inventory data and interpolating between successive inventory-based estimates of C stocks. Harvested wood C estimates are based on factors such as the allocation of wood to various primary and end-use products as well as half-life (the time at which half of amount placed in use will have been discarded from use) and expected disposition (e.g., product pool, SWDS, combustion). An overview of the different methodologies and data sources used to estimate the C in forest ecosystems or harvested wood products is provided here. See Annex 3.12 for details and additional information related to the methods and data.

Forest Ecosystem Carbon from Forest Inventory

Forest ecosystem stock and flux estimates are based on the stock-difference method and calculations for all estimates are in units of C. Separate estimates are made for the five IPCC C storage pools described above. All estimates are based on data collected from the extensive array of permanent forest inventory plots in the United States as well as models employed to fill gaps in field data. Carbon conversion factors are applied at the disaggregated level of each inventory plot and then appropriately expanded to population estimates. A combination of tiers as outlined by IPCC (2006) is used. The Tier 3 biomass C values are from forest inventory tree-level data. The Tier 2 dead organic and soil C pools are based on empirical or process models from the inventory data. All carbon conversion factors are specific to regions or individual states within the U.S., which are further classified according to characteristic forest types within each region.

The first step in developing forest ecosystem estimates is to identify useful inventory data and resolve any inconsistencies among datasets. Forest inventory data were obtained from the USDA Forest Service FIA program (Frayer and Furnival 1999, USDA Forest Service 2010b). Inventories include data collected on permanent inventory plots on forest lands[177] and are organized as a number of separate datasets, each representing a complete inventory, or survey, of an individual state at a specified time. Some of the more recent annual inventories reported for some states include "moving window" averages, which means that a portion—but not all—of the previous year's inventory is updated each year (USDA Forest Service 2010d). Forest C calculations are organized according to these state surveys, and the frequency of surveys varies by state. All available data sets are identified for each state starting with pre-1990 data, and all unique surveys are identified for stock and change calculations. Since C stock change is based on differences between successive surveys within each state, accurate estimates of net C flux thus depend on consistent representation of forest land between these successive inventories. In order to achieve this consistency from 1990 to the present, states are sometimes subdivided into sub-state areas where the sum of sub-state inventories produces the best whole-state representation of C change as discussed in Smith et al. (2010).

The principal FIA datasets employed are freely available for download at USDA Forest Service (2010b) as the Forest Inventory and Analysis Database (FIADB) Version 4.0. However, to achieve consistent representation (spatial and temporal), two other general sources of past FIA data are included as necessary. First, older FIA plot- and tree-level data—not in the current FIADB format—are used if available. Second, Resources Planning Act Assessment (RPA) databases, which are periodic, plot-level only, summaries of state inventories, are used mostly to provide the data at or before 1990. An additional forest inventory data source is the Integrated Database (IDB), which is a compilation of periodic forest inventory data from the 1990s for California, Oregon, and Washington (Waddell and Hiserote 2005). These data were identified by Heath et al. (submitted) as the most appropriate non-FIADB sources for these states and are included in this inventory. See USDA Forest Service (2010a) for information on current and older data as well as additional FIA Program features. A detailed list of the specific forest inventory data used in this inventory is in Annex 3.12.

Forest C stocks are estimated from inventory data by a collection of conversion factors and models (Birdsey and Heath 1995, Birdsey and Heath 2001, Heath et al. 2003, Smith et al. 2004, Smith et al. 2006), which have been formalized in an FIADB-to-carbon calculator (Smith et al. 2010). The conversion factors and model coefficients are categorized by region and forest type, and forest C stock estimates are calculated from application of these factors at the scale of FIA inventory plots. The results are estimates of C density (Mg C per hectare) for six forest ecosystem pools: live trees, standing dead trees, understory vegetation, down dead wood, forest floor, and soil organic matter. The six carbon pools used in the FIADB-to-carbon calculator are aggregated to the 5 carbon pools defined by IPCC (2006): aboveground biomass, belowground biomass, dead wood, litter, and soil organic matter. All non-soil pools except forest floor are separated into aboveground and belowground components. The live tree and understory C pools are pooled as biomass, and standing dead trees and down dead wood are pooled as dead wood, in accordance with IPCC (2006).

Once plot-level C stocks are calculated as C densities on *Forest Land Remaining Forest Land* for the five IPCC (2006) reporting pools, the stocks are expanded to population estimates according to methods appropriate to the respective inventory data (for example, see Bechtold and Patterson (2005)). These expanded C stock estimates are summed to state or sub-state total C stocks. Annualized estimates of C stocks are developed by using available FIA inventory data and interpolating or extrapolating to assign a C stock to each year in the 1990 through2010 time series. Flux, or net annual stock change, is estimated by calculating the difference between two successive years and applying the appropriate sign convention; net increases in ecosystem C are identified as negative flux. By convention, inventories are assigned to represent stocks as of January 1 of the inventory year; an estimate of flux for 1996 requires estimates of C stocks for 1996 and 1997, for example. Additional discussion of the use of FIA inventory data and the C conversion process is in Annex 3.12.

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[177] Forest land in the United States includes land that is at least 10 percent stocked with trees of any size. Timberland is the most productive type of forest land, which is on unreserved land and is producing or capable of producing crops of industrial wood.

Carbon in Biomass

Live tree C pools include aboveground and belowground (coarse root) biomass of live trees with diameter at diameter breast height (d.b.h.) of at least 2.54 cm at 1.37 m above the forest floor. Separate estimates are made for full-tree and aboveground-only biomass in order to estimate the belowground component. If inventory plots include data on individual trees, tree C is based on Jenkins et al. (2003) and is a function of species and diameter. Some inventory data do not provide measurements of individual trees; tree C in these plots is estimated from plot-level volume of merchantable wood, or growing-stock volume, of live trees, which is calculated from updates of Smith et al. (2003). These biomass conversion and expansion factors (BCEFs) are applied to about 3 percent of the inventory records, all of which are pre-1998 data. Some inventory data, particularly some of the older datasets, may not include sufficient information to calculate tree C because of incomplete or missing tree or volume data; C estimates for these plots are based on averages from similar, but more complete, inventory data. This applies to an additional 2 percent of inventory records, which represent older (pre-1998) non-timberlands.

Understory vegetation is a minor component of biomass, which is defined as all biomass of undergrowth plants in a forest, including woody shrubs and trees less than 2.54 cm d.b.h. In the current inventory, it is assumed that 10 percent of total understory C mass is belowground. Estimates of C density are based on information in Birdsey (1996). Understory frequently represents over 1 percent of C in biomass, but its contribution rarely exceeds 2 percent of the total.

Carbon in Dead Organic Matter

Dead organic matter is initially calculated as three separate pools with C stocks modeled from inventory data. Estimates are specific to regions and forest types within each region, and stratification of forest land for dead organic matter calculations is identical to that used for biomass through the state and sub-state use of FIA data as discussed above. The two components of dead wood—standing dead trees and down dead wood—are estimated separately. The standing dead tree C pools include aboveground and belowground (coarse root) mass and include trees of at least 2.54 cm d.b.h. Calculations are BCEF-like factors based on updates of Smith et al. (2003). Down dead wood is defined as pieces of dead wood greater than 7.5 cm diameter, at transect intersection, that are not attached to live or standing dead trees. Down dead wood includes stumps and roots of harvested trees. Ratios of down dead wood to live tree are used to estimate this quantity. Litter C is the pool of organic C (also known as duff, humus, and fine woody debris) above the mineral soil and includes woody fragments with diameters of up to 7.5 cm. Estimates are based on equations of Smith and Heath (2002).

Carbon in Forest Soil

Soil organic C (SOC) includes all organic material in soil to a depth of 1 meter but excludes the coarse roots of the biomass or dead wood pools. Estimates of SOC are based on the national STATSGO spatial database (USDA 1991), which includes region and soil type information. SOC determination is based on the general approach described by Amichev and Galbraith (2004). Links to FIA inventory data were developed with the assistance of the USDA Forest Service FIA Geospatial Service Center by overlaying FIA forest inventory plots on the soil C map. This method produced mean SOC densities stratified by region and forest type group. It did not provide separate estimates for mineral or organic soils but instead weighted their contribution to the overall average based on the relative amount of each within forest land. Thus, forest SOC is a function of species and location, and net change also depends on these two factors as total forest area changes. In this respect, SOC provides a country-specific reference stock for 1990-present, but it does not reflect effects of past land use.

Harvested Wood Carbon

Estimates of the HWP contribution to forest C sinks and emissions (hereafter called “HWP Contribution”) are based on methods described in Skog (2008) using the WOODCARB II model. These methods are based on IPCC (2006) guidance for estimating HWP C. IPCC (2006) provides methods that allow Parties to report HWP Contribution using one of several different accounting approaches: production, stock change and atmospheric flow, as well as a default method that assumes there is no change in HWP C stocks (see Annex 3.12 for more details about each approach). The United States uses the production accounting approach to report HWP Contribution. Under the production approach, C in exported wood is estimated as if it remains in the United States, and C in imported wood is not included in inventory estimates. Though reported U.S. HWP estimates are based on the production approach, estimates resulting from use of the two alternative approaches, the stock change and atmospheric flow approaches, are also presented for comparison (see Annex 3.12). Annual estimates of change are calculated by tracking the additions to and removals from the pool of products held in end uses (i.e., products in use such as housing or publications) and the pool of products held in solid waste disposal sites (SWDS).

Solidwood products added to pools include lumber and panels. End-use categories for solidwood include single and multifamily housing, alteration and repair of housing, and other end-uses. There is one product category and one end-use category for paper. Additions to and removals from pools are tracked beginning in 1900, with the exception that additions of softwood lumber to housing begins in 1800. Solidwood and paper product production and trade data are from USDA Forest Service and other sources (Hair and Ulrich 1963; Hair 1958; USDC Bureau of Census; 1976; Ulrich, 1985, 1989; Steer 1948; AF&PA 2006a 2006b; Howard 2003, 2007). Estimates for disposal of products reflect the change over time in the fraction of products discarded to SWDS (as opposed to burning or recycling) and the fraction of SWDS that are in sanitary landfills versus dumps.

There are five annual HWP variables that are used in varying combinations to estimate HWP Contribution using any one of the three main approaches listed above. These are:

(1A) annual change of C in wood and paper products in use in the United States,

(1B) annual change of C in wood and paper products in SWDS in the United States,

(2A) annual change of C in wood and paper products in use in the United States and other countries where the wood came from trees harvested in the United States,

(2B) annual change of C in wood and paper products in SWDS in the United States and other countries where the wood came from trees harvested in the United States,

(3) C in imports of wood, pulp, and paper to the United States,

(4) C in exports of wood, pulp and paper from the United States, and

(5) C in annual harvest of wood from forests in the United States.

The sum of variables 2A and 2B yields the estimate for HWP Contribution under the production accounting approach. A key assumption for estimating these variables is that products exported from the United States and held in pools in other countries have the same half lives for products in use, the same percentage of discarded products going to SWDS, and the same decay rates in SWDS as they would in the United States.

Uncertainty and Time Series Consistency

A quantitative uncertainty analysis placed bounds on current flux for forest ecosystems as well as C in harvested wood products through Monte Carlo simulation of the Methods described above and probabilistic sampling of C conversion factors and inventory data. See Annex 3.12 for additional information. The 2009 flux estimate for forest C stocks is estimated to be between -1,014 and -714 Tg CO_2 Eq. at a 95 percent confidence level. This includes a range of -662 to -959 Tg CO_2 Eq. in forest ecosystems and -69 to -41 Tg CO_2 Eq. for HWP.

Table 7-10: Tier 2 Quantitative Uncertainty Estimates for Net CO_2 Flux from Forest Land Remaining Forest Land: Changes in Forest C Stocks (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Flux Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Flux Estimate**[a]			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Forest Ecosystem	CO_2	(808.9)	(959.4)	(661.7)	-19%	-18%
Harvested Wood Products	CO_2	(54.3)	(68.6)	(41.0)	-27%	-24%
Total Forest	**CO_2**	**(863.1)**	**(1,014.4)**	**(713.9)**	**-18%**	**-17%**

Note: Parentheses indicate negative values or net sequestration.

[a] Range of flux estimates predicted by Monte Carlo stochastic simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

As discussed above, the FIA program has conducted consistent forest surveys based on extensive statistically-based sampling of most of the forest land in the conterminous United States, dating back to 1952. The main purpose of the FIA program has been to estimate areas, volume of growing stock, and timber products output and utilization factors. The FIA program includes numerous quality assurance and quality control (QA/QC) procedures, including calibration among field crews, duplicate surveys of some plots, and systematic checking of recorded data. Because of the statistically-based sampling, the large number of survey plots, and the quality of the data, the survey databases developed by the FIA program form a strong foundation for C stock estimates. Field sampling protocols, summary data, and detailed inventory databases are archived and are publicly available on the Internet (USDA Forest Service 2010d).

Many key calculations for estimating current forest C stocks based on FIA data were developed to fill data gaps in assessing forest carbon and have been in use for many years to produce national assessments of forest C stocks and stock changes (see additional discussion and citations in the Methodology section above and in Annex 3.12). General quality control procedures were used in performing calculations to estimate C stocks based on survey data. For example, the derived C datasets, which include inventory variables such as areas and volumes, were compared to standard inventory summaries such as the forest resource statistics of Smith et al. (2009) or selected population estimates generated from FIADB 4.0, which are available at an FIA internet site (USDA Forest Service 2009b). Agreement between the C datasets and the original inventories is important to verify accuracy of the data used. Finally, C stock estimates were compared with previous inventory report estimates to ensure that any differences could be explained by either new data or revised calculation methods (see the “Recalculations” discussion, below).

Estimates of the HWP variables and the HWP contribution under the production accounting approach use data from U.S. Census and USDA Forest Service surveys of production and trade. Factors to convert wood and paper to units C are based on estimates by industry and Forest Service published sources. The WOODCARB II model uses estimation methods suggested by IPCC (2006). Estimates of annual C change in solidwood and paper products in use were calibrated to meet two independent criteria. The first criterion is that the WOODCARB II model estimate of C in houses standing in 2001 needs to match an independent estimate of C in housing based on U.S. Census and USDA Forest Service survey data. Meeting the first criterion resulted in an estimated half life of about 80 years for single family housing built in the 1920s, which is confirmed by other U.S. Census data on housing. The second criterion is that the WOODCARB II model estimate of wood and paper being discarded to SWDS needs to match EPA estimates of discards each year over the period 1990 to 2000 (EPA 2006). These criteria help reduce uncertainty in estimates of annual change in C in products in use in the United States and, to a lesser degree, reduce uncertainty in estimates of annual change in C in products made from wood harvested in the United States. In addition, WOODCARB II landfill decay rates have been validated by ensuring that estimates of CH_4 emissions from landfills based on EPA (2006) data are reasonable in comparison with CH_4 estimates based on WOODCARB II landfill decay rates.

Recalculations Discussion

The basic models used to estimate forest ecosystem and HWP C stocks and change are unchanged from the previous Inventory (Smith et al. 2010, Skog 2008). Many of the state-level estimates for 1990 through the present are relatively similar to the values previously reported (EPA 2010). Recent forest inventory additions to the FIADB include newer annual inventory data for most states including Oklahoma, which had the effect of increasing overall net sequestration estimated for the interval from 2000 through 2008. An additional change to the FIADB was the addition of some older periodic inventories for some southern states; these were incorporated into the calculations but did not appreciably affect national trends. The addition of the IDB forest inventories for a part of the series for California, Oregon, and Washington did affect recalculations for those states and the United States as a whole; it tended to decrease net sequestration throughout the 1990 to 2008 interval. However, the decreased sequestration associated with the use of the IDB was offset by the increased sequestration associated with newer annual inventory data for the post-2000 interval.

Planned Improvements

The ongoing annual surveys by the FIA Program will improve precision of forest C estimates as new state surveys become available (USDA Forest Service 2010b), particularly in western states. The annual surveys will eventually include all states. To date, three states are not yet reporting any data from the annualized sampling design of FIA: Hawaii, New Mexico and Wyoming. Estimates for these states are currently based on older, periodic data. Hawaii and U.S. territories will also be included when appropriate forest C data are available. In addition, the more intensive sampling of down dead wood, litter, and soil organic C on some of the permanent FIA plots continues and will substantially improve resolution of C pools at the plot level for all U.S. forest land as this information becomes available (Woodall et al. in press). Improved resolution, incorporating more of Alaska's forests, and using annualized sampling data as it becomes available for those states currently not reporting are planned for future reporting.

As more information becomes available about historical land use, the ongoing effects of changes in land use and forest management will be better accounted for in estimates of soil C (Birdsey and Lewis 2003, Woodbury et al. 2006, Woodbury et al. 2007). Currently, soil C estimates are based on the assumption that soil C density depends only on broad forest type group, not on land-use history, but long-term residual effects on soil and forest floor C stocks are likely after land-use change. Estimates of such effects depend on identifying past land use changes associated with forest lands.

Similarly, agroforestry practices, such as windbreaks or riparian forest buffers along waterways, are not currently accounted for in the inventory. In order to properly account for the C stocks and fluxes associated with agroforestry, research will be needed that provides the basis and tools for including these plantings in a nation-wide inventory, as well as the means for entity-level reporting.

Non-CO_2 Emissions from Forest Fires

Emissions of non-CO_2 gases from forest fires were estimated using the default IPCC (2003) methodology incorporating default IPCC (2006) emissions factors and combustion factor for wildfires. Emissions from this source in 2009 were estimated to be 7.8 Tg CO_2 Eq**.** of CH_4 and 6.4 Tg CO_2 Eq. of N_2O, as shown in Table 7-11 and Table 7-12. The estimates of non-CO_2 emissions from forest fires account for wildfires in the lower 48 states and Alaska as well as prescribed fires in the lower 48 states.

Table 7-11: Estimated Non-CO_2 Emissions from Forest Fires (Tg CO_2 Eq.) for U.S. Forests[1]

Gas	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
CH_4	3.2		14.3		9.8	21.6	20.0	11.9	7.8
N_2O	2.6		11.7		8.0	17.6	16.3	9.8	6.4
Total	**5.8**		**26.0**		**17.8**	**39.2**	**36.3**	**21.7**	**14.2**

[1] Calculated based on C emission estimates in *Changes in Forest Carbon Stocks* and default factors in IPCC (2003, 2006).

Table 7-12: Estimated Non-CO_2 Emissions from Forest Fires (Gg Gas) for U.S. Forests[1]

Gas	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
CH_4	152		682		467	1,027	953	569	372
N_2O	8		38		26	57	53	31	21

[1] Calculated based on C emission estimates *in Changes in Forest Carbon Stocks* and default factors in IPCC (2003, 2006).

Methodology

The IPCC (2003) Tier 2 default methodology was used to calculate non-CO_2 emissions from forest fires. However, more up-to-date default emission factors from IPCC (2006) were converted into gas-specific emission ratios and incorporated into the methodology**.** Estimates of CH_4 and N_2O emissions were calculated by multiplying the total estimated CO_2 emitted from forest burned by the gas-specific emissions ratios. CO_2 emissions were estimated by multiplying total C emitted (Table 7-13) by the C to CO_2 conversion factor of 44/12 and by 92.8 percent, which is the estimated proportion of C emitted as CO_2 (Smith 2008a). The equations used were:

$$CH_4 \text{ Emissions} = (\text{C released}) \times 92.8\% \times (44/12) \times (CH_4 \text{ to } CO_2 \text{ emission ratio})$$

$$N_2O \text{ Emissions} = (\text{C released}) \times 92.8\% \times (44/12) \times (N_2O \text{ to } CO_2 \text{ emission ratio})$$

Estimates for C emitted from forest fires are the same estimates used to generate estimates of CO_2 presented earlier in Box 7-1. Estimates for C emitted include emissions from wildfires in both Alaska and the lower 48 states as well as emissions from prescribed fires in the lower 48 states only (based on expert judgment that prescribed fires only occur in the lower 48 states) (Smith 2008a). The IPCC (2006) default combustion factor of 0.45 for “all ‘other’ temperate forests” was applied in estimating C emitted from both wildfires and prescribed fires. See the explanation in Annex 3.12 for more details on the methodology used to estimate C emitted from forest fires.

Table 7-13: Estimated Carbon Released from Forest Fires for U.S. Forests

Year	C Emitted (Tg/yr)
1990	14.9
2000	66.8
2005	45.8
2006	100.8
2007	93.5
2008	55.8
2009	36.5

Uncertainty and Time-Series Consistency

Non-CO_2 gases emitted from forest fires depend on several variables, including: forest area for Alaska and the lower 48 states; average C densities for wildfires in Alaska, wildfires in the lower 48 states, and prescribed fires in the lower 48 states; emission ratios; and combustion factor values (proportion of biomass consumed by fire). To quantify the uncertainties for emissions from forest fires, a Monte Carlo (Tier 2) uncertainty analysis was performed using information about the uncertainty surrounding each of these variables. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-14.

Table 7-14: Tier 2 Quantitative Uncertainty Estimates of Non-CO_2 Emissions from Forest Fires in Forest Land Remaining Forest Land (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Non-CO_2 Emissions from Forest Fires	CH_4	7.8	2.2	19.2	-72%	+145%
Non-CO_2 Emissions from Forest Fires	N_2O	6.4	1.8	15.7	-72%	+145%

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

Tier 1 and Tier 2 QA/QC activities were conducted consistent with the U.S. QA/QC plan. Source-specific quality control measures for forest fires included checking input data, documentation, and calculations to ensure data were properly handled through the inventory process. Errors that were found during this process were corrected as necessary.

Recalculations Discussion

This is the second year in which non-CO_2 emissions were calculated using the 2006 IPCC default emission factors for CH_4 and N_2O instead of the 2003 IPCC default emission factors. These default emission factors were converted to CH_4 to CO_2 and N_2O to CO_2 emission ratios and then multiplied by CO_2 emissions to estimate CH_4 and N_2O emissions. The previous 2003 IPCC methodology provides emission ratios that are multiplied by total carbon emitted.

Planned Improvements

The default combustion factor of 0.45 from IPCC (2006) was applied in estimating C emitted from both wildfires and prescribed fires. Additional research into the availability of a combustion factor specific to prescribed fires is being conducted.

Direct N_2O Fluxes from Forest Soils (IPCC Source Category 5A1)

Of the synthetic N fertilizers applied to soils in the United States, no more than one percent is applied to forest soils. Application rates are similar to those occurring on cropped soils, but in any given year, only a small proportion of total forested land receives N fertilizer. This is because forests are typically fertilized only twice during their approximately 40-year growth cycle (once at planting and once approximately 20 years later). Thus, while the rate of N fertilizer application for the area of forests that receives N fertilizer in any given year is relatively high, the average annual application is quite low as inferred by dividing all forest land that may undergo N fertilization at some point during its growing cycle by the amount of N fertilizer added to these forests in a given year. Direct N_2O emissions from forest soils in 2009 were 0.4 Tg CO_2 Eq. (1 Gg). Emissions have increased by 455 percent from 1990 to 2009 as a result of an increase in the area of N fertilized pine plantations in the southeastern United States and Douglas-fir timberland in western Washington and Oregon. Total forest soil N_2O emissions are summarized in Table 7-15.

Table 7-15: Direct N_2O Fluxes from Soils in *Forest Land Remaining Forest Land* (Tg CO_2 Eq. and Gg N_2O)

Year	Tg CO_2 Eq.	Gg
1990	0.1	0.2
2000	0.4	1.3
2005	0.4	1.2
2006	0.4	1.2
2007	0.4	1.2
2008	0.4	1.2
2009	0.4	1.2

Note: These estimates include direct N_2O emissions from N fertilizer additions only. Indirect N_2O emissions from fertilizer additions are reported in the Agriculture chapter. These estimates include emissions from both *Forest Land Remaining Forest Land* and from *Land Converted to Forest Land*.

Methodology

The IPCC Tier 1 approach was used to estimate N_2O from soils within *Forest Land Remaining Forest Land*. According to U.S. Forest Service statistics for 1996 (USDA Forest Service 2001), approximately 75 percent of trees planted were for timber, and about 60 percent of national total harvested forest area is in the southeastern United States. Although southeastern pine plantations represent the majority of fertilized forests in the United States, this Inventory also accounted for N fertilizer application to commercial Douglas-fir stands in western Oregon and Washington. For the Southeast, estimates of direct N_2O emissions from fertilizer applications to forests were based on the area of pine plantations receiving fertilizer in the southeastern United States and estimated application rates (Albaugh et al. 2007). Not accounting for fertilizer applied to non-pine plantations is justified because fertilization is routine for pine forests but rare for hardwoods (Binkley et al. 1995). For each year, the area of pine receiving N fertilizer was multiplied by the weighted average of the reported range of N fertilization rates (121 lbs. N per acre). Area data for pine plantations receiving fertilizer in the Southeast were not available for 2005, 2006, 2007 and 2008, so data from 2004 were used for these years. For commercial forests in Oregon and Washington, only fertilizer applied to Douglas-fir was accounted for, because the vast majority (~95 percent) of the total fertilizer applied to forests in this region is applied to Douglas-fir (Briggs 2007). Estimates of total Douglas-fir area and the portion of fertilized area were multiplied to obtain annual area estimates of fertilized Douglas-fir stands. The annual area estimates were multiplied by the typical rate used in this region (200 lbs. N per acre) to estimate total N applied (Briggs 2007), and the total N applied to forests was multiplied by the IPCC (2006) default emission factor of 1 percent to estimate direct N_2O emissions. The volatilization and leaching/runoff N fractions for forest land, calculated according to the IPCC default factors of 10 percent and 30 percent, respectively, were included with the indirect emissions in the Agricultural Soil Management source category (consistent with reporting guidance that all indirect emissions are included in the Agricultural Soil Management source category).

Uncertainty and Time-Series Consistency

The amount of N_2O emitted from forests depends not only on N inputs and fertilized area, but also on a large number of variables, including organic C availability, oxygen gas partial pressure, soil moisture content, pH, temperature, and tree planting/harvesting cycles. The effect of the combined interaction of these variables on N_2O flux is complex and highly uncertain. IPCC (2006) does not incorporate any of these variables into the default methodology, except variation in estimated fertilizer application rates and estimated areas of forested land receiving N fertilizer. All forest soils are treated equivalently under this methodology. Furthermore, only synthetic N fertilizers are captured, so applications of organic N fertilizers are not estimated. However, the total quantity of organic N inputs to soils is included in the Agricultural Soil Management and *Settlements Remaining Settlements* sections.

Uncertainties exist in the fertilization rates, annual area of forest lands receiving fertilizer, and the emission factors. Fertilization rates were assigned a default level[178] of uncertainty at ±50 percent, and area receiving fertilizer was assigned a ±20 percent according to expert knowledge (Binkley 2004). IPCC (2006) provided estimates for the uncertainty associated with direct N_2O emission factor for synthetic N fertilizer application to soils. Quantitative uncertainty of this source category was estimated through the IPCC-recommended Tier 2 uncertainty estimation methodology. The uncertainty ranges around the 2005 activity data and emission factor input variables were directly applied to the 2009 emissions estimates. The results of the quantitative uncertainty analysis are summarized in Table 7-16. N_2O fluxes from soils were estimated to be between 0.1 and 1.1 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 59 percent below and 211 percent above the 2009 emission estimate of 0.4 Tg CO_2 Eq.

Table 7-16: Quantitative Uncertainty Estimates of N_2O Fluxes from Soils in *Forest Land Remaining Forest Land* (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Forest Land Remaining Forest Land: N_2O Fluxes from Soils	N_2O	0.4	0.1	1.1	-59%	+211%

Note: This estimate includes direct N_2O emissions from N fertilizer additions to both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*.

Planned Improvements

State-level area data will be acquired for southeastern pine plantations and northwestern Douglas-fir forests receiving fertilizer to estimate soil N_2O emission by state and provide information about regional variation in emission patterns.

7.3. Land Converted to Forest Land (IPCC Source Category 5A2)

Land-use change is constantly occurring, and areas under a number of differing land-use types are converted to forest each year, just as forest land is converted to other uses. However, the magnitude of these changes is not currently known. Given the paucity of available land-use information relevant to this particular IPCC source category, it is not possible to separate CO_2 or N_2O fluxes on *Land Converted to Forest Land* from fluxes on *Forest Land Remaining Forest Land* at this time.

7.4. Cropland Remaining Cropland (IPCC Source Category 5B1)

Mineral and Organic Soil Carbon Stock Changes

Soils contain both organic and inorganic forms of C, but soil organic C (SOC) stocks are the main source and sink for atmospheric CO_2 in most soils. Changes in inorganic C stocks are typically minor. In addition, soil organic C is

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[178] Uncertainty is unknown for the fertilization rates so a conservative value of ±50% was used in the analysis.

the dominant organic C pool in cropland ecosystems, because biomass and dead organic matter have considerably less C and those pools are relatively ephemeral. IPCC (2006) recommends reporting changes in soil organic C stocks due to agricultural land-use and management activities on mineral and organic soils.[179]

Typical well-drained mineral soils contain from 1 to 6 percent organic C by weight, although mineral soils that are saturated with water for substantial periods during the year may contain significantly more C (NRCS 1999). Conversion of mineral soils from their native state to agricultural uses can cause as much as half of the SOC to be decomposed and the C lost to the atmosphere. The rate and ultimate magnitude of C loss will depend on pre-conversion conditions, conversion method and subsequent management practices, climate, and soil type. In the tropics, 40 to 60 percent of the C loss generally occurs within the first 10 years following conversion; C stocks continue to decline in subsequent decades but at a much slower rate. In temperate regions, C loss can continue for several decades, reducing stocks by 20 to 40 percent of native C levels. Eventually, the soil can reach a new equilibrium that reflects a balance between C inputs (e.g., decayed plant matter, roots, and organic amendments such as manure and crop residues) and C loss through microbial decomposition of organic matter. However, land use, management, and other conditions may change before the new equilibrium is reached. The quantity and quality of organic matter inputs and their rate of decomposition are determined by the combined interaction of climate, soil properties, and land use. Land use and agricultural practices such as clearing, drainage, tillage, planting, grazing, crop residue management, fertilization, and flooding can modify both organic matter inputs and decomposition, and thereby result in a net flux of C to or from the pool of soil C.

Organic soils, also referred to as histosols, include all soils with more than 12 to 20 percent organic C by weight, depending on clay content (NRCS 1999, Brady and Weil 1999). The organic layer of these soils can be very deep (i.e., several meters), forming under inundated conditions in which minimal decomposition of plant residue occurs. When organic soils are prepared for crop production, they are drained and tilled, leading to aeration of the soil, which accelerates the rate of decomposition and CO_2 emissions. Because of the depth and richness of the organic layers, C loss from drained organic soils can continue over long periods of time. The rate of CO_2 emissions varies depending on climate and composition (i.e., decomposability) of the organic matter. Also, the use of organic soils for annual crop production leads to higher C loss rates than drainage of organic soils in grassland or forests, due to deeper drainage and more intensive management practices in cropland (Armentano and Verhoeven 1990, as cited in IPCC/UNEP/OECD/IEA 1997). Carbon losses are estimated from drained organic soils under both grassland and cropland management in this Inventory.

Cropland Remaining Cropland includes all cropland in an inventory year that had been cropland for the last 20 years[180] according to the USDA NRI land-use survey (USDA-NRCS 2000). The Inventory includes all privately-owned croplands in the conterminous United States and Hawaii, but there is a minor amount of cropland on federal lands that is not currently included in the estimation of C stock changes, leading to a discrepancy between the total amount of managed area in *Cropland Remaining Cropland* (see Section 7.1) and the cropland area included in the Inventory. It is important to note that plans are being made to include federal croplands in future C inventories.

The area of *Cropland Remaining Cropland* changes through time as land is converted to or from cropland management. CO_2 emissions and removals[181] due to changes in mineral soil C stocks are estimated using a Tier 3 approach for the majority of annual crops. A Tier 2 IPCC method is used for the remaining crops (vegetables, tobacco, perennial/horticultural crops, and rice) not included in the Tier 3 method. In addition, a Tier 2 method is used for very gravelly, cobbly, or shaley soils (i.e., classified as soils that have greater than 35 percent of soil volume comprised of gravel, cobbles, or shale) and for additional changes in mineral soil C stocks that were not addressed with the Tier 3 approach (i.e., change in C stocks after 2003 due to Conservation Reserve Program enrollment). Emissions from organic soils are estimated using a Tier 2 IPCC method.

Of the two sub-source categories, land-use and land management of mineral soils was the most important component of total net C stock change between 1990 and 2009 (see Table 7-17 and Table 7-18). In 2009, mineral soils were estimated to remove 45.1 Tg CO_2 Eq. (12.3 Tg C). This rate of C storage in mineral soils represented about a 20 percent decrease in the rate since the initial reporting year of 1990. Emissions from organic soils were

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[179] CO_2 emissions associated with liming are also estimated but are included in a separate section of the report.

[180] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

[181] Note that removals occur through crop and forage uptake of CO_2 into biomass C that is later incorporated into soil pools.

27.7 Tg CO_2 Eq. (7.5 Tg C) in 2009. In total, U.S. agricultural soils in *Cropland Remaining Cropland* removed approximately 17.4 Tg CO_2 Eq. (4.7 Tg C) in 2009.

Table 7-17: Net CO_2 Flux from Soil C Stock Changes in *Cropland Remaining Cropland* (Tg CO_2 Eq.)

Soil Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Mineral Soils	(56.8)	(57.9)	(45.9)	(46.8)	(47.3)	(45.7)	(45.1)
Organic Soils	27.4	27.7	27.7	27.7	27.7	27.7	27.7
Total Net Flux	**(29.4)**	**(30.2)**	**(18.3)**	**(19.1)**	**(19.7)**	**(18.1)**	**(17.4)**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

Table 7-18: Net CO_2 Flux from Soil C Stock Changes in *Cropland Remaining Cropland* (Tg C)

Soil Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Mineral Soils	(15.5)	(15.8)	(12.5)	(12.8)	(12.9)	(12.5)	(12.3)
Organic Soils	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Total Net Flux	**(8.0)**	**(8.2)**	**(5.0)**	**(5.2)**	**(5.4)**	**(4.9)**	**(4.7)**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

The net reduction in soil C accumulation over the time series (39 percent from 1990 to 2009) was largely due to the declining influence of annual cropland enrolled in the Conservation Reserve Program, which began in the late 1980s. However, there were still positive increases in C stocks from land enrolled in the reserve program, as well as intensification of crop production by limiting the use of bare-summer fallow in semi-arid regions, increased hay production, and adoption of conservation tillage (i.e., reduced- and no-till practices).

The spatial variability in annual CO_2 flux associated with C stock changes in mineral and organic soils is displayed in Figure 7-5 and Figure 7-6. The highest rates of net C accumulation in mineral soils occurred in the Midwest, which is the area with the largest amounts of cropland managed with conservation tillage. Rates were also high in the Great Plains due to enrollment in the Conservation Reserve Program. Emission rates from drained organic soils were highest along the southeastern coastal region, in the northeast central United States surrounding the Great Lakes, and along the central and northern portions of the West Coast.

Figure 7-5: Total Net Annual CO_2 Flux for Mineral Soils under Agricultural Management within States, 2009, *Cropland Remaining Cropland*

Figure 7-6: Total Net Annual CO_2 Flux for Organic Soils under Agricultural Management within States, 2009, *Cropland Remaining Cropland*

Methodology

The following section includes a description of the methodology used to estimate changes in soil C stocks due to: (1) agricultural land-use and management activities on mineral soils; and (2) agricultural land-use and management activities on organic soils for *Cropland Remaining Cropland*.

Soil C stock changes were estimated for *Cropland Remaining Cropland* (as well as agricultural land falling into the IPCC categories *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland*) according to land-use histories recorded in the USDA National Resources Inventory (NRI) survey (USDA-NRCS 2000). The NRI is a statistically-based sample of all non-federal land, and includes approximately 260,000 points in agricultural land for the conterminous United States and Hawaii.[182] Each point is associated with an "expansion factor" that allows scaling of C stock changes from NRI points to the entire country (i.e., each expansion factor represents the amount of area with the same land-use/management history as the sample point). Land-use and some

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[182] NRI points were classified as agricultural if under grassland or cropland management between 1990 and 2003.

management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. For cropland, data were collected for 4 out of 5 years in the cycle (i.e., 1979-1982, 1984-1987, 1989-1992, and 1994-1997). However, the NRI program began collecting annual data in 1998, and data are currently available through 2003. NRI points were classified as *Cropland Remaining Cropland* in a given year between 1990 and 2009 if the land use had been cropland for 20 years.[183] Cropland includes all land used to produce food and fiber, or forage that is harvested and used as feed (e.g., hay and silage).

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach was applied to estimate C stock changes for mineral soils used to produce a majority of annual crops in the United States (Ogle et al. 2010). The remaining crops on mineral soils were estimated using an IPCC Tier 2 method (Ogle et al. 2003), including vegetables, tobacco, perennial/horticultural crops, rice, and crops rotated with these crops. The Tier 2 method was also used for very gravelly, cobbly, or shaley soils (greater than 35 percent by volume). Mineral SOC stocks were estimated using a Tier 2 method for these areas because the Century model, which is used for the Tier 3 method, has not been fully tested to address its adequacy for estimating C stock changes associated with certain crops and rotations, as well as cobbly, gravelly, or shaley soils. An additional stock change calculation was made for mineral soils using Tier 2 emission factors, accounting for enrollment patterns in the Conservation Reserve Program after 2003, which was not addressed by the Tier 3 methods.

Further elaboration on the methodology and data used to estimate stock changes from mineral soils are described below and in Annex 3.13.

Tier 3 Approach

Mineral SOC stocks and stock changes were estimated using the Century biogeochemical model (Parton et al. 1987, 1988, 1994; Metherell et al. 1993), which simulates the dynamics of C and other elements in cropland, grassland, forest, and savanna ecosystems. It uses monthly weather data as an input, along with information about soil physical properties. Input data on land use and management are specified at monthly resolution and include land-use type, crop/forage type, and management activities (e.g., planting, harvesting, fertilization, manure amendments, tillage, irrigation, residue removal, grazing, and fire). The model computes net primary productivity and C additions to soil, soil temperature, and water dynamics, in addition to turnover, stabilization, and mineralization of soil organic matter C and nutrient (N, K, S) elements. This method is more accurate than the Tier 1 and 2 approaches provided by the IPCC, because the simulation model treats changes as continuous over time rather than the simplified discrete changes represented in the default method (see Box 7-3 for additional information). National estimates were obtained by simulating historical land-use and management patterns as recorded in the USDA National Resources Inventory (NRI) survey.

[BEGIN BOX]

Box 7-3: Tier 3 Approach for Soil C Stocks Compared to Tier 1 or 2 Approaches

A Tier 3 model-based approach is used to inventory soil C stock changes on the majority of agricultural land with mineral soils. This approach entails several fundamental differences compared to the IPCC Tier 1 or 2 methods, which are based on a classification of land areas into a number of discrete classes based on a highly aggregated classification of climate, soil, and management (i.e., only six climate regions, seven soil types and eleven management systems occur in U.S. agricultural land under the IPCC classification). Input variables to the Tier 3 model, including climate, soils, and management activities (e.g., fertilization, crop species, tillage, etc.), are represented in considerably more detail both temporally and spatially, and exhibit multi-dimensional interactions through the more complex model structure compared with the IPCC Tier 1 or 2 approach. The spatial resolution of

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[183] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began. Therefore, the classification prior to 2002 was based on less than 20 years of recorded land-use history for the time series.

the analysis is also finer in the Tier 3 method compared to the lower tier methods as implemented in the United States for previous Inventories (e.g., 3,037 counties versus 181 Major Land Resource Areas (MLRAs), respectively).

In the Century model, soil C dynamics (and CO_2 emissions and uptake) are treated as continuous variables, which change on a monthly time step. Carbon emissions and removals are an outcome of plant production and decomposition processes, which are simulated in the model structure. Thus, changes in soil C stocks are influenced by not only changes in land use and management but also inter-annual climate variability and secondary feedbacks between management activities, climate, and soils as they affect primary production and decomposition. This latter characteristic constitutes one of the greatest differences between the methods, and forms the basis for a more complete accounting of soil C stock changes in the Tier 3 approach compared with Tier 2 methodology.

Because the Tier 3 model simulates a continuous time period rather than the equilibrium step change used in the IPCC methodology (Tier 1 and 2), the Tier 3 model addresses the delayed response of soils to management and land-use changes. Delayed responses can occur due to variable weather patterns and other environmental constraints that interact with land use and management and affect the time frame over which stock changes occur. Moreover, the Tier 3 method also accounts for the overall effect of increasing yields and, hence, C input to soils that have taken place across management systems and crop types within the United States. Productivity has increased by 1 to 2 percent annually over the past 4 to 5 decades for most major crops in the United States (Reilly and Fuglie 1998), which is believed to have led to increases in cropland soil C stocks (e.g., Allmaras et al. 2000). This is a major difference from the IPCC-based Tier 1 and 2 approaches, in which trends in soil C stocks only capture discrete changes in management and/or land use, rather than a longer term trend such as gradual increases in crop productivity.

[END BOX]

Additional sources of activity data were used to supplement the land-use information from NRI. The Conservation Technology Information Center (CTIC 1998) provided annual data on tillage activity at the county level since 1989, with adjustments for long-term adoption of no-till agriculture (Towery 2001). Information on fertilizer use and rates by crop type for different regions of the United States were obtained primarily from the USDA Economic Research Service Cropping Practices Survey (ERS 1997) with additional data from other sources, including the National Agricultural Statistics Service (NASS 1992, 1999, 2004). Frequency and rates of manure application to cropland during 1997 were estimated from data compiled by the USDA Natural Resources Conservation Service (Edmonds et al. 2003), and then adjusted using county-level estimates of manure available for application in other years. Specifically, county-scale ratios of manure available for application to soils in other years relative to 1997 were used to adjust the area amended with manure (see Annex 3.13 for further details). Greater availability of managed manure N relative to 1997 was, thus, assumed to increase the area amended with manure, while reduced availability of manure N relative to 1997 was assumed to reduce the amended area. The amount of manure produced by each livestock type was calculated for managed and unmanaged waste management systems based on methods described in the Manure Management section (Section 6.2) and annex (Annex 3.10).

Manure amendments were an input to the Century Model based on manure N available for application from all managed or unmanaged systems except Pasture/Range/Paddock.[184] Data on the county-level N available for application were estimated for managed systems based on the total amount of N excreted in manure minus N losses during storage and transport, and including the addition of N from bedding materials. Nitrogen losses include direct nitrous oxide emissions, volatilization of ammonia and NO_x, runoff and leaching, and poultry manure used as a feed supplement. More information on these losses is available in the description of the Manure Management source category. For unmanaged systems, it is assumed that no N losses or additions occur prior to the application of manure to the soil.

Monthly weather data were used as an input in the model simulations, based on an aggregation of gridded weather data to the county scale from the Parameter-elevation Regressions on Independent Slopes Model (PRISM) database

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[184] Pasture/Range/Paddock manure additions to soils are addressed in the *Grassland Remaining Grassland* and *Land Converted to Grassland* categories.

(Daly et al. 1994). Soil attributes, which were obtained from an NRI database, were assigned based on field visits and soil series descriptions. Each NRI point was run 100 times as part of the uncertainty assessment, yielding a total of over 18 million simulation runs for the analysis. Carbon stock estimates from Century were adjusted using a structural uncertainty estimator accounting for uncertainty in model algorithms and parameter values (Ogle et al. 2007, 2010). C stocks and 95 percent confidence intervals were estimated for each year between 1990 and 2003, but C stock changes from 2004 to 2009 were assumed to be similar to 2003 because no additional activity data are currently available from the NRI for the latter years.

Tier 2 Approach

In the IPCC Tier 2 method, data on climate, soil types, land-use, and land management activity were used to classify land area to apply appropriate stock change factors. MLRAs formed the base spatial unit for mapping climate regions in the United States; each MLRA represents a geographic unit with relatively similar soils, climate, water resources, and land uses (NRCS 1981). MLRAs were classified into climate regions according to the IPCC categories using the PRISM climate database of Daly et al. (1994).

Reference C stocks were estimated using the National Soil Survey Characterization Database (NRCS 1997) with cultivated cropland as the reference condition, rather than native vegetation as used in IPCC (2003, 2006). Changing the reference condition was necessary because soil measurements under agricultural management are much more common and easily identified in the National Soil Survey Characterization Database (NRCS 1997) than those that are not considered cultivated cropland.

U.S.-specific stock change factors were derived from published literature to determine the impact of management practices on SOC storage, including changes in tillage, cropping rotations and intensification, and land-use change between cultivated and uncultivated conditions (Ogle et al. 2003, Ogle et al. 2006). U.S. factors associated with organic matter amendments were not estimated because there were an insufficient number of studies to analyze those impacts. Instead, factors from IPCC (2003) were used to estimate the effect of those activities. Euliss and Gleason (2002) provided the data for computing the change in SOC storage resulting from restoration of wetland enrolled in the Conservation Reserve Program.

Activity data were primarily based on the historical land-use/management patterns recorded in the NRI. Each NRI point was classified by land use, soil type, climate region (using PRISM data, Daly et al. 1994) and management condition. Classification of cropland area by tillage practice was based on data from the Conservation Tillage Information Center (CTIC 1998, Towery 2001) as described above. Activity data on wetland restoration of Conservation Reserve Program land were obtained from Euliss and Gleason (2002). Manure N amendments over the inventory time period were based on application rates and areas amended with manure N from Edmonds et al. (2003), in addition to the managed manure production data discussed in the previous methodology subsection on the Tier 3 analysis for mineral soils.

Combining information from these data sources, SOC stocks for mineral soils were estimated 50,000 times for 1982, 1992, and 1997, using a Monte Carlo simulation approach and the probability distribution functions for U.S.-specific stock change factors, reference C stocks, and land-use activity data (Ogle et al. 2002, Ogle et al. 2003). The annual C flux for 1990 through 1992 was determined by calculating the average annual change in stocks between 1982 and 1992; annual C flux for 1993 through 2009 was determined by calculating the average annual change in stocks between 1992 and 1997.

Additional Mineral C Stock Change

Annual C flux estimates for mineral soils between 1990 and 2009 were adjusted to account for additional C stock changes associated with gains or losses in soil C after 2003 due to changes in Conservation Reserve Program enrollment. The change in enrollment acreage relative to 2003 was based on data from USDA-FSA (2009) for 2004 through 2009, and the differences in mineral soil areas were multiplied by 0.5 metric tons C per hectare per year to estimate the net effect on soil C stocks. The stock change rate is based on estimations using the IPCC method (see Annex 3.13 for further discussion).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Cropland Remaining Cropland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), with U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. The final estimates included a measure of uncertainty as determined from the Monte Carlo simulation with 50,000 iterations. Emissions were based on the 1992 and 1997 *Cropland Remaining Cropland* areas from the *1997 National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty associated with the *Cropland Remaining Cropland* land-use category was addressed for changes in agricultural soil C stocks (including both mineral and organic soils). Uncertainty estimates are presented in Table 7-19 for mineral soil C stocks and organic soil C stocks disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006). The combined uncertainty was calculated by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. More details on how the individual uncertainties were developed are in Annex 3.13. The combined uncertainty for soil C stocks in *Cropland Remaining Cropland* ranged from 172 percent below to 167 percent above the 2009 stock change estimate of -17.4 Tg CO_2 Eq.

Table 7-19: Tier 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within *Cropland Remaining Cropland* (Tg CO_2 Eq. and Percent)

Source	**2009 Flux Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Flux Estimate (Tg CO_2 Eq.)**		**(%)**	
		Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Mineral Soil C Stocks: Cropland Remaining Cropland, Tier 3 Inventory Methodology	(42.3)	(69.6)	(15.1)	-64%	+64%
Mineral Soil C Stocks: Cropland Remaining Cropland, Tier 2 Inventory Methodology	(3.0)	(6.9)	0.8	-127%	+128%
Mineral Soil C Stocks: Cropland Remaining Cropland (Change in CRP enrollment relative to 2003)	(0.3)	(0.1)	(0.4)	-50%	+50%
Organic Soil C Stocks: Cropland Remaining Cropland, Tier 2 Inventory Methodology	27.7	15.8	36.9	-43%	+33%
Combined Uncertainty for Flux associated with Agricultural Soil Carbon Stock Change in Cropland Remaining Cropland	**(17.4)**	**(47.3)**	**11.6**	**-172%**	**+167%**

Note: Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

Quality control measures included checking input data, model scripts, and results to ensure data were properly handled throughout the inventory process. As discussed in the uncertainty section, results were compared to field measurements, and a statistical relationship was developed to assess uncertainties in the model's predictive capability. The comparisons included over 40 long-term experiments, representing about 800 combinations of management treatments across all of the sites (Ogle et al. 2007). Inventory reporting forms and text were reviewed and revised as needed to correct transcription errors.

Planned Improvements

The first improvement is to update the Tier 2 inventory analysis with the latest annual National Resources Inventory (NRI) data. While the land base for the Tier 3 approach uses the latest available data from the NRI, the Tier 2 portion of the Inventory has not updated and is based on the Revised 1997 NRI data product (USDA-NRCS 2000).

This improvement will extend the time series of the land use data from 1997 through 2003 for the Tier 2 portion of the Inventory.

The second improvement is to incorporate remote sensing in the analysis for estimation of crop and forage production, and conduct the Tier 3 assessment of soil C stock changes and soil nitrous oxide emissions in a single analysis. Specifically, the Enhanced Vegetation Index (EVI) product that is derived from MODIS satellite imagery is being used to refine the production estimation for the Tier 3 assessment framework based on the DAYCENT simulation model. EVI reflects changes in plant "greenness" over the growing season and can be used to compute production based on the light use efficiency of the crop or forage (Potter et al. 1993). In the current framework, production is simulated based on the weather data, soil characteristics, and the genetic potential of the crop. While this method produces reasonable results, remote sensing can be used to refine the productivity estimates and reduce biases in crop production and subsequent C input to soil systems. It is anticipated that precision in the Tier 3 assessment framework will be increased by 25 percent or more with the new method. In addition, DAYCENT is currently used for estimating soil nitrous oxide emissions in the Inventory, and can also be used to estimate soil organic C stock changes using the same algorithms in the CENTURY model. Simulating both soil C stock changes and nitrous oxide emissions in a single analysis will ensure consistency in the treatment of these sources, which are coupled through the N and C cycles in agricultural systems.

CO_2 Emissions from Agricultural Liming

IPCC (2006) recommends reporting CO_2 emissions from lime additions (in the form of crushed limestone ($CaCO_3$) and dolomite ($CaMg(CO_3)_2$) to agricultural soils. Limestone and dolomite are added by land managers to ameliorate acidification. When these compounds come in contact with acid soils, they degrade, thereby generating CO_2. The rate and ultimate magnitude of degradation of applied limestone and dolomite depends on the soil conditions, climate regime, and the type of mineral applied. Emissions from liming have fluctuated over the past nineteen years, ranging from 3.8 Tg CO_2 Eq. to 5.0 Tg CO_2 Eq. In 2009, liming of agricultural soils in the United States resulted in emissions of 4.2 Tg CO_2 Eq. (1.2 Tg C), representing about a 10 percent decrease in emissions since 1990 (see Table 7-20 and Table 7-21). The trend is driven entirely by the amount of lime and dolomite estimated to have been applied to soils over the time period.

Table 7-20: Emissions from Liming of Agricultural Soils (Tg CO_2 Eq.)

Source	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Liming of Soils[1]	4.7		4.3		4.3	4.2	4.5	5.0	4.2

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

[1] Also includes emissions from liming on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland*, and *Settlements Remaining Settlements*.

Table 7-21: Emissions from Liming of Agricultural Soils (Tg C)

Source	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Liming of Soils[1]	1.3		1.2		1.2	1.2	1.2	1.4	1.2

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

[1] Also includes emissions from liming on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland*, and *Settlements Remaining Settlements*.

Methodology

CO_2 emissions from degradation of limestone and dolomite applied to agricultural soils were estimated using a Tier 2 methodology consistent with IPCC (2006). The annual amounts of limestone and dolomite applied (see Table 7-22) were multiplied by CO_2 emission factors from West and McBride (2005). These emission factors (0.059 metric ton C/metric ton limestone, 0.064 metric ton C/metric ton dolomite) are lower than the IPCC default emission factors because they account for the portion of agricultural lime that may leach through the soil and travel by rivers to the ocean (West and McBride 2005). This analysis of lime dissolution is based on liming occurring in the Mississippi River basin, where the vast majority of all U.S. liming takes place (West 2008). U.S. liming that does not occur in the Mississippi River basin tends to occur under similar soil and rainfall regimes, and, thus, the emission factor is appropriate for use across the United States (West 2008). The annual application rates of limestone and dolomite were derived from estimates and industry statistics provided in the *Minerals Yearbook* and *Mineral Industry Surveys* (Tepordei 1993 through 2006; Willett 2007a, b, 2009 through 2010; USGS 2008 through

2010). To develop these data, the U.S. Geological Survey (USGS; U.S. Bureau of Mines prior to 1997) obtained production and use information by surveying crushed stone manufacturers. Because some manufacturers were reluctant to provide information, the estimates of total crushed limestone and dolomite production and use were divided into three components: (1) production by end-use, as reported by manufacturers (i.e., “specified” production); (2) production reported by manufacturers without end-uses specified (i.e., “unspecified” production); and (3) estimated additional production by manufacturers who did not respond to the survey (i.e., “estimated” production).

The “unspecified” and “estimated” amounts of crushed limestone and dolomite applied to agricultural soils were calculated by multiplying the percentage of total “specified” limestone and dolomite production applied to agricultural soils by the total amounts of “unspecified” and “estimated” limestone and dolomite production. In other words, the proportion of total “unspecified” and “estimated” crushed limestone and dolomite that was applied to agricultural soils (as opposed to other uses of the stone) was assumed to be proportionate to the amount of “specified” crushed limestone and dolomite that was applied to agricultural soils. In addition, data were not available for 1990, 1992, and 2009 on the fractions of total crushed stone production that were limestone and dolomite, and on the fractions of limestone and dolomite production that were applied to soils. To estimate the 1990 and 1992 data, a set of average fractions were calculated using the 1991 and 1993 data. These average fractions were applied to the quantity of "total crushed stone produced or used" reported for 1990 and 1992 in the 1994 *Minerals Yearbook* (Tepordei 1996). To estimate 2009 data, the previous year’s fractions were applied to a 2009 estimate of total crushed stone presented in the USGS *Mineral Industry Surveys: Crushed Stone and Sand and Gravel in the First Quarter of 2010* (USGS 2010); thus, the 2009 data in Table 7-20 through Table 7-22 are shaded to indicate that they are based on a combination of data and projections.

The primary source for limestone and dolomite activity data is the *Minerals Yearbook*, published by the Bureau of Mines through 1994 and by the USGS from 1995 to the present. In 1994, the “Crushed Stone” chapter in the *Minerals Yearbook* began rounding (to the nearest thousand metric tons) quantities for total crushed stone produced or used. It then reported revised (rounded) quantities for each of the years from 1990 to 1993. In order to minimize the inconsistencies in the activity data, these revised production numbers have been used in all of the subsequent calculations. Since limestone and dolomite activity data are also available at the state level, the national-level estimates reported here were broken out by state, although state-level estimates are not reported here.

Table 7-22: Applied Minerals (Million Metric Tons)

Mineral	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Limestone	19.01		15.86		18.09	16.54	17.46	20.55	17.20
Dolomite	2.36		3.81		1.85	2.73	2.92	2.54	2.13

Note: These numbers represent amounts applied to *Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland*, and *Settlements Remaining Settlements*. Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

Uncertainty and Time-Series Consistency

Uncertainty regarding limestone and dolomite activity data inputs was estimated at ±15 percent and assumed to be uniformly distributed around the inventory estimate (Tepordei 2003b). Analysis of the uncertainty associated with the emission factors included the following: the fraction of agricultural lime dissolved by nitric acid versus the fraction that reacts with carbonic acid, and the portion of bicarbonate that leaches through the soil and is transported to the ocean. Uncertainty regarding the time associated with leaching and transport was not accounted for, but should not change the uncertainty associated with CO_2 emissions (West 2005). The uncertainties associated with the fraction of agricultural lime dissolved by nitric acid and the portion of bicarbonate that leaches through the soil were each modeled as a smoothed triangular distribution between ranges of zero percent to 100 percent. The uncertainty surrounding these two components largely drives the overall uncertainty estimates reported below. More information on the uncertainty estimates for Liming of Agricultural Soils is contained within the Uncertainty Annex.

A Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the uncertainty of CO_2 emissions from liming. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-23. CO_2 emissions from Liming of Agricultural Soils in 2008 were estimated to be between 0.1 and 8.4 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of 97 percent below to 99 percent above the 2009 emission estimate of 4.2 Tg CO_2 Eq.

Table 7-23: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Liming of Agricultural Soils (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emissions Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Liming of Agricultural Soils[1]	CO_2	4.2	0.1	8.4	-97%	+99%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

[1] Also includes emissions from liming on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland,* and *Settlements Remaining Settlements*.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. The QA/QC analysis did not reveal any inaccuracies or incorrect input values.

Recalculations Discussion

Several adjustments were made in the current Inventory to improve the results. The quantity of applied minerals reported in the previous Inventory for 2007 has been revised; the updated activity data for 2007 are approximately 1,480 thousand metric tons greater than the data used for the previous Inventory, consequently, the reported emissions resulting from liming in 2007 increased by about 8.4 percent. In the previous Inventory, to estimate 2008 data, the previous year's fractions were applied to a 2008 estimate of total crushed stone presented in the USGS *Mineral Industry Surveys: Crushed Stone and Sand and Gravel in the First Quarter of 2009* (USGS 2009). Since publication of the previous Inventory, the *Minerals Yearbook* has published actual quantities of crushed stone sold or used by producers in the United States in 2008. These values have replaced those used in the previous Inventory to calculate the quantity of minerals applied to soil and the emissions from liming. The updated activity data for 2008 are approximately 5,460 thousand metric tons greater than the data used in the previous Inventory. As a result, the reported emissions from liming in 2008 increased by about 36 percent.

CO_2 Emissions from Urea Fertilization

The use of urea ($CO(NH_2)_2$) as fertilizer leads to emissions of CO_2 that was fixed during the industrial production process. Urea in the presence of water and urease enzymes is converted into ammonium (NH_4^+), hydroxyl ion (OH^-), and bicarbonate (HCO_3^-). The bicarbonate then evolves into CO_2 and water. Emissions from urea fertilization in the United States totaled 3.6 Tg CO_2 Eq. (1.0 Tg C) in 2009 (Table 7-24 and Table 7-25). Emissions from urea fertilization have grown 49 percent between 1990 and 2009, due to an increase in the use of urea as fertilizer.

Table 7-24: CO_2 Emissions from Urea Fertilization in *Cropland Remaining Cropland* (Tg CO_2 Eq.)

Source	1990		2000		2005	2006	2007	2008	2009
Urea Fertilization[1]	2.4		3.2		3.5	3.7	3.7	3.6	3.6

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

[1] Also includes emissions from urea fertilization on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements*, and *Forest Land Remaining Forest Land*.

Table 7-25: CO_2 Emissions from Urea Fertilization in *Cropland Remaining Cropland* (Tg C)

Source	1990		2000		2005	2006	2007	2008	2009
Urea Fertilization[1]	0.7		0.9		1.0	1.0	1.0	1.0	1.0

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

[1] Also includes emissions from urea fertilization on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements*, and *Forest Land Remaining Forest Land*.

Methodology

Carbon dioxide emissions from the application of urea to agricultural soils were estimated using the IPCC (2006) Tier 1 methodology. The annual amounts of urea fertilizer applied (see Table 7-26) were derived from state-level fertilizer sales data provided in *Commercial Fertilizers* (TVA 1991, 1992, 1993, 1994; AAPFCO 1995 through 2010) and were multiplied by the default IPCC (2006) emission factor of 0.20, which is equal to the C content of urea on an atomic weight basis. Because fertilizer sales data are reported in fertilizer years (July through June), a calculation was performed to convert the data to calendar years (January through December). According to historic monthly fertilizer use data (TVA 1992b), 65 percent of total fertilizer used in any fertilizer year is applied between January and June of that calendar year, and 35 percent of total fertilizer used in any fertilizer year is applied between July and December of the previous calendar year. Fertilizer sales data for the 2009 fertilizer year were not available in time for publication. Accordingly, urea application in the 2009 fertilizer year was assumed to be equal to that of the 2008 fertilizer year. Since 2010 fertilizer year data were not available, July through December 2009 fertilizer consumption was assumed to be equal to July through December 2008 fertilizer consumption; thus, the 2009 data in Table 7-24 through Table 7-26 are shaded to indicate that they are based on a combination of data and projections. State-level estimates of CO_2 emissions from the application of urea to agricultural soils were summed to estimate total emissions for the entire United States.

Table 7-26: Applied Urea (Million Metric Tons)

	1990		2000		2005	2006	2007	2008	2009
Urea Fertilizer[1]	3.30		4.38		4.78	4.98	5.10	4.92	4.92

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.
[1] These numbers represent amounts applied to all agricultural land, including *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements*, and *Forest Land Remaining Forest Land*.

Uncertainty and Time-Series Consistency

Uncertainty estimates are presented in Table 7-27 for Urea Fertilization. A Tier 2 Monte Carlo analysis was completed. The largest source of uncertainty was the default emission factor, which assumes that 100 percent of the C applied to soils is ultimately emitted into the environment as CO_2. This factor does not incorporate the possibility that some of the C may be retained in the soil. The emission estimate is, thus, likely to be high. In addition, each urea consumption data point has an associated uncertainty. Urea for non-fertilizer use, such as aircraft deicing, may be included in consumption totals; it was determined through personal communication with Fertilizer Regulatory Program Coordinator David L. Terry (2007), however, that this amount is most likely very small. Research into aircraft deicing practices also confirmed that urea is used minimally in the industry; a 1992 survey found a known annual usage of approximately 2,000 tons of urea for deicing; this would constitute 0.06 percent of the 1992 consumption of urea (EPA 2000). Similarly, surveys conducted from 2002 to 2005 indicate that total urea use for deicing at U.S. airports is estimated to be 3,740 MT per year, or less than 0.07 percent of the fertilizer total for 2007 (Itle 2009). Lastly, there is uncertainty surrounding the assumptions behind the calculation that converts fertilizer years to calendar years. CO_2 emissions from urea fertilization of agricultural soils in 2009 were estimated to be between 2.1 and 3.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of 43 percent below to 3 percent above the 2009 emission estimate of 3.6 Tg CO_2 Eq.

Table 7-27: Quantitative Uncertainty Estimates for CO_2 Emissions from Urea Fertilization (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emissions Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Urea Fertilization	CO_2	3.6	2.1	3.7	-43%	+3%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.
Note: These numbers represent amounts applied to all agricultural land, *including Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements*, and *Forest Land Remaining Forest Land*.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. Inventory reporting forms and text were reviewed. No errors were found.

Recalculations Discussion

July to December 2007 urea application data were updated with assumptions for fertilizer year 2008, and the 2007 emission estimate was revised accordingly. The activity data decreased about 800,000 metric tons for 2007 and this change resulted in an approximately 3 percent decrease in emissions in 2007 relative to the previous Inventory. In the previous Inventory, the application for this period was calculated based on application during July to December 2006. January to June 2008 data were also used to update 2008 emission estimates. The activity data decreased about 270,000 metric tons for 2008, resulting in an approximately 5 percent decrease in emissions in 2008 relative to the previous Inventory.

Planned Improvements

The primary planned improvement is to investigate using a Tier 2 or Tier 3 approach, which would utilize country-specific information to estimate a more precise emission factor.

7.5. Land Converted to Cropland (IPCC Source Category 5B2)

Land Converted to Cropland includes all cropland in an inventory year that had been another land use at any point during the previous 20 years[185] according to the USDA NRI land-use survey (USDA-NRCS 2000). Consequently, lands are retained in this category for 20 years as recommended by the IPCC guidelines (IPCC 2006) unless there is another land-use change. The Inventory includes all privately-owned croplands in the conterminous United States and Hawaii, but there is a minor amount of cropland on federal lands that is not currently included in the estimation of C stock changes, leading to a discrepancy between the total amount of managed area in *Land Converted to Cropland* (see Section 7.1) and the cropland area included in the Inventory. It is important to note that plans are being made to include these areas in future C inventories.

Background on agricultural C stock changes is provided in *Cropland Remaining Cropland* and will only be summarized here for *Land Converted to Cropland*. Soils are the largest pool of C in agricultural land, and also have the greatest potential for storage or release of C, because biomass and dead organic matter C pools are relatively small and ephemeral compared with soils. The IPCC (2006) recommends reporting changes in soil organic C stocks due to: (1) agricultural land-use and management activities on mineral soils, and (2) agricultural land-use and management activities on organic soils.[186]

Land-use and management of mineral soils in *Land Converted to Cropland* generally led to relatively small increases in soil C during the 1990s but the pattern changed to small losses of C through the latter part of the time series (Table 7-28 and Table 7-29). The total rate of change in soil C stocks was 5.9 Tg CO_2 Eq. (1.6 Tg C) in 2009. Mineral soils were estimated to lose 3.3 Tg CO_2 Eq. (0.9 Tg C) in 2009, while drainage and cultivation of organic soils led to annual losses of 2.6 Tg CO_2 Eq. (0.7 Tg C) in 2009.

Table 7-28: Net CO_2 Flux from Soil C Stock Changes in Land *Converted to Cropland* (Tg CO_2 Eq.)

Soil Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Mineral Soils	(0.3)	(0.3)	3.3	3.3	3.3	3.3	3.3
Organic Soils	2.4	2.6	2.6	2.6	2.6	2.6	2.6
Total Net Flux	**2.2**	**2.4**	**5.9**	**5.9**	**5.9**	**5.9**	**5.9**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

Table 7-29: Net CO_2 Flux from Soil C Stock Changes in *Land Converted to Cropland* (Tg C)

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[185] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

[186] CO_2 emissions associated with liming are also estimated but included in a separate section of the report.

Soil Type	1990		2000		2005	2006	2007	2008	2009
Mineral Soils	(0.1)		(0.1)		0.9	0.9	0.9	0.9	0.9
Organic Soils	0.7		0.7		0.7	0.7	0.7	0.7	0.7
Total Net Flux	**0.6**		**0.6**		**1.6**	**1.6**	**1.6**	**1.6**	**1.6**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

The spatial variability in annual CO_2 flux associated with C stock changes in mineral and organic soils for *Land Converted to Cropland* is displayed in Figure 7-7 and Figure 7-8. While a large portion of the United States had net losses of soil C for *Land Converted to Cropland*, there were some notable areas with net C accumulation in the Great Plains, Midwest, mid-Atlantic states. These areas were gaining C following conversion, because the land had been brought into hay production, including grass and legume hay, leading to enhanced plant production relative to the previous land use, and thus higher C input to the soil. Emissions from organic soils were largest in California, Florida, and the upper Midwest, which coincided with largest concentrations of cultivated organic soils in the United States.

Figure 7-7: Total Net Annual CO_2 Flux for Mineral Soils under Agricultural Management within States, 2009, *Land Converted to Cropland*

Figure 7-8: Total Net Annual CO_2 Flux for Organic Soils under Agricultural Management within States, 2009, *Land Converted to Cropland*

Methodology

The following section includes a brief description of the methodology used to estimate changes in soil C stocks due to agricultural land-use and management activities on mineral and organic soils for *Land Converted to Cropland*. Further elaboration on the methodologies and data used to estimate stock changes for mineral and organic soils are provided in the *Cropland Remaining Cropland* section and Annex 3.13.

Soil C stock changes were estimated for *Land Converted to Cropland* according to land-use histories recorded in the USDA NRI survey (USDA-NRCS 2000). Land-use and some management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. However, the NRI program initiated annual data collection in 1998, and the annual data are currently available through 2003. NRI points were classified as *Land Converted to Cropland* in a given year between 1990 and 2009 if the land use was cropland but had been another use during the previous 20 years. Cropland includes all land used to produce food or fiber, or forage that is harvested and used as feed (e.g., hay and silage).

Mineral Soil Carbon Stock Changes

A Tier 3 model-based approach was applied to estimate C stock changes for soils on *Land Converted to Cropland* used to produce a majority of all crops (Ogle et al. 2010). Soil C stock changes on the remaining soils were estimated with the IPCC Tier 2 method (Ogle et al. 2003), including land used to produce vegetable, tobacco, perennial/horticultural crops, and rice; land on very gravelly, cobbly, or shaley soils (greater than 35 percent by volume); and land converted from forest or federal ownership.[187]

Tier 3 Approach

Mineral SOC stocks and stock changes were estimated using the Century biogeochemical model for the Tier 3

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[187] Federal land is not a land use, but rather an ownership designation that is treated as forest or nominal grassland for purposes of these calculations. The specific use for federal lands is not identified in the NRI survey (USDA-NRCS 2000).

methods. National estimates were obtained by using the model to simulate historical land-use change patterns as recorded in the USDA National Resources Inventory (USDA-NRCS 2000). The methods used for *Land Converted to Cropland* are the same as those described in the Tier 3 portion of *Cropland Remaining Cropland* section for mineral soils (see *Cropland Remaining Cropland* Tier 3 methods section and Annex 3.13 for additional information).

Tier 2 Approach

For the mineral soils not included in the Tier 3 analysis, SOC stock changes were estimated using a Tier 2 Approach for *Land Converted to Cropland* as described in the Tier 2 portion of *Cropland Remaining Cropland* section for mineral soils (see *Cropland Remaining Cropland* Tier 2 methods section for additional information).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Land Converted to Cropland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), with U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. The final estimates included a measure of uncertainty as determined from the Monte Carlo simulation with 50,000 iterations. Emissions were based on the 1992 and 1997 *Land Converted to Cropland* areas from the *1997 National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty analysis for mineral soil C stock changes using the Tier 3 and Tier 2 approaches were based on the same method described for *Cropland Remaining Cropland*, except that the uncertainty inherent in the structure of the Century model was not addressed. The uncertainty for annual C emission estimates from drained organic soils in *Land Converted to Cropland* was estimated using the Tier 2 approach, as described in the *Cropland Remaining Cropland* section.

Uncertainty estimates are presented in Table 7-30 for each subsource (i.e., mineral soil C stocks and organic soil C stocks) disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in agricultural soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006), i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. The combined uncertainty for soil C stocks in *Land Converted to Cropland* was estimated to be 40 percent below and 36 percent above the inventory estimate of 5.9 Tg CO_2 Eq.

Table 7-30: Tier 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within *Land Converted to Cropland* (Tg CO_2 Eq. and Percent)

Source	2009 Flux Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Flux Estimate (Tg CO_2 Eq.)		Uncertainty Range Relative to Flux Estimate (%)	
		Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Mineral Soil C Stocks: Land Converted to Cropland, Tier 3 Inventory Methodology	(0.8)	(1.5)	(0.1)	-84%	+84%
Mineral Soil C Stocks: Land Converted to Cropland, Tier 2 Inventory Methodology	4.1	2.3	5.8	-44%	+41%
Organic Soil C Stocks: Land Converted to Cropland, Tier 2 Inventory Methodology	2.6	1.2	3.7	-53%	+41%
Combined Uncertainty for Flux associated with Soil Carbon Stock Change in Land Converted to Cropland	**5.9**	**3.5**	**8.1**	**-40%**	**+36%**

Note: Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

See QA/QC and Verification section under *Cropland Remaining Cropland*.

Planned Improvements

The empirically-based uncertainty estimator described in the *Cropland Remaining Cropland* section for the Tier 3 approach has not been developed to estimate uncertainties related to the structure of the Century model for *Land Converted to Cropland,* but this is a planned improvement. This improvement will produce a more rigorous assessment of uncertainty. See Planned Improvements section under *Cropland Remaining Cropland* for additional planned improvements.

7.6. Grassland Remaining Grassland (IPCC Source Category 5C1)

Grassland Remaining Grassland includes all grassland in an inventory year that had been grassland for the previous 20 years[188] according to the USDA NRI land use survey (USDA-NRCS 2000). The Inventory includes all privately-owned grasslands in the conterminous United States and Hawaii, but does not address changes in C stocks for grasslands on federal lands, leading to a discrepancy between the total amount of managed area in *Grassland Remaining Grassland* (see Section 7.1) and the grassland area included in the Inventory. While federal grasslands probably have minimal changes in land management and C stocks, plans are being made to further evaluate and potentially include these areas in future C inventories.

Background on agricultural C stock changes is provided in the *Cropland Remaining Cropland* section and will only be summarized here for *Grassland Remaining Grassland.* Soils are the largest pool of C in agricultural land, and also have the greatest potential for storage or release of C, because biomass and dead organic matter C pools are relatively small and ephemeral compared to soils. IPCC (2006) recommends reporting changes in soil organic C stocks due to: (1) agricultural land-use and management activities on mineral soils, and (2) agricultural land-use and management activities on organic soils.[189]

Land-use and management of mineral soils in *Grassland Remaining Grassland* increased soil C, while organic soils lost relatively small amounts of C in each year 1990 through 2009. Due to the pattern for mineral soils, the overall trend was a gain in soil C over the time series although the rates varied from year to year, with a net removal of 8.3 Tg CO_2 Eq. (2.3 Tg C) in 2009. There was considerable variation over the time series driven by variability in weather patterns and associated interaction with land management activity. The change rates on per hectare basis were small, however, even in the years with larger total changes in stocks. Overall, flux rates declined by 43.8 Tg CO_2 Eq. (12.0 Tg C) when comparing the net change in soil C from 1990 and 2009.

Table 7-31: Net CO_2 Flux from Soil C Stock Changes in *Grassland Remaining Grassland* (Tg CO_2 Eq.)

Soil Type	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Mineral Soils	(56.0)		(56.3)		(12.6)	(12.4)	(12.3)	(12.2)	(12.0)
Organic Soils	3.9		3.7		3.7	3.7	3.7	3.7	3.7
Total Net Flux	**(52.2)**		**(52.6)**		**(8.9)**	**(8.8)**	**(8.6)**	**(8.5)**	**(8.3)**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

Table 7-32: Net CO_2 Flux from Soil C Stock Changes in Grassland Remaining Grassland (Tg C)

Soil Type	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Mineral Soils	(15.3)		(15.3)		(3.4)	(3.4)	(3.4)	(3.3)	(3.3)
Organic Soils	1.1		1.0		1.0	1.0	1.0	1.0	1.0
Total Net Flux	**(14.2)**		**(14.3)**		**(2.4)**	**(2.4)**	**(2.3)**	**(2.3)**	**(2.3)**

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[188] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

[189] CO_2 emissions associated with liming are also estimated but included in a separate section of the report.

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

The spatial variability in annual CO_2 flux associated with C stock changes in mineral and organic soils is displayed in Figure 7-9 and Figure 7-10. Grassland gained soil organic C in several regions during 2009, including the Northeast, Midwest, Southwest and far western states; although these were relatively small increases in C on a per-hectare basis. Emission rates from drained organic soils were highest along the southeastern coastal region, in the northeast central United States surrounding the Great Lakes, and along the central and northern portions of the West Coast.

Figure 7-9: Total Net Annual CO_2 Flux for Mineral Soils under Agricultural Management within States, 2009, *Grassland Remaining Grassland*

Figure 7-10: Total Net Annual CO_2 Flux for Organic Soils under Agricultural Management within States, 2009, *Grassland Remaining Grassland*

Methodology

The following section includes a brief description of the methodology used to estimate changes in soil C stocks due to agricultural land-use and management activities on mineral and organic soils for *Grassland Remaining Grassland*. Further elaboration on the methodologies and data used to estimate stock changes from mineral and organic soils are provided in the *Cropland Remaining Cropland* section and Annex 3.13.

Soil C stock changes were estimated for *Grassland Remaining Grassland* according to land-use histories recorded in the USDA NRI survey (USDA-NRCS 2000). Land-use and some management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. However, the NRI program initiated annual data collection in 1998, and the annual data are currently available through 2003. NRI points were classified as *Grassland Remaining Grassland* in a given year between 1990 and 2009 if the land use had been grassland for 20 years. Grassland includes pasture and rangeland used for grass forage production, where the primary use is livestock grazing. Rangelands are typically extensive areas of native grassland that are not intensively managed, while pastures are often seeded grassland, possibly following tree removal, that may or may not be improved with practices such as irrigation and interseeding legumes.

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach was applied to estimate C stock changes for most mineral soils in *Grassland Remaining Grassland*. The C stock changes for the remaining soils were estimated with an IPCC Tier 2 method (Ogle et al. 2003), including gravelly, cobbly, or shaley soils (greater than 35 percent by volume) and additional stock changes associated with sewage sludge amendments.

Tier 3 Approach

Mineral soil organic C stocks and stock changes for *Grassland Remaining Grassland* were estimated using the Century biogeochemical model, as described in *Cropland Remaining Cropland*. Historical land-use and management patterns were used in the Century simulations as recorded in the USDA National Resources Inventory (NRI) survey, with supplemental information on fertilizer use and rates from the USDA Economic Research Service Cropping Practices Survey (ERS 1997) and National Agricultural Statistics Service (NASS 1992, 1999, 2004). Frequency and rates of manure application to grassland during 1997 were estimated from data compiled by the USDA Natural Resources Conservation Service (Edmonds, et al. 2003), and then adjusted using county-level estimates of manure available for application in other years. Specifically, county-scale ratios of manure available for application to soils in other years relative to 1997 were used to adjust the area amended with manure (see Annex 3.13 for further details). Greater availability of managed manure N relative to 1997 was, thus, assumed to increase the area amended with manure, while reduced availability of manure N relative to 1997 was assumed to reduce the amended area.

The amount of manure produced by each livestock type was calculated for managed and unmanaged waste management systems based on methods described in the Manure Management Section (Section 6.2) and Annex (Annex 3.10). In contrast to manure amendments, Pasture/Range/Paddock (PRP) manure N deposition was estimated internally in the Century model, as part of the grassland system simulations (i.e., PRP manure deposition was not an external input into the model). See the Tier 3 methods in *Cropland Remaining Cropland* section for additional discussion on the Tier 3 methodology for mineral soils.

Tier 2 Approach

The Tier 2 approach is based on the same methods described in the Tier 2 portion of *Cropland Remaining Cropland* section for mineral soils (see *Cropland Remaining Cropland* Tier 2 methods section and Annex 3.13 for additional information).

Additional Mineral C Stock Change Calculations

Annual C flux estimates for mineral soils between 1990 and 2009 were adjusted to account for additional C stock changes associated with sewage sludge amendments using a Tier 2 method. Estimates of the amounts of sewage sludge N applied to agricultural land were derived from national data on sewage sludge generation, disposition, and N content. Total sewage sludge generation data for 1988, 1996, and 1998, in dry mass units, were obtained from an EPA report (EPA 1999) and estimates for 2004 were obtained from an independent national biosolids survey (NEBRA 2007). These values were linearly interpolated to estimate values for the intervening years. N application rates from Kellogg et al. (2000) were used to determine the amount of area receiving sludge amendments. Although sewage sludge can be added to land managed for other land uses, it was assumed that agricultural amendments occur in grassland. Cropland is assumed to rarely be amended with sewage sludge due to the high metal content and other pollutants in human waste. The soil C storage rate was estimated at 0.38 metric tons C per hectare per year for sewage sludge amendments to grassland. The stock change rate is based on country-specific factors and the IPCC default method (see Annex 3.13 for further discussion).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Grassland Remaining Grassland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), which utilizes U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. Emissions were based on the 1992 and 1997 *Grassland Remaining Grassland* areas from the *1997 National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty estimates are presented in Table 7-33 for each subsource (i.e., mineral soil C stocks and organic soil C stocks) disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in agricultural soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006), i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. The combined uncertainty for soil C stocks in *Grassland Remaining Grassland* was estimated to be 32 percent below and 25 percent above the inventory estimate of -8.3 Tg CO_2 Eq.

Table 7-33: Tier 2 Quantitative Uncertainty Estimates for C Stock Changes occurring within *Grassland Remaining Grassland* (Tg CO_2 Eq. and Percent)

Source	2009 Flux Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Flux Estimate (Tg CO_2 Eq.)		Uncertainty Range Relative to Flux Estimate (%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mineral Soil C Stocks Grassland Remaining Grassland, Tier 3 Methodology	(10.6)	(11.4)	(9.8)	-7%	+7%

Mineral Soil C Stocks: Grassland Remaining Grassland, Tier 2 Methodology	(0.2)	(0.3)	0.0	-89%	+127%
Mineral Soil C Stocks: Grassland Remaining Grassland, Tier 2 Methodology (Change in Soil C due to Sewage Sludge Amendments)	(1.2)	(1.9)	(0.6)	-50%	+50%
Organic Soil C Stocks: Grassland Remaining Grassland, Tier 2 Methodology	3.7	1.2	5.5	-66%	+49%
Combined Uncertainty for Flux Associated with Agricultural Soil Carbon Stock Change in Grassland Remaining Grassland	**(8.3)**	**(11.0)**	**(6.3)**	**-32%**	**+25%**

Note: Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Uncertainties in Mineral Soil Carbon Stock Changes

The uncertainty analysis for *Grassland Remaining Grassland* using the Tier 3 approach and Tier 2 approach were based on the same method described for *Cropland Remaining Cropland*, except that the uncertainty inherent in the structure of the Century model was not addressed. See the Tier 3 approach for mineral soils under the *Cropland Remaining Cropland* section for additional discussion.

A ±50 percent uncertainty was assumed for additional adjustments to the soil C stocks between 1990 and 2009 to account for additional C stock changes associated with amending grassland soils with sewage sludge.

Uncertainties in Soil Carbon Stock Changes for Organic Soils

Uncertainty in C emissions from organic soils was estimated using country-specific factors and a Monte Carlo analysis. Probability distribution functions for emission factors were derived from a synthesis of 10 studies, and combined with uncertainties in the NRI land use and management data for organic soils in the Monte Carlo analysis. See the Tier 2 section under minerals soils of *Cropland Remaining Cropland* for additional discussion.

QA/QC and Verification

Quality control measures included checking input data, model scripts, and results to ensure data were properly handled through the inventory process. A minor error was found in the post-processing results to compute the final totals, which was corrected. No additional errors were found.

Recalculations Discussion

There were minor changes in the estimated area of grasslands associated with reconciling the forestland areas from the Forest Inventory and Analysis (FIA) survey with the data from the National Resources Inventory (NRI) (see section 7.1 for more information. The revised areas led to small changes in the soil C stock changes for *Grassland Remaining Grassland*.

Planned Improvements

The main planned improvement for the next Inventory is to integrate the assessments of soil C stock changes and soil N_2O emissions into a single analysis. This improvement will ensure that the N and C cycles are treated consistently in the Inventory, which is important because the cycles of these elements are linked through plant and soil processes in agricultural lands. This improvement will include the development of an empirically-based uncertainty analysis, which will provide a more rigorous assessment of uncertainty. See Planned Improvements section under *Cropland Remaining Cropland* for additional planned improvements.

7.7. Land Converted to Grassland (IPCC Source Category 5C2)

Land Converted to Grassland includes all grassland in an inventory year that had been in another land use at any point during the previous 20 years[190] according to the USDA NRI land-use survey (USDA-NRCS 2000). Consequently, lands are retained in this category for 20 years as recommended by IPCC (2006) unless there is another land use change. The Inventory includes all privately-owned grasslands in the conterminous United States and Hawaii, but does not address changes in C stocks for grasslands on federal lands, leading to a discrepancy between the total amount of managed area for *Land Converted to Grassland* (see Section 7.1) and the grassland area included in the Inventory. It is important to note that plans are being made to include these areas in future C inventories.

Background on agricultural C stock changes is provided in *Cropland Remaining Cropland* and will only be summarized here for *Land Converted to Grassland*. Soils are the largest pool of C in agricultural land, and also have the greatest potential for storage or release of C, because biomass and dead organic matter C pools are relatively small and ephemeral compared with soils. IPCC (2006) recommend reporting changes in soil organic C stocks due to: (1) agricultural land-use and management activities on mineral soils, and (2) agricultural land-use and management activities on organic soils.[191]

Land-use and management of mineral soils in *Land Converted to Grassland* led to an increase in soil C stocks from 1990 through 2009, which was largely due to annual cropland conversion to pasture (see Table 7-34 and Table 7-35). For example, the stock change rates were estimated to remove 20.3 Tg CO_2 Eq./yr (5.5 Tg C) and 24.5 Tg CO_2 Eq./yr (6.7 Tg C) from mineral soils in 1990 and 2009, respectively. Drainage of organic soils for grazing management led to losses varying from 0.5 to 0.9 Tg CO_2 Eq./yr (0.1 to 0.2 Tg C).

Table 7-34: Net CO_2 Flux from Soil C Stock Changes for *Land Converted to Grassland* (Tg CO_2 Eq.)

Soil Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Mineral Soils[a]	(20.3)	(28.1)	(25.3)	(25.1)	(24.9)	(24.7)	(24.5)
Organic Soils	0.5	0.9	0.9	0.9	0.9	0.9	0.9
Total Net Flux	**(19.8)**	**(27.2)**	**(24.4)**	**(24.2)**	**(24.0)**	**(23.8)**	**(23.6)**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.
[a] Stock changes due to application of sewage sludge are reported in *Grassland Remaining Grassland*.

Table 7-35: Net CO_2 Flux from Soil C Stock Changes for *Land Converted to Grassland* (Tg C)

Soil Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Mineral Soils[a]	(5.5)	(7.7)	(6.9)	(6.8)	(6.8)	(6.7)	(6.7)
Organic Soils	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Total Net Flux	**(5.4)**	**(7.4)**	**(6.7)**	**(6.6)**	**(6.5)**	**(6.5)**	**(6.4)**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.
[a] Stock changes due to application of sewage sludge in *Land Converted to Grassland* are reported in *Grassland Remaining Grassland*.

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The spatial variability in annual CO_2 flux associated with C stock changes in mineral soils is displayed in Figure 7-11and Figure 7-12. Soil C stock increased in most states for *Land Converted to Grassland*. The largest gains were in the South-Central region, Midwest, and northern Great Plains. The patterns were driven by conversion of annual cropland into continuous pasture. Emissions from organic soils were largest in California, Florida, and the upper Midwest, coinciding with largest concentrations of organic soils in the United States that are used for agricultural production.

Figure 7-11: Total Net Annual CO_2 Flux for Mineral Soils under Agricultural Management within States, 2009,

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[190] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

[191] CO_2 emissions associated with liming are also estimated but included in a separate section of the report.

Land Converted to Grassland

Figure 7-12: Total Net Annual CO_2 Flux for Organic Soils under Agricultural Management within States, 2009, *Land Converted to Grassland*

Methodology

This section includes a brief description of the methodology used to estimate changes in soil C stocks due to agricultural land-use and management activities on mineral soils for *Land Converted to Grassland*. Biomass C stock changes are not explicitly included in this category but losses of associated with conversion of forest to grassland are included in the *Forest Land Remaining Forest Land* section. Further elaboration on the methodologies and data used to estimate stock changes from mineral and organic soils are provided in the *Cropland Remaining Cropland* section and Annex 3.13.

Soil C stock changes were estimated for *Land Converted to Grassland* according to land-use histories recorded in the USDA NRI survey (USDA-NRCS 2000). Land-use and some management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. However, the NRI program initiated annual data collection in 1998, and the annual data are currently available through 2003. NRI points were classified as *Land Converted to Grassland* in a given year between 1990 and 2009 if the land use was grassland, but had been another use in the previous 20 years. Grassland includes pasture and rangeland used for grass forage production, where the primary use is livestock grazing. Rangeland typically includes extensive areas of native grassland that are not intensively managed, while pastures are often seeded grassland, possibly following tree removal, that may or may not be improved with practices such as irrigation and interseeding legumes.

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach was applied to estimate C stock changes for *Land Converted to Grassland* on most mineral soils. C stock changes on the remaining soils were estimated with an IPCC Tier 2 approach (Ogle et al. 2003), including prior cropland used to produce vegetables, tobacco, perennial/horticultural crops, and rice; land areas with very gravelly, cobbly, or shaley soils (greater than 35 percent by volume); and land converted from forest or federal ownership.[192] A Tier 2 approach was also used to estimate additional changes in mineral soil C stocks due to sewage sludge amendments. However, stock changes associated with sewage sludge amendments are reported in the *Grassland Remaining Grassland* section.

Tier 3 Approach

Mineral SOC stocks and stock changes were estimated using the Century biogeochemical model as described for *Grassland Remaining Grassland*. Historical land-use and management patterns were used in the Century simulations as recorded in the NRI survey, with supplemental information on fertilizer use and rates from the USDA Economic Research Service Cropping Practices Survey (ERS 1997) and the National Agricultural Statistics Service (NASS 1992, 1999, 2004) (see *Grassland Remaining Grassland* Tier 3 methods section for additional information).

Tier 2 Approach

The Tier 2 approach used for *Land Converted to Grassland* on mineral soils is the same as described for *Cropland Remaining Cropland* (See *Cropland Remaining Cropland* Tier 2 Approach and Annex 3.13 for additional information).

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[192] Federal land is not a land use, but rather an ownership designation that is treated as forest or nominal grassland for purposes of these calculations. The specific use for federal lands is not identified in the NRI survey (USDA-NRCS 2000).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Land Converted to Grassland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), which utilizes U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. Emissions were based on the 1992 and 1997 *Land Converted to Grassland* areas from the *1997 National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty analysis for mineral soil C stock changes using the Tier 3 and Tier 2 approaches were based on the same method described in *Cropland Remaining Cropland*, except that the uncertainty inherent in the structure of the Century model was not addressed. The uncertainty or annual C emission estimates from drained organic soils in *Land Converted to Grassland* was estimated using the Tier 2 approach, as described in the *Cropland Remaining Cropland* section.

Uncertainty estimates are presented in Table 7-36 for each subsource (i.e., mineral soil C stocks and organic soil C stocks), disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in agricultural soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006) (i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities). The combined uncertainty for soil C stocks in *Land Converted to Grassland* ranged from 15 percent below to 15 percent above the 2009 estimate of -23.6 Tg CO_2 Eq.

Table 7-36: Tier 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within *Land Converted to Grassland* (Tg CO_2 Eq. and Percent)

Source	2009 Flux Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Flux Estimate (Tg CO_2 Eq.)		Uncertainty Range Relative to Flux Estimate (%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mineral Soil C Stocks: Land Converted to Grassland, Tier 3 Inventory Methodology	(19.5)	(22.2)	(16.7)	-14%	+14%
Mineral Soil C Stocks: Land Converted to Grassland, Tier 2 Inventory Methodology	(5.0)	(7.0)	(2.8)	-39%	+43%
Organic Soil C Stocks: Land Converted to Grassland, Tier 2 Inventory Methodology	0.9	0.2	1.8	-76%	+104%
Combined Uncertainty for Flux associated with Agricultural Soil Carbon Stocks in Land Converted to Grassland	**(23.6)**	**(27.0)**	**(20.0)**	**-15%**	**+15%**

Note: Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

See the QA/QC and Verification section under *Grassland Remaining Grassland*.

Recalculations Discussion

There were minor changes in the current Inventory relative to the previous version in the estimated area of grasslands associated with reconciling the forestland areas from the Forest Inventory and Analysis (FIA) survey with the data from the National Resources Inventory (NRI) (see section 7.1 for more information). The revised areas led to small changes in the soil C stock changes for *Land Converted to Grassland*.

Planned Improvements

The main planned improvement for the next Inventory is to integrate the assessments of soil C stock changes and soil nitrous oxide emissions into a single analysis. This improvement will ensure that the nitrogen and carbon cycles are treated consistently in the national inventory, which is important because the cycles of these elements are linked through plant and soil processes in agricultural lands. This improvement will include the development of an empirically-based uncertainty analysis, which will provide a more rigorous assessment of uncertainty. See Planned Improvements section under *Cropland Remaining Cropland* for additional planned improvements.

7.8. *Wetlands Remaining Wetlands*

Peatlands Remaining Peatlands

Emissions from Managed Peatlands

Managed peatlands are peatlands which have been cleared and drained for the production of peat. The production cycle of a managed peatland has three phases: land conversion in preparation for peat extraction (e.g., draining, and clearing surface biomass), extraction (which results in the emissions reported under *Peatlands Remaining Peatlands*), and abandonment, restoration or conversion of the land to another use.

CO_2 emissions from the removal of biomass and the decay of drained peat constitute the major greenhouse gas flux from managed peatlands. Managed peatlands may also emit CH_4 and N_2O. The natural production of CH_4 is largely reduced but not entirely shut down when peatlands are drained in preparation for peat extraction (Strack et al., 2004 as cited in IPCC 2006); however, CH_4 emissions are assumed to be insignificant under Tier 1 (IPCC, 2006). N_2O emissions from managed peatlands depend on site fertility. In addition, abandoned and restored peatlands continue to release greenhouse gas emissions, and at present no methodology is provided by IPCC (2006) to estimate greenhouse gas emissions or removals from restored peatlands. This inventory estimates both CO_2 and N_2O emissions from *Peatlands Remaining Peatlands* in accordance with Tier 1 IPCC (2006) guidelines.

CO_2 and N_2O Emissions from *Peatlands Remaining Peatlands*

IPCC (2006) recommends reporting CO_2 and N_2O emissions from lands undergoing active peat extraction (i.e., *Peatlands Remaining Peatlands*) as part of the estimate for emissions from managed wetlands. Peatlands occur in wetland areas where plant biomass has sunk to the bottom of water bodies and water-logged areas and exhausted the oxygen supply below the water surface during the course of decay. Due to these anaerobic conditions, much of the plant matter does not decompose but instead forms layers of peat over decades and centuries. In the United States, peat is extracted for horticulture and landscaping growing media, and for a wide variety of industrial, personal care, and other products. It has not been used for fuel in the United States for many decades. Peat is harvested from two types of peat deposits in the United States: sphagnum bogs in northern states and wetlands in states further south. The peat from sphagnum bogs in northern states, which is nutrient poor, is generally corrected for acidity and mixed with fertilizer. Production from more southerly states is relatively coarse (i.e., fibrous) but nutrient rich.

IPCC (2006) recommends considering both on-site and off-site emissions when estimating CO_2 emissions from *Peatlands Remaining Peatlands* using the Tier 1 approach. Current methodologies estimate only on-site N_2O emissions, since off-site N_2O estimates are complicated by the risk of double-counting emissions from nitrogen fertilizers added to horticultural peat. On-site emissions from managed peatlands occur as the land is cleared of vegetation and the underlying peat is exposed to sun and weather. As this occurs, some peat deposit is lost and CO_2 is emitted from the oxidation of the peat. On-site N_2O is emitted during draining depending on site fertility and if the deposit contains significant amounts of organic nitrogen in inactive form. Draining land in preparation for peat extraction allows bacteria to convert the nitrogen into nitrates which leach to the surface where they are reduced to N_2O.

Off-site CO_2 emissions from managed peatlands occur from the horticultural and landscaping use of peat. CO_2 emissions occur as the nutrient-poor (but now fertilizer-enriched) peat is used in bedding plants, other greenhouse and plant nursery production, and by consumers, and as nutrient-rich (but relatively coarse) peat is used directly in landscaping, athletic fields, golf courses, and plant nurseries. Most of the CO_2 emissions from peat occur off-site, as the peat is processed and sold to firms which, in the United States, use it predominately for horticultural purposes. The magnitude of the CO_2 emitted from peat depends on whether the peat has been extracted from nutrient-rich or nutrient-poor peat deposits.

Total emissions from *Peatlands Remaining Peatlands* were estimated to be 1.095 Tg CO_2 Eq. in 2009 (see Table 7-37) comprising 1.090 Tg CO_2 Eq. (1,090 Gg) of CO_2 and 0.005 Tg CO_2 Eq. (0.016 Gg) of N_2O. Total emissions in 2009 were about 10 percent larger than total emissions in 2008, with the increase due to the higher peat production reported in Alaska in 2009.

Total emissions from *Peatlands Remaining Peatlands* have fluctuated between 0.88 and 1.23 Tg CO_2 Eq. across the time series with a decreasing trend from 1990 until 1994 followed by an increasing trend through 2000. Since 2000, total emissions show a decreasing trend until 2006 followed by an increasing trend in recent years. CO_2 emissions from *Peatlands Remaining Peatlands* have fluctuated between 0.88 and 1.23 Tg CO_2 across the time series and drive the trends in total emissions. N_2O emissions remained close to zero across the time series, with a decreasing trend from 1990 until 1995 followed by an increasing trend through 2000. N_2O emissions decreased between 2000 and 2008, followed by a leveling off in 2009.

Table 7-37: Emissions from *Peatlands Remaining Peatlands* (Tg CO_2 Eq.)

Gas	1990		2000		2005	2006	2007	2008	2009
CO_2	1.0		1.2		1.1	0.9	1.0	1.0	1.1
N_2O	+		+		+	+	+	+	+
Total	**1.0**		**1.2**		**1.1**	**0.9**	**1.0**	**1.0**	**1.1**

+ Less than 0.01 Tg CO_2 Eq.

Note: These numbers are based on U.S. production data in accordance with Tier 1 guidelines, which does not take into account imports, exports and stockpiles (i.e., apparent consumption).

Table 7-38: Emissions from *Peatlands Remaining Peatlands* (Gg)

Gas	1990		2000		2005	2006	2007	2008	2009
CO_2	1,033		1,227		1,079	879	1,012	992	1,090
N_2O	+		+		+	+	+	+	+

+ Less than 0.05 Gg

Note: These numbers are based on U.S. production data in accordance with Tier 1 guidelines, which does not take into account imports, exports and stockpiles (i.e., apparent consumption).

Methodology

Off-Site CO_2 Emissions

CO_2 emissions from domestic peat production were estimated using a Tier 1 methodology consistent with IPCC (2006). Off-site CO_2 emissions from *Peatlands Remaining Peatlands* were calculated by apportioning the annual weight of peat produced in the United States (Table 7-39) into peat extracted from nutrient-rich deposits and peat extracted from nutrient-poor deposits using annual percentage by weight figures. These nutrient-rich and nutrient-poor production values were then multiplied by the appropriate default carbon fraction conversion factor taken from IPCC (2006) in order to obtain off-site emission estimates. For the lower 48 states, both annual percentages of peat type by weight and domestic peat production data were sourced from estimates and industry statistics provided in the *Minerals Yearbook* and *Mineral Commodity Summaries* from the U.S. Geological Survey (USGS 1991–2010). To develop these data, the U.S. Geological Survey (USGS; U.S. Bureau of Mines prior to 1997) obtained production and use information by surveying domestic peat producers. The USGS often receives a response to the survey from most of the smaller peat producers, but fewer of the larger ones. For example, of the four active operations producing 23,000 or more metric tons per year, two did not respond to the survey in 2007. As a result, the USGS estimates production from the non-respondent peat producers based on responses to previous surveys (responses from 2004 and 2005, in the case above) or other sources.

The Alaska estimates rely on reported peat production from Alaska's annual Mineral Industry Reports (Szumigala et al. 2010). Similar to the U.S. Geological Survey, Alaska's Mineral Industry Report methodology solicits voluntary reporting of peat production from producers. However, the report does not estimate production for the non-reporting producers, resulting in larger inter-annual variation in reported peat production from Alaska depending on the number of producers who report in a given year (Szumigala 2011). In addition, in both the lower 48 states and Alaska, large variations in peat production can also result from variations in precipitation and the subsequent moisture conditions, since unusually wet years can hamper peat production (USGS 2010). The methodology estimates Alaska emissions separately from lower 48 emissions because the state conducts its own mineral survey and reports peat production by volume, rather than by weight (Table 7-40). However, volume production data was used to calculate off-site CO_2 emissions from Alaska applying the same methodology but with volume-specific carbon fraction conversion factors from IPCC (2006).[193]

The *apparent consumption* of peat, which includes production plus imports minus exports plus the decrease in stockpiles, in the United States is over two-and-a-half times the amount of domestic peat production. Therefore, off-site CO_2 emissions from the use of all horticultural peat within the United States are not accounted for using the Tier 1 approach. The United States has increasingly imported peat from Canada for horticultural purposes; from 2005 to 2008, imports of sphagnum moss (nutrient-poor) peat from Canada represented 97 percent of total U.S. peat imports (USGS 2010). Most peat produced in the United States is reed-sedge peat, generally from southern states, which is classified as nutrient rich by IPCC (2006). Higher-tier calculations of CO_2 emissions from apparent consumption would involve consideration of the percentages of peat types stockpiled (nutrient rich versus nutrient poor) as well as the percentages of peat types imported and exported.

Table 7-39: Peat Production of Lower 48 States (in thousands of Metric Tons)

Type of Deposit	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Nutrient-Rich	595.1		728.6		657.6	529.0	581.0	559.7	554.2
Nutrient-Poor	55.4		63.4		27.4	22.0	54.0	55.4	54.8
Total Production	**692.0**		**792.0**		**685.0**	**551.0**	**635.0**	**615.0**	**609.0**

Sources: *Minerals Yearbook: Peat* (1990–2008 Reports), *Mineral Commodity Summaries: Peat* (1996–2009 Reports), and Apodaca (2010). United States Geological Survey.

Table 7-40: Peat Production of Alaska (in thousands of Cubic Meters)

	1990		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Total Production	**49.7**		**27.2**		**47.8**	**50.8**	**52.3**	**64.1**	**183.9**

Sources: *Alaska's Mineral Industry* (1992–2009) Reports. Division of Geological & Geophysical Surveys, Alaska Department of Natural Resources.

On-site CO_2 Emissions

IPCC (2006) suggests basing the calculation of on-site emissions estimates on the area of peatlands managed for peat extraction differentiated by the nutrient type of the deposit (rich versus poor). Information on the area of land managed for peat extraction is currently not available for the United States, but in accordance with IPCC (2006), an average production rate for the industry was applied to derive an area estimate. In a mature industrialized peat industry, such as exists in the United States and Canada, the vacuum method[194] can extract up to 100 metric ton per hectare per year (Cleary et al. 2005 as cited in IPCC 2006). The area of land managed for peat extraction in the United States was estimated using nutrient-rich and nutrient-poor production data and the assumption that 100 metric tons of peat are extracted from a single hectare in a single year. The annual land area estimates were then multiplied by the appropriate nutrient-rich or nutrient-poor IPCC (2006) default emission factor in order to calculate on-site CO_2 emission estimates. Production data are not available by weight for Alaska. In order to calculate on-site emissions resulting from *Peatlands Remaining Peatlands* in Alaska, the production data by volume were converted to weight using annual average bulk peat density values, and then converted to land area estimates using the same assumption that a single hectare yields 100 metric tons. The IPCC (2006) on-site emissions equation also includes a term which accounts for emissions resulting from the change in carbon stocks that occurs during the clearing of vegetation prior to peat extraction. Area data on land undergoing conversion to peatlands for peat extraction is also unavailable for the United States. However, USGS records show that the number of active operations in the United

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[193] Peat produced from Alaska was assumed to be nutrient poor; as is the case in Canada, "where deposits of high-quality [but nutrient poor] sphagnum moss are extensive" (USGS 2008).

[194] The vacuum method is one type of extraction that annually "mills" or breaks up the surface of the peat into particles, which then dry during the summer months. The air-dried peat particles are then collected by vacuum harvesters and transported from the area to stockpiles (IPCC 2006).

States has been declining since 1990; therefore it seems reasonable to assume that no new areas are being cleared of vegetation for managed peat extraction. Other changes in carbon stocks in living biomass on managed peatlands are also assumed to be zero under the Tier 1 methodology (IPCC 2006).

On-site N_2O Emissions

IPCC (2006) suggests basing the calculation of on-site N_2O emissions estimates on the area of nutrient-rich peatlands managed for peat extraction. These area data are not available directly for the United States, but the on-site CO_2 emissions methodology above details the calculation of area data from production data. In order to estimate N_2O emissions, the area of nutrient rich *Peatlands Remaining Peatlands* was multiplied by the appropriate default emission factor taken from IPCC (2006).

Uncertainty

The uncertainty associated with peat production data was estimated to be ± 25 percent (Apodaca 2008) and assumed to be normally distributed. The uncertainty associated with peat production data stems from the fact that the USGS receives data from the smaller peat producers but estimates production from some larger peat distributors. This same uncertainty and distribution was assumed for the peat type production percentages. The uncertainty associated with the Alaskan reported production data was assumed to be the same as the lower 48 states, or ± 25 percent with a normal distribution. It should be noted that the Alaskan Department of Natural Resources estimate that around half of producers do not respond to their survey with peat production data; therefore, the production numbers reported are likely to underestimate Alaska peat production (Szumigala 2008). The uncertainty associated with the average bulk density values was estimated to be ± 25 percent with a normal distribution (Apodaca 2008). IPCC (2006) gives uncertainty values for the emissions factors for the area of peat deposits managed for peat extraction based on the range of underlying data used to determine the emissions factors. The uncertainty associated with the emission factors was assumed to be triangularly distributed. The uncertainty values surrounding the carbon fractions were based on IPCC (2006) and the uncertainty was assumed to be uniformly distributed. Based on these values and distributions, a Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the uncertainty of CO_2 and N_2O emissions from *Peatlands Remaining Peatlands*. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-41. CO_2 emissions from *Peatlands Remaining Peatlands* in 2009 were estimated to be between 0.8 and 1.5 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of 30 percent below to 34 percent above the 2009 emission estimate of 1.1 Tg CO_2 Eq. N_2O emissions from *Peatlands Remaining Peatlands* in 2009 were estimated to be between 0.001 and 0.007 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of 74 percent below to 41 percent above the 2009 emission estimate of 0.005 Tg CO_2 Eq.

Table 7-41: Tier-2 Quantitative Uncertainty Estimates for CO_2 Emissions from *Peatlands Remaining Peatlands*

Source	**Gas**	**2009 Emissions Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emissions Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Peatlands Remaining Peatlands	CO_2	1.1	0.8	1.5	-30%	34%
	N_2O	+	+	+	-74%	41%

+ Does not exceed 0.01 Tg CO_2 Eq. or 0.5 Gg.

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. The QA/QC analysis did not reveal any inaccuracies or incorrect input values.

Recalculations Discussion

The current Inventory represents the third Inventory report in which emissions from *Peatlands Remaining Peatlands* are included . A revised 2008 estimate of peat production by volume for Alaska was reported in 2010 (Szumigala et al. 2010). Updating the 2008 production data with this revised estimate led to a 5 percent increase over the previous 2008 emission estimate.

Planned Improvements

In order to further improve estimates of CO_2 and N_2O emissions from *Peatlands Remaining Peatlands*, future efforts will consider options for obtaining better data on the quantity of peat harvested per hectare and the total area undergoing peat extraction.

7.9. Settlements Remaining Settlements

Changes in Carbon Stocks in Urban Trees (IPCC Source Category 5E1)

Urban forests constitute a significant portion of the total U.S. tree canopy cover (Dwyer et al. 2000). Urban areas (cities, towns, and villages) are estimated to cover over 4 percent of the United States (Nowak et al. 2005). With an average tree canopy cover of 27 percent, urban areas account for approximately 3 percent of total tree cover in the continental United States (Nowak et al. 2001). Trees in urban areas of the United States were estimated to account for an average annual net sequestration of 76.5 Tg CO_2 Eq. (20.9 Tg C) over the period from 1990 through 2009. Net C flux from urban trees in 2009 was estimated to be -95.9 Tg CO_2 Eq. (-26.2 Tg C). Annual estimates of CO_2 flux (Table 7-42) were developed based on periodic (1990 and 2000) U.S. Census data on urbanized area. This estimated urban area is smaller than the area categorized as *Settlements* in the Representation of the U.S. Land Base developed for this report, by an average of 21 percent over the 1990 through 2009 time series—i.e., the Census urban area is a subset of the *Settlements* area. Census area data are preferentially used to develop C flux estimates for this source category since these data are more applicable for use with the available peer-reviewed data on urban tree canopy cover and urban tree C sequestration. Annual sequestration increased by 68 percent between 1990 and 2009 due to increases in urban land area. Data on C storage and urban tree coverage were collected since the early 1990s and have been applied to the entire time series in this report.

Net C flux from urban trees is proportionately greater on an area basis than that of forests. This trend is primarily the result of different net growth rates in urban areas versus forests—urban trees often grow faster than forest trees because of the relatively open structure of the urban forest (Nowak and Crane 2002). However, areas in each case are accounted for differently. Because urban areas contain less tree coverage than forest areas, the C storage per hectare of land is in fact smaller for urban areas. However, urban tree reporting occurs on a basis of C sequestered per unit area of tree cover, rather than C sequestered per total land area. Areas covered by urban trees, therefore, appear to have a greater C density than do forested areas (Nowak and Crane 2002).

Table 7-42: Net C Flux from Urban Trees (Tg CO_2 Eq. and Tg C)

Year	Tg CO_2 Eq.	Tg C
1990	(57.1)	(15.6)
2000	(77.5)	(21.1)
2005	(87.8)	(23.9)
2006	(89.8)	(24.5)
2007	(91.9)	(25.1)
2008	(93.9)	(25.6)
2009	(95.9)	(26.2)

Note: Parentheses indicate net sequestration.

Methodology

Methods for quantifying urban tree biomass, C sequestration, and C emissions from tree mortality and decomposition were taken directly from Nowak and Crane (2002) and Nowak (1994). In general, the methodology used by Nowak and Crane (2002) to estimate net C sequestration in urban trees followed three steps. First, field data from 14 cities were used to generate allometric estimates of biomass from measured tree dimensions. Second, estimates of tree growth and biomass increment were generated from published literature and adjusted for tree condition and land-use class to generate estimates of gross C sequestration in urban trees. Third, estimates of C emissions due to mortality and decomposition were subtracted from gross C sequestration values to derive estimates of net C sequestration. Sequestration estimates for these cities, in units of carbon sequestered per unit area of tree cover, were then used to estimate urban forest C sequestration in the U.S. by using urban area estimates from U.S. Census data and urban tree cover estimates from remote sensing data, an approach consistent with Nowak and Crane (2002).

This approach is also consistent with the default IPCC methodology in IPCC (2006), although sufficient data are not yet available to separately determine interannual gains and losses in C stocks in the living biomass of urban trees. Annual changes in net C flux from urban trees are based solely on changes in total urban area in the United States.

In order to generate the allometric relationships between tree dimensions and tree biomass, Nowak and Crane (2002) and Nowak (1994, 2007c, 2009) collected field measurements in a number of U.S. cities between 1989 and 2002. For a sample of trees in each of the cities in Table 7-43, data including tree measurements of stem diameter, tree height, crown height and crown width, and information on location, species, and canopy condition were collected. The data for each tree were converted into C storage by applying allometric equations to estimate aboveground biomass, a root-to-shoot ratio to convert aboveground biomass estimates to whole tree biomass, moisture content, a C content of 50 percent (dry weight basis), and an adjustment factor of 0.8 to account for urban trees having less aboveground biomass for a given stem diameter than predicted by allometric equations based on forest trees (Nowak 1994). C storage estimates for deciduous trees include only carbon stored in wood. These calculations were then used to develop an allometric equation relating tree dimensions to C storage for each species of tree, encompassing a range of diameters.

Tree growth was estimated using annual height growth and diameter growth rates for specific land uses and diameter classes. Growth calculations were adjusted by a factor to account for tree condition (fair to excellent, poor, critical, dying, or dead). For each tree, the difference in C storage estimates between year 1 and year (x + 1) represents the gross amount of C sequestered. These annual gross C sequestration rates for each species (or genus), diameter class, and land-use condition (e.g., parks, transportation, vacant, golf courses) were then scaled up to city estimates using tree population information. The area of assessment for each city was defined by its political boundaries; parks and other forested urban areas were thus included in sequestration estimates (Nowak 2011).

Most of the field data used to develop the methodology of Nowak et al. were analyzed using the U.S. Forest Service's Urban Forest Effects (UFORE) model. UFORE is a computer model that uses standardized field data from random plots in each city and local air pollution and meteorological data to quantify urban forest structure, values of the urban forest, and environmental effects, including total C stored and annual C sequestration. UFORE was used with field data from a stratified random sample of plots in each city to quantify the characteristics of the urban forest. (Nowak et al. 2007a).

Gross C emissions result from tree death and removals. Estimates of gross C emissions from urban trees were derived by applying estimates of annual mortality and condition, and assumptions about whether dead trees were removed from the site to the total C stock estimate for each city. Estimates of annual mortality rates by diameter class and condition class were derived from a study of street-tree mortality (Nowak 1986). Different decomposition rates were applied to dead trees left standing compared with those removed from the site. For removed trees, different rates were applied to the removed/aboveground biomass in contrast to the belowground biomass. The estimated annual gross C emission rates for each species (or genus), diameter class, and condition class were then scaled up to city estimates using tree population information.

The field data for 13 of the 14 cities are described in Nowak and Crane (2002), Nowak et al. (2007a), and references cited therein. Data for the remaining city, Chicago, were taken from unpublished results (Nowak 2009). The allometric equations applied to the field data for each tree were taken from the scientific literature (see Nowak 1994, Nowak et al. 2002), but if no allometric equation could be found for the particular species, the average result for the genus was used. The adjustment (0.8) to account for less live tree biomass in urban trees was based on information in Nowak (1994). A root-to-shoot ratio of 0.26 was taken from Cairns et al. (1997), and species- or genus-specific moisture contents were taken from various literature sources (see Nowak 1994). Tree growth rates were taken from existing literature. Average diameter growth was based on the following sources: estimates for trees in forest stands came from Smith and Shifley (1984); estimates for trees on land uses with a park-like structure came from deVries (1987); and estimates for more open-grown trees came from Nowak (1994). Formulas from Fleming (1988) formed the basis for average height growth calculations. As described above, growth rates were adjusted to account for tree condition. Growth factors for Atlanta, Boston, Freehold, Jersey City, Moorestown, New York, Philadelphia, and Woodbridge were adjusted based on the typical growth conditions of different land-use categories (e.g., forest stands, park-like stands). Growth factors for the more recent studies in Baltimore, Chicago, Minneapolis, San

Francisco, Syracuse, and Washington were adjusted using an updated methodology based on the condition of each individual tree, which is determined using tree competition factors (depending on whether it is open grown or suppressed) (Nowak 2007b). Assumptions for which dead trees would be removed versus left standing were developed specific to each land use and were based on expert judgment of the authors. Decomposition rates were based on literature estimates (Nowak and Crane 2002).

Estimates of gross and net sequestration rates for each of the 14 cities (Table 7-43) were compiled in units of C sequestration per unit area of tree canopy cover. These rates were used in conjunction with estimates of national urban area and urban tree cover data to calculate national annual net C sequestration by urban trees for the United States. This method was described in Nowak and Crane (2002) and has been modified to incorporate U.S. Census data.

Specifically, urban area estimates were based on 1990 and 2000 U.S. Census data. The 1990 U.S. Census defined urban land as “urbanized areas,” which included land with a population density greater than 1,000 people per square mile, and adjacent “urban places,” which had predefined political boundaries and a population total greater than 2,500. In 2000, the U.S. Census replaced the “urban places” category with a new category of urban land called an “urban cluster,” which included areas with more than 500 people per square mile. Urban land area increased by approximately 36 percent from 1990 to 2000; Nowak et al. (2005) estimate that the changes in the definition of urban land are responsible for approximately 20 percent of the total reported increase in urban land area from 1990 to 2000. Under both 1990 and 2000 definitions, the urban category encompasses most cities, towns, and villages (i.e., it includes both urban and suburban areas).

Settlements area, as assessed in the Representation of the U.S. Land Base developed for this report, encompassed all developed parcels greater than 0.1 hectares in size, including rural transportation corridors, and as previously mentioned represent a larger area than the Census-derived urban area estimates. However, the Census-derived urban area estimates were deemed to be more suitable for estimating national urban tree cover given the data available in the peer-reviewed literature. Specifically, tree canopy cover of U.S. urban areas was estimated by Nowak et al. (2001) to be 27 percent, assessed across Census-delineated urbanized areas, urban places, and places containing urbanized area. This canopy cover percentage is multiplied by the urban area estimated for each year to produce an estimate of national urban tree cover area.

Net annual C sequestration estimates were derived for the 14 cities by subtracting the gross annual emission estimates from the gross annual sequestration estimates. The gross and net annual C sequestration values for each city were divided by each city’s area of tree cover to determine the average annual sequestration rates per unit of tree area for each city. The median value for gross sequestration per unit area of tree cover (0.29 kg C/m^2-yr) was then multiplied by the estimate of national urban tree cover area to estimate national annual gross sequestration, per the methods of Nowak and Crane (2002). To estimate national annual net sequestration, the estimate of national annual gross sequestration was multiplied by the average of the ratios of net to gross sequestration (0.72) for those cities that had both estimates. The urban tree cover estimates for each of the 14 cities and the United States were obtained from Dwyer et al. (2000), Nowak et al. (2002), Nowak (2007a), and Nowak (2009). The urban area estimates were taken from Nowak et al. (2005).

Table 7-43: C Stocks (Metric Tons C), Annual C Sequestration (Metric Tons C/yr), Tree Cover (Percent), and Annual C Sequestration per Area of Tree Cover (kg C/m^2-yr) for 14 U.S. Cities

City	Carbon Stocks	Gross Annual Sequestration	Net Annual Sequestration	Tree Cover	Gross Annual Sequestration per Area of Tree Cover	Net Annual Sequestration per Area of Tree Cover	Net:Gross Annual Sequestration Ratio
Atlanta, GA	1,219,256	42,093	32,169	36.7%	0.34	0.26	0.76
Baltimore, MD	541,589	14,696	9,261	21.0%	0.35	0.22	0.63
Boston, MA	289,392	9,525	6,966	22.3%	0.30	0.22	0.73
Chicago, IL	649,000	22,800	16,100	17.2%	0.22	0.16	0.71
Freehold, NJ	18,144	494	318	34.4%	0.28	0.18	0.64
Jersey City, NJ	19,051	807	577	11.5%	0.18	0.13	0.71
Minneapolis, MN	226,796	8,074	4,265	26.4%	0.20	0.11	0.53
Moorestown, NJ	106,141	3,411	2,577	28.0%	0.32	0.24	0.76
New York, NY	1,224,699	38,374	20,786	20.9%	0.23	0.12	0.54
Philadelphia, PA	480,808	14,606	10,530	15.7%	0.27	0.20	0.72

San Francisco, CA	175,994	4,627	4,152	11.9%	0.33	0.29	0.90
Syracuse, NY	156,943	4,917	4,270	23.1%	0.33	0.29	0.87
Washington, DC	477,179	14,696	11,661	28.6%	0.32	0.26	0.79
Woodbridge, NJ	145,150	5,044	3,663	29.5%	0.28	0.21	0.73
					Median: 0.29		**Mean:** 0.72

NA = not analyzed.
Sources: Nowak and Crane (2002), Nowak (2007a,c), and Nowak (2009).

Uncertainty and Time-Series Consistency

Uncertainty associated with changes in C stocks in urban trees includes the uncertainty associated with urban area, percent urban tree coverage, and estimates of gross and net C sequestration for each of the 14 U.S. cities. A 10 percent uncertainty was associated with urban area estimates while a 5 percent uncertainty was associated with percent urban tree coverage. Both of these uncertainty estimates were based on expert judgment. Uncertainty associated with estimates of gross and net C sequestration for each of the 14 U.S. cities was based on standard error estimates for each of the city-level sequestration estimates reported by Nowak (2007c) and Nowak (2009). These estimates are based on field data collected in each of the 14 U.S. cities, and uncertainty in these estimates increases as they are scaled up to the national level.

Additional uncertainty is associated with the biomass equations, conversion factors, and decomposition assumptions used to calculate C sequestration and emission estimates (Nowak et al. 2002). These results also exclude changes in soil C stocks, and there may be some overlap between the urban tree C estimates and the forest tree C estimates. Due to data limitations, urban soil flux is not quantified as part of this analysis, while reconciliation of urban tree and forest tree estimates will be addressed through the land-representation effort described in the Planned Improvements section of this chapter.

A Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the overall uncertainty of the sequestration estimate. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-44. The net C flux from changes in C stocks in urban trees in 2009 was estimated to be between -116.8 and -77.7 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 22 percent below and 19 percent above the 2009 flux estimate of -95.9 Tg CO_2 Eq.

Table 7-44: Tier 2 Quantitative Uncertainty Estimates for Net C Flux from Changes in C Stocks in Urban Trees (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Flux Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Flux Estimate (Tg CO_2 Eq.)		(%)	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Changes in C Stocks in Urban Trees	CO_2	(95.9)	(116.8)	(77.7)	−22%	+19%

Note: Parentheses indicate negative values or net sequestration.

Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

The net C flux resulting from urban trees was predominately calculated using estimates of gross and net C sequestration estimates for urban trees and urban tree coverage area published in the literature. The validity of these data for their use in this section of the inventory was evaluated through correspondence established with an author of the papers. Through this correspondence, the methods used to collect the urban tree sequestration and area data were further clarified and the use of these data in the inventory was reviewed and validated (Nowak 2002a, 2007b, 2011).

Planned Improvements

A consistent representation of the managed land base in the United States is being developed. A component of this effort, which is discussed at the beginning of the Land Use, Land-Use Change, and Forestry chapter, will involve reconciling the overlap between urban forest and non-urban forest greenhouse gas inventories. It is highly likely that urban forest inventories are including areas also defined as forest land under the Forest Inventory and Analysis (FIA) program of the USDA Forest Service, resulting in “double-counting” of these land areas in estimates of C stocks and fluxes for the inventory. The Forest Service is currently conducting research that will define urban area boundaries and make it possible to distinguish forest from forested urban areas. Once those data become available, they will be incorporated into estimates of net C flux resulting from urban trees.

Urban forest data for additional cities are expected in the near future, as are updated data for cities currently included in the estimates. The use of these data will further refine the estimated median sequestration value. It may also be possible to report C losses and gains separately in the future. It is currently not possible, since existing studies estimate rather than measure natality or mortality; net sequestration estimates are based on assumptions about whether dead trees are being removed, burned, or chipped. There is an effort underway to assess urban tree loss to mortality and removals, which would allow for direct calculation of C losses and gains from observed rather than estimated natality and mortality of trees.

Data from the 2010 U.S. Census is expected to provide updated U.S. urbanized area, which would allow for refinement of the urban area time series. Revisions to urban area time series will result in revisions to prior years’ C flux estimates.

A revised average tree canopy cover percentage for U.S. urban areas is anticipated to become available in the peer-reviewed literature in the near future, which would allow for updated C flux estimates. Furthermore, urban tree cover data specific to each state is also expected in the near future. It may be possible to develop a set of state-specific sequestration rates for more granular and regionally precise C flux estimates by coupling these data with adjusted growth rates for each U.S. state. Future research may also enable more complete coverage of changes in the C stock in urban trees for all *Settlements* land. To provide estimates for all *Settlements*, research would need to establish the extent of overlap between *Settlements* and Census-defined urban areas, and would have to characterize sequestration on non-urban *Settlements* land.

Direct N_2O Fluxes from Settlement Soils (IPCC Source Category 5E1)

Of the synthetic N fertilizers applied to soils in the United States, approximately 2.5 percent are currently applied to lawns, golf courses, and other landscaping occurring within settlement areas. Application rates are lower than those occurring on cropped soils, and, therefore, account for a smaller proportion of total U.S. soil N_2O emissions per unit area. In addition to synthetic N fertilizers, a portion of surface applied sewage sludge is applied to settlement areas. In 2009, N_2O emissions from this source were 1.5 Tg CO_2 Eq. (4.9 Gg). There was an overall increase of 55 percent over the period from 1990 through 2009 due to a general increase in the application of synthetic N fertilizers to an expanding settlement area. Interannual variability in these emissions is directly attributable to interannual variability in total synthetic fertilizer consumption and sewage sludge applications in the United States. Emissions from this source are summarized in Table 7-45.

Table 7-45: Direct N_2O Fluxes from Soils in *Settlements Remaining Settlements* (Tg CO_2 Eq. and Gg N_2O)

Year	Tg CO_2 Eq.	Gg
1990	1.0	3.2
2000	1.1	3.7
2005	1.5	4.7
2006	1.5	4.8
2007	1.6	5.1
2008	1.5	4.9
2009	1.5	4.9

Note: These estimates include direct N_2O emissions from N fertilizer additions only. Indirect N_2O emissions from fertilizer additions are reported in the Agriculture chapter. These estimates include emissions from both *Settlements Remaining Settlements* and from *Land Converted to Settlements*.

Methodology

For soils within *Settlements Remaining Settlements*, the IPCC Tier 1 approach was used to estimate soil N_2O emissions from synthetic N fertilizer and sewage sludge additions. Estimates of direct N_2O emissions from soils in settlements were based on the amount of N in synthetic commercial fertilizers applied to settlement soils, and the amount of N in sewage sludge applied to non-agricultural land and surface disposal of sewage sludge (see Annex 3.11 for a detailed discussion of the methodology for estimating sewage sludge application).

Nitrogen applications to settlement soils are estimated using data compiled by the USGS (Ruddy et al. 2006). The USGS estimated on-farm and non-farm fertilizer use is based on sales records at the county level from 1982 through 2001 (Ruddy et al. 2006). Non-farm N fertilizer was assumed to be applied to settlements and forest lands; values for 2002 through 2008 were based on 2001 values adjusted for annual total N fertilizer sales in the United States because there is no new activity data on application after 2001. Settlement application was calculated by subtracting forest application from total non-farm fertilizer use. Sewage sludge applications were derived from national data on sewage sludge generation, disposition, and N content (see Annex 3.11 for further detail). The total amount of N resulting from these sources was multiplied by the IPCC default emission factor for applied N (1 percent) to estimate direct N_2O emissions (IPCC 2006). The volatilized and leached/runoff N fractions for settlements, calculated with the IPCC default volatilization factors (10 or 20 percent, respectively, for synthetic or organic N fertilizers) and leaching/runoff factor for wet areas (30 percent), were included with indirect emissions, as reported in the N_2O Emissions from Agricultural Soil Management source category of the Agriculture chapter (consistent with reporting guidance that all indirect emissions are included in the Agricultural Soil Management source category).

Uncertainty and Time-Series Consistency

The amount of N_2O emitted from settlements depends not only on N inputs and fertilized area, but also on a large number of variables, including organic C availability, oxygen gas partial pressure, soil moisture content, pH, temperature, and irrigation/watering practices. The effect of the combined interaction of these variables on N_2O flux is complex and highly uncertain. The IPCC default methodology does not explicitly incorporate any of these variables, except variations in fertilizer N and sewage sludge application rates. All settlement soils are treated equivalently under this methodology.

Uncertainties exist in both the fertilizer N and sewage sludge application rates in addition to the emission factors. Uncertainty in fertilizer N application was assigned a default level[195] of ±50 percent. Uncertainty in the amounts of sewage sludge applied to non-agricultural lands and used in surface disposal was derived from variability in several factors, including: (1) N content of sewage sludge; (2) total sludge applied in 2000; (3) wastewater existing flow in 1996 and 2000; and (4) the sewage sludge disposal practice distributions to non-agricultural land application and surface disposal. Uncertainty in the emission factors was provided by the IPCC (2006).

Quantitative uncertainty of this source category was estimated through the IPCC-recommended Tier 2 uncertainty estimation methodology. The uncertainty ranges around the 2005 activity data and emission factor input variables were directly applied to the 2009 emission estimates. The results of the quantitative uncertainty analysis are summarized in Table 7-46. N_2O emissions from soils in Settlements Remaining Settlements in 2009 were estimated to be between 0.8 and 4.0 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 49 percent below to 163 percent above the 2009 emission estimate of 1.5 Tg CO_2 Eq.

Table 7-46: Quantitative Uncertainty Estimates of N_2O Emissions from Soils in *Settlements Remaining Settlements* (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emissions (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Settlements Remaining Settlements:						
N_2O Fluxes from Soils	N_2O	1.5	0.8	4.0	-49%	163%

Note: This estimate includes direct N_2O emissions from N fertilizer additions to both *Settlements Remaining Settlements* and from *Land Converted to Settlements*.

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[195] No uncertainty is provided with the USGS application data (Ruddy et al. 2006) so a conservative ±50% was used in the analysis.

Planned Improvements

A minor improvement is planned to update the uncertainty analysis for direct emissions from settlements to be consistent with the most recent activity data for this source.

7.10. Land Converted to Settlements (Source Category 5E2)

Land-use change is constantly occurring, and land under a number of uses undergoes urbanization in the United States each year. However, data on the amount of land converted to settlements is currently lacking. Given the lack of available information relevant to this particular IPCC source category, it is not possible to separate CO_2 or N_2O fluxes on *Land Converted to Settlements* from fluxes on *Settlements Remaining Settlements* at this time.

7.11. Other (IPCC Source Category 5G)

Changes in Yard Trimming and Food Scrap Carbon Stocks in Landfills

In the United States, a significant change in C stocks results from the removal of yard trimmings (i.e., grass clippings, leaves, and branches) and food scraps from settlements to be disposed in landfills. Yard trimmings and food scraps account for a significant portion of the municipal waste stream, and a large fraction of the collected yard trimmings and food scraps are discarded in landfills. C contained in landfilled yard trimmings and food scraps can be stored for very long periods.

Carbon storage estimates are associated with particular land uses. For example, harvested wood products are accounted for under *Forest Land Remaining Forest Land* because these wood products are a component of the forest ecosystem. The wood products serve as reservoirs to which C resulting from photosynthesis in trees is transferred, but the removals in this case occur in the forest. C stock changes in yard trimmings and food scraps are associated with settlements, but removals in this case do not occur within settlements. To address this complexity, yard trimming and food scrap C storage is therefore reported under the “Other” source category.

Both the amount of yard trimmings collected annually and the fraction that is landfilled have declined over the last decade. In 1990, over 53 million metric tons (wet weight) of yard trimmings and food scraps were generated (i.e., put at the curb for collection to be taken to disposal sites or to composting facilities) (EPA 2011; Schneider 2007, 2008). Since then, programs banning or discouraging yard trimmings disposal have led to an increase in backyard composting and the use of mulching mowers, and a consequent 5 percent decrease in the tonnage generated (i.e., collected for composting or disposal). At the same time, an increase in the number of municipal composting facilities has reduced the proportion of collected yard trimmings that are discarded in landfills—from 72 percent in 1990 to 33 percent in 2009. The net effect of the reduction in generation and the increase in composting is a 57 percent decrease in the quantity of yard trimmings disposed in landfills since 1990.

Food scraps generation has grown by 44 percent since 1990, and though the proportion of food scraps discarded in landfills has decreased slightly from 82 percent in 1990 to 80 percent in 2009, the tonnage disposed in landfills has increased considerably (by 40 percent). Overall, the decrease in the yard trimmings landfill disposal rate has more than compensated for the increase in food scrap disposal in landfills, and the net result is a decrease in annual landfill carbon storage from 24.2 Tg CO_2 Eq. in 1990 to 12.6 Tg CO_2 Eq. in 2009 (Table 7-47 and Table 7-48).

Table 7-47: Net Changes in Yard Trimming and Food Scrap Stocks in Landfills (Tg CO_2 Eq.)

Carbon Pool	1990	2000	2005	2006	2007	2008	2009
Yard Trimmings	**(21.0)**	**(8.8)**	**(7.3)**	**(7.5)**	**(7.0)**	**(7.3)**	**(8.5)**
Grass	(1.8)	(0.7)	(0.6)	(0.6)	(0.6)	(0.7)	(0.8)
Leaves	(9.0)	(3.9)	(3.3)	(3.4)	(3.2)	(3.4)	(3.9)
Branches	(10.2)	(4.2)	(3.3)	(3.4)	(3.2)	(3.3)	(3.8)
Food Scraps	**(3.2)**	**(4.4)**	**(4.3)**	**(3.5)**	**(3.9)**	**(3.9)**	**(4.1)**
Total Net Flux	**(24.2)**	**(13.2)**	**(11.5)**	**(11.0)**	**(10.9)**	**(11.2)**	**(12.6)**

Note: Totals may not sum due to independent rounding.

Table 7-48: Net Changes in Yard Trimming and Food Scrap Stocks in Landfills (Tg C)

Carbon Pool	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Yard Trimmings	**(5.7)**	**(2.4)**	**(2.0)**	**(2.0)**	**(1.9)**	**(2.0)**	**(2.3)**
Grass	(0.5)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Leaves	(2.5)	(1.1)	(0.9)	(0.9)	(0.9)	(0.9)	(1.1)
Branches	(2.8)	(1.2)	(0.9)	(0.9)	(0.9)	(0.9)	(1.0)
Food Scraps	**(0.9)**	**(1.2)**	**(1.2)**	**(1.0)**	**(1.1)**	**(1.1)**	**(1.1)**
Total Net Flux	**(6.6)**	**(3.6)**	**(3.1)**	**(3.0)**	**(3.0)**	**(3.1)**	**(3.4)**

Note: Totals may not sum due to independent rounding.

Methodology

When wastes of biogenic origin (such as yard trimmings and food scraps) are landfilled and do not completely decompose, the C that remains is effectively removed from the global C cycle. Empirical evidence indicates that yard trimmings and food scraps do not completely decompose in landfills (Barlaz 1998, 2005, 2008; De la Cruz and Barlaz 2010), and thus the stock of carbon in landfills can increase, with the net effect being a net atmospheric removal of carbon. Estimates of net C flux resulting from landfilled yard trimmings and food scraps were developed by estimating the change in landfilled C stocks between inventory years, based on methodologies presented for the Land Use, Land-Use Change, and Forestry sector in IPCC (2003). C stock estimates were calculated by determining the mass of landfilled C resulting from yard trimmings or food scraps discarded in a given year; adding the accumulated landfilled C from previous years; and subtracting the mass of C landfilled in previous years that decomposed.

To determine the total landfilled C stocks for a given year, the following were estimated: (1) the composition of the yard trimmings; (2) the mass of yard trimmings and food scraps discarded in landfills; (3) the C storage factor of the landfilled yard trimmings and food scraps; and (4) the rate of decomposition of the degradable C. The composition of yard trimmings was assumed to be 30 percent grass clippings, 40 percent leaves, and 30 percent branches on a wet weight basis (Oshins and Block 2000). The yard trimmings were subdivided, because each component has its own unique adjusted C storage factor and rate of decomposition. The mass of yard trimmings and food scraps disposed of in landfills was estimated by multiplying the quantity of yard trimmings and food scraps discarded by the proportion of discards managed in landfills. Data on discards (i.e., the amount generated minus the amount diverted to centralized composting facilities) for both yard trimmings and food scraps were taken primarily from *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures for 2009* (EPA 2011), which provides data for 1960, 1970, 1980, 1990, 2000, and 2005 through 2009. To provide data for some of the missing years, detailed backup data were obtained from Schneider (2007, 2008). Remaining years in the time series for which data were not provided were estimated using linear interpolation. The EPA (2011) report does not subdivide discards of individual materials into volumes landfilled and combusted, although it provides an estimate of the proportion of overall waste stream discards managed in landfills[196] and combustors with energy recovery (i.e., ranging from 100 percent and 0 percent, respectively, in 1960 to 81 percent and 19 percent in 2000); it is assumed that the proportion of each individual material (food scraps, grass, leaves, branches) that is landfilled is the same as the proportion across the overall waste stream.

The amount of C disposed of in landfills each year, starting in 1960, was estimated by converting the discarded landfilled yard trimmings and food scraps from a wet weight to a dry weight basis, and then multiplying by the initial (i.e., pre-decomposition) C content (as a fraction of dry weight). The dry weight of landfilled material was calculated using dry weight to wet weight ratios (Tchobanoglous et al. 1993, cited by Barlaz 1998) and the initial C contents and the C storage factors were determined by Barlaz (1998, 2005, 2008) (Table 7-49).

The amount of C remaining in the landfill for each subsequent year was tracked based on a simple model of C fate. As demonstrated by Barlaz (1998, 2005, 2008), a portion of the initial C resists decomposition and is essentially persistent in the landfill environment. Barlaz (1998, 2005, 2008) conducted a series of experiments designed to

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[196] EPA (2011) reports discards in two categories: "combustion with energy recovery" and "landfill, other disposal," which includes combustion without energy recovery. For years in which there is data from previous EPA reports on combustion without energy recovery, EPA assumes these estimates are still applicable. For 2000 to present, EPA assumes that any combustion of MSW that occurs includes energy recovery, so all discards to "landfill, other disposal" are assumed to go to landfills.

measure biodegradation of yard trimmings, food scraps, and other materials, in conditions designed to promote decomposition (i.e., by providing ample moisture and nutrients). After measuring the initial C content, the materials were placed in sealed containers along with a "seed" containing methanogenic microbes from a landfill. Once decomposition was complete, the yard trimmings and food scraps were re-analyzed for C content; the C remaining in the solid sample can be expressed as a proportion of initial C (shown in the row labeled "CS" in Table 7-49).

The modeling approach applied to simulate U.S. landfill C flows builds on the findings of Barlaz (1998, 2005, 2008). The proportion of C stored is assumed to persist in landfills. The remaining portion is assumed to degrade, resulting in emissions of CH_4 and CO_2 (the CH_4 emissions resulting from decomposition of yard trimmings and food scraps are accounted for in the "Waste" chapter). The degradable portion of the C is assumed to decay according to first-order kinetics.

The first-order decay rates, *k*, for each component were derived from De la Cruz and Barlaz (2010). De la Cruz and Barlaz (2010) calculate first-order decay rates using laboratory data published in Eleazer et al. (1997), and a correction factor, *f*, is found so that the weighted average decay rate for all components is equal to the AP-42 default decay rate (0.04) for mixed MSW for regions that receive more than 25 inches of rain annually. Because AP-42 values were developed using landfill data from approximately 1990, 1990 waste composition for the United States from EPA's *Characterization of Municipal Solid Waste in the United States: 1990 Update* was used to calculate *f*. This correction factor is then multiplied by the Eleazer et al. (1997) decay rates of each waste component to develop field-scale first-order decay rates.

De la Cruz and Barlaz (2010) also use other assumed initial decay rates for mixed MSW in place of the AP-42 default value based on different types of environments in which landfills in the United States are found, including dry conditions (less than 25 inches of rain annually, k=0.02) and bioreactor landfill conditions (moisture is controlled for rapid decomposition, k=0.12). The *Landfills* section of the Inventory (which estimates CH_4 emissions) estimates the overall MSW decay rate by partitioning the U.S. landfill population into three categories, based on annual precipitation ranges of (1) less than 20 inches of rain per year, (2) 20 to 40 inches of rain per year, and (3) greater than 40 inches of rain per year. These correspond to overall MSW decay rates of 0.020, 0.038, and 0.057 yr^{-1}, respectively.

De la Cruz and Barlaz (2010) calculate component-specific decay rates corresponding to the first value (0.020 yr^{-1}), but not for the other two overall MSW decay rates. To maintain consistency between landfill methodologies across the Inventory, the correction factors (*f*) were developed for decay rates of 0.038 and 0.057 yr^{-1} through linear interpolation. A weighted national average component-specific decay rate was calculated by assuming that waste generation is proportional to population (the same assumption used in the landfill methane emission estimate), based on population data from the 2000 U.S. Census. The component-specific decay rates are shown in Table 7-49.

For each of the four materials (grass, leaves, branches, food scraps), the stock of C in landfills for any given year is calculated according to the following formula:

$$LFC_{i,t} = \sum_{n}^{t} W_{i,n} \times (1 - MC_i) \times ICC_i \times \{[CS_i \times ICC_i] + [(1 - (CS_i \times ICC_i)) \times e^{-k(t-n)}]\}$$

where,

t = Year for which C stocks are being estimated (year),
i = Waste type for which C stocks are being estimated (grass, leaves, branches, food scraps),
$LFC_{i,t}$ = Stock of C in landfills in year t, for waste i (metric tons),
$W_{i,n}$ = Mass of waste i disposed in landfills in year n (metric tons, wet weight),
n = Year in which the waste was disposed (year, where $1960 < n < t$),
MC_i = Moisture content of waste i (percent of water),
CS_i = Proportion of initial C that is stored for waste i (percent),
ICC_i = Initial C content of waste i (percent),
e = Natural logarithm, and
k = First-order decay rate for waste i, ($year^{-1}$).

For a given year t, the total stock of C in landfills ($TLFC_t$) is the sum of stocks across all four materials (grass, leaves, branches, food scraps). The annual flux of C in landfills (F_t) for year t is calculated as the change in stock compared to the preceding year:

$$F_t = TLFC_t - TLFC_{(t-1)}$$

Thus, the C placed in a landfill in year *n* is tracked for each year *t* through the end of the inventory period (2009). For example, disposal of food scraps in 1960 resulted in depositing about 1,135,000 metric tons of C. Of this amount, 16 percent (179,000 metric tons) is persistent; the remaining 84 percent (956,000 metric tons) is degradable. By 1965, more than half of the degradable portion (518,000 metric tons) decomposes, leaving a total of 617,000 metric tons (the persistent portion, plus the remainder of the degradable portion).

Continuing the example, by 2009, the total food scraps C originally disposed in 1960 had declined to 179,000 metric tons (i.e., virtually all degradable C had decomposed). By summing the C remaining from 1960 with the C remaining from food scraps disposed in subsequent years (1961 through 2009), the total landfill C from food scraps in 2009 was 35.9 million metric tons. This value is then added to the C stock from grass, leaves, and branches to calculate the total landfill C stock in 2009, yielding a value of 247.1 million metric tons (as shown in Table 7-50). In exactly the same way total net flux is calculated for forest C and harvested wood products, the total net flux of landfill C for yard trimmings and food scraps for a given year (Table 7-48) is the difference in the landfill C stock for that year and the stock in the preceding year. For example, the net change in 2009 shown in Table 7-48 (3.4 Tg C) is equal to the stock in 2009 (247.1 Tg C) minus the stock in 2008 (243.7 Tg C).

The C stocks calculated through this procedure are shown in Table 7-50.

Table 7-49: Moisture Content (%), C Storage Factor, Proportion of Initial C Sequestered (%), Initial C Content (%), and Decay Rate (year^{-1}) for Landfilled Yard Trimmings and Food Scraps in Landfills

	Yard Trimmings			**Food Scraps**
Variable	**Grass**	**Leaves**	**Branches**	
Moisture Content (% H_2O)	70	30	10	70
CS, proportion of initial C stored (%)	53	85	77	16
Initial C Content (%)	45	46	49	51
Decay Rate (year^{-1})	0.323	0.185	0.016	0.156

Table 7-50: C Stocks in Yard Trimmings and Food Scraps in Landfills (Tg C)

Carbon Pool	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Yard Trimmings	**155.8**	**191.9**	**202.9**	**205.0**	**206.9**	**208.9**	**211.2**
Branches	74.6	92.4	97.5	98.5	99.3	100.2	101.3
Leaves	66.7	82.4	87.3	88.3	89.1	90.1	91.1
Grass	14.5	17.2	18.1	18.2	18.4	18.6	18.8
Food Scraps	**21.3**	**27.0**	**31.7**	**32.7**	**33.7**	**34.8**	**35.9**
Total Carbon Stocks	**177.2**	**218.9**	**234.6**	**237.6**	**240.6**	**243.7**	**247.1**

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

The uncertainty analysis for landfilled yard trimmings and food scraps includes an evaluation of the effects of uncertainty for the following data and factors: disposal in landfills per year (tons of C), initial C content, moisture content, decay rate, and proportion of C stored. The C storage landfill estimates are also a function of the composition of the yard trimmings (i.e., the proportions of grass, leaves and branches in the yard trimmings mixture). There are respective uncertainties associated with each of these factors.

A Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the overall uncertainty of the sequestration estimate. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-51. Total yard trimmings and food scraps CO_2 flux in 2009 was estimated to be between -21.2 and -6.2 Tg CO_2 Eq. at a 95 percent confidence level (or 19 of 20 Monte Carlo stochastic simulations). This indicates a range of 68 percent below to 51 percent above the 2009 flux estimate of -12.6 Tg CO_2 Eq. More information on the uncertainty estimates for Yard Trimmings and Food Scraps in Landfills is contained within the Uncertainty Annex.

Table 7-51: Tier 2 Quantitative Uncertainty Estimates for CO_2 Flux from Yard Trimmings and Food Scraps in Landfills (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Flux Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Flux Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Yard Trimmings and Food Scraps	CO_2	(12.6)	(21.2)	(6.2)	-68%	+51%

[a] Range of flux estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Note: Parentheses indicate negative values or net C sequestration.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation and did not reveal any systematic inaccuracies or incorrect input values.

Recalculations Discussion

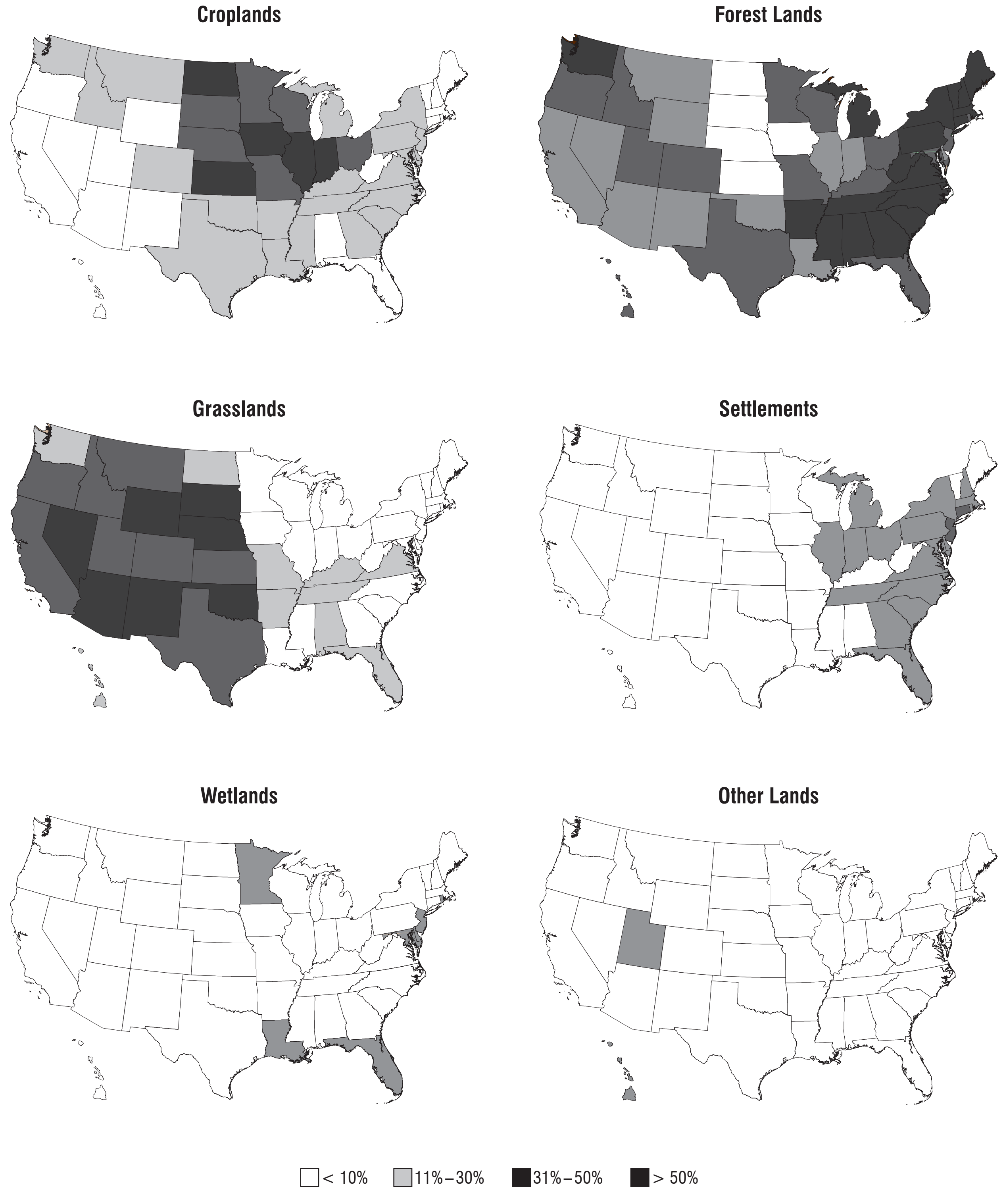
First-order decay rate constants were updated based on De la Cruz and Barlaz (2010), as described in the methodology section. Input data were updated for the years: 1990, 2000, 2005, and 2007 through 2009 based on the updated values reported in *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures for 2009* (EPA 2011). As a result, C storage estimates for those years were revised relative to the previous Inventory. While data inputs for intervening years in the timeseries were not revised, overall C storage in any given year is dependent on the previous year's storage (as shown in the second equation above), and so C storage estimates for those years were also revised. These revisions resulted in an annual average increase in C stored in landfills of 4.2 percent across the timeseries.

Planned Improvements

Future work is planned to evaluate the potential contribution of inorganic C, primarily in the form of carbonates, to landfill sequestration, as well as the consistency between the estimates of C storage described in this chapter and the estimates of landfill CH_4 emissions described in the Waste chapter.

Figure 7-1

Percent of Total Land Area in the General Land Use Categories for 2009



Croplands

Forest Lands

Grasslands

Settlements

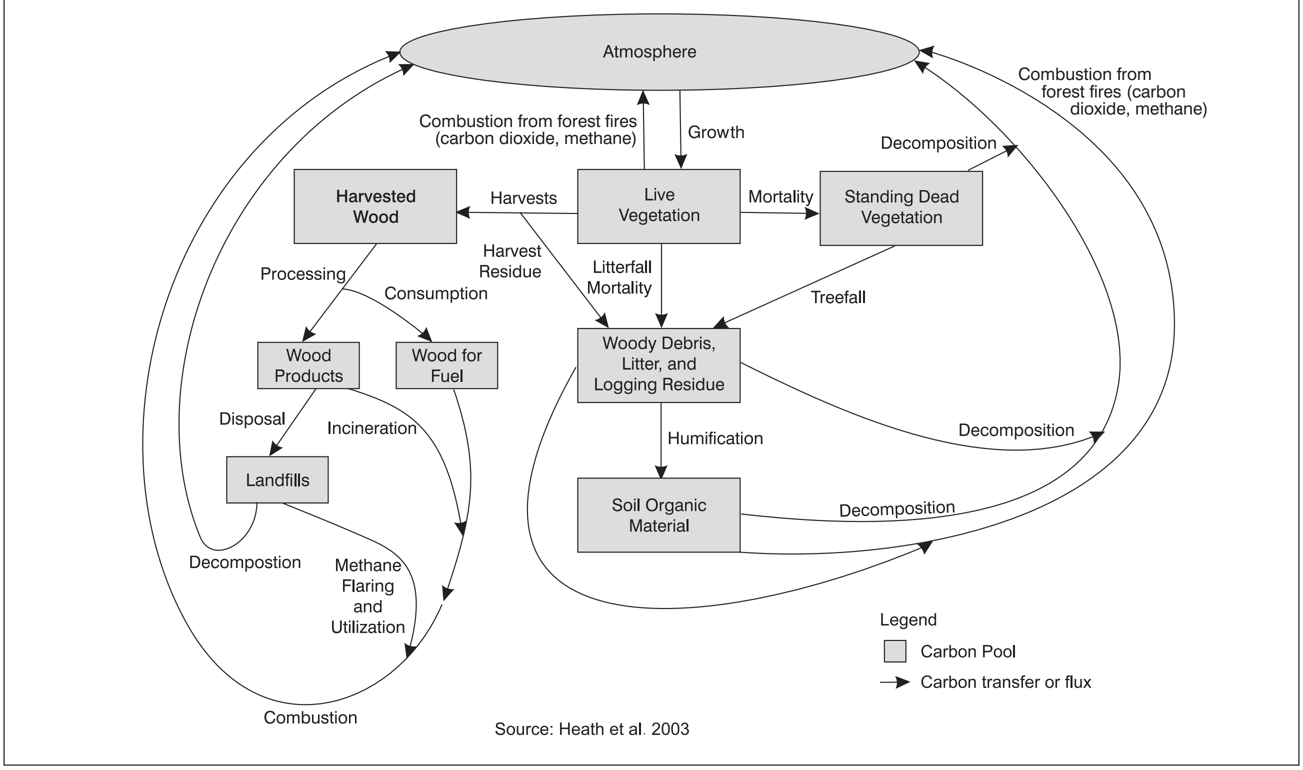
Wetlands

Other Lands

Note: Land use/land-use change categories were aggregated into the 6 general land-use categories based on the current use in 2009.

Figure 7-2

Forest Sector Carbon Pools and Flows



Source: Heath et al. 2003

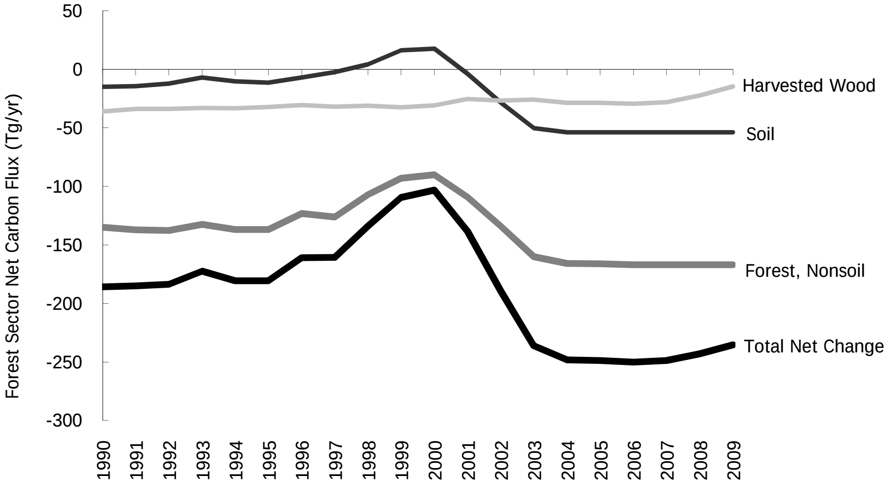
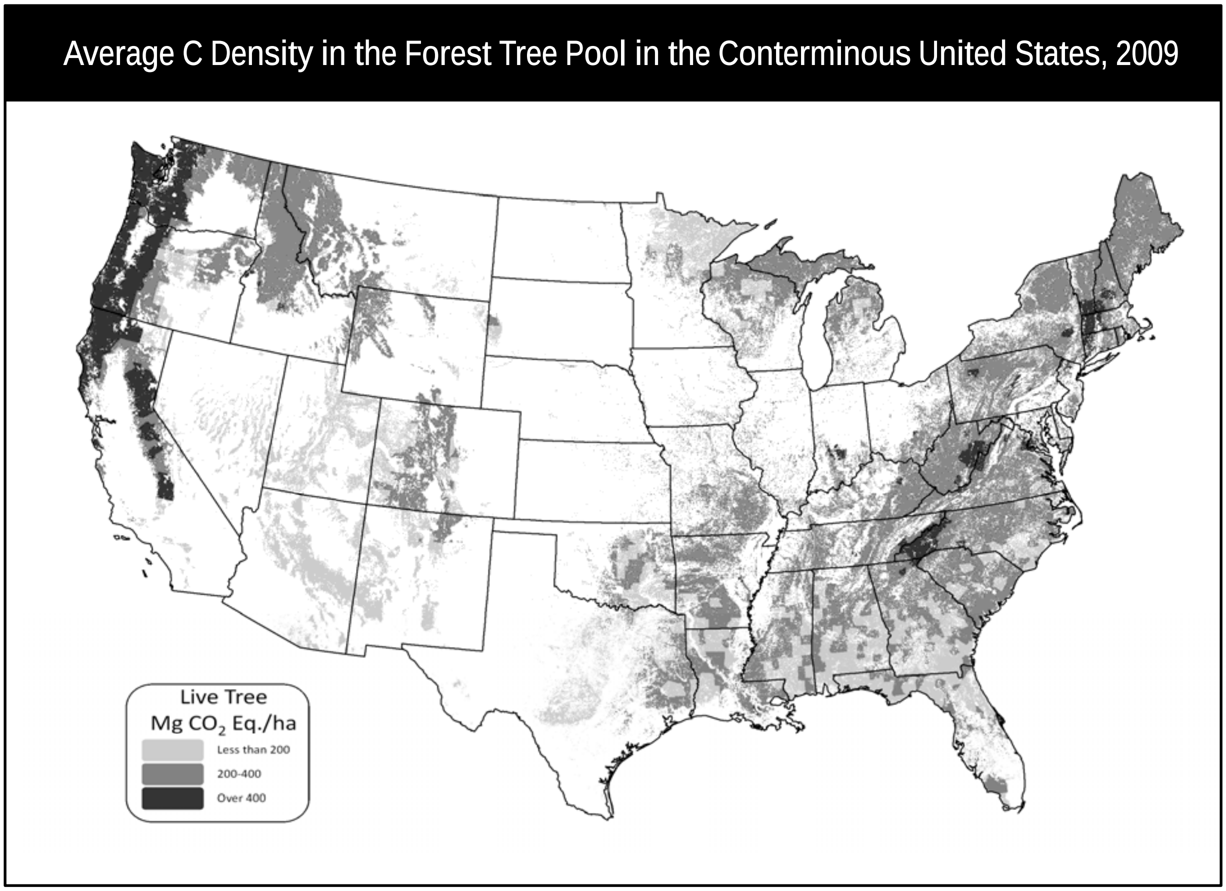


Figure 7-3: Estimates of Net Annual Changes in C Stocks for Major C Pools

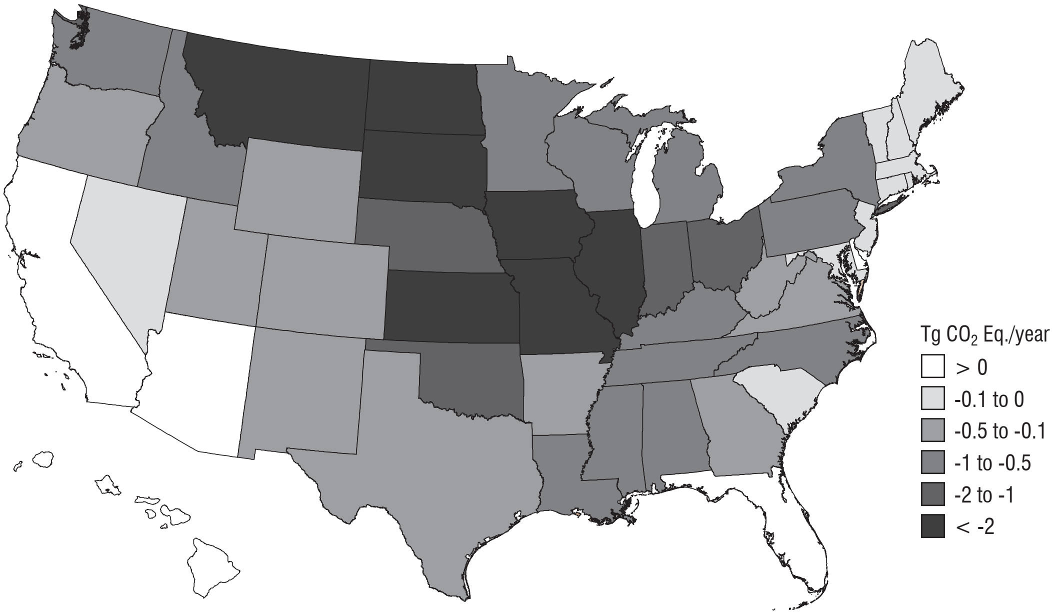
Figure 7-4



Average C Density in the Forest Tree Pool in the Conterminous United States, 2009

Figure 7-5

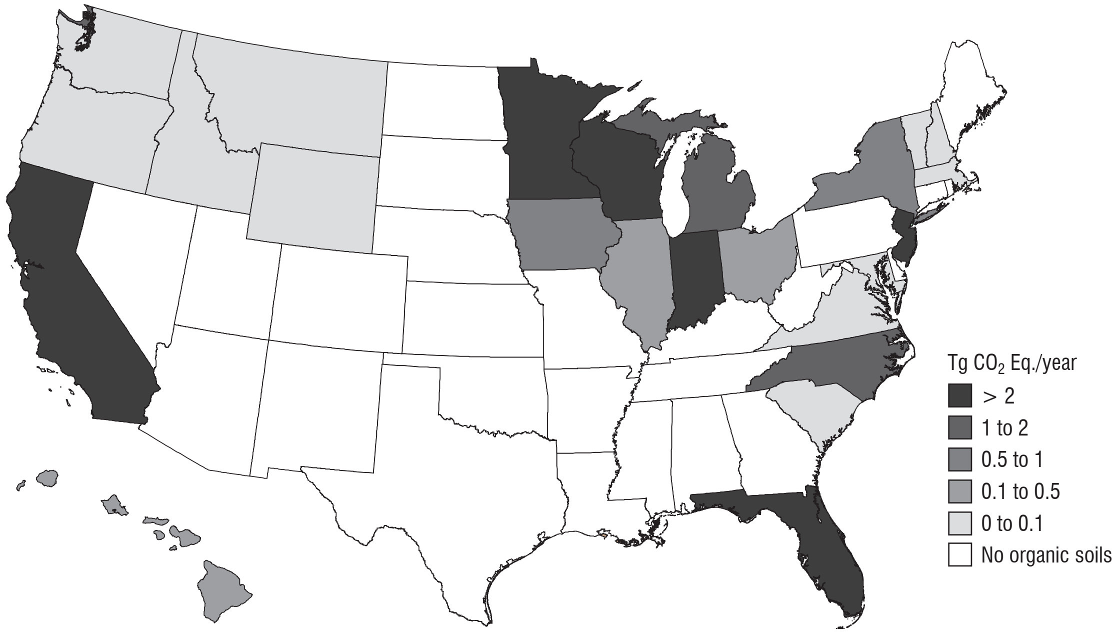
Total Net Annual CO_2 Flux for Mineral Soils Under Agricultural Management within States, 2009, *Cropland Remaining Cropland*



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

Figure 7-6

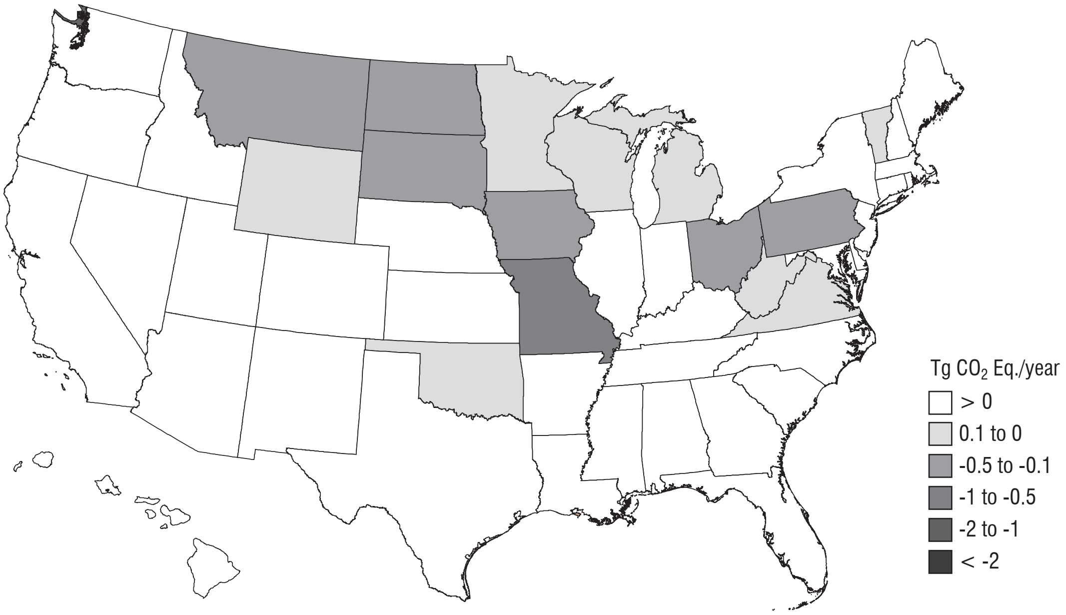
Total Net Annual CO_2 Flux for Organic Soils Under Agricultural Management within States, 2009, *Cropland Remaining Cropland*



Note: Values greater than zero represent emissions.

Figure 7-7

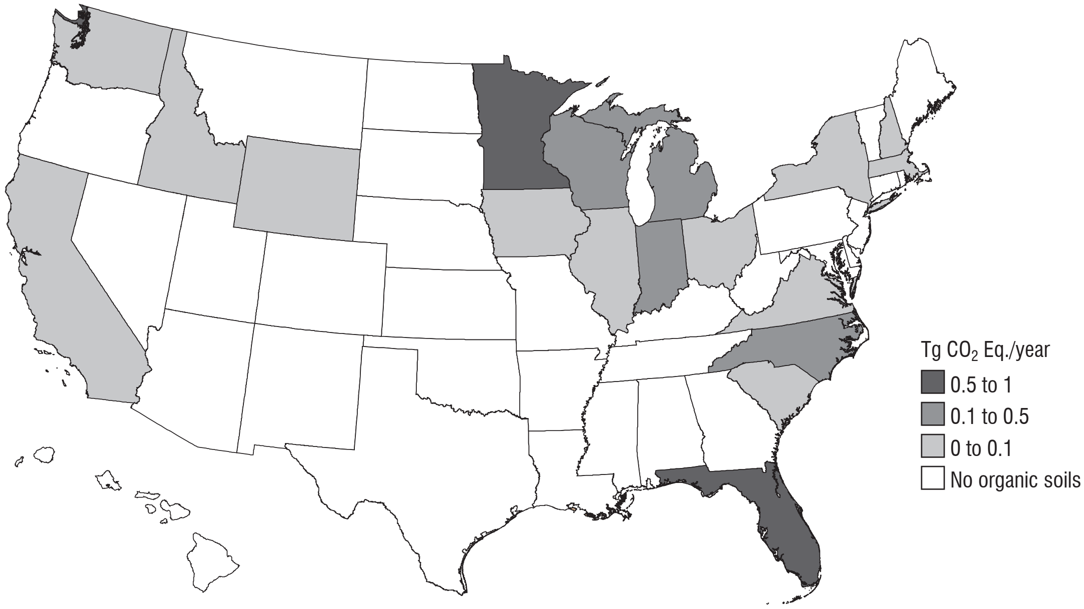
Total Net Annual CO_2 Flux for Mineral Soils Under Agricultural Management within States, 2009, *Land Converted to Cropland*



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

Figure 7-8

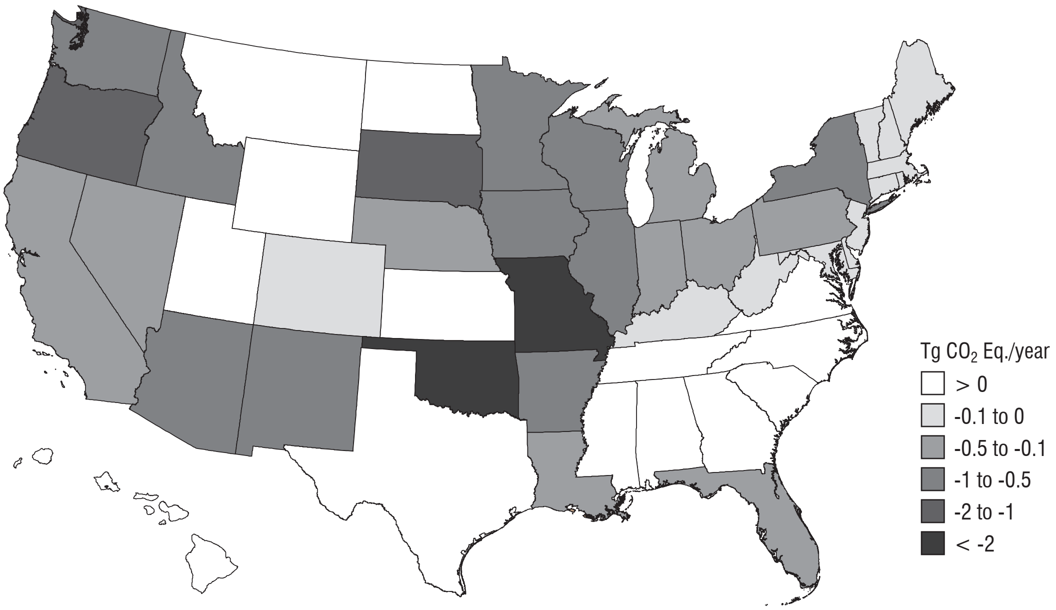
Total Net Annual CO_2 Flux for Organic Soils Under Agricultural Management within States, 2009, *Land Converted to Cropland*



Note: Values greater than zero represent emissions.

Figure 7-9

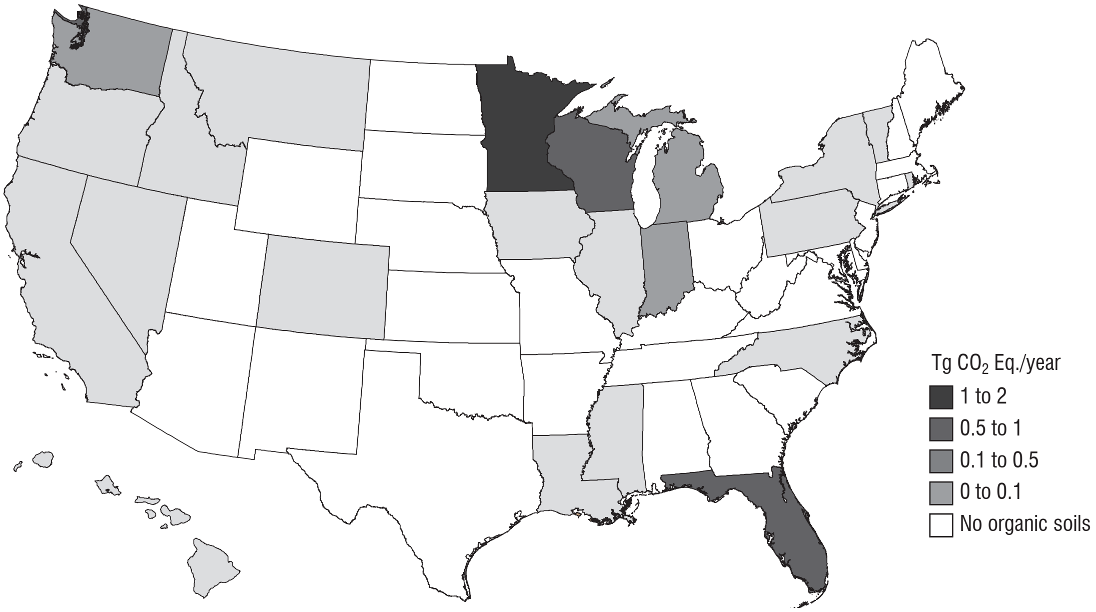
Total Net Annual CO_2 Flux for Mineral Soils Under Agricultural Management within States, 2009, *Grassland Remaining Grassland*



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

Figure 7-10

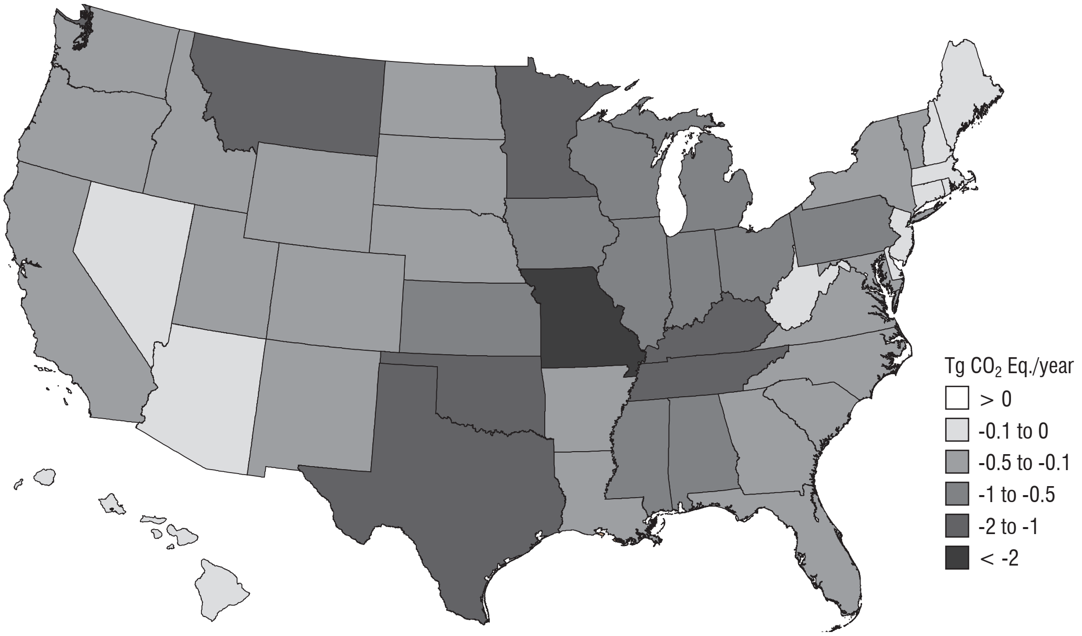
Total Net Annual CO_2 Flux for Organic Soils Under Agricultural Management within States, 2009, *Grassland Remaining Grassland*



Note: Values greater than zero represent emissions.

Figure 7-11

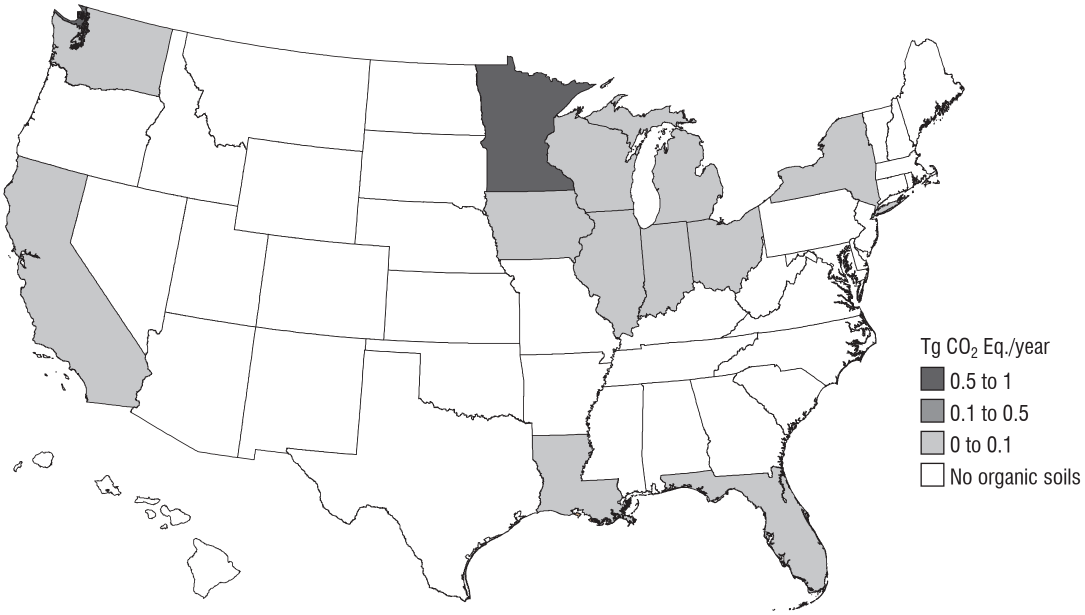
Total Net Annual CO_2 Flux for Mineral Soils Under Agricultural Management within States, 2009, *Land Converted to Grassland*



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

Figure 7-12

Total Net Annual CO_2 Flux for Organic Soils Under Agricultural Management within States, 2009, *Land Converted to Grassland*



Note: Values greater than zero represent emissions.

8. Waste

Waste management and treatment activities are sources of greenhouse gas emissions (see Figure 8-1). Landfills accounted for approximately 17 percent of total U.S. anthropogenic methane (CH_4) emissions in 2009, the third largest contribution of any CH_4 source in the United States. Additionally, wastewater treatment and composting of organic waste accounted for approximately 4 percent and less than 1 percent of U.S. CH_4 emissions, respectively. Nitrous oxide (N_2O) emissions from the discharge of wastewater treatment effluents into aquatic environments were estimated, as were N_2O emissions from the treatment process itself. N_2O emissions from composting were also estimated. Together, these waste activities account for less than 3 percent of total U.S. N_2O emissions. Nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs) are emitted by waste activities, and are addressed separately at the end of this chapter. A summary of greenhouse gas emissions from the Waste chapter is presented in Table 8-1 and Table 8-2.

CO_2, N_2O, and CH_4 emissions from the incineration of waste are accounted for in the Energy sector rather than in the Waste sector because almost all incineration of municipal solid waste (MSW) in the United States occurs at waste-to-energy facilities where useful energy is recovered. Similarly, the Energy sector also includes an estimate of emissions from burning waste tires because virtually all of the combustion occurs in industrial and utility boilers that recover energy. The incineration of waste in the United States in 2009 resulted in 12.7 Tg CO_2 Eq. emissions, nearly half of which is attributable to the combustion of plastics. For more details on emissions from the incineration of waste, see Section 3.3.

Figure 8-1: 2009 Waste Chapter Greenhouse Gas Sources

[BEGIN BOX]

Box 8-1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report, and this chapter, are organized by source and sink categories and calculated using internationally-accepted methods provided by the Intergovernmental Panel on Climate Change (IPCC).[197] Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[198] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this Inventory do not preclude alternative examinations,[199] but rather this Inventory presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself, and this chapter, follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

[END BOX]

Overall, in 2009, waste activities generated emissions of 150.5 Tg CO_2 Eq., or just over 2 percent of total U.S. greenhouse gas emissions.

Table 8-1. Emissions from Waste (Tg CO_2 Eq.)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CH_4	**171.2**	**138.1**	**138.4**	**137.8**	**137.4**	**142.1**	**143.6**
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5

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[197] See http://www.ipcc-nggip.iges.or.jp/public/index.html.

[198] See http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php.

[199] For example, see http://www.epa.gov/aboutepa/oswer.html.

Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
N_2O	**4.0**	**5.9**	**6.5**	**6.6**	**6.7**	**6.8**	**6.9**
Domestic Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Total	**175.2**	**143.9**	**144.9**	**144.4**	**144.1**	**149.0**	**150.5**

Note: Totals may not sum due to independent rounding.

Table 8-2. Emissions from Waste (Gg)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CH_4	**8,152**	**6,576**	**6,591**	**6,563**	**6,541**	**6,769**	**6,840**
Landfills	7,018	5,317	5,358	5,321	5,299	5,520	5,593
Wastewater Treatment	1,118	1,199	1,159	1,167	1,163	1,168	1,167
Composting	15	60	75	75	79	80	79
N_2O	**13**	**19**	**21**	**21**	**22**	**22**	**22**
Domestic Wastewater Treatment	12	14	15	16	16	16	16
Composting	1	4	6	6	6	6	6

Note: Totals may not sum due to independent rounding.

8.1. Landfills (IPCC Source Category 6A1)

In 2009, landfill CH_4 emissions were approximately 117.5 Tg CO_2 Eq. (5,593 Gg of CH_4), representing the third largest source of CH_4 emissions in the United States, behind natural gas systems and enteric fermentation. Emissions from municipal solid waste (MSW) landfills, which received about 64.5 percent of the total solid waste generated in the United States, accounted for about 94 percent of total landfill emissions, while industrial landfills accounted for the remainder. Approximately 1,800 operational landfills exist in the United States, with the largest landfills receiving most of the waste and generating the majority of the CH_4 (*BioCycle* 2006, adjusted to include missing data from five states).

After being placed in a landfill, waste (such as paper, food scraps, and yard trimmings) is initially decomposed by aerobic bacteria. After the oxygen has been depleted, the remaining waste is available for consumption by anaerobic bacteria, which break down organic matter into substances such as cellulose, amino acids, and sugars. These substances are further broken down through fermentation into gases and short-chain organic compounds that form the substrates for the growth of methanogenic bacteria. These CH_4-producing anaerobic bacteria convert the fermentation products into stabilized organic materials and biogas consisting of approximately 50 percent carbon dioxide (CO_2) and 50 percent CH_4, by volume. Significant CH_4 production typically begins one or two years after waste disposal in a landfill and continues for 10 to 60 years or longer.

Methane emissions from landfills are a function of several factors, including: (1) the total amount of waste in MSW landfills, which is related to total waste landfilled annually; (2) the characteristics of landfills receiving waste (i.e., composition of waste-in-place, size, climate); (3) the amount of CH_4 that is recovered and either flared or used for energy purposes; and (4) the amount of CH_4 oxidized in landfills instead of being released into the atmosphere. From 1990 to 2009, net CH_4 emissions from landfills decreased by approximately 20 percent (see Table 8-3 and Table 8-4). This net CH_4 emissions decrease can be attributed to many factors, including changes in waste composition, an increase in the amount of landfill gas collected and combusted, a higher frequency of composting, and increased rates of recovery for degradeable materials (e.g, paper and paperboard).

The estimated annual quantity of waste placed in MSW landfills increased from about 209 Tg in 1990 to 297 Tg in 2009, an increase of 42 percent (see Annex 3.14). Despite increased waste disposal, the amount of decomposable materials (i.e., paper and paperboard, food scraps, and yard trimmings) discarded in MSW landfills have decreased by approximately 21 percent from 1990 to 2008 (EPA, 2009b). In addition, the amount of landfill gas collected and combusted has increased. In 1990, for example, approximately 970 Gg of CH_4 were recovered and combusted (i.e., used for energy or flared) from landfills, while in 2009, 7,208 Gg CH_4 was combusted, which represents a 3 percent increase in the quantity of CH_4 recovered and combusted from 2008 levels. In 2009, an estimated 49 new landfill gas-to-energy (LFGTE) projects and 32 new flares began operation.

Over the past 9 years, however, the net CH_4 emissions have fluctuated from year to year, but a slowly increasing trend has been observed. While the amount of landfill gas collected and combusted continues to increase every year, the rate of increase in collection and combustion no longer exceeds the rate of additional CH_4 generation from the amount of organic MSW landfilled as the U.S. population grows.

Over the next several years, the total amount of municipal solid waste generated is expected to increase as the U.S. population continues to grow. The percentage of waste landfilled, however, may decline due to increased recycling and composting practices. In addition, the quantity of CH_4 that is recovered and either flared or used for energy purposes is expected to continue to increase as a result of 1996 federal regulations that require large municipal solid waste landfills to collect and combust landfill gas (see 40 CFR Part 60, Subpart Cc 2005 and 40 CFR Part 60, Subpart WWW 2005), voluntary programs that encourage CH_4 recovery and use such as EPA's Landfill Methane Outreach Program (LMOP), and federal and state incentives that promote renewable energy (e.g., tax credits, low interest loans, and Renewable Portfolio Standards).

Table 8-3. CH_4 Emissions from Landfills (Tg CO_2 Eq.)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
MSW Landfills	172.6	206.9	241.2	248.1	254.2	260.3	266.3
Industrial Landfills	11.5	14.3	15.2	15.3	15.4	15.5	15.6
Recovered							
Gas-to-Energy	(13.6)	(49.4)	(56.5)	(59.0)	(63.7)	(67.0)	(72.0)
Flared	(6.7)	(47.8)	(74.9)	(80.2)	(82.3)	(80.0)	(79.4)
Oxidized[a]	(16.4)	(12.4)	(12.5)	(12.4)	(12.4)	(12.9)	(13.1)
Total	**147.4**	**111.7**	**112.5**	**111.7**	**111.3**	**115.9**	**117.5**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

[a] Includes oxidation at both municipal and industrial landfills.

Table 8-4. CH_4 Emissions from Landfills (Gg)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
MSW Landfills	8,219	9,854	11,486	11,813	12,107	12,395	12,679
Industrial Landfills	549	682	724	727	732	738	744
Recovered							
Gas-to-Energy	(649)	(2,352)	(2,691)	(2,807)	(3,033)	(3,189)	(3,429)
Flared	(321)	(2,276)	(3,566)	(3,820)	(3,918)	(3,810)	(3,779)
Oxidized[a]	(780)	(591)	(596)	(592)	(589)	(614)	(622)
Total	**7,018**	**5,317**	**5,358**	**5,321**	**5,299**	**5,520**	**5,593**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

[a] Includes oxidation at municipal and industrial landfills.

Methodology

A detailed description of the methodology used to estimate CH_4 emissions from landfills can be found in Annex 3.14.

CH_4 emissions from landfills were estimated as the CH_4 produced from municipal solid waste landfills, plus the CH_4 produced by industrial landfills, minus the CH_4 recovered and combusted, minus the CH_4 oxidized before being released into the atmosphere:

$$CH_{4,\text{Solid Waste}} = [CH_{4,\text{MSW}} + CH_{4,\text{Ind}} - R] - Ox$$

where,

$CH_{4,\text{Solid Waste}}$ = CH_4 emissions from solid waste
$CH_{4,\text{MSW}}$ = CH_4 generation from municipal solid waste landfills,
$CH_{4,\text{Ind}}$ = CH_4 generation from industrial landfills,
R = CH_4 recovered and combusted, and
Ox = CH_4 oxidized from MSW and industrial landfills before release to the atmosphere.

The methodology for estimating CH_4 emissions from municipal solid waste landfills is based on the first order decay model described by the Intergovernmental Panel on Climate Change (IPCC 2006). Values for the CH_4 generation potential (L_0) and rate constant (k) were obtained from an analysis of CH_4 recovery rates for a database of 52 landfills and from published studies of other landfills (RTI 2004; EPA 1998; SWANA 1998; Peer, Thorneloe, and Epperson 1993). The rate constant was found to increase with average annual rainfall; consequently, values of k were developed for 3 ranges of rainfall. The annual quantity of waste placed in landfills was apportioned to the 3 ranges of rainfall based on the percent of the U.S. population in each of the 3 ranges, and historical census data were used to account for the shift in population to more arid areas over time. For further information, see Annex 3.14.

National landfill waste generation and disposal data for 2007, 2008, and 2009 were extrapolated based on *BioCycle* data and the U.S. Census population from 2009. Data for 1989 through 2006 were obtained from *BioCycle* (2008). Because *BioCycle* does not account for waste generated in U.S. territories, waste generation for the territories was estimated using population data obtained from the U.S. Census Bureau (2010) and national per capita solid waste generation from *BioCycle* (2008). Estimates of the annual quantity of waste landfilled for 1960 through 1988 were obtained from EPA's *Anthropogenic Methane Emissions in the United States, Estimates for 1990: Report to Congress* (EPA 1993) and an extensive landfill survey by the EPA's Office of Solid Waste in 1986 (EPA 1988). Although waste placed in landfills in the 1940s and 1950s contributes very little to current CH_4 generation, estimates for those years were included in the first order decay model for completeness in accounting for CH_4 generation rates and are based on the population in those years and the per capita rate for land disposal for the 1960s. For calculations in this inventory, wastes landfilled prior to 1980 were broken into two groups: wastes disposed in landfills (Methane Conversion Factor, MCF, of 1) and those disposed in dumps (MCF of 0.6). Please see Annex 3.14 for more details.

The estimated landfill gas recovered per year was based on updated data collected from vendors of flaring equipment, a database of landfill gas-to-energy (LFGTE) projects compiled by LMOP (EPA 2009a), and a database maintained by the Energy Information Administration (EIA) for the voluntary reporting of greenhouse gases (EIA 2007). As the EIA database only included data through 2006; 2007 to 2009 recovery for projects included in the EIA database were assumed to be the same as in 2006. The three databases were carefully compared to identify landfills that were in two or all three of the databases to avoid double counting reductions. Based on the information provided by the EIA and flare vendor databases, the CH_4 combusted by flares in operation from 1990 to 2009 was estimated. This quantity likely underestimates flaring because these databases do not have information on all flares in operation. Additionally, the EIA and LMOP databases provided data on landfill gas flow and energy generation for landfills with LFGTE projects. If a landfill in the EIA database was also in the LMOP and/or the flare vendor database, the emissions avoided were based on the EIA data because landfill owners or operators reported the amount recovered based on measurements of gas flow and concentration, and the reporting accounted for changes over time. If both flare data and LMOP recovery data were available for any of the remaining landfills (i.e., not in the EIA database), then the emissions recovery was based on the LMOP data, which provides reported landfill-specific data on gas flow for direct use projects and project capacity (i.e., megawatts) for electricity projects. The flare data, on the other hand, only provided a range of landfill gas flow for a given flare size. Given that each LFGTE project is likely to also have a flare, double counting reductions from flares and LFGTE projects in the LMOP database was avoided by subtracting emission reductions associated with LFGTE projects for which a flare had not been identified from the emission reductions associated with flares. A further explanation of the improvements made to estimate the landfill gas recovered for the current Inventory can be found in Annex 3.14.

A destruction efficiency of 99 percent was applied to CH_4 recovered to estimate CH_4 emissions avoided. The value for efficiency was selected based on the range of efficiencies (98 to 100 percent) recommended for flares in EPA's AP-42 Compilation of Air Pollutant Emission Factors, Chapter 2.4 (EPA 1998), efficiencies used to establish new source performance standards (NSPS) for landfills, and in recommendations for closed flares used in LMOP.

Emissions from industrial landfills were estimated from activity data for industrial production (ERG 2010), waste disposal factors, and the first order decay model. As over 99 percent of the organic waste placed in industrial landfills originated from the food processing (meat, vegetables, fruits) and pulp and paper industries, estimates of industrial landfill emissions focused on these two sectors (EPA 1993). The amount of CH_4 oxidized by the landfill cover at both municipal and industrial landfills was assumed to be ten percent of the CH_4 generated that is not recovered (IPCC 2006, Mancinelli and McKay 1985, Czepiel et al. 1996). To calculate net CH_4 emissions, both CH_4 recovered and CH_4 oxidized were subtracted from CH_4 generated at municipal and industrial landfills.

Uncertainty and Time-Series Consistency

Several types of uncertainty are associated with the estimates of CH_4 emissions from landfills. The primary uncertainty concerns the characterization of landfills. Information is not available on two fundamental factors affecting CH_4 production: the amount and composition of waste placed in every landfill for each year of its operation. The approach used here assumes that the CH_4 generation potential and the rate of decay that produces CH_4, as determined from several studies of CH_4 recovery at landfills, are representative of U.S. landfills.

Additionally, the approach used to estimate the contribution of industrial wastes to total CH_4 generation introduces uncertainty. Aside from uncertainty in estimating CH_4 generation potential, uncertainty exists in the estimates of oxidation by cover soils. There is also uncertainty in the estimates of CH_4 that is recovered by flaring and energy projects. The IPCC default value of 10 percent for uncertainty in recovery estimates was used in the uncertainty analysis when metering was in place (for about 64 percent of the CH_4 estimated to be recovered). For flaring without metered recovery data (approximately 34 percent of the CH_4 estimated to be recovered), a much higher uncertainty of approximately 50 percent was used (e.g., when recovery was estimated as 50 percent of the flare's design capacity).

N_2O emissions from the application of sewage sludge on landfills are not explicitly modeled as part of greenhouse gas emissions from landfills. N_2O emissions from sewage sludge applied to landfills would be relatively small because the microbial environment in landfills is not very conducive to the nitrification and denitrification processes that result in N_2O emissions. Furthermore, the 2006 IPCC Guidelines (IPCC 2006) did not include a methodology for estimating N_2O emissions from solid waste disposal sites "because they are not significant." Therefore, any uncertainty or bias caused by not including N_2O emissions from landfills is expected to be minimal.

The results of the IPCC Good Practice Guidance Tier 2 quantitative uncertainty analysis are summarized in Table 8-5. Landfill CH_4 emissions in 2009 were estimated to be between 61.1 and 164.5 Tg CO_2 Eq., which indicates a range of 48 percent below to 40 percent above the 2009 emission estimate of 117.5 Tg CO_2 Eq.

Table 8-5. Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Landfills (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Landfills	**CH_4**	**117.5**	**61.1**	**164.5**	**-48%**	**+40%**
MSW	CH_4	103.4	61.0	167.5	-41%	+62%
Industrial	CH_4	14.1	10.2	17.1	-28%	+21%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. A primary focus of the QA/QC checks was to ensure that CH_4 recovery estimates were not double-counted. Both manual and electronic checks were made to ensure that emission avoidance from each landfill was calculated in only one of the three databases. The primary calculation spreadsheet is tailored from the IPCC waste model and has been verified previously using the original, peer-reviewed IPCC waste model. All model input values were verified by secondary QA/QC review.

Recalculations Discussion

In developing the current Inventory, a separate Monte Carlo analysis was conducted for MSW and industrial landfills to better characterize the greater amount of uncertainty surrounding industrial waste data. Additional steps were also taken to better characterize the food waste decay rate and the methodology for the flare correction factor. A weighted component-specific decay rate for food waste of 0.156 yr^{-1} was used in the current Inventory as recommended by ICF International (2009). This replaced the previous Inventory's default food waste decay rate of 0.185 yr^{-1} and resulted in a decrease of landfill emissions of less than 1 percent. The majority of changes in CH_4 emissions from landfills over the time series resulted from improvements made to the flare correction factor to better associate flares in the flare vendor database with a landfill and/or Landfill Gas to Energy (LFGTE) project in the

EIA and LMOP databases.

The flare correction factor for the 1990 through 2008 Inventory report consisted of approximately 512 cases where flares were not directly associated with a landfill and/or LFGTE project in the EIA and/or LMOP databases. For these projects, CH_4 avoided would be overestimated as both the CH_4 avoided from flaring and the LFGTE project would be counted. To abstain from overestimating emissions avoided from flaring, the CH_4 avoided from flares with no identified landfill or LFGTE project were determined and the flaring estimate from the flare vendor database was reduced by this quantity (referred to as a flare correction factor) on a state-by-state basis.

If comprehensive data on flares were available, the majority of LFGTE projects in the EIA and LMOP databases would have an identified flare because it is assumed that most LFGTE projects have flares. However, given that the flare vendor data only covers approximately 50 to 75 percent of the flare population, an associated flare was not identified for all LFGTE projects. These LFGTE projects likely have flares; however, flares were unable to be identified due to one of two reasons: (1) inadequate identifier information provided by the flare vendor; or (2) a lack of the flare in the flare vendor database.

Additional effort was undertaken to improve the methodology behind the flare correction factor for the current Inventory to reduce the overall number of flares that were not matched (512) to landfills and/or LFGTE projects in the EIA and LMOP databases. Each flare in the flare vendor database not associated with a LFGTE project in the EIA or LMOP databases was investigated to determine if it could be matched to either a landfill in the EIA database or a LFGTE project in the LMOP database. For some unmatched flares, the location information was missing or incorrectly transferred to the flare vendor database. In other instances, the landfill names were slightly different between what the flare vendor provided and the actual landfill name as listed in the EIA and/or LMOP databases.

It was found that a large majority of the unidentified flares are associated with landfills in LMOP that are currently flaring, but are also considering LFGTE. These landfill projects considering a LFGTE project are labeled as candidate, potential, or construction in the LMOP database. The flare vendor database was improved to match flares with operational, shutdown as well as candidate, potential, and construction LFGTE projects, thereby reducing the total number of unidentified flares in the flare vendor database, all of which are used in the flare correction factor. The results of this effort significantly decreased the number of flares used in the flare correction factor from 512 to 27, impacted emission estimates for the entire time series, and resulted in an average annual decrease of 8.2 Tg CO_2 Eq. (6.5 percent) in CH_4 emissions from the Landfills source category for the period 1990 through 2008.

Planned Improvements

Beginning in 2010, all MSW landfills that accepted waste on or after January 1, 1980 and generate CH_4 in amounts equivalent to 25,000 metric tons or more of carbon dioxide equivalent (CO_2 Eq.) will be required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program (GHGRP). This consists of the landfill, landfill gas collection systems, and landfill gas destruction devices, including flares. In addition to reporting greenhouse gas information to EPA, landfill-specific characteristics such as annual waste disposal quantity, waste composition data, surface area, and cover type must also be reported. The data collected from the GHGRP will be used in future inventories to revise the parameters used in the CH_4 generation calculations, including degradeable organic carbon (DOC), the flare correction factor, the methane correction factor (MCF), fraction of DOC dissimilated (DOC_F), the destruction efficiency of flares, the oxidation factor (Ox), and the rate constant (k). The addition of this higher tier data will improve the emission calculations to provide a more accurate representation of gresnhouse gas emissions from MSW landfills.

[Begin Text Box]

Box 8-1: Biogenic Wastes in Landfills

Regarding the depositing of wastes of biogenic origin in landfills, empirical evidence shows that some of these wastes degrade very slowly in landfills, and the C they contain is effectively sequestered in landfills over a period of time (Barlaz 1998, 2006). Estimates of C removals from landfilling of forest products, yard trimmings, and food scraps are further described in the Land Use, Land-Use Change, and Forestry chapter, based on methods presented in IPCC (2003) and IPCC (2006).

[End Box]

8.2. Wastewater Treatment (IPCC Source Category 6B)

Wastewater treatment processes can produce anthropogenic CH_4 and N_2O emissions. Wastewater from domestic[200] and industrial sources is treated to remove soluble organic matter, suspended solids, pathogenic organisms, and chemical contaminants. Treatment may either occur on site, most commonly through septic systems or package plants, or off site at centralized treatment systems. Centralized wastewater treatment systems may include a variety of processes, ranging from lagooning to advanced tertiary treatment technology for removing nutrients. In the United States, approximately 20 percent of domestic wastewater is treated in septic systems or other on-site systems, while the rest is collected and treated centrally (U.S. Census Bureau 2009).

Soluble organic matter is generally removed using biological processes in which microorganisms consume the organic matter for maintenance and growth. The resulting biomass (sludge) is removed from the effluent prior to discharge to the receiving stream. Microorganisms can biodegrade soluble organic material in wastewater under aerobic or anaerobic conditions, where the latter condition produces CH_4. During collection and treatment, wastewater may be accidentally or deliberately managed under anaerobic conditions. In addition, the sludge may be further biodegraded under aerobic or anaerobic conditions. The generation of N_2O may also result from the treatment of domestic wastewater during both nitrification and denitrification of the N present, usually in the form of urea, ammonia, and proteins. These compounds are converted to nitrate (NO_3) through the aerobic process of nitrification. Denitrification occurs under anoxic conditions (without free oxygen), and involves the biological conversion of nitrate into dinitrogen gas (N_2). N_2O can be an intermediate product of both processes, but is more often associated with denitrification.

The principal factor in determining the CH_4 generation potential of wastewater is the amount of degradable organic material in the wastewater. Common parameters used to measure the organic component of the wastewater are the Biochemical Oxygen Demand (BOD) and Chemical Oxygen Demand (COD). Under the same conditions, wastewater with higher COD (or BOD) concentrations will generally yield more CH_4 than wastewater with lower COD (or BOD) concentrations. BOD represents the amount of oxygen that would be required to completely consume the organic matter contained in the wastewater through aerobic decomposition processes, while COD measures the total material available for chemical oxidation (both biodegradable and non-biodegradable). Because BOD is an aerobic parameter, it is preferable to use COD to estimate CH_4 production. The principal factor in determining the N_2O generation potential of wastewater is the amount of N in the wastewater.

In 2009, CH_4 emissions from domestic wastewater treatment were 16.0 Tg CO_2 Eq. (760 Gg). Emissions gradually increased from 1990 through 1997, but have decreased since that time due to decreasing percentages of wastewater being treated in anaerobic systems, including reduced use of on-site septic systems and central anaerobic treatment systems. In 2009, CH_4 emissions from industrial wastewater treatment were estimated to be 8.5 Tg CO_2 Eq. (407 Gg). Industrial emission sources have increased across the time series through 1999 and then fluctuated up and down with production changes associated with the treatment of wastewater from the pulp and paper manufacturing, meat and poultry processing, fruit and vegetable processing, starch-based ethanol production, and petroleum refining industries. Table 8-6 and Table 8-7 provide CH_4 and N_2O emission estimates from domestic and industrial wastewater treatment.

With respect to N_2O, the United States identifies two distinct sources for N_2O emissions from domestic wastewater: emissions from centralized wastewater treatment processes, and emissions from effluent from centralized treatment systems that has been discharged into aquatic environments. The 2009 emissions of N_2O from centralized wastewater treatment processes and from effluent were estimated to be 0.3 Tg CO_2 Eq. (1 Gg) and 4.7 Tg CO_2 Eq. (15.2 Gg), respectively. Total N_2O emissions from domestic wastewater were estimated to be 5.0 Tg CO_2 Eq. (16.2 Gg). N_2O emissions from wastewater treatment processes gradually increased across the time series as a result of increasing U.S. population and protein consumption.

Table 8-6. CH_4 and N_2O Emissions from Domestic and Industrial Wastewater Treatment (Tg CO_2 Eq.)

Activity	1990		2000		2005	2006	2007	2008	2009

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[200] Throughout the inventory, emissions from domestic wastewater also include any commercial and industrial wastewater collected and co-treated with domestic wastewater.

CH_4	**23.5**		**25.2**		**24.3**	**24.5**	**24.4**	**24.5**	**24.5**
Domestic	16.4		16.8		16.2	16.0	15.9	15.8	16.0
Industrial*	7.1		8.4		8.2	8.5	8.5	8.6	8.5
N_2O	**3.7**		**4.5**		**4.8**	**4.8**	**4.9**	**5.0**	**5.0**
Domestic	3.7		4.5		4.8	4.8	4.9	5.0	5.0
Total	**27.2**		**29.6**		**29.1**	**29.3**	**29.3**	**29.5**	**29.5**

* Industrial activity includes the pulp and paper manufacturing, meat and poultry processing, fruit and vegetable processing, starch-based ethanol production, and petroleum refining industries.

Note: Totals may not sum due to independent rounding.

Table 8-7. CH_4 and N_2O Emissions from Domestic and Industrial Wastewater Treatment (Gg)

Activity	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
CH_4	**1,118**		**1,199**		**1,159**	**1,167**	**1,163**	**1,168**	**1,167**
Domestic	780		801		770	764	758	759	760
Industrial*	338		398		389	403	405	409	407
N_2O	**12**		**14**		**15**	**16**	**16**	**16**	**16**
Domestic	12		14		15	16	16	16	16

* Industrial activity includes the pulp and paper manufacturing, meat and poultry processing, fruit and vegetable processing, starch-based ethanol production, and petroleum refining industries.

Note: Totals may not sum due to independent rounding.

Methodology

Domestic Wastewater CH_4 Emission Estimates

Domestic wastewater CH_4 emissions originate from both septic systems and from centralized treatment systems, such as publicly owned treatment works (POTWs). Within these centralized systems, CH_4 emissions can arise from aerobic systems that are not well managed or that are designed to have periods of anaerobic activity (e.g., constructed wetlands), anaerobic systems (anaerobic lagoons and facultative lagoons), and from anaerobic digesters when the captured biogas is not completely combusted. CH_4 emissions from septic systems were estimated by multiplying the total 5-day BOD (BOD_5) produced in the United States by the percent of wastewater treated in septic systems (20 percent), the maximum CH_4 producing capacity for domestic wastewater (0.60 kg CH_4/kg BOD), and the CH_4 correction factor (MCF) for septic systems (0.5). CH_4 emissions from POTWs were estimated by multiplying the total BOD_5 produced in the United States by the percent of wastewater treated centrally (80 percent), the relative percentage of wastewater treated by aerobic and anaerobic systems, the relative percentage of wastewater facilities with primary treatment, the percentage of BOD_5 treated after primary treatment (67.5 percent), the maximum CH_4-producing capacity of domestic wastewater (0.6), and the relative MCFs for aerobic (zero or 0.3) and anaerobic (0.8) systems with all aerobic systems assumed to be well-managed. CH_4 emissions from anaerobic digesters were estimated by multiplying the amount of biogas generated by wastewater sludge treated in anaerobic digesters by the proportion of CH_4 in digester biogas (0.65), the density of CH_4 (662 g CH_4/m^3 CH_4) , and the destruction efficiency associated with burning the biogas in an energy/thermal device (0.99). The methodological equations are:

Emissions from Septic Systems = A
= (% onsite) × (total BOD_5 produced) × (B_o) × (MCF-septic) × 1/10^6

Emissions from Centrally Treated Aerobic Systems = B
= [(% collected) × (total BOD_5 produced) × (% aerobic) × (% aerobic w/out primary) + (% collected) × (total BOD_5 produced) × (% aerobic) × (% aerobic w/primary) × (1-% BOD removed in prim. treat.)] × (% operations not well managed) × (B_o) × (MCF-aerobic_not_well_man) × 1/10^6

Emissions from Centrally Treated Anaerobic Systems = C
= [(% collected) × (total BOD_5 produced) × (% anaerobic) × (% anaerobic w/out primary) + (% collected) × (total BOD_5 produced) × (% anaerobic) × (% anaerobic w/primary) × (1-%BOD removed in prim. treat.)] × (B_o) × (MCF-anaerobic) × 1/10^6

Emissions from Anaerobic Digesters = D
= [(POTW_flow_AD) × (digester gas)/ (per capita flow)] × conversion to m^3 × (FRAC_CH_4) × (365.25) × (density of CH_4) × (1-DE) × 1/10^9

Total CH_4 Emissions (Gg) = A + B + C + D

Where:

% onsite = Flow to septic systems / total flow
% collected = Flow to POTWs / total flow
% aerobic = Flow to aerobic systems / total flow to POTWs
% anaerobic = Flow to anaerobic systems / total flow to POTWs
% aerobic w/out primary = Percent of aerobic systems that do not employ primary treatment
% aerobic w/primary = Percent of aerobic systems that employ primary treatment
% BOD removed in prim. treat. = 32.5%
% operations not well managed = Percent of aerobic systems that are not well managed and in which some anaerobic degradation occurs
% anaerobic w/out primary = Percent of anaerobic systems that do not employ primary treatment
% anaerobic w/primary = Percent of anaerobic systems that employ primary treatment
Total BOD_5 produced = kg BOD/capita/day × U.S. population × 365.25 days/yr
B_o = Maximum CH_4-producing capacity for domestic wastewater (0.60 kg CH_4/kg BOD)
MCF-septic = CH_4 correction factor for septic systems (0.5)
1/10^6 = Conversion factor, kg to Gg
MCF-aerobic_not_well_man. = CH_4 correction factor for aerobic systems that are not well managed (0.3)
MCF-anaerobic = CH_4 correction factor for anaerobic systems (0.8)
DE = CH_4 destruction efficiency from flaring or burning in engine (0.99 for enclosed flares)
POTW_flow_AD = Wastewater influent flow to POTWs that have anaerobic digesters (gal)
digester gas = Cubic feet of digester gas produced per person per day (1.0 ft^3/person/day) (Metcalf and Eddy 1991)
per capita flow = Wastewater flow to POTW per person per day (100 gal/person/day)
conversion to m^3 = Conversion factor, ft^3 to m^3 (0.0283)
FRAC_CH_4 = Proportion CH_4 in biogas (0.65)
density of CH_4 = 662 (g CH_4/m^3 CH_4)
1/10^9 = Conversion factor, g to Gg

U.S. population data were taken from the U.S. Census Bureau International Database (U.S. Census 2010) and include the populations of the United States, American Samoa, Guam, Northern Mariana Islands, Puerto Rico, and the Virgin Islands. Table 8-8 presents U.S. population and total BOD_5 produced for 1990 through 2009, while Table 8-9 presents domestic wastewater CH_4 emissions for both septic and centralized systems in 2009. The proportions of domestic wastewater treated onsite versus at centralized treatment plants were based on data from the 1989, 1991, 1993, 1995, 1997, 1999, 2001, 2003, 2005, 2007, and 2009 American Housing Surveys conducted by the U.S. Census Bureau (U.S. Census 2009), with data for intervening years obtained by linear interpolation. The percent of wastewater flow to aerobic and anaerobic systems, the percent of aerobic and anaerobic systems that do and do not employ primary treatment, and the wastewater flow to POTWs that have anaerobic digesters were obtained from the 1992, 1996, 2000, and 2004 Clean Watershed Needs Survey (EPA 1992, 1996, 2000, and 2004a). Data for intervening years were obtained by linear interpolation and the years 2004 through 2009 were forecasted from the rest of the time series. The BOD_5 production rate (0.09 kg/capita/day) and the percent BOD_5 removed by primary treatment for domestic wastewater were obtained from Metcalf and Eddy (1991 and 2003). The CH_4 emission factor (0.6 kg CH_4/kg BOD_5) and the MCFs were taken from IPCC (2006). The CH_4 destruction efficiency for methane recovered from sludge digestion operations, 99 percent, was selected based on the range of efficiencies (98 to 100 percent) recommended for flares in AP-42 Compilation of Air Pollutant Emission Factors, Chapter 2.4 (EPA 1998), efficiencies used to establish new source performance standards (NSPS) for landfills, and in recommendations for closed flares used by the Landfill Methane Outreach Program (LMOP). The cubic feet of digester gas produced per person per day (1.0 ft^3/person/day) and the proportion of CH_4 in biogas (0.65) come from

Metcalf and Eddy (1991). The wastewater flow to a POTW (100 gal/person/day) was taken from the Great Lakes-Upper Mississippi River Board of State and Provincial Public Health and Environmental Managers, "Recommended Standards for Wastewater Facilities (Ten-State Standards)" (2004).

Table 8-8. U.S. Population (Millions) and Domestic Wastewater BOD_5 Produced (Gg)

Year	Population	BOD_5
1990	254	8,333
2000	286	9,414
2005	300	9,864
2006	303	9,958
2007	306	10,057
2008	309	10,149
2009	311	10,236

Source: U.S. Census Bureau (2010); Metcalf & Eddy 1991 and 2003.

Table 8-9. Domestic Wastewater CH_4 Emissions from Septic and Centralized Systems (2009)

	CH_4 emissions (Tg CO_2 Eq.)	% of Domestic Wastewater CH_4
Septic Systems	13.2	82.5%
Centralized Systems	2.8	17.5%
Total	**16.0**	**100%**

Note: Totals may not sum due to independent rounding.

Industrial Wastewater CH_4 Emission Estimates

CH_4 emissions estimates from industrial wastewater were developed according to the methodology described in IPCC (2006). Industry categories that are likely to produce significant CH_4 emissions from wastewater treatment were identified. High volumes of wastewater generated and a high organic wastewater load were the main criteria. The top five industries that meet these criteria are pulp and paper manufacturing; meat and poultry processing; vegetables, fruits, and juices processing; starch-based ethanol production; and petroleum refining. Wastewater treatment emissions for these sectors for 2009 are displayed in Table 8-10 below. Table 8-11 contains production data for these industries.

Table 8-10. Industrial Wastewater CH_4 Emissions by Sector (2009)

	CH_4 emissions (Tg CO_2 Eq.)	% of Industrial Wastewater CH_4
Pulp & Paper	4.1	48%
Meat & Poultry	3.6	42%
Petroleum Refineries	0.6	7%
Fruit & Vegetables	0.1	1%
Ethanol Refineries	0.1	1%
Total	**8.5**	**100%**

Note: Totals may not sum due to independent rounding.

Table 8-11. U.S. Pulp and Paper, Meat, Poultry, Vegetables, Fruits and Juices, Ethanol, and Petroleum Refining Production (Tg)

Year	Pulp and Paper	Meat (Live Weight Killed)	Poultry (Live Weight Killed)	Vegetables, Fruits and Juices	Ethanol	Petroleum Refining
1990	128.9	27.3	14.6	38.7	2.7	702.4
2000	142.8	32.1	22.2	50.9	4.9	795.2
2005	131.4	31.4	25.1	42.9	11.7	818.6
2006	137.4	32.5	25.5	42.9	14.5	826.7
2007	135.9	33.4	26.0	44.7	19.4	827.6
2008	134.5	34.4	26.6	45.1	26.9	836.8

2009	137.0	33.8	25.2	47.0	31.7	822.4

CH_4 emissions from these categories were estimated by multiplying the annual product output by the average outflow, the organics loading (in COD) in the outflow, the percentage of organic loading assumed to degrade anaerobically, and the emission factor. Ratios of BOD:COD in various industrial wastewaters were obtained from EPA (1997a) and used to estimate COD loadings. The B_o value used for all industries is the IPCC default value of 0.25 kg CH_4/kg COD (IPCC 2006).

For each industry, the percent of plants in the industry that treat wastewater on site, the percent of plants that have a primary treatment step prior to biological treatment, and the percent of plants that treat wastewater anaerobically were defined. The percent of wastewater treated anaerobically onsite (TA) was estimated for both primary treatment and secondary treatment. For plants that have primary treatment in place, an estimate of COD that is removed prior to wastewater treatment in the anaerobic treatment units was incorporated.

The methodological equations are:

$$CH_4 \text{ (industrial wastewater)} = P \times W \times COD \times \%TA \times B_o \times MCF$$

$$\%TA_p = [\%Plants_o \times \%WW_{a,p} \times \%COD_p]$$

$$\%TA_s = [\%Plants_a \times \%WW_{a,s} \times \%COD_s] + [\%Plants_t \times \%WW_{a,t} \times \%COD_s]$$

Where:

CH_4 (industrial wastewater)= Total CH_4 emissions from industrial wastewater (kg/year)
P = Industry output (metric tons/year)
W = Wastewater generated (m^3/metric ton of product)
COD = Organics loading in wastewater (kg/m^3)
%TA = Percent of wastewater treated anaerobically on site
$\%TA_p$ = Percent of wastewater treated anaerobically on site in primary treatment
$\%TA_s$ = Percent of wastewater treated anaerobically on site in secondary treatment
$\%Plants_o$ = Percent of plants with onsite treatment
$\%WW_{a,p}$ = Percent of wastewater treated anaerobically in primary treatment
$\%COD_p$ = Percent of COD entering primary treatment
$\%Plants_a$ = Percent of plants with anaerobic secondary treatment
$\%Plants_t$ = Percent of plants with other secondary treatment
$\%WW_{a,s}$ = Percent of wastewater treated anaerobically in anaerobic secondary treatment
$\%WW_{a,t}$ = percent of wastewater treated anaerobically in other secondary treatment
$\%COD_s$ = percent of COD entering secondary treatment
B_o = Maximum CH_4 producing potential of industrial wastewater (default value of 0.25 kg CH_4/kg COD)
MCF = CH_4 correction factor, indicating the extent to which the organic content (measured as COD) degrades anaerobically

As described below, the values presented in Table 8-12 were used in the emission calculations.

Table 8-12. Variables Used to Calculate Percent Wastewater Treated Anaerobically by Industry (%)

Variable	**Industry**						
	Pulp and Paper	**Meat Processing**	**Poultry Processing**	**Fruit/ Vegetable Processing**	**Ethanol Production – Wet Mill**	**Ethanol Production – Dry Mill**	**Petroleum Refining**
$\%TA_p$	0	0	0	0	0	0	0
$\%TA_s$	10.5	33	25	4.2	33.3	75	100
$\%Plants_o$	60	100	100	11	100	100	100
$\%Plants_a$	25	33	25	5.5	33.3	75	100
$\%Plants_t$	35	67	75	5.5	66.7	25	0
$\%WW_{a,p}$	0	0	0	0	0	0	0
$\%WW_{a,s}$	100	100	100	100	100	100	100
$\%WW_{a,t}$	0	0	0	0	0	0	0

%COD_p	100	100	100	100	100	100	100
%COD_s	42	100	100	77	100	100	100

Pulp and Paper. Wastewater treatment for the pulp and paper industry typically includes neutralization, screening, sedimentation, and flotation/hydrocycloning to remove solids (World Bank 1999, Nemerow and Dasgupta 1991). Secondary treatment (storage, settling, and biological treatment) mainly consists of lagooning. In determining the percent that degrades anaerobically, both primary and secondary treatment were considered. In the United States, primary treatment is focused on solids removal, equalization, neutralization, and color reduction (EPA 1993). The vast majority of pulp and paper mills with on-site treatment systems use mechanical clarifiers to remove suspended solids from the wastewater. About 10 percent of pulp and paper mills with treatment systems use settling ponds for primary treatment and these are more likely to be located at mills that do not perform secondary treatment (EPA 1993). However, because the vast majority of primary treatment operations at U.S. pulp and paper mills use mechanical clarifiers, and less than 10 percent of pulp and paper wastewater is managed in primary settling ponds that are not expected to have anaerobic conditions, negligible emissions are assumed to occur during primary treatment.

Approximately 42 percent of the BOD passes on to secondary treatment, which consists of activated sludge, aerated stabilization basins, or non-aerated stabilization basins. No anaerobic activity is assumed to occur in activated sludge systems or aerated stabilization basins (note: although IPCC recognizes that some CH_4 can be emitted from anaerobic pockets, they recommend an MCF of zero). However, about 25 percent of the wastewater treatment systems used in the United States are non-aerated stabilization basins. These basins are typically 10 to 25 feet deep. These systems are classified as anaerobic deep lagoons (MCF = 0.8).

A time series of CH_4 emissions for 1990 through 2001 was developed based on production figures reported in the Lockwood-Post Directory (Lockwood-Post 2002). Published data from the American Forest and Paper Association, data published by Paper Loop, and other published statistics were used to estimate production for 2002 through 2009 (Pulp and Paper 2005, 2006, and monthly reports from 2003 through 2008; Paper 360° 2007). The overall wastewater outflow was estimated to be 85 m^3/metric ton, and the average BOD concentrations in raw wastewater was estimated to be 0.4 gram BOD/liter (EPA 1997b, EPA 1993, World Bank 1999).

Meat and Poultry Processing. The meat and poultry processing industry makes extensive use of anaerobic lagoons in sequence with screening, fat traps and dissolved air flotation when treating wastewater on site. About 33 percent of meat processing operations (EPA 2002) and 25 percent of poultry processing operations (U.S. Poultry 2006) perform on-site treatment in anaerobic lagoons. The IPCC default B_o of 0.25 kg CH_4/kg COD and default MCF of 0.8 for anaerobic lagoons were used to estimate the CH_4 produced from these on-site treatment systems. Production data, in carcass weight and live weight killed for the meat and poultry industry, were obtained from the USDA Agricultural Statistics Database and the Agricultural Statistics Annual Reports (USDA 2010). Data collected by EPA's Office of Water provided estimates for wastewater flows into anaerobic lagoons: 5.3 and 12.5 m^3/metric ton for meat and poultry production (live weight killed), respectively (EPA 2002). The loadings are 2.8 and 1.5 g BOD/liter for meat and poultry, respectively.

Vegetables, Fruits, and Juices Processing. Treatment of wastewater from fruits, vegetables, and juices processing includes screening, coagulation/settling, and biological treatment (lagooning). The flows are frequently seasonal, and robust treatment systems are preferred for on-site treatment. Effluent is suitable for discharge to the sewer. This industry is likely to use lagoons intended for aerobic operation, but the large seasonal loadings may develop limited anaerobic zones. In addition, some anaerobic lagoons may also be used (Nemerow and Dasgupta 1991). Consequently, 4.2 percent of these wastewater organics are assumed to degrade anaerobically. The IPCC default B_o of 0.25 kg CH_4/kg COD and default MCF of 0.8 for anaerobic treatment were used to estimate the CH_4 produced from these on-site treatment systems. The USDA National Agricultural Statistics Service (USDA 2010) provided production data for potatoes, other vegetables, citrus fruit, non-citrus fruit, and grapes processed for wine. Outflow and BOD data, presented in Table 8-13, were obtained from EPA (1974) for potato, citrus fruit, and apple processing, and from EPA (1975) for all other sectors.

Table 8-13. Wastewater Flow (m^3/ton) and BOD Production (g/L) for U.S. Vegetables, Fruits, and Juices Production

Commodity	Wastewater Outflow (m^3/ton)	BOD (g/L)
Vegetables		
Potatoes	10.27	1.765
Other Vegetables	8.74	0.801

Fruit		
Apples	3.66	1.371
Citrus	10.11	0.317
Non-citrus	12.42	1.204
Grapes (for wine)	2.78	1.831

Ethanol Production. Ethanol, or ethyl alcohol, is produced primarily for use as a fuel component, but is also used in industrial applications and in the manufacture of beverage alcohol. Ethanol can be produced from the fermentation of sugar-based feedstocks (e.g., molasses and beets), starch- or grain-based feedstocks (e.g., corn, sorghum, and beverage waste), and cellulosic biomass feedstocks (e.g., agricultural wastes, wood, and bagasse). Ethanol can also be produced synthetically from ethylene or hydrogen and carbon monoxide. However, synthetic ethanol comprises only about 2 percent of ethanol production, and although the Department of Energy predicts cellulosic ethanol to greatly increase in the coming years, currently it is only in an experimental stage in the United States. According to the Renewable Fuels Association, 82 percent of ethanol production facilities use corn as the sole feedstock and 7 percent of facilities use a combination of corn and another starch-based feedstock. The fermentation of corn is the principal ethanol production process in the United States and is expected to increase through 2012, and potentially more; therefore, emissions associated with wastewater treatment at starch-based ethanol production facilities were estimated (ERG 2006).

Ethanol is produced from corn (or other starch-based feedstocks) primarily by two methods: wet milling and dry milling. Historically, the majority of ethanol was produced by the wet milling process, but now the majority is produced by the dry milling process. The wastewater generated at ethanol production facilities is handled in a variety of ways. Dry milling facilities often combine the resulting evaporator condensate with other process wastewaters, such as equipment wash water, scrubber water, and boiler blowdown and anaerobically treat this wastewater using various types of digesters. Wet milling facilities often treat their steepwater condensate in anaerobic systems followed by aerobic polishing systems. Wet milling facilities may treat the stillage (or processed stillage) from the ethanol fermentation/distillation process separately or together with steepwater and/or wash water. CH_4 generated in anaerobic digesters is commonly collected and either flared or used as fuel in the ethanol production process (ERG 2006).

Available information was compiled from the industry on wastewater generation rates, which ranged from 1.25 gallons per gallon ethanol produced (for dry milling) to 10 gallons per gallon ethanol produced (for wet milling) (Ruocco 2006a,b; Merrick 1998; Donovan 1996; and NRBP 2001). COD concentrations were also found to be about 3 g/L (Ruocco 2006a; Merrick 1998; White and Johnson 2003). The amount of wastewater treated anaerobically was estimated, along with how much of the CH_4 is recovered through the use of biomethanators (ERG 2006). CH_4 emissions were then estimated as follows:

$$\text{Methane} = [\text{Production} \times \text{Flow} \times \text{COD} \times 3.785 \times ([\%\text{Plants}_o \times \%\text{WW}_{a,p} \times \%\text{COD}_p] + [\%\text{Plants}_a \times \%\text{WW}_{a,s} \times \%\text{COD}_s] + [\%\text{Plants}_t \times \%\text{WW}_{a,t} \times \%\text{COD}_s]) \times B_o \times \text{MCF} \times \%\ \text{Not Recovered}] + [\text{Production} \times \text{Flow} \times 3.785 \times \text{COD} \times ([\%\text{Plants}_o \times \%\text{WW}_{a,p} \times \%\text{COD}_p] + [\%\text{Plants}_a \times \%\text{WW}_{a,s} \times \%\text{COD}_s] + [\%\text{Plants}_t \times \%\text{WW}_{a,t} \times \%\text{COD}_s]) \times B_o \times \text{MCF} \times (\%\ \text{Recovered}) \times (1\text{-DE})] \text{ x } 1/10^{\wedge}9$$

Where:

Production = gallons ethanol produced (wet milling or dry milling)
Flow = gallons wastewater generated per gallon ethanol produced (1.25 dry milling, 10 wet milling)
COD = COD concentration in influent (3 g/l)
3.785 = conversion, gallons to liters
$\%\text{Plants}_o$ = percent of plants with onsite treatment (100%)
$\%\text{WW}_{a,p}$ = percent of wastewater treated anaerobically in primary treatment (0%)
$\%\text{COD}_p$ = percent of COD entering primary treatment (100%)
$\%\text{Plants}_a$ = percent of plants with anaerobic secondary treatment (33.3% wet, 75% dry)
$\%\text{Plants}_t$ = percent of plants with other secondary treatment (66.7% wet, 25% dry)
$\%\text{WW}_{a,s}$ = percent of wastewater treated anaerobically in anaerobic secondary treatment (100%)
$\%\text{WW}_{a,t}$ = percent of wastewater treated anaerobically in other secondary treatment (0%)
$\%\text{COD}_s$ = percent of COD entering secondary treatment (100%)

B_o = maximum methane producing capacity (0.25 g CH_4/g COD)
MCF = methane conversion factor (0.8 for anaerobic systems)
% Recovered = percent of wastewater treated in system with emission recovery
% Not Recovered = 1 - percent of wastewater treated in system with emission recovery
DE = destruction efficiency of recovery system (99%)
1/10^9 = conversion factor, g to Gg

A time series of CH_4 emissions for 1990 through 2009 was developed based on production data from the Renewable Fuels Association (RFA 2010).

Petroleum Refining. Petroleum refining wastewater treatment operations produce CH_4 emissions from anaerobic wastewater treatment. The wastewater inventory section includes CH_4 emissions from petroleum refining wastewater treated on site under intended or unintended anaerobic conditions. Most facilities use aerated biological systems, such as trickling filters or rotating biological contactors; these systems can also exhibit anaerobic conditions that can result in the production of CH_4. Oil/water separators are used as a primary treatment method; however, it is unlikely that any COD is removed in this step.

Available information from the industry was compiled. The wastewater generation rate, from CARB (2007) and Timm (1985), was determined to be 35 gallons per barrel of finished product. An average COD value in the wastewater was estimated at 0.45 kg/m^3 (Benyahia et al. 2006).

The equation used to calculate CH_4 generation at petroleum refining wastewater treatment systems is presented below:

$$\text{Methane} = \text{Flow} \times \text{COD} \times B_o \times \text{MCF}$$

Where:

Flow = Annual flow treated through anaerobic treatment system (m^3/year)
COD = COD loading in wastewater entering anaerobic treatment system (kg/m^3)
B_o = maximum methane producing potential of industrial wastewater (default value of 0.25 kg CH_4 /kg COD)
MCF = methane conversion factor (0.3)

A time series of CH_4 emissions for 1990 through 2009 was developed based on production data from the Energy Information Association (EIA 2010).

Domestic Wastewater N_2O Emission Estimates

N_2O emissions from domestic wastewater (wastewater treatment) were estimated using the IPCC (2006) methodology, including calculations that take into account N removal with sewage sludge, non-consumption and industrial wastewater N, and emissions from advanced centralized wastewater treatment plants:

- In the United States, a certain amount of N is removed with sewage sludge, which is applied to land, incinerated, or landfilled (N_{SLUDGE}). The N disposal into aquatic environments is reduced to account for the sewage sludge application.
- The IPCC methodology uses annual, per capita protein consumption (kg protein/[person-year]). For this inventory, the amount of protein available to be consumed is estimated based on per capita annual food availability data and its protein content, and then adjusts that data using a factor to account for the fraction of protein actually consumed.
- Small amounts of gaseous nitrogen oxides are formed as by-products in the conversion of nitrate to N gas in anoxic biological treatment systems. Approximately 7 grams N_2O is generated per capita per year if wastewater treatment includes intentional nitrification and denitrification (Scheehle and Doorn 2001). Analysis of the 2004 CWNS shows that plants with denitrification as one of their unit operations serve a population of 2.4 million people. Based on an emission factor of 7 grams per capita per year, approximately 21.2 metric tons of additional N_2O may have been emitted via denitrification in 2004. Similar analyses were completed for each year in the Inventory using data from CWNS on the amount of wastewater in centralized systems treated in denitrification units. Plants without intentional nitrification/denitrification are assumed to generate 3.2 grams N_2O per capita

per year.

N_2O emissions from domestic wastewater were estimated using the following methodology:

$$N_2O_{TOTAL} = N_2O_{PLANT} + N_2O_{EFFLUENT}$$

$$N_2O_{PLANT} = N_2O_{NIT/DENIT} + N_2O_{WOUT\ NIT/DENIT}$$

$$N_2O_{NIT/DENIT} = [(US_{POPND}) \times EF_2 \times F_{IND\text{-}COM}] \times 1/10^{\wedge}9$$

$$N_2O_{WOUT\ NIT/DENIT} = \{[(US_{POP} \times WWTP) - US_{POPND}] \times F_{IND\text{-}COM} \times EF_1\} \times 1/10^{\wedge}9$$

$$N_2O_{EFFLUENT} = \{[((US_{POP} - (0.9 \times US_{POPND})) \times Protein \times F_{NPR} \times F_{NON\text{-}CON} \times F_{IND\text{-}COM}) - N_{SLUDGE}] \times EF_3 \times 44/28\} \times 1/10^{\wedge}6$$

where,

N_2O_{TOTAL} = Annual emissions of N_2O (Gg)
N_2O_{PLANT} = N_2O emissions from centralized wastewater treatment plants (Gg)
$N_2O_{NIT/DENIT}$ = N_2O emissions from centralized wastewater treatment plants with nitrification/denitrification (Gg)
$N_2O_{WOUT\ NIT/DENIT}$ = N_2O emissions from centralized wastewater treatment plants without nitrification/denitrification (Gg)
$N_2O_{EFFLUENT}$ = N_2O emissions from wastewater effluent discharged to aquatic environments (Gg)
US_{POP} = U.S. population
US_{POPND} = U.S. population that is served by biological denitrification (from CWNS)
WWTP = Fraction of population using WWTP (as opposed to septic systems)
EF_1 = Emission factor (3.2 g N_2O/person-year) – plant with no intentional denitrification
EF_2 = Emission factor (7 g N_2O/person-year) – plant with intentional denitrification
Protein = Annual per capita protein consumption (kg/person/year)
F_{NPR} = Fraction of N in protein, default = 0.16 (kg N/kg protein)
$F_{NON\text{-}CON}$ = Factor for non-consumed protein added to wastewater (1.4)
$F_{IND\text{-}COM}$ =Factor for industrial and commercial co-discharged protein into the sewer system (1.25)
N_{SLUDGE} = N removed with sludge, kg N/yr
EF_3 = Emission factor (0.005 kg N_2O -N/kg sewage-N produced) – from effluent
0.9 = Amount of nitrogen removed by denitrification systems
44/28 = Molecular weight ratio of N_2O to N_2

U.S. population data were taken from the U.S. Census Bureau International Database (U.S. Census 2010) and include the populations of the United States, American Samoa, Guam, Northern Mariana Islands, Puerto Rico, and the Virgin Islands. The fraction of the U.S. population using wastewater treatment plants is based on data from the 1989, 1991, 1993, 1995, 1997, 1999, 2001, 2003, 2005, 2007, and 2009 American Housing Survey (U.S. Census 2009). Data for intervening years were obtained by linear interpolation. The emission factor (EF_1) used to estimate emissions from wastewater treatment was taken from IPCC (2006). Data on annual per capita protein intake were provided by U.S. Department of Agriculture Economic Research Service (USDA 2009). Protein consumption data for 2005 through 2009 were extrapolated from data for 1990 through 2004. Table 8-14 presents the data for U.S. population and average protein intake. An emission factor to estimate emissions from effluent (EF_3) has not been specifically estimated for the United States, thus the default IPCC value (0.005 kg N_2O-N/kg sewage-N produced) was applied. The fraction of N in protein (0.16 kg N/kg protein) was also obtained from IPCC (2006). The factor for non-consumed protein and the factor for industrial and commercial co-discharged protein were obtained from IPCC (2006). Sludge generation was obtained from EPA (1999) for 1988, 1996, and 1998 and from Beecher et al. (2007) for 2004. Intervening years were interpolated, and estimates for 2005 through 2009 were forecasted from the rest of the time series. An estimate for the N removed as sludge (N_{SLUDGE}) was obtained by determining the amount of sludge disposed by incineration, by land application (agriculture or other), through surface disposal, in landfills, or through ocean dumping. In 2009, 271 Gg N was removed with sludge.

Table 8-14. U.S. Population (Millions), Available Protein (kg/person-year), and Protein Consumed (kg/person-year)

Year	Population	Available Protein	Protein Consumed
1990	254	38.7	29.6

2000	286	41.3	31.6
2005	300	41.7	32.1
2006	303	41.9	32.1
2007	306	42.1	32.2
2008	309	42.2	32.4
2009	311	42.4	32.5

Source: U.S. Census Bureau 2010, USDA 2009.

Uncertainty and Time-Series Consistency

The overall uncertainty associated with both the 2009 CH_4 and N_2O emission estimates from wastewater treatment and discharge was calculated using the IPCC Good Practice Guidance Tier 2 methodology (2000). Uncertainty associated with the parameters used to estimate CH_4 emissions include that of numerous input variables used to model emissions from domestic wastewater, and wastewater from pulp and paper manufacture, meat and poultry processing, fruits and vegetable processing, ethanol production, and petroleum refining. Uncertainty associated with the parameters used to estimate N_2O emissions include that of sewage sludge disposal, total U.S. population, average protein consumed per person, fraction of N in protein, non-consumption nitrogen factor, emission factors per capita and per mass of sewage-N, and for the percentage of total population using centralized wastewater treatment plants.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 8-15. CH_4 emissions from wastewater treatment were estimated to be between 15.3 and 35.9 Tg CO_2 Eq. at the 95 percent confidence level (or in 19 out of 20 Monte Carlo Stochastic Simulations). This indicates a range of approximately 37 percent below to 47 percent above the 2009 emissions estimate of 24.5 Tg CO_2 Eq. N_2O emissions from wastewater treatment were estimated to be between 1.2 and 9.7 Tg CO_2 Eq., which indicates a range of approximately 76 percent below to 93 percent above the actual 2009 emissions estimate of 5.0 Tg CO_2 Eq.

Table 8-15. Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Wastewater Treatment (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a]**			
			(Tg CO2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Wastewater Treatment	**CH_4**	**24.5**	**15.3**	**35.9**	**-37%**	**+47%**
Domestic	CH_4	16.0	7.6	26.6	-52%	+66%
Industrial	CH_4	8.5	5.1	13.1	-41%	+54%
Wastewater Treatment	**N_2O**	**5.0**	**1.2**	**9.7**	**-76%**	**+93%**

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed on activity data, documentation, and emission calculations. This effort included a Tier 1 analysis, including the following checks:

- Checked for transcription errors in data input;
- Ensured references were specified for all activity data used in the calculations;
- Checked a sample of each emission calculation used for the source category;
- Checked that parameter and emission units were correctly recorded and that appropriate conversion factors were used;
- Checked for temporal consistency in time series input data for each portion of the source category;
- Confirmed that estimates were calculated and reported for all portions of the source category and for all years;
- Investigated data gaps that affected emissions estimates trends; and

- Compared estimates to previous estimates to identify significant changes.

All transcription errors identified were corrected. The QA/QC analysis did not reveal any systemic inaccuracies or incorrect input values.

Planned Improvements Discussion

The methodology to estimate CH_4 emissions from domestic wastewater treatment currently utilizes estimates for the percentage of centrally treated wastewater that is treated by aerobic systems and anaerobic systems. These data come from the 1992, 1996, 2000, and 2004 CWNS. The question of whether activity data for wastewater treatment systems are sufficient across the timeseries to further differentiate aerobic systems with the potential to generate small amounts of CH_4 (aerobic lagoons) versus other types of aerobic systems, and to differentiate between anaerobic systems to allow for the use of different MCFs for different types of anaerobic treatment systems, continues to be explored. Recently available CWNS data for 2008 also is being evaluated for incorporation into the inventory. Due to significant changes in format, this dataset was unable to be included in the domestic wastewater calculations for the current Inventory. However, EPA continues to evaluate ways to incorporate the updated data into future years of the Inventory.

Currently, it is assumed that all aerobic systems are well managed and produce no CH_4 and that all anaerobic systems have an MCF of 0.8. Efforts to obtain better data reflecting emissions from various types of municipal treatment systems are currently being pursued.

A review of other industrial wastewater treatment sources for those industries believed to discharge significant loads of BOD and COD has been ongoing. Food processing industries have the highest potential for CH_4 generation due to the waste characteristics generated, and the greater likelihood to treat the wastes anaerobically. However, in all cases there is dated information available on U.S. treatment operations for these industries. A review of the organic chemicals industry was conducted in April 2010, during which only 1987 data was readily identified. It was concluded that current industry-level treatment system information is very difficult to obtain, as is time series data. Based on the 1987 data, emissions from this source are small and are not a likely industry category for significant CH_4 emissions. Therefore, this industry has not been included in the Inventory and there are no near future plans to do so. Similarly, the seafood processing industry was reviewed to estimate its potential to generate CH_4. Due to minimal anaerobic wastewater treatment operations at processing facilities, this industry was not selected for inclusion in the Inventory. Other industries will be reviewed as necessary for inclusion in future years of the Inventory.

Available data will be reviewed regarding anaerobic treatment at petroleum refineries. If necessary, the %TA for this industry will be revised accordingly. Currently, all petroleum plants are assumed to have anaerobic treatment.

With respect to estimating N_2O emissions, the default emission factor for indirect N_2O from wastewater effluent and direct N_2O from centralized wastewater treatment facilities has a high uncertainty. Current research is being conducted by the Water Environment Research Foundation (WERF) to measure N_2O emissions from municipal treatment systems. Such data will be reviewed as they are available to determine if a country-specific N_2O emission factor can or should be developed, or if alternate emission factors should be used. EPA expects WERF to publish a final N_2O generation report by the end of 2011. In addition, WERF recently conducted a study of greenhouse gas emissions from septic systems located in California. This study concluded that the emission rate for methane and nitrous oxide were 10.7 and 0.20 g/capita-d, respectively. EPA is currently reviewing the results of this study to determine if the systems evaluated are representative of U.S. operations and if a country-specific factor for septic systems can be introduced into the inventory. The effect would be to lower current estimates of CH_4 emissions by about half, and to include N_2O emission estimates where previously none were calculated. In addition, more investigation of new study results will be used to evaluate the method used to calculate N_2O emissions associated with effluent and whether septic systems are appropriately included in the calculation.

In addition, the estimate of N entering municipal treatment systems is under review. The factor that accounts for non-sewage N in wastewater (bath, laundry, kitchen, industrial components) also has a high uncertainty. Obtaining data on the changes in average influent N concentrations to centralized treatment systems over the time series would improve the estimate of total N entering the system, which would reduce or eliminate the need for other factors for non-consumed protein or industrial flow. The dataset previously provided by the National Association of Clean Water Agencies (NACWA) was reviewed to determine if it was representative of the larger population of centralized treatment plants for potential inclusion into the inventory. However, this limited dataset was not representative of the number of systems by state or the service populations served in the United States, and therefore could not be incorporated into the inventory methodology. Additional data sources will continue to be researched with the goal of improving the uncertainty of the estimate of N entering municipal treatment systems.

8.3. Composting (IPCC Source Category 6D)

Composting of organic waste, such as food waste, garden (yard) and park waste, and sludge, is common in the United States. Advantages of composting include reduced volume in the waste material, stabilization of the waste, and destruction of pathogens in the waste material. The end products of composting, depending on its quality, can be recycled as fertilizer and soil amendment, or be disposed in a landfill.

Composting is an aerobic process and a large fraction of the degradable organic carbon in the waste material is converted into carbon dioxide (CO_2). Methane (CH_4) is formed in anaerobic sections of the compost, but it is oxidized to a large extent in the aerobic sections of the compost. Anaerobic sections are created in composting piles when there is excessive moisture or inadequate aeration (or mixing) of the compost pile. The estimated CH_4 released into the atmosphere ranges from less than 1 percent to a few percent of the initial C content in the material (IPCC 2006). Composting can also produce nitrous oxide (N_2O) emissions. The range of the estimated emissions varies from less than 0.5 percent to 5 percent of the initial nitrogen content of the material (IPCC 2006).

From 1990 to 2009, the amount of material composted in the United States has increased from 3,810 Gg to 19,857 Gg, an increase of approximately 421 percent. From 2000 to 2009, the amount of material composted in the United States has increased by approximately 33 percent. Emissions of CH_4 and N_2O from composting have increased by the same percentage (see Table 8-16 and Table 8-17). In 2009, CH_4 emissions from composting were 1.7 Tg CO_2 Eq. (79 Gg), and N_2O emissions from composting were 1.8 Tg CO_2 Eq. (6 Gg). The wastes that are composted include primarily yard trimmings (grass, leaves, and tree and brush trimmings) and food scraps from residences and commercial establishments (such as grocery stores, restaurants, and school and factory cafeterias). The composting waste quantities reported here do not include backyard composting. The growth in composting is attributable primarily to two factors: (1) steady growth in population and residential housing, and (2) state and local governments started enacting legislation that discouraged the disposal of yard trimmings in landfills. In 1992, 11 states and the District of Columbia had legislation in effect that banned or discouraged disposal of yard trimmings in landfills. In 2005, 21 states and the District of Columbia, representing about 50 percent of the nation's population, had enacted such legislation (EPA 2008).

Table 8-16. CH_4 and N_2O Emissions from Composting (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
CH_4	0.3	1.3	1.6	1.6	1.7	1.7	1.7
N_2O	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Total	**0.7**	**2.7**	**3.3**	**3.3**	**3.5**	**3.5**	**3.5**

Table 8-17. CH_4 and N_2O Emissions from Composting (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
CH_4	15	60	75	75	79	80	79
N_2O	1	4	6	6	6	6	6

Methodology

CH_4 and N_2O emissions from composting depend on factors such as the type of waste composted, the amount and type of supporting material (such as wood chips and peat) used, temperature, moisture content and aeration during the process.

The emissions shown in Table 8-16 and Table 8-17 were estimated using the IPCC default (Tier 1) methodology (IPCC 2006), which is the product of an emission factor and the mass of organic waste composted (note: no CH_4 recovery is expected to occur at composting operations):

$$E_i = M \times EF_i$$

where,

E_i = CH_4 or N_2O emissions from composting, Gg CH_4 or N_2O,
M = mass of organic waste composted in Gg,
EF_i = emission factor for composting, 4 g CH_4/kg of waste treated (wet basis) and 0.3 g N_2O/kg of waste treated (wet basis), and
i = designates either CH_4 or N_2O.

Estimates of the quantity of waste composted (M) are presented in Table 8-18. Estimates of the quantity composted for 1990 and 1995 were taken from the *Characterization of Municipal Solid Waste in the United States: 1996 Update* (Franklin Associates 1997); estimates of the quantity composted for 2000, 2005, 2006, 2007, and 2008 were taken from EPA's *Municipal Solid Waste In The United States: 2008 Facts and Figures* (EPA 2009); estimates of the quantity composted for 2009 were calculated using the 2008 quantity composted.

Table 8-18: U.S. Waste Composted (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
Waste Composted	3,810	14,923	18,643	18,852	19,695	20,049	19,857

Source: Franklin Associates 1997 and EPA 2009.

Uncertainty and Time-Series Consistency

The estimated uncertainty from the 2006 IPCC Guidelines is ±50 percent for the Tier 1 methodology. Emissions from composting in 2009 were estimated to be between 1.8 and 5.3 Tg CO_2 Eq., which indicates a range of 50 percent below to 50 percent above the actual 2009 emission estimate of 3.5 Tg CO_2 Eq. (see Table 8-19).

Table 8-19 : Tier 1 Quantitative Uncertainty Estimates for Emissions from Composting (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**			
			(Tg CO2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Composting	CH_4, N_2O	3.5	1.8	5.3	-50%	+50%

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

For future Inventories, additional efforts will be made to improve the estimates of CH_4 and N_2O emissions from composting. For example, a literature search may be conducted to determine if emission factors specific to various composting systems and composted materials are available.

8.4. Waste Sources of Indirect Greenhouse Gases

In addition to the main greenhouse gases addressed above, waste generating and handling processes are also sources of indirect greenhouse gas emissions. Total emissions of NO_x, CO, and NMVOCs from waste sources for the years 1990 through 2009 are provided in Table 8-20.

Table 8-20: Emissions of NO_x, CO, and NMVOC from Waste (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
NO_x	**+**	**2**	**2**	**2**	**2**	**2**	**2**
Landfills	+	2	2	2	2	2	2
Wastewater Treatment	+	+	+	+	+	+	+
Miscellaneous[a]	+	+	+	+	+	+	0
CO	**1**	**8**	**7**	**7**	**7**	**7**	**7**
Landfills	1	7	6	6	6	6	6
Wastewater Treatment	+	1	+	+	+	+	+
Miscellaneous[a]	+	+	+	+	+	+	+
NMVOCs	**673**	**119**	**114**	**113**	**111**	**109**	**76**
Wastewater Treatment	57	51	49	49	48	47	33
Miscellaneous[a]	557	46	43	43	42	41	29
Landfills	58	22	22	21	21	21	14

[a] Miscellaneous includes TSDFs (Treatment, Storage, and Disposal Facilities under the Resource Conservation and Recovery Act [42 U.S.C. § 6924, SWDA § 3004]) and other waste categories.

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.5 Gg.

Methodology

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emission estimates of these gases were provided by sector, using a “top down” estimating procedure—emissions were calculated either for individual sources or for many sources combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual source categories from various agencies. Depending on the source category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

Uncertainty and Time-Series Consistency

No quantitative estimates of uncertainty were calculated for this source category. Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009.

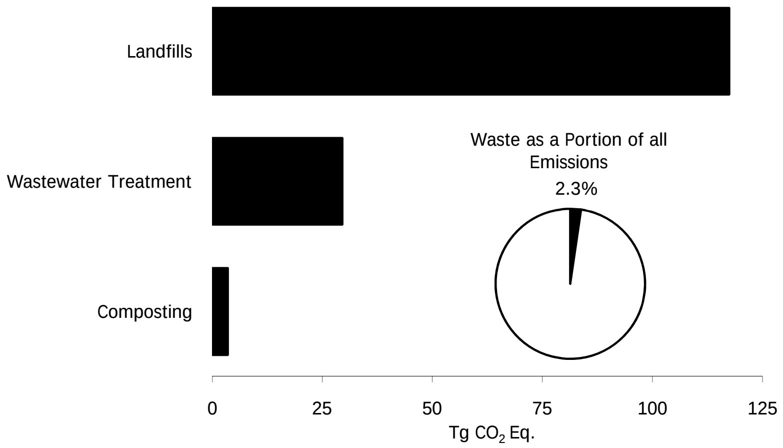

Figure 8-1: 2009 Waste Chapter Greenhouse Gas Sources

9. Other

The United States does not report any greenhouse gas emissions under the Intergovernmental Panel on Climate Change (IPCC) “Other” sector.

10. Recalculations and Improvements

Each year, emission and sink estimates are recalculated and revised for all years in the Inventory of U.S. Greenhouse Gas Emissions and Sinks, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In this effort, the United States follows the 2006 IPCC Guidelines (IPCC 2006), which states, “Both methodological changes and refinements over time are an essential part of improving inventory quality. It is *good practice* to change or refine methods” when: available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors.”

The results of all methodological changes and historical data updates are presented in this section; detailed descriptions of each recalculation are contained within each source’s description found in this report, if applicable. Table 10-1 summarizes the quantitative effect of these changes on U.S. greenhouse gas emissions and Table 10-2 summarizes the quantitative effect on net CO_2 flux to the atmosphere, both relative to the previously published U.S. Inventory (i.e., the 1990 through 2008 report). These tables present the magnitude of these changes in units of teragrams of carbon dioxide equivalent (Tg CO_2 Eq.).

The Recalculations Discussion section of each source presents the details of each recalculation. In general, when methodological changes have been implemented, the entire time series (i.e., 1990 through 2008) has been recalculated to reflect the change, per IPCC (2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies.

The following emission sources, which are listed in descending order of absolute average annual change in emissions between 1990 and 2008, underwent some of the most important methodological and historical data changes. A brief summary of the recalculations and/or improvements undertaken is provided for each emission source.

- *Natural Gas Systems (CH_4).* For the current Inventory, methodologies for gas well cleanups and condensate storage tanks were revised, and new data sources for centrifugal compressors with wet seals, unconventional gas well completions, and unconventional gas well workovers were used, relative to the previous Inventory. The net effect of these changes was an increase in total CH_4 emissions from natural gas systems of between 46.5 and 119.7 percent each year between 1990 and 2008, resulting in an overall annual average increase of 79.3 Tg CO_2 Eq. (66.4 percent). The natural gas production segment accounted for the largest increases, largely due to the methodological changes to gas well cleanups and the addition of unconventional gas well completions and workovers.

- *Landfills (CH_4)* Changes in CH_4 emissions from Landfills relative to the previous Inventory resulted from improvements made to better associate flares with the correct landfills or Landfill Gas to Energy projects across the nation. In addition, steps were also taken to further characterize the food waste decay rate. A weighted component-specific decay rate for food waste of 0.156 yr^{-1} was used in the current Inventory, replacing the previous Inventory’s default food waste decay rate of 0.185 yr^{-1} These revisions impacted emission estimates for the entire time series and resulted in an average annual decrease of 8.3 Tg CO_2 Eq. (6.5 percent) in CH_4 emissions from Landfills for the period 1990 through 2008.

- *Manure Management (CH_4).* Changes in CH_4 emissions from Manure Management relative to the previous Inventory resulted from several updates. Volatile solid production rates for all animal types were updated based on data from the USDA and EPA’s Cattle Enteric Fermentation Model. In addition, USDA data on swine were re-categorized, which changed the typical animal mass for two categories. These changes impacted emission estimates for the entire time series and resulted in an average annual increase of 3.5 Tg CO_2 Eq. (9.4 percent) in CH_4 emissions from Manure Management across the entire time series relative to the previous Inventory.

- *Agricultural Soil Management (N_2O).* Changes in N_2O emissions from Agricultural Soil Management relative to the previous Inventory resulted from methodological changes for estimating grassland areas and livestock manure nitrogen. These recalculations have opposing effects on emissions; grassland area was reduced, resulting in lower emissions, and livestock manure nitrogen increased, resulting in higher emissions. These changes affected the entire time series, resulting in an average annual reduction in N_2O emissions of 3.2 Tg CO_2 Eq. (1.5 percent) for the period 1990 through 2008 relative to the previous Inventory.

- *Iron and Steel Production & Metallurgical Coke Production (CO_2).* A calculation error in the previous Inventory regarding coal tar production and coke breeze production estimates was corrected for the current Inventory, resulting in an average annual decrease in CO_2 emissions from Iron and Steel Production & Metallurgical Coke Production of 2.2 Tg CO_2 Eq. (2.7 percent) for the period 1990 through 2008.
- *Non-Energy Uses of Fossil Fuels (CO_2).* Updates to the EIA Manufacturer's Energy Consumption Survey (MECS) for 2006 resulted in changes to CO_2 emissions from Non-Energy Uses of Fossil Fuels for 2003 through 2008 relative to the previous Inventory. Adjustments were made to the entire MECS time series to remove scrap tire consumption for use as a fuel, which is associated with the Waste Incineration chapter. In addition, emissions from synthetic rubber were revised across the entire time series. These changes impacted emission estimates from 1990 through 2008 resulting in an average annual decrease in CO_2 emissions of 1.4 Tg CO_2 Eq. (1.0 percent) across the entire time series.
- *Petroleum Systems (CH_4).* Well completion venting, well drilling, and offshore platform activity factors were updated relative to the previous Inventory from existing data sources from 1990 onward, and the emission factor for venting from fixed roof storage tanks in the crude oil production segment was increased to reflect the occurrence of gas venting through storage tanks. These changes affected the entire time series from Petroleum Systems, resulting in an average annual increase in CH_4 emissions of 1.3 Tg CO_2 Eq. (4.3 percent) for the period 1990 through 2008 relative to the previous report.
- *Nitric Acid Production (N_2O).* Changes in N_2O emission from Nitric Acid Production relative to the previous Inventory resulted from updated information on abatement technologies in use at production facilities and revised production data from the U.S. Census Bureau. These changes resulted in an average annual decrease in N_2O emissions of 1.3 Tg CO_2 Eq. (6.7 percent) across the entire time series relative to the previous report.
- *Electrical Transmission and Distribution (SF_6).* SF_6 emission estimates for the period 1990 through 2008 were updated relative to the previous Inventory based on (1) new data from EPA's SF_6 Emission Reduction Partnership; (2) revisions to interpolated and extrapolated non-reported Partner data; and (3) a correction made to 2004 transmission mile data for a large Partnership utility that had been interpreted incorrectly from the UDI database in previous years. In addition, the method for estimating potential emissions from the sector was updated for the current Inventory to assume that all SF_6 purchased by equipment manufacturers is either emitted or sent to utilities. These changes affected the entire time series, resulting in an average annual increase of 1.2 Tg CO_2 Eq. (6.6 percent) for the period 1990 through 2008 relative to the previous report.
- *Forestland Remaining Forestland (C Sink).* Changes to the estimated carbon stored in Forestland Remaining Forestland stemmed from recent additions to the Forest Inventory and Analysis Database (FIADB). Newer annual inventory data for most states including Oklahoma, California, Oregon, and Washington were added. Some older periodic inventories for some southern states were also updated. These changes resulted in an average annual increase in carbon stored in forestland of 6.8 Tg CO_2 Eq. (2.4 percent) for the period 1990 through 2008 relative to the previous inventory report.

Table 10-1: Revisions to U.S. Greenhouse Gas Emissions (Tg CO2 Eq.)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**
CO_2	**(1.1)**	**(2.2)**	**5.3**	**3.9**	**(0.2)**	**0.2**
Fossil Fuel Combustion	2.7	1.5	(0.1)	0.3	(0.3)	(6.8)
Electricity Generation	+	+	+	NC	+	(2.6)
Transportation	0.2	+	1.3	1.4	0.2	4.7
Industrial	1.0	(1.1)	(2.5)	(2.5)	(0.2)	(16.4)
Residential	(0.8)	(0.5)	(0.5)	(0.5)	0.7	5.5
Commercial	2.3	3.2	2.3	2.6	2.0	4.7
U.S. Territories	NC	NC	(0.7)	(0.7)	(3.0)	(2.7)
Non-Energy Use of Fuels	(1.0)	(1.2)	6.9	4.2	1.9	6.8
Iron and Steel Production & Metallurgical Coke Production	(3.0)	(2.2)	(1.8)	(1.8)	(1.8)	(3.0)
Natural Gas Systems	0.3	0.5	0.4	1.2	0.2	2.9
Cement Production	NC	(0.8)	(0.7)	(0.8)	(0.7)	(0.6)
Incineration of Waste	(0.1)	(0.2)	(0.2)	(0.2)	(0.6)	(1.0)

Ammonia Production and Urea Consumption	NC	NC	NC	NC	0.1	0.2
Lime Production	NC	NC	NC	NC	NC	NC
Cropland Remaining Cropland	NC	NC	NC	NC	(0.1)	1.0
Limestone and Dolomite Use	NC	NC	NC	NC	NC	(0.3)
Soda Ash Production and Consumption	NC	NC	NC	NC	NC	NC
Aluminum Production	NC	NC	NC	NC	NC	NC
Petrochemical Production	NC	NC	NC	NC	NC	NC
Carbon Dioxide Consumption	NC	NC	NC	+	NC	NC
Titanium Dioxide Production	NC	NC	NC	NC	NC	NC
Ferroalloy Production	NC	NC	NC	NC	NC	NC
Wetlands Remaining Wetlands	NC	NC	NC	NC	NC	0.1
Phosphoric Acid Production	NC	NC	NC	NC	NC	+
Zinc Production	(0.3)	(0.1)	0.6	0.6	0.7	0.8
Lead Production	0.2	0.3	0.3	0.3	0.3	0.3
Petroleum Systems	+	+	+	+	+	+
Silicon Carbide Production and Consumption	NC	NC	NC	NC	NC	NC
Land Use, Land-Use Change, and Forestry (Sink)[a]	*47.9*	*87.7*	*(106.1)*	*(105.2)*	*(105.5)*	*(100.1)*
Biomass - Wood[a]	*NC*	*NC*	*NC*	*(4.0)*	*(4.1)*	*(0.1)*
International Bunker Fuels[a]	*+*	*+*	*(0.8)*	*(0.7)*	*0.6*	*(1.5)*
Biomass - Ethanol[a]	*0.1*	*0.2*	*0.4*	*0.5*	*0.7*	*1.4*
CH$_4$	**61.5**	**73.9**	**78.3**	**103.9**	**95.4**	**109.1**
Natural Gas Systems	60.3	78.6	86.8	114.6	105.7	115.4
Enteric Fermentation	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Landfills	(1.9)	(9.0)	(13.1)	(15.3)	(15.2)	(10.4)
Coal Mining	NC	NC	NC	+	(0.2)	(0.5)
Manure Management	2.4	3.8	4.3	4.4	4.9	4.4
Petroleum Systems	1.5	1.3	1.1	1.1	1.2	1.1
Wastewater Treatment	+	+	+	+	+	0.2
Forest Land Remaining Forest Land	+	+	+	+	+	+
Rice Cultivation	NC	NC	NC	NC	NC	NC
Stationary Combustion	+	+	+	+	+	(0.2)
Abandoned Underground Coal Mines	NC	NC	+	(0.1)	(0.1)	+
Mobile Combustion	+	+	+	+	+	+
Composting	NC	NC	NC	NC	NC	+
Petrochemical Production	NC	NC	NC	NC	NC	NC
Iron and Steel Production & Metallurgical Coke Production	NC	NC	NC	NC	NC	NC
Field Burning of Agricultural Residues	(0.5)	(0.6)	(0.7)	(0.7)	(0.7)	(0.7)
Ferroalloy Production	NC	NC	NC	NC	NC	NC
Silicon Carbide Production and Consumption	NC	NC	NC	NC	NC	NC
Incineration of Waste	NC	NC	NC	NC	+	+
International Bunker Fuels[a]	+	+	+	+	+	+
N$_2$O	**(7.1)**	**(4.5)**	**(5.4)**	**(3.1)**	**(2.6)**	**(7.4)**
Agricultural Soil Management	(5.7)	(3.3)	(4.5)	(2.3)	(1.6)	(5.1)
Mobile Combustion	+	+	+	+	+	+
Manure Management	0.1	0.4	0.6	0.7	0.8	0.8
Nitric Acid Production	(1.2)	(1.3)	(1.1)	(1.1)	(1.3)	(2.6)
Stationary Combustion	+	+	+	(0.1)	(0.1)	+
Forest Land Remaining Forest Land	+	+	+	+	+	+
Wastewater Treatment	+	+	+	+	+	+
N2O from Product Uses	NC	NC	NC	NC	NC	NC
Adipic Acid Production	+	+	NC	NC	NC	NC
Composting	NC	NC	NC	NC	NC	+
Settlements Remaining Settlements	NC	NC	NC	NC	+	(0.1)
Incineration of Waste	NC	NC	NC	NC	+	+

Field Burning of Agricultural Residues	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Wetlands Remaining Wetlands	NC	NC	NC	NC	NC	+
International Bunker Fuels[a]	+	+	+	+	+	+
HFCs	**NC**	**+**	**1.0**	**1.6**	**2.1**	**2.5**
Substitution of Ozone Depleting Substances	NC	+	1.0	1.6	2.1	2.5
HCFC-22 Production	NC	NC	NC	NC	NC	NC
Semiconductor Manufacture	NC	NC	NC	NC	+	+
PFCs	**NC**	**NC**	**NC**	**NC**	**+**	**+**
Semiconductor Manufacture	NC	NC	NC	NC	+	+
Aluminum Production	NC	NC	NC	NC	NC	NC
SF_6	**1.8**	**1.0**	**1.2**	**0.9**	**0.5**	**+**
Electrical Transmission and Distribution	1.8	1.0	1.2	0.9	0.5	0.3
Magnesium Production and Processing	NC	NC	+	+	+	(0.1)
Semiconductor Manufacture	NC	NC	NC	NC	+	(0.2)
Net Change in Total Emissions[b]	**55.0**	**68.2**	**80.3**	**107.1**	**95.3**	**104.4**
Percent Change	**0.9%**	**1.0%**	**1.1%**	**1.5%**	**1.3%**	**1.5%**

+ Absolute value does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.

Parentheses indicate negative values

NC (No Change)

[a] Not included in emissions total.

[b] Excludes net CO_2 flux from Land Use, Land-Use Change, and Forestry, and emissions from International Bunker Fuels.

Note: Totals may not sum due to independent rounding.

Table 10-2: Revisions to Net Flux of CO_2 to the Atmosphere from Land Use, Land-Use Change, and Forestry (Tg CO_2 Eq.)

Component: Net CO_2 Flux From Land Use, Land-Use Change, and Forestry	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**
Forest Land Remaining Forest Land	48.8	89.4	(105.0)	(105.0)	(105.0)	(99.1)
Cropland Remaining Cropland	NC	NC	NC	NC	NC	NC
Land Converted to Cropland	NC	NC	NC	NC	NC	NC
Grassland Remaining Grassland	(0.1)	+	0.1	0.1	0.2	0.2
Land Converted to Grassland	+	+	0.2	0.3	0.3	0.4
Settlements Remaining Settlements	NC	NC	NC	NC	NC	NC
Other	(0.7)	(1.9)	(1.4)	(0.6)	(1.1)	(1.7)
Net Change in Total Flux	**47.9**	**87.7**	**(106.1)**	**(105.2)**	**(105.5)**	**(100.1)**
Percent Change	**5.3%**	**13.2%**	**(11.2%)**	**(11.0%)**	**(11.0%)**	**(10.6%)**

NC (No Change)

Note: Numbers in parentheses indicate a decrease in estimated net flux of CO_2 to the atmosphere, or an increase in net sequestration.

Note: Totals may not sum due to independent rounding.

+ Absolute value does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.

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Executive Summary

An emissions inventory that identifies and quantifies a country's primary anthropogenic[1] sources and sinks of greenhouse gases is essential for addressing climate change. This inventory adheres to both (1) a comprehensive and detailed set of methodologies for estimating sources and sinks of anthropogenic greenhouse gases, and (2) a common and consistent mechanism that enables Parties to the United Nations Framework Convention on Climate Change (UNFCCC) to compare the relative contribution of different emission sources and greenhouse gases to climate change.

In 1992, the United States signed and ratified the UNFCCC. As stated in Article 2 of the UNFCCC, “The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner.”[2]

Parties to the Convention, by ratifying, “shall develop, periodically update, publish and make available…national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies…”[3] The United States views this report as an opportunity to fulfill these commitments.

This chapter summarizes the latest information on U.S. anthropogenic greenhouse gas emission trends from 1990 through 2010. To ensure that the U.S. emissions inventory is comparable to those of other UNFCCC Parties, the estimates presented here were calculated using methodologies consistent with those recommended in the Revised 1996 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000), and the IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003). Additionally, the U.S. emission inventory has continued to incorporate new methodologies and data from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The structure of this report is consistent with the UNFCCC guidelines for inventory reporting.[4] For most source categories, the IPCC methodologies were expanded, resulting in a more comprehensive and detailed estimate of emissions.

[BEGIN BOX]

Box ES- 1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the IPCC.[5] Additionally, the calculated emissions and sinks in a given year for the United States are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[6] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that

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[1] The term “anthropogenic,” in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC/UNEP/OECD/IEA 1997).

[2] Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <http://unfccc.int>.

[3] Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <http://unfccc.int>.

[4] See < http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

[5] See < http://www.ipcc-nggip.iges.or.jp/public/index.html>.

[6] See < http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>.

these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule for the mandatory reporting of greenhouse gases (GHG) from large GHG emissions sources in the United States. Implementation of 40 CFR Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP). 40 CFR part 98 applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO_2 underground for sequestration or other reasons. Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. For calendar year 2010, the first year in which data were reported, facilities in 29 categories provided in 40 CFR part 98 were required to report their 2010 emissions by the September 30, 2011 reporting deadline.[7] The GHGRP dataset and the data presented in this inventory report are complementary and, as indicated in the respective planned improvements sections in this report's chapters, EPA is analyzing how to use facility-level GHGRP data to improve the national estimates presented in this inventory.

[END BOX]

ES.1. Background Information

Naturally occurring greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). As stratospheric ozone depleting substances, CFCs, HCFCs, and halons are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty. Consequently, Parties to the UNFCCC are not required to include these gases in their national greenhouse gas emission inventories.[8] Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas emission inventories.

There are also several gases that do not have a direct global warming effect but indirectly affect terrestrial and/or solar radiation absorption by influencing the formation or destruction of greenhouse gases, including tropospheric and stratospheric ozone. These gases include carbon monoxide (CO), oxides of nitrogen (NO_x), and non-CH_4 volatile organic compounds (NMVOCs). Aerosols, which are extremely small particles or liquid droplets, such as those produced by sulfur dioxide (SO_2) or elemental carbon emissions, can also affect the absorptive characteristics of the atmosphere.

Although the direct greenhouse gases CO_2, CH_4, and N_2O occur naturally in the atmosphere, human activities have changed their atmospheric concentrations. From the pre-industrial era (i.e., ending about 1750) to 2010, concentrations of these greenhouse gases have increased globally by 39, 158, and 19 percent, respectively (IPCC 2007 and NOAA/ESLR 2009).

Beginning in the 1950s, the use of CFCs and other stratospheric ozone depleting substances (ODS) increased by nearly 10 percent per year until the mid-1980s, when international concern about ozone depletion led to the entry into force of the Montreal Protocol. Since then, the production of ODS is being phased out. In recent years, use of ODS substitutes such as HFCs and PFCs has grown as they begin to be phased in as replacements for CFCs and

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[7] See <http://www.epa.gov/climatechange/emissions/ghgrulemaking.html> and <http://ghgdata.epa.gov/ghgp/main.do>.

[8] Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in the annexes of the Inventory report for informational purposes.

HCFCs. Accordingly, atmospheric concentrations of these substitutes have been growing (IPCC 2007).

Global Warming Potentials

Gases in the atmosphere can contribute to the greenhouse effect both directly and indirectly. Direct effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations of the substance produce other greenhouse gases, when a gas influences the atmospheric lifetimes of other gases, and/or when a gas affects atmospheric processes that alter the radiative balance of the earth (e.g., affect cloud formation or albedo).[9] The IPCC developed the Global Warming Potential (GWP) concept to compare the ability of each greenhouse gas to trap heat in the atmosphere relative to another gas.

The GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2001). Direct radiative effects occur when the gas itself is a greenhouse gas. The reference gas used is CO_2, and therefore GWP-weighted emissions are measured in teragrams (or million metric tons) of CO_2 equivalent (Tg CO_2 Eq.).[10,11] All gases in this Executive Summary are presented in units of Tg CO_2 Eq.

The UNFCCC reporting guidelines for national inventories were updated in 2006,[12] but continue to require the use of GWPs from the IPCC Second Assessment Report (SAR) (IPCC 1996). This requirement ensures that current estimates of aggregate greenhouse gas emissions for 1990 to 2010 are consistent with estimates developed prior to the publication of the IPCC Third Assessment Report (TAR) (IPCC 2001) and the IPCC Fourth Assessment Report (AR4) (IPCC 2007). Therefore, to comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. All estimates are provided throughout the report in both CO_2 equivalents and unweighted units. A comparison of emission values using the SAR GWPs versus the TAR and AR4 GWPs can be found in Chapter 1 and, in more detail, in Annex 6.1 of this report. The GWP values used in this report are listed below in Table ES-1.

Table ES-1: Global Warming Potentials (100-Year Time Horizon) Used in this Report

Gas	**GWP**
CO_2	1
CH_4*	21
N_2O	310
HFC-23	11,700
HFC-32	650
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF_4	6,500
C_2F_6	9,200
C_4F_{10}	7,000
C_6F_{14}	7,400
SF_6	23,900

Source: IPCC (1996)
* The CH_4 GWP includes the direct effects and those indirect effects due

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[9] Albedo is a measure of the Earth's reflectivity, and is defined as the fraction of the total solar radiation incident on a body that is reflected by it.

[10] Carbon comprises 12/44ths of carbon dioxide by weight.

[11] One teragram is equal to 10^{12} grams or one million metric tons.

[12] See <http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Global warming potentials are not provided for CO, NO_x, NMVOCs, SO_2, and aerosols because there is no agreed-upon method to estimate the contribution of gases that are short-lived in the atmosphere, spatially variable, or have only indirect effects on radiative forcing (IPCC 1996).

ES.2. Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2010, total U.S. greenhouse gas emissions were 6,821.8 Tg or million metric tons CO_2 Eq. Total U.S. emissions have increased by 10.5 percent from 1990 to 2010, and emissions increased from 2009 to 2010 by 3.2 percent (213.5 Tg CO_2 Eq.). The increase from 2009 to 2010 was primarily due to an increase in economic output resulting in an increase in energy consumption across all sectors, and much warmer summer conditions resulting in an increase in electricity demand for air conditioning that was generated primarily by combusting coal and natural gas. Since 1990, U.S. emissions have increased at an average annual rate of 0.5 percent.

Figure ES-1 through Figure ES-3 illustrate the overall trends in total U.S. emissions by gas, annual changes, and absolute change since 1990. Table ES-2 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2010.

Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg or million metric tons CO_2 Eq.)

Gas/Source	1990	2005	2006	2007	2008	2009	2010
CO_2	**5,100.5**	**6,107.6**	**6,019.0**	**6,118.6**	**5,924.3**	**5,500.5**	**5,706.4**
Fossil Fuel Combustion	4,738.3	5,746.5	5,653.0	5,757.8	5,571.5	5,206.2	5,387.8
Electricity Generation	1,820.8	2,402.1	2,346.4	2,412.8	2,360.9	2,146.4	2,258.4
Transportation	1,485.9	1,896.6	1,878.1	1,893.9	1,789.8	1,727.9	1,745.5
Industrial	846.4	816.4	848.1	844.4	806.5	726.6	777.8
Residential	338.3	357.9	321.5	341.6	349.3	339.0	340.2
Commercial	219.0	223.5	208.6	218.9	225.1	224.6	224.2
U.S. Territories	27.9	50.0	50.3	46.1	39.8	41.7	41.6
Non-Energy Use of Fuels	119.6	144.1	143.8	134.9	138.6	123.7	125.1
Iron and Steel Production & Metallurgical Coke Production	99.6	66.0	68.9	71.1	66.1	42.1	54.3
Natural Gas Systems	37.6	29.9	30.8	31.0	32.8	32.2	32.3
Cement Production	33.3	45.2	45.8	44.5	40.5	29.0	30.5
Lime Production	11.5	14.4	15.1	14.6	14.3	11.2	13.2
Incineration of Waste	8.0	12.5	12.5	12.7	11.9	11.7	12.1
Limestone and Dolomite Use	5.1	6.8	8.0	7.7	6.3	7.6	10.0
Ammonia Production	13.0	9.2	8.8	9.1	7.9	7.9	8.7
Cropland Remaining Cropland	7.1	7.9	7.9	8.2	8.6	7.2	8.0
Urea Consumption for Non-Agricultural Purposes	3.8	3.7	3.5	4.9	4.1	3.4	4.4
Soda Ash Production and Consumption	4.1	4.2	4.2	4.1	4.1	3.6	3.7
Petrochemical Production	3.3	4.2	3.8	3.9	3.4	2.7	3.3

Aluminum Production	6.8	4.1	3.8	4.3	4.5	3.0	3.0
Carbon Dioxide Consumption	1.4	1.3	1.7	1.9	1.8	1.8	2.2
Titanium Dioxide Production	1.2	1.8	1.8	1.9	1.8	1.6	1.9
Ferroalloy Production	2.2	1.4	1.5	1.6	1.6	1.5	1.7
Zinc Production	0.6	1.0	1.0	1.0	1.2	0.9	1.2
Phosphoric Acid Production	1.5	1.4	1.2	1.2	1.2	1.0	1.0
Wetlands Remaining Wetlands	1.0	1.1	0.9	1.0	1.0	1.1	1.0
Lead Production	0.5	0.6	0.6	0.6	0.5	0.5	0.5
Petroleum Systems	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.1	0.2
Land Use, Land-Use Change, and Forestry (Sink)[a]	*(881.8)*	*(1,085.9)*	*(1,110.4)*	*(1,108.2)*	*(1,087.5)*	*(1,062.6)*	*(1,074.7)*
Wood Biomass and Ethanol Consumption[b]	*218.6*	*228.6*	*233.7*	*241.1*	*252.1*	*244.1*	*266.1*
International Bunker Fuels[c]	*111.8*	*109.8*	*128.4*	*127.6*	*133.7*	*122.3*	*127.8*
CH_4	**668.3**	**625.8**	**664.6**	**656.2**	**667.9**	**672.2**	**666.5**
Natural Gas Systems	189.6	190.5	217.7	205.3	212.7	220.9	215.4
Enteric Fermentation	133.8	139.0	141.4	143.8	143.4	142.6	141.3
Landfills	147.7	112.7	111.7	111.7	113.1	111.2	107.8
Coal Mining	84.1	56.8	58.1	57.8	66.9	70.1	72.6
Manure Management	31.7	47.9	48.4	52.7	51.8	50.7	52.0
Petroleum Systems	35.2	29.2	29.2	29.8	30.0	30.7	31.0
Wastewater Treatment	15.9	16.5	16.7	16.6	16.6	16.5	16.3
Rice Cultivation	7.1	6.8	5.9	6.2	7.2	7.3	8.6
Stationary Combustion	7.5	6.6	6.2	6.5	6.6	6.3	6.3
Abandoned Underground Coal Mines	6.0	5.5	5.5	5.3	5.3	5.1	5.0
Forest Land Remaining Forest Land	2.5	8.1	17.9	14.6	8.8	5.8	4.8
Mobile Combustion	4.7	2.5	2.4	2.2	2.1	2.0	1.9
Composting	0.3	1.6	1.6	1.7	1.7	1.6	1.6
Petrochemical Production	0.9	1.1	1.0	1.0	0.9	0.8	0.9
Iron and Steel Production & Metallurgical Coke Production	1.0	0.7	0.7	0.7	0.6	0.4	0.5
Field Burning of Agricultural Residues	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuesl[c]	0.2	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*	*0.2*
N_2O	**316.2**	**331.9**	**336.8**	**334.9**	**317.1**	**304.0**	**306.2**
Agricultural Soil Management	200.0	213.1	211.1	211.1	212.9	207.3	207.8
Stationary Combustion	12.3	20.6	20.8	21.2	21.1	20.7	22.6
Mobile Combustion	43.9	37.0	33.7	29.0	25.2	22.5	20.6
Manure Management	14.8	17.6	18.4	18.5	18.3	18.2	18.3
Nitric Acid Production	17.6	16.4	16.1	19.2	16.4	14.5	16.7
Wastewater Treatment	3.5	4.7	4.8	4.8	4.9	5.0	5.0
N_2O from Product Uses	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Forest Land Remaining Forest Land	2.1	7.0	15.0	12.2	7.5	5.1	4.3
Adipic Acid Production	15.8	7.4	8.9	10.7	2.6	2.8	2.8
Composting	0.4	1.7	1.8	1.8	1.9	1.8	1.7
Settlements Remaining Settlements	1.0	1.5	1.5	1.6	1.5	1.4	1.4
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*1.1*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*	*1.2*
HFCs	**36.9**	**115.0**	**116.0**	**120.0**	**117.5**	**112.1**	**123.0**
Substitution of Ozone Depleting	0.3	99.0	101.9	102.7	103.6	106.3	114.6

Substances							
HCFC-22 Production	36.4	15.8	13.8	17.0	13.6	5.4	8.1
Semiconductor Manufacture	0.2	0.2	0.3	0.3	0.3	0.3	0.3
PFCs	**20.6**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**	**5.6**
Semiconductor Manufacture	2.2	3.2	3.5	3.7	4.0	4.0	4.1
Aluminum Production	18.4	3.0	2.5	3.8	2.7	1.6	1.6
SF_6	**32.6**	**17.8**	**16.8**	**15.6**	**15.0**	**13.9**	**14.0**
Electrical Transmission and Distribution	26.7	13.9	13.0	12.2	12.2	11.8	11.8
Magnesium Production and Processing	5.4	2.9	2.9	2.6	1.9	1.1	1.3
Semiconductor Manufacture	0.5	1.0	1.0	0.8	0.9	1.0	0.9
Total	**6,175.2**	**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Net Emission (Sources and Sinks)	**5,293.4**	**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Parentheses indicate negative values or sequestration. The net CO_2 flux total includes both emissions and sequestration, and constitutes a net sink in the United States. Sinks are only included in net emissions total.

[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

[c] Emissions from International Bunker Fuels are not included in totals.

[d] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Figure ES-4 illustrates the relative contribution of the direct greenhouse gases to total U.S. emissions in 2010. The primary greenhouse gas emitted by human activities in the United States was CO_2, representing approximately 83.6 percent of total greenhouse gas emissions. The largest source of CO_2, and of overall greenhouse gas emissions, was fossil fuel combustion. CH_4 emissions, which have decreased by 0.3 percent since 1990, resulted primarily from natural gas systems, enteric fermentation associated with domestic livestock, and decomposition of wastes in landfills. Agricultural soil management, mobile source fuel combustion and stationary fuel combustion were the major sources of N_2O emissions. Ozone depleting substance substitute emissions and emissions of HFC-23 during the production of HCFC-22 were the primary contributors to aggregate HFC emissions. PFC emissions resulted from semiconductor manufacturing and as a by-product of primary aluminum production, while electrical transmission and distribution systems accounted for most SF_6 emissions.

Figure ES-4: 2010 Greenhouse Gas Emissions by Gas (percentages based on Tg CO_2 Eq.)

Overall, from 1990 to 2010, total emissions of CO_2 increased by 605.9 Tg CO_2 Eq. (11.9 percent), while total emissions of CH_4 and N_2O decreased by 1.7 Tg CO_2 Eq. (0.3 percent), and 10.0 Tg CO_2 Eq. (3.2 percent), respectively. During the same period, aggregate weighted emissions of HFCs, PFCs, and SF_6 rose by 52.5 Tg CO_2 Eq. (58.2 percent). From 1990 to 2010, HFCs increased by 86.1 Tg CO_2 Eq. (233.1 percent), PFCs decreased by 15.0 Tg CO_2 Eq. (72.7 percent), and SF_6 decreased by 18.6 Tg CO_2 Eq. (57.0 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, and SF_6 are significant because many of these gases have extremely high global warming potentials and, in the cases of PFCs and SF_6, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by carbon sequestration in forests, trees in urban areas, agricultural soils, and landfilled yard trimmings and food scraps, which, in aggregate, offset 15.8 percent of total emissions in 2010. The following sections describe each gas's contribution to total U.S. greenhouse gas emissions in more detail.

Carbon Dioxide Emissions

The global carbon cycle is made up of large carbon flows and reservoirs. Billions of tons of carbon in the form of CO_2 are absorbed by oceans and living biomass (i.e., sinks) and are emitted to the atmosphere annually through natural processes (i.e., sources). When in equilibrium, carbon fluxes among these various reservoirs are roughly balanced. Since the Industrial Revolution (i.e., about 1750), global atmospheric concentrations of CO_2 have risen about 39 percent (IPCC 2007 and NOAA/ESLR 2009), principally due to the combustion of fossil fuels. Within the

United States, fossil fuel combustion accounted for 94.4 percent of CO_2 emissions in 2010. Globally, approximately 30,313 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[13] Changes in land use and forestry practices can also emit CO_2 (e.g., through conversion of forest land to agricultural or urban use) or can act as a sink for CO_2 (e.g., through net additions to forest biomass). In addition to fossil-fuel combustion, several other sources emit significant quantities of CO_2. These sources include, but are not limited to non-energy use of fuels, iron and steel production and cement production (Figure ES-5).

Figure ES-5: 2010 Sources of CO_2 Emissions

As the largest source of U.S. greenhouse gas emissions, CO_2 from fossil fuel combustion has accounted for approximately 78 percent of GWP-weighted emissions since 1990, growing slowly from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2010. Emissions of CO_2 from fossil fuel combustion increased at an average annual rate of 0.7 percent from 1990 to 2010. The fundamental factors influencing this trend include (1) a generally growing domestic economy over the last 21 years, and (2) an overall growth in emissions from electricity generation and transportation activities. Between 1990 and 2010, CO_2 emissions from fossil fuel combustion increased from 4,738.3 Tg CO_2 Eq. to 5,387.8 Tg CO_2 Eq.—a 13.7 percent total increase over the twenty-one-year period. From 2009 to 2010, these emissions increased by 181.6 Tg CO_2 Eq. (3.5 percent).

Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends. Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, and seasonal temperatures. In the short term, the overall consumption of fossil fuels in the United States fluctuates primarily in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants. In the long term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Figure ES-6: 2010 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Figure ES-7: 2010 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

The five major fuel consuming sectors contributing to CO_2 emissions from fossil fuel combustion are electricity generation, transportation, industrial, residential, and commercial. CO_2 emissions are produced by the electricity generation sector as they consume fossil fuel to provide electricity to one of the other four sectors, or "end-use" sectors. For the discussion below, electricity generation emissions have been distributed to each end-use sector on the basis of each sector's share of aggregate electricity consumption. This method of distributing emissions assumes that each end-use sector consumes electricity that is generated from the national average mix of fuels according to their carbon intensity. Emissions from electricity generation are also addressed separately after the end-use sectors have been discussed.

Note that emissions from U.S. territories are calculated separately due to a lack of specific consumption data for the individual end-use sectors.

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[13] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010a).

Figure ES-6, Figure ES-7, and Table ES-3 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Table ES-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Consuming End-Use Sector (Tg or million metric tons CO_2 Eq.)

End-Use Sector	1990	2005	2006	2007	2008	2009	2010
Transportation	**1,489.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.5**	**1,732.4**	**1,750.0**
Combustion	1,485.9	1,896.6	1,878.1	1,893.9	1,789.8	1,727.9	1,745.5
Electricity	3.0	4.7	4.5	5.1	4.7	4.5	4.5
Industrial	**1,533.1**	**1,553.3**	**1,560.2**	**1,559.8**	**1,503.8**	**1,328.6**	**1,415.4**
Combustion	846.4	816.4	848.1	844.4	806.5	726.6	777.8
Electricity	686.8	737.0	712.0	715.4	697.3	602.0	637.6
Residential	**931.4**	**1,214.7**	**1,152.4**	**1,205.2**	**1,192.2**	**1,125.5**	**1,183.7**
Combustion	338.3	357.9	321.5	341.6	349.3	339.0	340.2
Electricity	593.0	856.7	830.8	863.5	842.9	786.5	843.5
Commercial	**757.0**	**1,027.2**	**1,007.6**	**1,047.7**	**1,041.1**	**978.0**	**997.1**
Combustion	219.0	223.5	208.6	218.9	225.1	224.6	224.2
Electricity	538.0	803.7	799.0	828.8	816.0	753.5	772.9
U.S. Territories[a]	**27.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**	**41.6**
Total	**4,738.3**	**5,746.5**	**5,653.0**	**5,757.8**	**5,571.5**	**5,206.2**	**5,387.8**
Electricity Generation	**1,820.8**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,146.4**	**2,258.4**

Note: Totals may not sum due to independent rounding. Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

[a] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report.

Transportation End-Use Sector. Transportation activities (excluding international bunker fuels) accounted for 32 percent of CO_2 emissions from fossil fuel combustion in 2010.[14] Virtually all of the energy consumed in this end-use sector came from petroleum products. Nearly 65 percent of the emissions resulted from gasoline consumption for personal vehicle use. The remaining emissions came from other transportation activities, including the combustion of diesel fuel in heavy-duty vehicles and jet fuel in aircraft. From 1990 to 2010, transportation emissions rose by 18 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 34 percent from 1990 to 2010, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

Industrial End-Use Sector. Industrial CO_2 emissions, resulting both directly from the combustion of fossil fuels and indirectly from the generation of electricity that is consumed by industry, accounted for 26 percent of CO_2 from fossil fuel combustion in 2010. Approximately 55 percent of these emissions resulted from direct fossil fuel combustion to produce steam and/or heat for industrial processes. The remaining emissions resulted from consuming electricity for motors, electric furnaces, ovens, lighting, and other applications. In contrast to the other end-use sectors, emissions from industry have steadily declined since 1990. This decline is due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements.

Residential and Commercial End-Use Sectors. The residential and commercial end-use sectors accounted for 22 and 19 percent, respectively, of CO_2 emissions from fossil fuel combustion in 2010. Both sectors relied heavily on electricity for meeting energy demands, with 71 and 78 percent, respectively, of their emissions attributable to electricity consumption for lighting, heating, cooling, and operating appliances. The remaining emissions were due to the consumption of natural gas and petroleum for heating and cooking. Emissions from these end-use sectors have increased 29 percent since 1990, due to increasing electricity consumption for lighting, heating, air conditioning, and operating appliances.

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[14] If emissions from international bunker fuels are included, the transportation end-use sector accounted for 34.0 percent of U.S. emissions from fossil fuel combustion in 2010.

Electricity Generation. The United States relies on electricity to meet a significant portion of its energy demands. Electricity generators consumed 36 percent of U.S. energy from fossil fuels and emitted 42 percent of the CO_2 from fossil fuel combustion in 2010. The type of fuel combusted by electricity generators has a significant effect on their emissions. For example, some electricity is generated with low CO_2 emitting energy technologies, particularly non-fossil options such as nuclear, hydroelectric, or geothermal energy. However, electricity generators rely on coal for over half of their total energy requirements and accounted for 94 percent of all coal consumed for energy in the United States in 2010. Consequently, changes in electricity demand have a significant impact on coal consumption and associated CO_2 emissions.

Other significant CO_2 trends included the following:

- CO_2 emissions from non-energy use of fossil fuels have increased 5.5 Tg CO_2 Eq. (4.6 percent) from 1990 through 2010. Emissions from non-energy uses of fossil fuels were 125.1 Tg CO_2 Eq. in 2010, which constituted 2.2 percent of total national CO_2 emissions, approximately the same proportion as in 1990.
- CO_2 emissions from iron and steel production and metallurgical coke production increased by 12.2 Tg CO_2 Eq. (28.9 percent) from 2009 to 2010, upsetting a trend of decreasing emissions. Despite this, from 1990 through 2010 emissions declined by 45.5 percent (45.3 Tg CO_2 Eq.). This decline is due to the restructuring of the industry, technological improvements, and increased scrap utilization.
- In 2010, CO_2 emissions from cement production increased by 1.5 Tg CO_2 Eq. (5.1 percent) from 2009. After decreasing in 1991 by two percent from 1990 levels, cement production emissions grew every year through 2006; emissions decreased in the three years prior to 2010. Overall, from 1990 to 2010, emissions from cement production have decreased by 8.3 percent, a decrease of 2.8 Tg CO_2 Eq.
- Net CO_2 uptake from Land Use, Land-Use Change, and Forestry increased by 192.8 Tg CO_2 Eq. (21.9 percent) from 1990 through 2010. This increase was primarily due to an increase in the rate of net carbon accumulation in forest carbon stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual carbon accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of carbon accumulation in urban trees increased.

Methane Emissions

Methane (CH_4) is more than 20 times as effective as CO_2 at trapping heat in the atmosphere (IPCC 1996). Over the last two hundred and fifty years, the concentration of CH_4 in the atmosphere increased by 158 percent (IPCC 2007). Anthropogenic sources of CH_4 include natural gas and petroleum systems, agricultural activities, landfills, coal mining, wastewater treatment, stationary and mobile combustion, and certain industrial processes (see Figure ES-8).

Figure ES-8: 2010 Sources of CH_4 Emissions

Some significant trends in U.S. emissions of CH_4 include the following:

- Natural gas systems were the largest anthropogenic source category of CH_4 emissions in the United States in 2010 with 215.4 Tg CO_2 Eq. of CH_4 emitted into the atmosphere. Those emissions have increased by 25.8 Tg CO_2 Eq. (13.6 percent) since 1990.
- Enteric fermentation is the second largest anthropogenic source of CH_4 emissions in the United States. In 2010, enteric fermentation CH_4 emissions were 141.3 Tg CO_2 Eq. (21.2 percent of total CH_4 emissions), which represents an increase of 7.5 Tg CO_2 Eq. (5.6 percent) since 1990.
- Landfills are the third largest anthropogenic source of CH_4 emissions in the United States, accounting for 16.2 percent of total CH_4 emissions (107.8 Tg CO_2 Eq.) in 2010. From 1990 to 2010, CH_4 emissions from landfills decreased by 39.8 Tg CO_2 Eq. (27.0 percent), with small increases occurring in some interim years. This downward trend in overall emissions is the result of increases in the amount of landfill gas

collected and combusted,[15] which has more than offset the additional CH_4 emissions resulting from an increase in the amount of municipal solid waste landfilled.

- In 2010, CH_4 emissions from coal mining were 72.6 Tg CO_2 Eq., a 2.5 Tg CO_2 Eq. (3.5 percent) increase over 2009 emission levels. The overall decline of 11.5 Tg CO_2 Eq. (13.6 percent) from 1990 results from the mining of less gassy coal from underground mines and the increased use of CH_4 collected from degasification systems.
- Methane emissions from manure management increased by 64.0 percent since 1990, from 31.7 Tg CO_2 Eq. in 1990 to 52.0 Tg CO_2 Eq. in 2010. The majority of this increase was from swine and dairy cow manure, since the general trend in manure management is one of increasing use of liquid systems, which tends to produce greater CH_4 emissions. The increase in liquid systems is the combined result of a shift to larger facilities, and to facilities in the West and Southwest, all of which tend to use liquid systems. Also, new regulations limiting the application of manure nutrients have shifted manure management practices at smaller dairies from daily spread to manure managed and stored on site.

Nitrous Oxide Emissions

N_2O is produced by biological processes that occur in soil and water and by a variety of anthropogenic activities in the agricultural, energy-related, industrial, and waste management fields. While total N_2O emissions are much lower than CO_2 emissions, N_2O is approximately 300 times more powerful than CO_2 at trapping heat in the atmosphere (IPCC 1996). Since 1750, the global atmospheric concentration of N_2O has risen by approximately 19 percent (IPCC 2007). The main anthropogenic activities producing N_2O in the United States are agricultural soil management, fuel combustion in motor vehicles, stationary fuel combustion, manure management and nitric acid production (see Figure ES-9).

Figure ES-9: 2010 Sources of N_2O Emissions

Some significant trends in U.S. emissions of N_2O include the following:

- In 2010, N_2O emissions from mobile combustion were 20.6 Tg CO_2 Eq. (approximately 6.7 percent of U.S. N_2O emissions). From 1990 to 2010, N_2O emissions from mobile combustion decreased by 53.1 percent. However, from 1990 to 1998 emissions increased by 25.6 percent, due to control technologies that reduced NO_x emissions while increasing N_2O emissions. Since 1998, newer control technologies have led to an overall decline in N_2O from this source.
- N_2O emissions from adipic acid production were 2.8 Tg CO_2 Eq. in 2010, and have decreased significantly in recent years due to the widespread installation of pollution control measures. Emissions from adipic acid production have decreased by 82.2 percent since 1990 and by 84.0 percent since a peak in 1995.
- N_2O emissions from stationary combustion increased 10.3 Tg CO_2 Eq. (84.4 percent) from 1990 through 2010. N_2O emissions from this source increased primarily as a result of an increase in the number of coal fluidized bed boilers in the electric power sector.
- Agricultural soils accounted for approximately 67.9 percent of N_2O emissions in the United States in 2010. Estimated emissions from this source in 2010 were 207.8 Tg CO_2 Eq. Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2010, although overall emissions were 3.9 percent higher in 2010 than in 1990.

HFC, PFC, and SF_6 Emissions

HFCs and PFCs are families of synthetic chemicals that are used as alternatives to ODS, which are being phased out under the Montreal Protocol and Clean Air Act Amendments of 1990. HFCs and PFCs do not deplete the

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[15] The CO_2 produced from combusted landfill CH_4 at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

stratospheric ozone layer, and are therefore acceptable alternatives under the Montreal Protocol.

These compounds, however, along with SF_6, are potent greenhouse gases. In addition to having high global warming potentials, SF_6 and PFCs have extremely long atmospheric lifetimes, resulting in their essentially irreversible accumulation in the atmosphere once emitted. Sulfur hexafluoride is the most potent greenhouse gas the IPCC has evaluated (IPCC 1996).

Other emissive sources of these gases include electrical transmission and distribution systems, HCFC-22 production, semiconductor manufacturing, aluminum production, and magnesium production and processing (see Figure ES-10).

Figure ES-10: 2010 Sources of HFCs, PFCs, and SF_6 Emissions

Some significant trends in U.S. HFC, PFC, and SF_6 emissions include the following:

- Emissions resulting from the substitution of ozone depleting substances (ODS) (e.g., CFCs) have been consistently increasing, from small amounts in 1990 to 114.6 Tg CO_2 Eq. in 2010. Emissions from ODS substitutes are both the largest and the fastest growing source of HFC, PFC, and SF_6 emissions. These emissions have been increasing as phase-out of ODS required under the Montreal Protocol came into effect, especially after 1994, when full market penetration was made for the first generation of new technologies featuring ODS substitutes.
- HFC emissions from the production of HCFC-22 decreased by 77.8 percent (28.3 Tg CO_2 Eq.) from 1990 through 2010, due to a steady decline in the emission rate of HFC-23 (i.e., the amount of HFC-23 emitted per kilogram of HCFC-22 manufactured) and the use of thermal oxidation at some plants to reduce HFC-23 emissions.
- SF_6 emissions from electric power transmission and distribution systems decreased by 55.7 percent (14.9 Tg CO_2 Eq.) from 1990 to 2010, primarily because of higher purchase prices for SF_6 and efforts by industry to reduce emissions.
- PFC emissions from aluminum production decreased by 91.5 percent (16.9 Tg CO_2 Eq.) from 1990 to 2010, due to both industry emission reduction efforts and declines in domestic aluminum production.

ES.3. Overview of Sector Emissions and Trends

In accordance with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), and the 2003 UNFCCC Guidelines on Reporting and Review (UNFCCC 2003), Figure ES-11 and Table ES-4 aggregate emissions and sinks by these chapters. Emissions of all gases can be summed from each source category from IPCC guidance. Over the twenty-one-year period of 1990 to 2010, total emissions in the Energy and Agriculture sectors grew by 645.8 Tg CO_2 Eq. (12.2 percent), and 40.6 Tg CO_2 Eq. (10.5 percent), respectively. Emissions slightly decreased in the Industrial Processes sector by 10.5 Tg CO_2 Eq. (3.4 percent) , while emissions from the Waste and Solvent and Other Product Use sectors decreased by 35.2 Tg CO_2 Eq. (21.0 percent) and less than 0.1 Tg CO_2 Eq. (0.4 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry (LULUCF) sector (magnitude of emissions plus CO_2 flux from all LULUCF source categories) increased by 187.0 Tg CO_2 Eq. (21.5 percent).

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

Table ES-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg or million metric tons CO_2 Eq.)

Chapter/IPCC Sector	**1990**		**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Energy	5,287.7		6,282.4	6,214.4	6,294.3	6,125.4	5,752.7	5,933.5
Industrial Processes	313.9		330.1	335.5	347.3	319.1	268.2	303.4

Solvent and Other Product Use	4.4		4.4	4.4	4.4	4.4	4.4	4.4
Agriculture	387.8		424.6	425.4	432.6	433.8	426.4	428.4
Land-Use Change and Forestry	13.8		25.6	43.2	37.6	27.4	20.6	19.6
Waste	167.7		137.2	136.5	136.7	138.2	136.0	132.5
Total Emissions	**6,175.2**		**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Land-Use Change and Forestry (Sinks)	(881.8)		(1,085.9)	(1,110.4)	(1,108.2)	(1,087.5)	(1,062.6)	(1,074.7)
Net Emissions (Emissions and Sinks)	**5,293.4**		**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

* The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total.

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Energy

The Energy chapter contains emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions. Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO_2 emissions for the period of 1990 through 2010. In 2010, approximately 85 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 15 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure ES-12). Energy-related activities are also responsible for CH_4 and N_2O emissions (50 percent and 14 percent of total U.S. emissions of each gas, respectively). Overall, emission sources in the Energy chapter account for a combined 87.0 percent of total U.S. greenhouse gas emissions in 2010.

Figure ES-12: 2010 U.S. Energy Consumption by Energy Source

Industrial Processes

The Industrial Processes chapter contains by-product or fugitive emissions of greenhouse gases from industrial processes not directly related to energy activities such as fossil fuel combustion. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO_2, CH_4, and N_2O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production and urea consumption, lime production, limestone and dolomite use (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO_2 consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, and zinc production. Additionally, emissions from industrial processes release HFCs, PFCs, and SF_6. Overall, emission sources in the Industrial Process chapter account for 4.4 percent of U.S. greenhouse gas emissions in 2010.

Solvent and Other Product Use

The Solvent and Other Product Use chapter contains greenhouse gas emissions that are produced as a by-product of various solvent and other product uses. In the United States, emissions from N_2O from product uses, the only source of greenhouse gas emissions from this sector, accounted for about 0.1 percent of total U.S. anthropogenic greenhouse gas emissions on a carbon equivalent basis in 2010.

Agriculture

The Agricultural chapter contains anthropogenic emissions from agricultural activities (except fuel combustion, which is addressed in the Energy chapter, and agricultural CO_2 fluxes, which are addressed in the Land Use, Land-Use Change, and Forestry Chapter). Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues. CH_4 and N_2O were the primary greenhouse gases emitted by agricultural activities. CH_4 emissions from enteric fermentation and manure management represented 21.2 percent and 7.8 percent of total CH_4 emissions from anthropogenic activities, respectively, in 2010. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N_2O emissions in 2010, accounting for 67.9 percent. In 2010, emission sources accounted for in the Agricultural chapters were responsible for 6.3 percent of total U.S. greenhouse gas emissions.

Land Use, Land-Use Change, and Forestry

The Land Use, Land-Use Change, and Forestry chapter contains emissions of CH_4 and N_2O, and emissions and removals of CO_2 from forest management, other land-use activities, and land-use change. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps resulted in a net uptake (sequestration) of C in the United States. Forests (including vegetation, soils, and harvested wood) accounted for 86 percent of total 2010 net CO_2 flux, urban trees accounted for 9 percent, mineral and organic soil carbon stock changes accounted for 4 percent, and landfilled yard trimmings and food scraps accounted for 1 percent of the total net flux in 2010. The net forest sequestration is a result of net forest growth and increasing forest area, as well as a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth in these areas. In agricultural soils, mineral and organic soils sequester approximately 5 times as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to permanent pastures and hay production, a reduction in summer fallow areas in semi-arid areas, an increase in the adoption of conservation tillage practices, and an increase in the amounts of organic fertilizers (i.e., manure and sewage sludge) applied to agriculture lands. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming carbon and food scraps in landfills.

Land use, land-use change, and forestry activities in 2010 resulted in a net C sequestration of 1,074.7 Tg CO_2 Eq. (Table ES-5). This represents an offset of 18.8 percent of total U.S. CO_2 emissions, or 15.8 percent of total greenhouse gas emissions in 2010. Between 1990 and 2010, total land use, land-use change, and forestry net C flux resulted in a 21.9 percent increase in CO_2 sequestration, primarily due to an increase in the rate of net C accumulation in forest C stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual C accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of annual C accumulation increased in urban trees.

Table ES-5: Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Sink Category	**1990**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Forest Land Remaining Forest Land	(701.4)	(940.9)	(963.5)	(959.2)	(938.3)	(910.6)	(921.8)
Cropland Remaining Cropland	(29.4)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)	(15.6)
Land Converted to Cropland	2.2	5.9	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)	(8.3)
Land Converted to Grassland	(19.8)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)	(23.6)
Settlements Remaining Settlements	(57.1)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)	(98.0)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(11.6)	(11.0)	(10.9)	(10.9)	(12.7)	(13.3)
Total	**(881.8)**	**(1,085.9)**	**(1,110.4)**	**(1,108.2)**	**(1,087.5)**	**(1,062.6)**	**(1,074.7)**

Note: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Emissions from Land Use, Land-Use Change, and Forestry are shown in Table ES-6. Liming of agricultural soils and urea fertilization in 2010 resulted in CO_2 emissions of 3.9 Tg CO_2 Eq. (3,906 Gg) and 4.1 Tg CO_2 Eq. (4,143 Gg), respectively. Lands undergoing peat extraction (i.e., *Peatlands Remaining Peatlands*) resulted in CO_2 emissions of 1.0 Tg CO_2 Eq. (983 Gg), and N_2O emissions of less than 0.05 Tg CO_2 Eq. The application of synthetic fertilizers to forest soils in 2010 resulted in direct N_2O emissions of 0.4 Tg CO_2 Eq. (1 Gg). Direct N_2O emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, direct N_2O emissions from fertilizer application to settlement soils in 2010 accounted for 1.4 Tg CO_2 Eq. (5 Gg). This represents an increase of 43 percent since 1990. Forest fires in 2010 resulted in CH_4 emissions of 4.8 Tg CO_2 Eq. (231 Gg), and in N_2O emissions of 4.0 Tg CO_2 Eq. (14 Gg).

Table ES-6: Emissions from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Source Category	1990	2005	2006	2007	2008	2009	2010
CO_2	**8.1**	**8.9**	**8.8**	**9.2**	**9.6**	**8.3**	**9.0**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.2	4.5	5.0	3.7	3.9
Cropland Remaining Cropland: Urea Fertilization	2.4	3.5	3.7	3.8	3.6	3.6	4.1
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.1	0.9	1.0	1.0	1.1	1.0
CH_4	**2.5**	**8.1**	**17.9**	**14.6**	**8.8**	**5.8**	**4.8**
Forest Land Remaining Forest Land: Forest Fires	2.5	8.1	17.9	14.6	8.8	5.8	4.8
N_2O	**3.1**	**8.5**	**16.5**	**13.8**	**9.0**	**6.5**	**5.7**
Forest Land Remaining Forest Land: Forest Fires	2.1	6.6	14.6	11.9	7.2	4.7	4.0
Forest Land Remaining Forest Land: Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils	1.0	1.5	1.5	1.6	1.5	1.4	1.4
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**13.8**	**25.6**	**43.2**	**37.6**	**27.4**	**20.6**	**19.6**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Waste

The Waste chapter contains emissions from waste management activities (except incineration of waste, which is addressed in the Energy chapter). Landfills were the largest source of anthropogenic greenhouse gas emissions in the Waste chapter, accounting for 81.4 percent of this chapter's emissions, and 16.2 percent of total U.S. CH_4 emissions.[16] Additionally, wastewater treatment accounts for 16.1 percent of Waste emissions, 2.5 percent of U.S. CH_4 emissions, and 1.6 percent of U.S. N_2O emissions. Emissions of CH_4 and N_2O from composting are also accounted for in this chapter; generating emissions of 1.6 Tg CO_2 Eq. and 1.7 Tg CO_2 Eq., respectively. Overall, emission sources accounted for in the Waste chapter generated 1.9 percent of total U.S. greenhouse gas emissions in 2010.

ES.4. Other Information

Emissions by Economic Sector

Throughout the Inventory of U.S. Greenhouse Gas Emissions and Sinks report, emission estimates are grouped into six sectors (i.e., chapters) defined by the IPCC: Energy; Industrial Processes; Solvent Use; Agriculture; Land Use, Land-Use Change, and Forestry; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following economic sectors: Residential, Commercial, Industry, Transportation, Electricity Generation, Agriculture, and U.S. Territories.

Table ES-7 summarizes emissions from each of these sectors, and Figure ES-13 shows the trend in emissions by sector from 1990 to 2010.

Figure ES-13: Emissions Allocated to Economic Sectors

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[16] Landfills also store carbon, due to incomplete degradation of organic materials such as wood products and yard trimmings, as described in the Land-Use, Land-Use Change, and Forestry chapter of the Inventory report.

Table ES-7: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg or million metric tons CO_2 Eq.)

Implied Sectors	**1990**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Electric Power Industry	1,866.2	2,448.8	2,393.0	2,459.1	2,405.8	2,191.4	2,306.5
Transportation	1,545.2	2,017.5	1,994.5	2,002.4	1,889.8	1,819.3	1,834.0
Industry	1,564.8	1,438.1	1,499.8	1,489.6	1,448.5	1,317.2	1,394.2
Agriculture	431.9	496.0	516.7	517.6	505.8	492.8	494.8
Commercial	388.0	374.3	359.9	372.2	381.8	382.0	381.7
Residential	345.4	371.3	336.1	358.4	368.4	360.0	365.2
U.S. Territories	33.7	58.2	59.3	53.5	48.4	45.5	45.5
Total Emissions	**6,175.2**	**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Land Use, Land-Use Change, and Forestry (Sinks)	(881.8)	(1,085.9)	(1,110.4)	(1,108.2)	(1,087.5)	(1,062.6)	(1,074.7)
Net Emissions (Sources and Sinks)	**5,293.4**	**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

Note: Totals may not sum due to independent rounding. Emissions include CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6.
See Table 2-12 for more detailed data.

Using this categorization, emissions from electricity generation accounted for the largest portion (34 percent) of U.S. greenhouse gas emissions in 2010. Transportation activities, in aggregate, accounted for the second largest portion (27 percent), while emissions from industry accounted for the third largest portion (20 percent) of U.S. greenhouse gas emissions in 2010. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and energy efficiency improvements. The remaining 19 percent of U.S. greenhouse gas emissions were contributed by, in order of importance, the agriculture, commercial, and residential sectors, plus emissions from U.S. territories. Activities related to agriculture accounted for 7 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N_2O emissions from agricultural soil management and CH_4 emissions from enteric fermentation. The commercial and residential sectors accounted for 6 and 5 percent, respectively, of emissions and U.S. territories accounted for 1 percent of emissions; emissions from these sectors primarily consisted of CO_2 emissions from fossil fuel combustion.

CO_2 was also emitted and sequestered by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Electricity is ultimately consumed in the economic sectors described above. Table ES-8 presents greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). To distribute electricity emissions among end-use sectors, emissions from the source categories assigned to electricity generation were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity.[17] These source categories include CO_2 from fossil fuel combustion and the use of limestone and dolomite for flue gas desulfurization, CO_2 and N_2O from incineration of waste, CH_4 and N_2O from stationary sources, and SF_6 from electrical transmission and distribution systems.

When emissions from electricity are distributed among these sectors, industrial activities account for the largest share of U.S. greenhouse gas emissions (30 percent) in 2010. Transportation is the second largest contributor to total U.S. emissions (27 percent). The residential and commercial sectors contributed the next largest shares of total U.S. greenhouse gas emissions in 2010. Emissions from these sectors increase substantially when emissions from electricity are included, due to their relatively large share of electricity consumption (e.g., lighting, appliances, etc.). In all sectors except agriculture, CO_2 accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels. Figure ES-14 shows the trend in these emissions by sector from 1990 to 2010.

Table ES-8: U.S Greenhouse Gas Emissions by Economic Sector with Electricity-Related Emissions Distributed

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[17] Emissions were not distributed to U.S. territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

(Tg or million metric tons CO_2 Eq.)

Implied Sectors	**1990**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Industry	2,237.7	2,159.9	2,198.5	2,185.9	2,131.5	1,905.8	2,019.0
Transportation	1,548.3	2,022.3	1,999.1	2,007.6	1,894.6	1,823.9	1,838.6
Residential	953.2	1,244.6	1,183.4	1,238.5	1,227.3	1,162.9	1,226.6
Commercial	939.4	1,193.6	1,174.8	1,216.9	1,213.3	1,151.3	1,171.0
Agriculture	462.9	525.5	544.2	550.5	533.3	518.9	521.1
U.S. Territories	33.7	58.2	59.3	53.5	48.4	45.5	45.5
Total Emissions	**6,175.2**	**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Land Use, Land-Use Change, and Forestry (Sinks)	(881.8)	(1,085.9)	(1,110.4)	(1,108.2)	(1,087.5)	(1,062.6)	(1,074.7)
Net Emissions (Sources and Sinks)	**5,293.4**	**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

See Table 2-14 for more detailed data.

Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

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Box ES- 2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and nonutilities combined—was the largest source of U.S. greenhouse gas emissions in 2010; (4) emissions per unit of total gross domestic product as a measure of national economic activity; and (5) emissions per capita.

Table ES-9 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.5 percent since 1990. This rate is slightly slower than that for total energy and for fossil fuel consumption, and much slower than that for electricity consumption, overall gross domestic product and national population (see Figure ES-15).

Table ES-9: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	**1990**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**Growth Rate**[a]
GDP[b]	100	157	161	165	164	158	163	2.5%
Electricity Consumption[c]	100	134	135	137	136	131	137	1.6%
Fossil Fuel Consumption[c]	100	119	117	119	116	109	113	0.6%
Energy Consumption[c]	100	119	118	121	119	113	117	0.8%
Population[d]	100	118	120	121	122	123	123	1.1%
Greenhouse Gas Emissions[e]	100	117	116	117	114	107	110	0.5%

[a] Average annual growth rate

[b] Gross Domestic Product in chained 2005 dollars (BEA 2010)

[c] Energy content-weighted values (EIA 2010b)

[d] U.S. Census Bureau (2010)

[e] GWP-weighted values

Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

Source: BEA (2010), U.S. Census Bureau (2010), and emission estimates in this report.

[END BOX]

Indirect Greenhouse Gases (CO, NO$_x$, NMVOCs, and SO$_2$)

The reporting requirements of the UNFCCC[18] request that information be provided on indirect greenhouse gases, which include CO, NO$_x$, NMVOCs, and SO$_2$. These gases do not have a direct global warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO$_2$, by affecting the absorptive characteristics of the atmosphere. Additionally, some of these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases.

Since 1970, the United States has published estimates of annual emissions of CO, NO$_x$, NMVOCs, and SO$_2$ (EPA 2010, EPA 2009),[19] which are regulated under the Clean Air Act. Table ES-10 shows that fuel combustion accounts for the majority of emissions of these indirect greenhouse gases. Industrial processes—such as the manufacture of chemical and allied products, metals processing, and industrial uses of solvents—are also significant sources of CO, NO$_x$, and NMVOCs.

Table ES-10: Emissions of NO$_x$, CO, NMVOCs, and SO$_2$ (Gg)

Gas/Activity	1990	2005	2006	2007	2008	2009	2010
NO$_x$	**21,705**	**15,899**	**15,039**	**14,380**	**13,545**	**11,467**	**11,467**
Mobile Fossil Fuel Combustion	10,862	9,012	8,488	7,965	7,441	6,206	6,206
Stationary Fossil Fuel Combustion	10,023	5,858	5,545	5,432	5,148	4,159	4,159
Industrial Processes	591	569	553	537	520	568	568
Oil and Gas Activities	139	321	319	318	318	393	393
Incineration of Waste	82	129	121	114	106	128	128
Agricultural Burning	8	6	7	8	8	8	8
Solvent Use	1	3	4	4	4	3	3
Waste	+	2	2	2	2	2	2
CO	**129,976**	**70,791**	**67,227**	**63,613**	**59,993**	**51,431**	**51,431**
Mobile Fossil Fuel Combustion	119,360	62,692	58,972	55,253	51,533	43,355	43,355
Stationary Fossil Fuel Combustion	5,000	4,649	4,695	4,744	4,792	4,543	4,543
Industrial Processes	4,125	1,555	1,597	1,640	1,682	1,549	1,549
Incineration of Waste	978	1,403	1,412	1,421	1,430	1,403	1,403
Agricultural Burning	268	184	233	237	270	247	247
Oil and Gas Activities	302	318	319	320	322	345	345
Waste	1	7	7	7	7	7	7
Solvent Use	5	2	2	2	2	2	2
NMVOCs	**20,930**	**13,761**	**13,594**	**13,423**	**13,254**	**9,313**	**9,313**
Mobile Fossil Fuel Combustion	10,932	6,330	6,037	5,742	5,447	4,151	4,151
Solvent Use	5,216	3,851	3,846	3,839	3,834	2,583	2,583
Industrial Processes	2,422	1,997	1,933	1,869	1,804	1,322	1,322
Stationary Fossil Fuel Combustion	912	716	918	1,120	1,321	424	424
Oil and Gas Activities	554	510	510	509	509	599	599
Incineration of Waste	222	241	238	234	230	159	159
Waste	673	114	113	111	109	76	76
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO$_2$	**20,935**	**13,466**	**12,388**	**11,799**	**10,368**	**8,599**	**8,599**
Stationary Fossil Fuel Combustion	18,407	11,541	10,612	10,172	8,891	7,167	7,167
Industrial Processes	1,307	831	818	807	795	798	798
Mobile Fossil Fuel Combustion	793	889	750	611	472	455	455
Oil and Gas Activities	390	181	182	184	187	154	154

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[18] See <http://unfccc.int/resource/docs/cop8/08.pdf>.

[19] NO$_x$ and CO emission estimates from field burning of agricultural residues were estimated separately, and therefore not taken from EPA (2008).

Incineration of Waste	38	24	24	24	23	24	24
Waste	+	1	1	1	1	1	1
Solvent Use	+	+	+	+	+	+	+
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA

Source: (EPA 2010, EPA 2009) except for estimates from field burning of agricultural residues.
NA (Not Available)
Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.5 Gg.

Key Categories

The 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) defines a key category as a "[source or sink category] that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both."[20] By definition, key categories are sources or sinks that have the greatest contribution to the absolute overall level of national emissions in any of the years covered by the time series. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key categories must also account for the influence of trends of individual source and sink categories. Finally, a qualitative evaluation of key categories should be performed, in order to capture any key categories that were not identified in either of the quantitative analyses.

Figure ES-16 presents 2010 emission estimates for the key categories as defined by a level analysis (i.e., the contribution of each source or sink category to the total inventory level). The UNFCCC reporting guidelines request that key category analyses be reported at an appropriate level of disaggregation, which may lead to source and sink category names which differ from those used elsewhere in the inventory report. For more information regarding key categories, see section 1.5 and Annex 1.

Figure ES-16: 2010 Key Categories

Quality Assurance and Quality Control (QA/QC)

The United States seeks to continually improve the quality, transparency, and credibility of the Inventory of U.S. Greenhouse Gas Emissions and Sinks. To assist in these efforts, the United States implemented a systematic approach to QA/QC. While QA/QC has always been an integral part of the U.S. national system for inventory development, the procedures followed for the current inventory have been formalized in accordance with the QA/QC plan and the UNFCCC reporting guidelines.

Uncertainty Analysis of Emission Estimates

While the current U.S. emissions inventory provides a solid foundation for the development of a more detailed and comprehensive national inventory, there are uncertainties associated with the emission estimates. Some of the current estimates, such as those for CO_2 emissions from energy-related activities and cement processing, are considered to have low uncertainties. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty associated with the estimates presented. Acquiring a better understanding of the uncertainty associated with inventory estimates is an important step in helping to prioritize future work and improve the overall quality of the Inventory. Recognizing the benefit of conducting an uncertainty analysis, the UNFCCC reporting guidelines follow the recommendations of the IPCC Good Practice Guidance (IPCC 2000) and require that countries provide single estimates of uncertainty for source and sink categories.

Currently, a qualitative discussion of uncertainty is presented for all source and sink categories. Within the

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[20] See Chapter 7 "Methodological Choice and Recalculation" in IPCC (2000). <http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>

discussion of each emission source, specific factors affecting the uncertainty surrounding the estimates are discussed. Most sources also contain a quantitative uncertainty assessment, in accordance with UNFCCC reporting guidelines.

[BEGIN BOX]

Box ES- 3: Recalculations of Inventory Estimates

Each year, emission and sink estimates are recalculated and revised for all years in the Inventory of U.S. Greenhouse Gas Emissions and Sinks, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In this effort, the United States follows the 2006 IPCC Guidelines (IPCC 2006), which states, “Both methodological changes and refinements over time are an essential part of improving inventory quality. It is good practice to change or refine methods” when: available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors.” In general, recalculations are made to the U.S. greenhouse gas emission estimates either to incorporate new methodologies or, most commonly, to update recent historical data.

In each Inventory report, the results of all methodology changes and historical data updates are presented in the "Recalculations and Improvements" chapter; detailed descriptions of each recalculation are contained within each source's description contained in the report, if applicable. In general, when methodological changes have been implemented, the entire time series (in the case of the most recent inventory report, 1990 through 2010) has been recalculated to reflect the change, per the 2006 IPCC Guidelines (IPCC 2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies. References for the data are provided for additional information.

[END BOX]

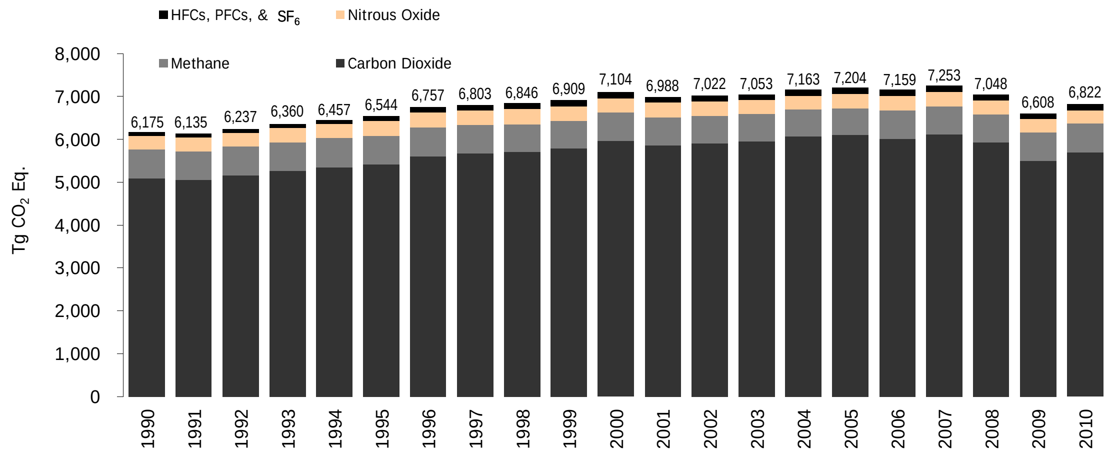


Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

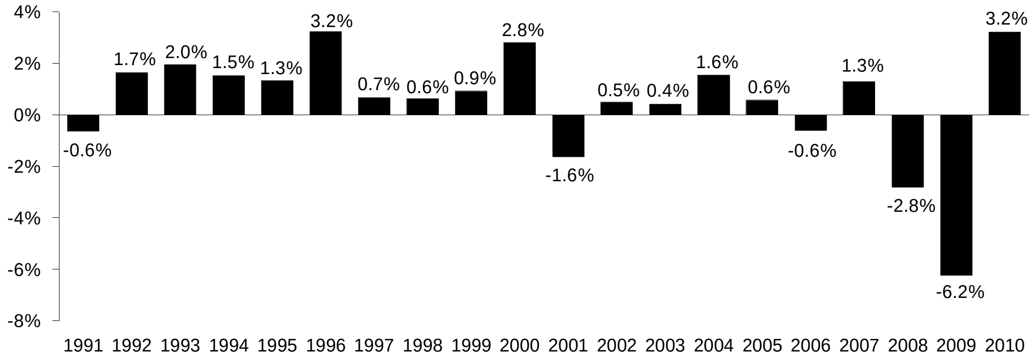


Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

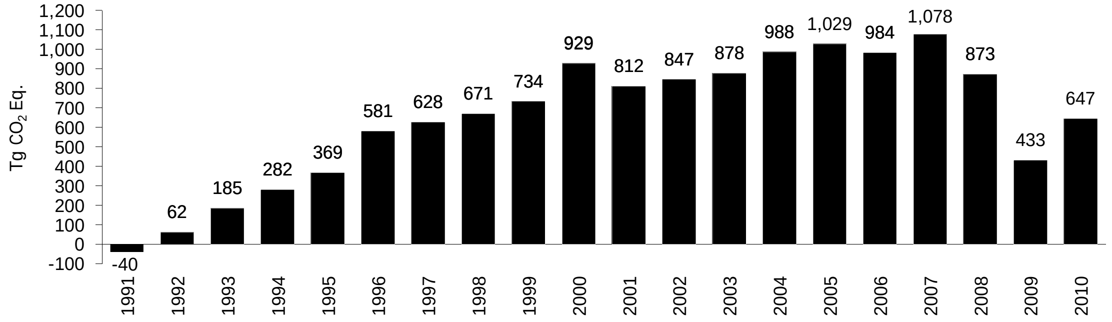


Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

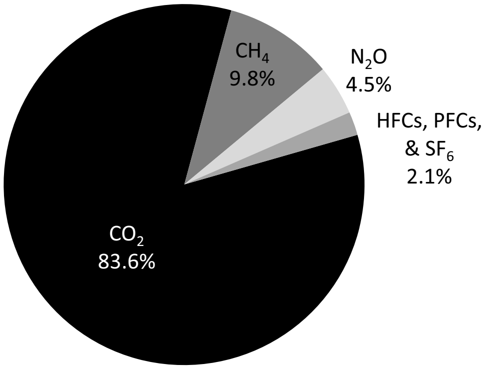


Figure ES-4: 2010 Greenhouse Gas Emissions by Gas (percents based on Tg CO$_2$ Eq.)

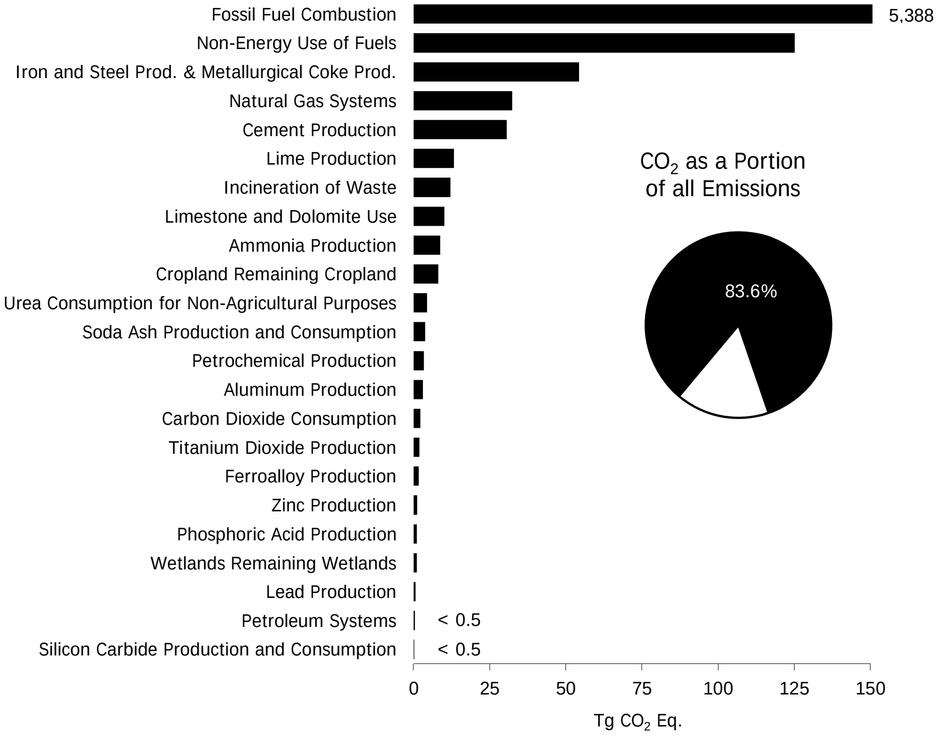


Figure ES-5: 2010 Sources of CO$_2$ Emissions

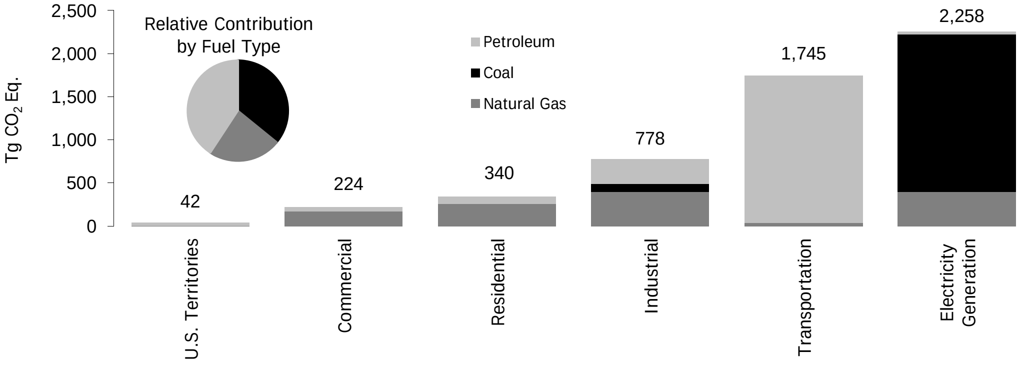


Figure ES-6: 2010 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: Electricity generation also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

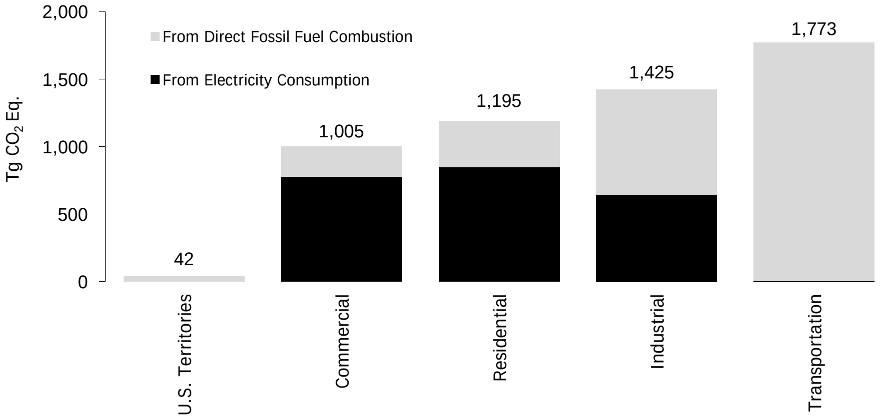


Figure ES-7: 2010 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

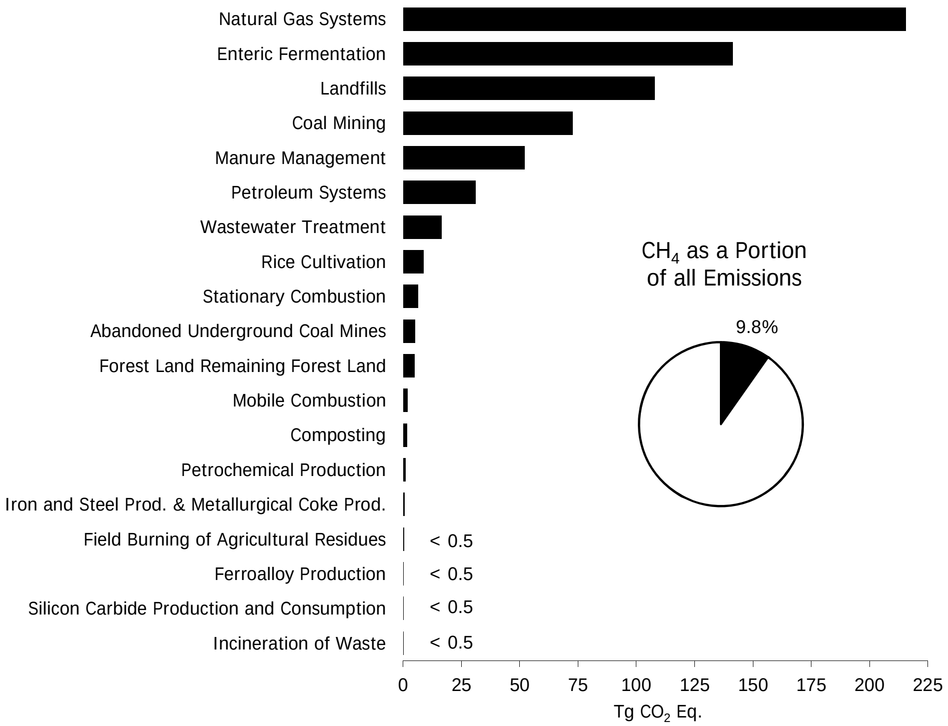


Figure ES-8: 2010 Sources of CH_4 Emissions

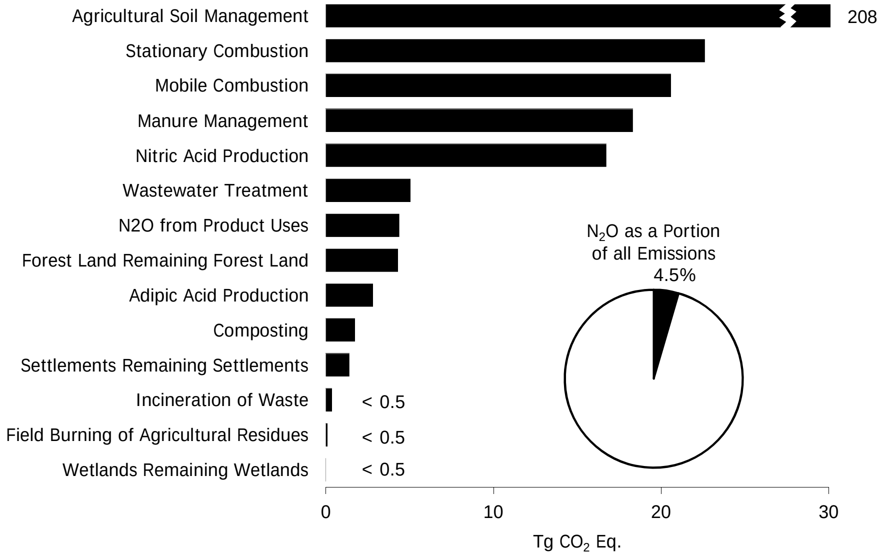


Figure ES-9: 2010 Sources of N_2O Emissions

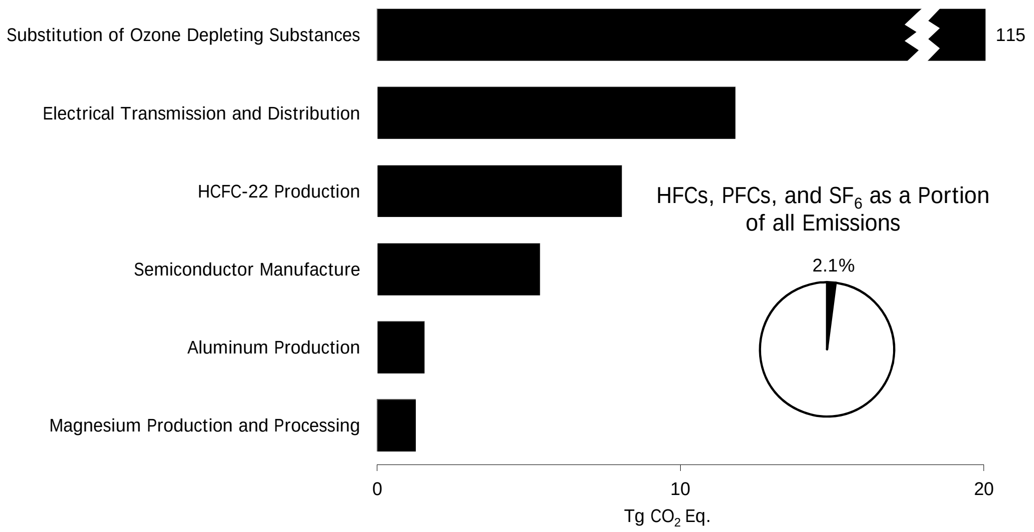
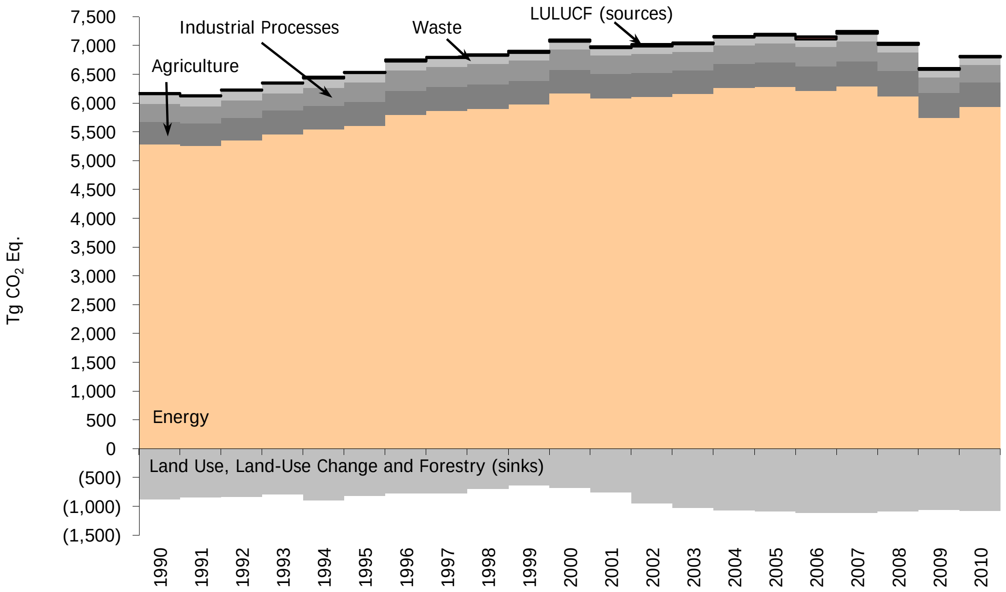


Figure ES-10: 2010 Sources of HFCs, PFCs, and SF_6 Emissions



Note: Relatively smaller amounts of GWP-weighted emissions are also emitted from the Solvent and Other Product Use sectors

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

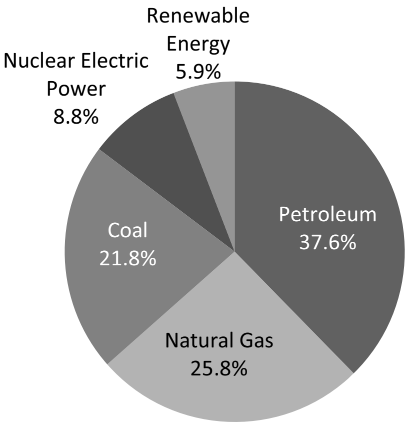


Figure ES-12: 2010 U.S. Energy Consumption by Energy Source

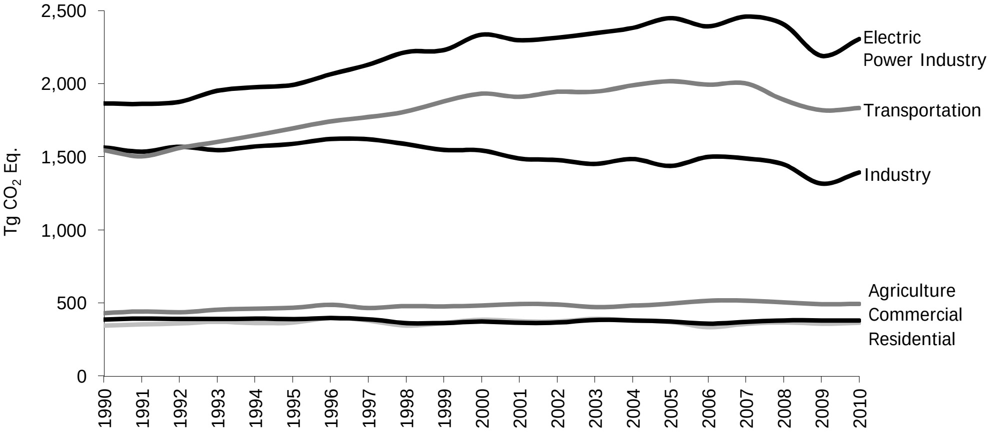


Figure ES-13: Emissions Allocated to Economic Sectors
Note: Does not include U.S. Territories.

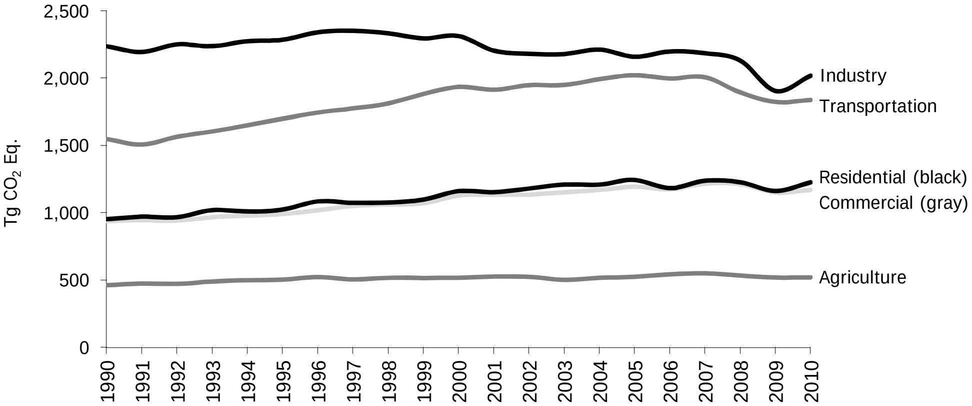


Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

Note: Does not include U.S. Territories.

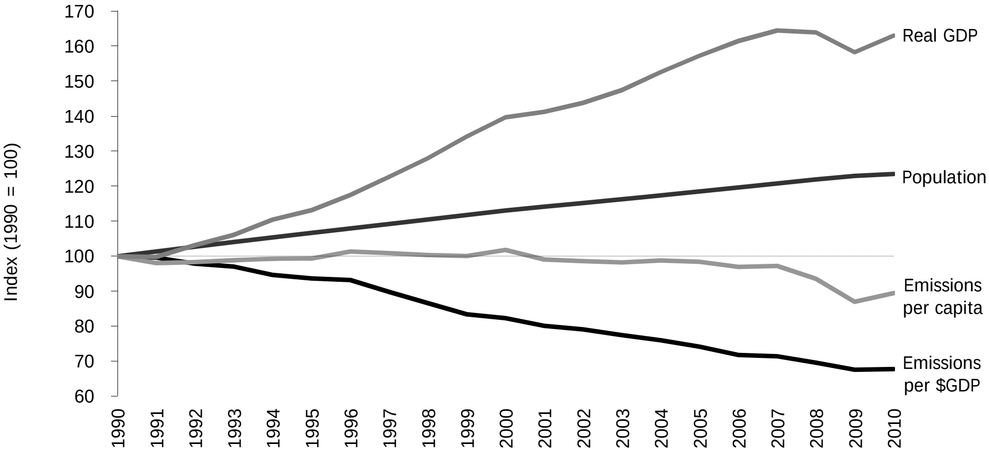


Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

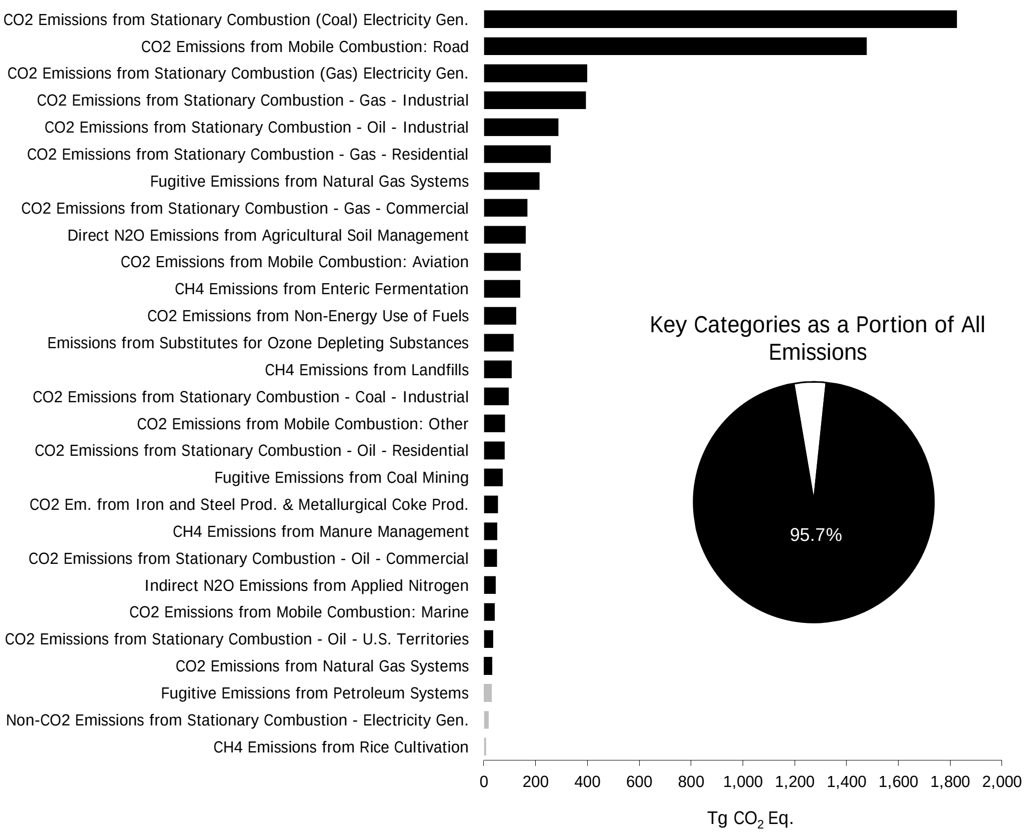


Figure ES-16: 2010 Key Categories

Notes: For a complete discussion of the key category analysis, see Annex 1.
Black bars indicate a Tier 1 level assessment key category.
Gray bars indicate a Tier 2 level assessment key category.

Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal

August 25, 2011

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Executive Summary

— **Research conclusion and key messages—natural gas offers greenhouse gas advantages over coal**: Natural gas has been widely discussed as a less carbon-intensive alternative to coal as a power sector fuel. In April 2011, the U.S. Environmental Protection Agency released revised methodologies for estimating fugitive methane emissions from natural gas systems. These revisions mostly affected the production component of the natural gas value chain (namely, gas well cleanups), causing a very substantial increase in the methane emissions estimate from U.S. natural gas systems.[1][2] This large increase in the upstream component of the natural gas value chain caused some to question the GHG advantage of gas versus coal over the entire life-cycle from source to use. As a result of this renewed attention, while it remains unambiguous that natural gas has a lower carbon content per unit of energy than coal does, several recent bottom-up studies have questioned whether natural gas retains its greenhouse gas advantage when the entire life cycles of both fuels are considered.[3]

Particular scrutiny has focused on shale formations, which are the United States' fastest growing marginal supply source of natural gas. Several recent bottom-up life-cycle studies have found the production of a unit of shale gas to be more GHG-intensive than that of conventional natural gas.[4] Consequently, if the upstream emissions associated with shale gas production are not mitigated, a growing share of shale gas would increase the average life-cycle greenhouse gas footprint of the total U.S. natural gas supply.

Applying the latest emission factors from the EPA's 2011 upward revisions, our top-down life-cycle analysis

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[1] *EPA, Inventory of U.S. Greenhouse Gas Emissions And Sinks:1990 – 2009, U.S. EPA, EPA 430-R-11-005,* *http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Complete_Report.pdf, cited in Mark Fulton, et al., "Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal," 14 March 2011, available at* *http://www.dbcca.com/dbcca/EN/_media/Comparing_Life_Cycle_Greenhouse_Gas.pdf.*

[2] *Note: For example, the EPA's estimates of methane emissions from U.S. natural gas systems in the base year of 2008 increased 120 percent between the 2010 and 2011 versions of their Inventory of U.S. Greenhouse Gas Emissions and Sinks.*

[3] *The two approaches for an LCA study are bottom-up and top-down. A bottom-up study analyzes the emissions from an individual representative or prototype process or facility and calculates the emissions of that specific part of the value chain. It then combines each step of the value chain to compute the total lifecycle emissions from source to use. A top-down study, in contrast, looks at the total national emissions for a particular use or sector and depicts the national average life-cycle emissions for each discrete part of source to use for that sector to arrive at an aggregate estimate. Each approach has benefits and limitations. The bottom-up approach provides insights into the emissions for a particular process or fuel source, but also depicts only that specific process or source. The top-down approach represents the emissions across an entire sector but does not focus on specific processes or technologies. Some of the data sources for a top-down analysis may be built up from bottom-up sources, but the top-down analysis still yields a more general result.*

[4] *Robert W. Howarth, et al., "Methane and the greenhouse-gas footprint of natural gas from shale formations,"* Climatic Change *(2011); Timothy J. Skone, National Energy Technology Laboratory (NETL), "Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States," presentation (Ithaca, NY: 12 May 2011; revised 23 May 2011); Mohan Jiang, et al., "Life cycle greenhouse gas emissions of Marcellus Shale gas,"* Environmental Research Letters *6 (3), 5 August 2011.*

(LCA)[5] finds that the EPA's new methodology increases the life-cycle emissions estimate of natural gas-fired electricity for the baseline year of 2008 by about 11 percent compared with its 2010 methodology. But even with these adjustments, we conclude that **on average, U.S. natural gas-fired electricity generation still emitted 47 percent less GHGs than coal from source to use using the IPCC's 100-year global warming potential for methane of 25**. This figure is consistent with the findings of all but one of the recent life-cycle analyses that we reviewed.

While our LCA finds that the EPA's updated estimates of methane emissions from natural gas systems do not undercut the greenhouse gas advantage of natural gas over coal, methane is nevertheless of concern as a GHG, and requires further attention. In its recent report on improving the safety of hydraulic fracturing, the U.S. Secretary of Energy's Advisory Board's Subcommittee on Shale Gas Production recommended that immediate efforts be launched to gather improved methane emissions data from shale gas operations.[6] In the meantime, methane emissions during the production, processing, transport, storage, and distribution of all forms of natural gas can be mitigated immediately using a range of existing technologies and best practices, many of which have payback times of three years or less.[7] Such capture potential presents a commercial and investment opportunity that would further improve the life-cycle GHG footprint of natural gas. Although the adoption of these practices has been largely voluntary to date, the EPA proposed new air quality rules in July 2011 that would require the industry to mitigate many of the methane emissions associated with natural gas development, and in particular with shale gas development.[8]

Our research methodology: This paper seeks to assess the current state of knowledge about the average greenhouse gas footprints of average coal and natural gas-fired electricity in the system today, how the growing share of natural gas production from shale formations could change this greenhouse gas footprint at the margin, and what the findings imply for policymakers, investors and the environment. In the first part of the paper, we examine recent bottom-up life-cycle analyses to provide context for our top-down analysis. These bottom-up analyses' estimation of the life-cycle GHG footprint of shale gas provides information about the potential marginal GHG impact of shale's rising share in the U.S. natural gas supply, as well as which emissions streams can be targeted for the greatest GHG mitigation. In the second part of the paper, we conduct our own top-down life-cycle analysis of GHGs from natural-gas and coal-fired electricity in 2008 using the EPA's revised 2011 estimates as well as other publically available government data. We make three key adjustments to the data sets in order to calculate a more accurate and meaningful national level inventory: we include: 1) emissions associated with net natural gas and coal imports; 2) natural gas produced as a byproduct of petroleum production, and 3) the share of natural gas that passes through distribution pipelines before reaching power plants. This top-down analysis examines the implications of the EPA's revised (2011) estimates for the current and future average greenhouse gas footprint of U.S. natural gas-fired electricity and its comparison with coal-fired electricity.

GWP and power plant efficiency matter: Global warming potentials (GWPs) are used to convert the volumes of greenhouse gases with different heat-trapping properties into units of carbon dioxide-equivalent (CO_2e) for the purpose of examining the relative climate forcing impacts of different volumes of gas over discrete time periods. The Intergovernmental Panel on Climate Change's (IPCC) most recent assessment, published in 2007, estimates methane's GWP to be 25 times greater than that of carbon dioxide over a 100-year timeframe and 72 times greater than that of carbon dioxide over a 20-year timeframe.[9] Unless

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[5] "Life-cycle analysis" (LCA) is a generic term, and the methodology and scope of analysis can vary significantly across studies. Our analysis assesses GHGs during the production, processing, transport, and use of natural gas and coal to generate electricity. Some studies include not only the direct and indirect emissions from the plant or factory that provides or makes a certain product, but also the emissions associated with the inputs used to manufacture and create the production facilities themselves. This study does not address the manufacturing, construction, or decommissioning of the equipment used in energy production. As with any study, the certainty of conclusions drawn from an LCA can only be as strong as the underlying data.

[6] U.S. Department of Energy, Secretary of Energy Advisory Board, Shale Gas Production Subcommittee, 90-Day Report, 18 August 2011, http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf.

[7] Numerous technologies and best practices to capture methane that would otherwise be vented during natural gas production, processing, transport, or distribution have been detailed by the U.S. EPA's voluntary Natural Gas STAR Program. Many of these have payback periods under 3 years. U.S. Environmental Protection Agency, Natural Gas STAR Program, "Recommended Technologies and Practices," available at http://www.epa.gov/gasstar/tools/recommended.html, viewed 29 July 2011.

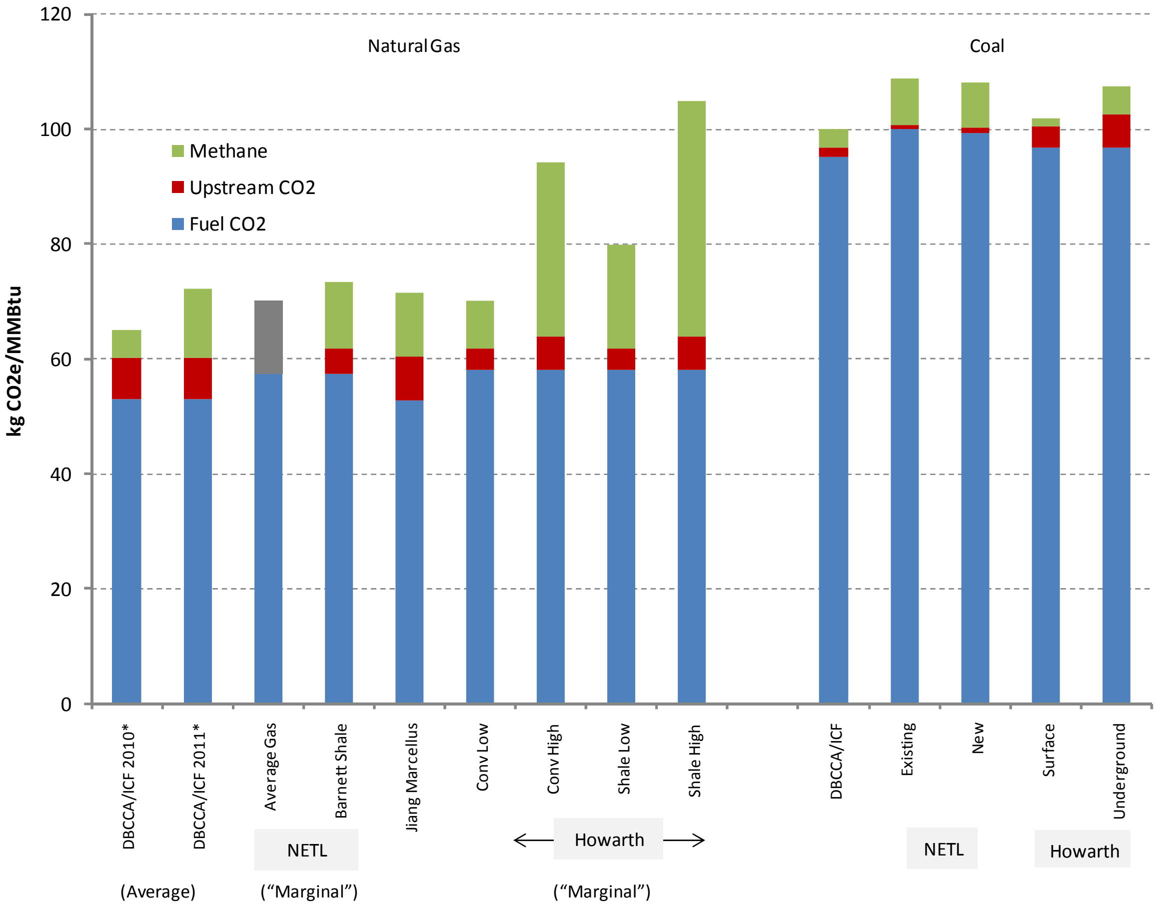
[8] EPA, "Oil and Natural Gas Air Pollution Standards," http://epa.gov/airquality/oilandgas/, viewed 18 August 2011.

[9] Piers Forster et al., 2007: Changes in Atmospheric Constituents and in Radiative Forcing. In: Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Solomon, S., D.

otherwise specified, our analysis uses the 100-year GWP of 25 but we also calculate life-cycle emissions using a range of methane GWPs that have been proposed—including 72 and 105—in Appendix B of this report in order to show the sensitivities of the outputs to GWP. The choice of GWP does impact the relative GHG footprint between coal and gas. However, the life-cycle GHG footprint of gas is lower than coal under all GWPs tested, with the smallest difference calculated using a GWP of 105, where the GHG emissions in kilograms CO_2 per megawatt-hour of electricity generated (kg CO_2e/MWh) are 27 percent less than those of coal-fired generation.

In addition, assumed power plant efficiencies also have a measurable impact on the life-cycle comparison between natural gas and coal-fired electricity generation. Unless otherwise specified, our analysis uses average U.S. heat rates for coal and natural gas plants for the existing capital stock: 11,044 Btu/kWh (31% efficiency) for coal and 8,044 Btu/kWh (41% efficiency) for natural gas plants. We also calculate life-cycle emissions using heat rate estimates for new U.S. natural gas and coal plants in Appendix A (Exhibit A-11).

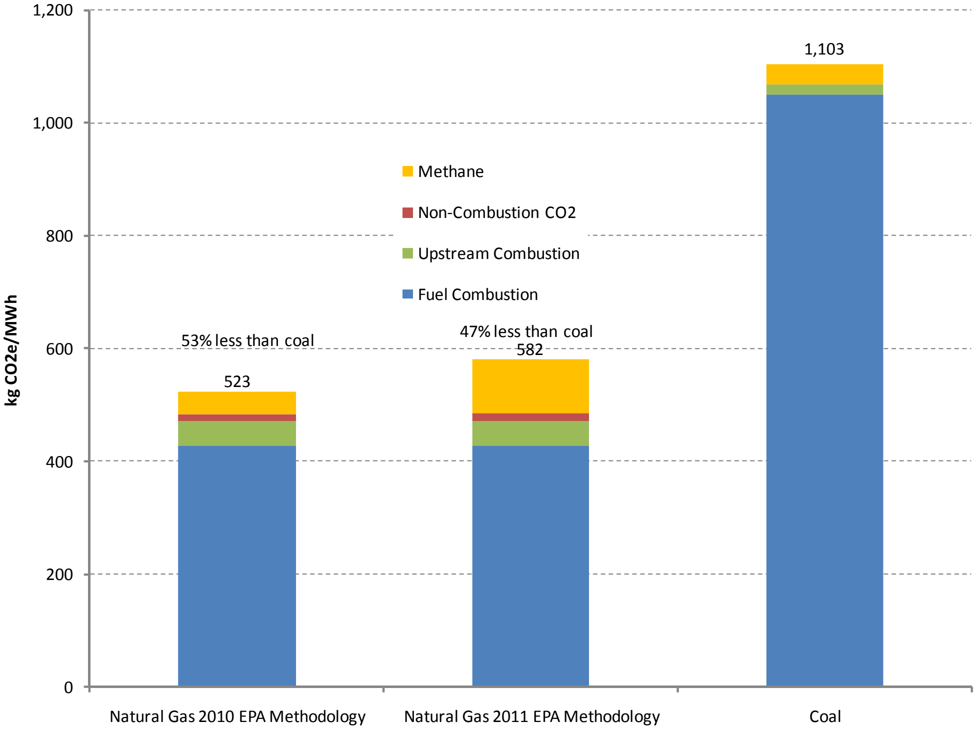
ES-1. Comparison of Recent Life-Cycle Assessments



Source: DBCCA Analysis 2011; NETL 2011; Jiang 2011; Howarth 2011. Note: NETL Average Gas study includes bar shaded grey due to inability to segregate upstream CO2 and methane values, which were both accounted for in the study. See page 10 for more information. *2011 EPA methodology compared to 2010.

Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M.Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA., p. 212.

ES-2. Average U.S. Life-Cycle GHG Emissions from Coal and Gas Electricity Generation, 2008
Comparing EPA 2010 Methodology with EPA 2011 Methodology



Source: DBCCA Analysis 2011. See pages 19 and 20 for more details.

Introduction and Key Exhibits

- **Our methodology:** Our top-down analysis addresses the emissions of three GHGs emitted during the production, processing, storage, transmission, distribution, and use of natural gas and coal in power plants:

    1. Carbon dioxide (CO_2);
    2. Methane (CH_4) and;
    3. Nitrous oxide (N_2O)

Carbon dioxide is a product of fossil fuel combustion and is also released during some stages of gas processing. Methane, the primary component of natural gas (roughly 98 percent of pipeline-quality gas), is a potent GHG.[10] It is released at many points during the life-cycle of natural gas production and use and also during coal mining, and it is an important component of the life-cycle emissions of both fuels, but especially of natural gas. Methane emissions can be categorized as “fugitive” or “vented” emissions. Fugitive emissions include unintentional “leaks” from poorly sealed valves, flanges, meters, and other equipment.[11] Venting is the intentional release of methane as part of the operating procedure for a particular process. For example, when a compressor or a pipeline is taken out of service for repair, the compressed gas in the equipment may be released. There are a variety of venting operations associated with natural gas production that account for the majority of methane emissions in the natural gas sector. Because the amount of fugitive and vented methane is highly dependent on the practices and technologies that are used, the amount of methane emitted can vary significantly by facility and/or the stripping and “clean up” process employed. Although small amounts of methane and nitrous oxide are also emitted during fossil fuel combustion, carbon dioxide is by far the largest greenhouse gas product. In this paper, because the amounts of methane and nitrous oxide are such a small fraction of the total combustion-related emissions, we include them together with CO_2 on tables and figures under the heading “combustion.”[12]

- **Reader roadmap:** In the section that follows, we start with a review of recent LCA studies. These studies have attempted to measure the life-cycle GHG footprint of shale gas and are valuable from our perspective in framing the marginal impact of shale gas on the GHG intensity of average natural gas-fired electricity. We then build up to a full comparison of the life-cycle emissions between natural gas and coal-fired electricity generation at a national level based on different assumptions and data adjustments in order to assess the impact that the EPA 2011 methodology change on GHG inventory has on the LCA comparison between average U.S. natural gas- and coal-fired electricity generation. We use emissions data for 2008 as a comparable baseline to show the impact of the 2010 and 2011 changes in EPA methane methodology to the life-cycle GHG emissions comparison between coal and natural gas in that year. (Note the Global Warming Potential used throughout this analysis is 25 unless otherwise noted – see Appendix B.) This overview provides a roadmap to follow the logic of our analytic approach.

    - **Step 1:** In Exhibit 2, page 10 we compare the most recent bottom-up studies of the LCA of gas from hydraulically fractured shale formations versus coal as a starting point;

    - **Step 2:** In Exhibit 4, page 13 we list the baseline EPA data for 2008 on the upstream natural gas emissions expressed as million metric tons of CO_2 equivalent ($MMTCO_2e$);

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[10] *Methane remains in the atmosphere for ~9-15 years, compared to 100+ years for CO_2; Methane, however, is much more effective at trapping heat in the atmosphere than CO_2, particularly over 20 year time periods (Please see Appendix B at the end of this report).*

[11] *Of critical importance, such leaks can be fairly easily mitigated from a technical perspective at reasonable cost, which means that there is scope for improvement.*

[12] *The EPA Greenhouse Gas Reporting Rule gives CH_4 and N_2O emission factors for the combustion of different fossil fuels. For CH_4, emission factors of 0.001 kg/MMBtu of natural gas and 0.011 kg/MMBtu of coal were used. For N2O, emission factors of 0.0001 kg/MMBtu of natural gas and 0.0016 kg/MMBtu of coal were used. The emission factors are in table C-2, page 38 of Subpart C of the rule. (Please see:* http://www.epa.gov/climatechange/emissions/downloads09/GHG-MRR-FinalRule.pdf)
These were then adjusted using GWPs for CH_4 and N_2O to obtain emissions factors in kg CO_2e/MMBtu. Unless otherwise noted in the paper, 100-year GWP values from the IPCC’s Fourth Assessment Report (2007) were used: 25 for CH_4 and 298 for N_2O. Using these values, the total GHGs emitted during the combustion of natural gas are 53.07 kg CO_2e/MMBtu (99.90% CO_2, 0.05% CH_4, 0.06% N_2O) and the total GHGs emitted during the combustion of coal are 95.13 kg CO_2e/MMBtu (99.21% CO_2, 0.29% CH_4, 0.50% N_2O).

- **Step 3:** In Exhibit 5, page 14, we adjust these baseline estimates to account for additional factors such as natural gas imports, methane emissions from other parts of the industry and other types of emissions associated with natural gas production;

- **Step 4:** In Exhibit 6, page 15, we combine our adjusted upstream and downstream natural gas emissions to derive a normalized life-cycle emissions expressed as kg/MMBTU (volume of greenhouse gases per unit of energy value delivered to the power plant) and compare with coal on an equivalent carbon-dioxide equivalent basis for the electricity sector using 2008 data and the EPA's 2011 methane emissions methodology;

- **Step 5:** In Exhibit 7, page 15, we rerun Step 3 above for 2008 emissions but using the EPA 2010 methane emission methodology from the EPA in order to show the impact of the revisions pre-combustion in kg CO_2e/MMBtu;

- **Step 6:** In Exhibit 8, page 15, we use EPA's 2011 methane emissions methodology to calculate emissions for 2009, the most recent year data available;

- **Step 7:** In Exhibit 10, page 17, we adjust upstream emissions from coal into standard volume units of $MMTCO_2e$ in order to assess the emissions associated with the production and transportation from the mine to the power plant using 2008 data for an apples-to-apples comparison with gas;

- **Step 8:** In Exhibit 11, page 17, we then normalize these upstream coal emission factors into kg CO_2e/MMBtu (emission volume per unit of energy delivered);

- **Step 9:** In Exhibit 12, page 19, we compare the life-cycle emissions of natural gas and coal delivered to the power plant in kg CO_2e/MMMBtu using 2008 data but adjusted for both 2010 and 2011 EPA methane emission factor methodologies for natural-gas to show the impact of EPA's revisions;

- **Step 10:** In Exhibit 13, page 20, we show the LCA in terms of emissions per megawatt-hour of electricity generated from gas and coal using the national average power plant efficiencies for 2008. The life-cycle emissions for gas are 11 percent higher using the updated methodology. The Exhibit shows a six percentage point change with gas producing 47 percent lower emissions than coal using EPA's 2011 methane methodology compared to producing 53 percent lower emissions using EPA 2010 methane methodology based on a 100-year GWP value for methane of 25.

- **Sensitivity Analysis Using Alternative GWPs:** In Appendix B, we show the sensitivities of our LCA to different GWPs.

Overview of Natural Gas Systems and Emission Sources

Between its 2010 and 2011 editions of the Inventory, the EPA significantly revised its methodology for estimating GHG emissions from natural gas systems, resulting in an estimate of methane emissions from Natural Gas Systems in 2008 that was 120 percent higher than its previous estimate. Up until 2010, the Inventory had relied extensively upon emission and activity factors developed in a study by the EPA and the Gas Research Institute in 1996. For the 2011 Inventory, the EPA modified its treatment of two emissions sources that had not been widely used at the time of the 1996 study, but have since become common: gas well completions and workovers with hydraulic fracturing. It also significantly modified the estimation methodology for emissions from gas well cleanups, condensate storage tanks, and centrifugal compressors.

The bulk of the EPA's recent upward revisions of natural gas emissions estimates are related to the production part of the gas value chain. The largest component of the increase is due to revised estimates of methane released from liquids unloading: In some natural gas wells, downhole gas pressure is used to blow reservoir liquids that have accumulated at the bottom of the well to the surface.[13] The revisions also include an increase in the share of gas that is produced from hydraulically fractured shale gas wells and a change in the assumption as to how much of the flow-back emissions are flared. Previously, the EPA assumed that 100 percent of these emissions were flared or captured for sale. The new estimate assumes that approximately one third are flared and another third are captured through "reduced emission completions." Both of these are based on estimated counts of equipment and facility and associated emission factors.

These revisions have caused some to question whether replacing coal with natural gas would actually reduce GHGs, when emissions over the entire life cycles of both fuels are taken into account. Addressing these questions requires an understanding of:

1) The best available data on emissions throughout the life cycles of natural gas and coal;
2) The specific sources and magnitudes of GHG emissions streams for natural gas produced from shale versus conventional formations; and
3) How an increase in the contribution of shale gas to the U.S. natural gas supply might impact the overall life-cycle GHG footprint of natural gas-fired electricity in the future as the marginal skews the average.

Up until the past few years, most of the U.S. natural gas supply came from the Gulf of Mexico and from western and southwestern states. More recently, mid-continental shale plays have been a growing source of supply. Natural gas is produced along with oil in most oil wells (as "associated gas") and also in gas wells that do not produce oil (as "non-associated gas").

Exhibit 1 illustrates the primary sources of GHG emissions during natural gas production, processing, transmission and distribution. The equipment for drilling both oil and gas wells is powered primarily by large diesel engines and also includes a variety of diesel-fueled mobile equipment. Raw natural gas is vented at various points during production and processing prior to compression and transport by pipeline. In some cases, the gas may be flared rather than vented to maintain safety and to relieve over-pressuring within different parts of the gas extraction and delivery system. Flaring produces CO_2, a less potent GHG than methane.

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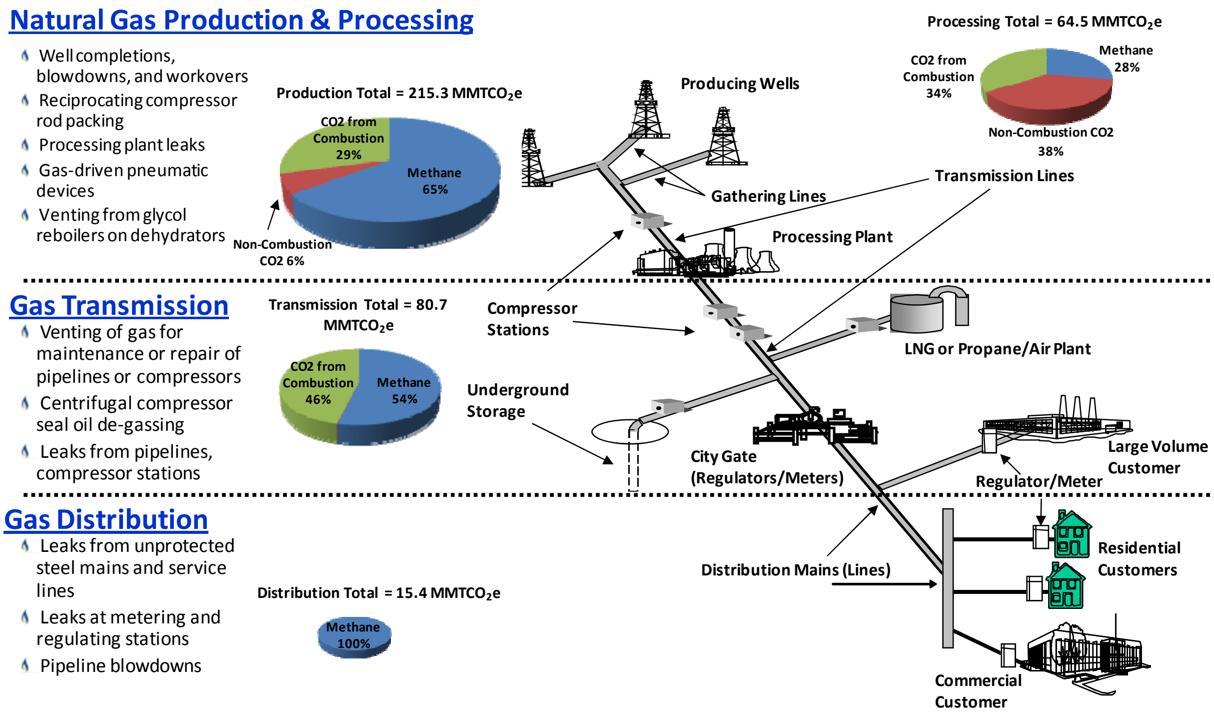
[13] *The technique of blowing out liquids is most frequently used in vertical wells containing "wet" or liquids-rich gas. It is being replaced by many producers with "plunger lifts" that remove liquids with much less gas release. In many shale wells, a technique is used where liquids are allowed to collect in a side section of the well and removed with a pump. EPA, Natural GAS Star, "Lessons Learned: Installing Plunger Lift Systems in Gas Wells," October 2006, available at http://www.epa.gov/gasstar/documents/ll_plungerlift.pdf.*

Exhibit 1. Natural Gas Industry Processes and Methane Emission Sources



Sources: American Gas Association; EPA Natural Gas STAR Program, DBCCA analysis, 2011.

The recent focus of new natural gas development has been shale gas, which currently represents about 14 percent of U.S. domestic production but is expected to reach 45 percent or more by 2035.[14] Most gas-bearing shale formations lie 8,000 to 12,000 feet below the surface and are tapped by drilling down from the surface and then horizontally through the target formation, with lateral drills extending anywhere from 3,000 to 10,000 feet. After drilling is complete, operators hydraulically fracture the shale, pumping fluids at high pressure into the well to stimulate the production of the gas trapped in the target rock formation. Horizontal drilling and pumping water for hydraulic fracturing release additional engine emissions compared to conventional production techniques. In addition, when the produced water "flows back" out of the well, raw gas from the producing formation can be released into the atmosphere at the wellhead.[15]

In both associated and non-associated gas production, water and hydrocarbon liquids are separated from the gas stream after it is produced at the wellhead. The gas separation process may involve some fuel combustion and can also involve some venting and/or flaring. Shale plays in particular are geologically heterogeneous, and the energy requirements to extract gas can vary widely. Moreover, the methane content of raw gas varies widely among different gas formations. Although some gas is pure enough to be used as-is, most gas is first transported by pipeline from the wellhead to a gas processing plant. Gas processing plants remove additional hydrocarbon liquids such as ethane and butane as well as gaseous impurities from the raw gas, including CO_2, in order for the gas to be pipeline-quality and ready to be compressed and transported. This "formation" CO_2 is vented at the gas processing plant and represents another source of GHG emissions along with the combustion emissions from the plant's processing equipment.

From the gas processing plant, natural gas is transported, generally over long distances by interstate pipeline to the "city gate" hub and then to the power plant. The vast majority of the compressors that pressurize the pipeline to move

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[14] *EIA Annual Energy Outlook 2011. DOE/EIA-0383ER(2011). Energy Information Administration, U.S. Department of Energy.* *http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf*

[15] *The GHG comparison between conventional and shale wells is important given the rapidly evolving industrial landscape with a share shift toward shale wells. For its part, the International Energy Agency (IEA) in a June 2011 Special Report: "Are We Entering a Global Age of Gas?" concluded that the LCA emissions of natural gas from shale wells is between 3.5 and 12 percent more than from conventional gas. IEA, June 2011, page 64.*

the gas are fueled by natural gas, although a small share is powered by electricity.[16] Compressors emit CO_2 emissions during fuel combustion and are also a source of fugitive and vented methane emissions through leaks in compressor seals, valves, and connections and through venting that occurs during operations and maintenance. Compressor stations constitute the primary source of vented methane emissions in natural gas transmission. Actual leakage from the pipelines themselves is very small.

Some power plants receive gas directly from transmission pipelines, while others have gas delivered through smaller distribution pipelines operated by local gas distribution companies (LDCs). Distribution lines do not typically require gas compression; however, some relatively small methane emissions do occur due to leakage from older distribution lines and valves, connections, and metering equipment.

Review of Recent Bottom-Up Life-Cycle Analyses: The Marginal Impact on Emissions

The assessment of how much more methane is released from shale gas production than from conventional production is a key factor in the discussion of possible changes in the life-cycle emissions of natural gas. As the shale gas component of U.S. production increases, a higher marginal greenhouse gas footprint from shale gas would raise the average greenhouse gas footprint of the U.S. natural gas supply overall. On the other hand, changing production technology and regulation could reduce emissions from both shale and other natural gas wells. The life-cycle GHG comparison between shale and conventional natural gas therefore has important implications for stakeholders who are considering policies and investment on the basis of how carbon-intensive natural gas is today and how carbon-intensive it is likely to be in the future.

A number of recent bottom-up life-cycle analyses attempt to quantify the GHG comparison between conventional and shale gas. Exhibit 2 shows the results of several of these analyses and how they compare to our top down analysis, which follows later.[17] Bottom-up figures are taken from studies by Skone, et al. (NETL), Jiang et al. (Jiang), and Howarth, et al. (Howarth). Because these and other life-cycle studies each make different assumptions as to the global warming potential of methane and the product whose greenhouse gas footprint is being measured—some use units of natural gas produced, others use units of natural gas delivered, and still other use units of electricity generated—we have normalized these figures using a GWP of 25. Any remaining variability in the GHG estimates are the result of differences in underlying emissions factors used. Despite differences in methodology and coverage, all of the recent studies except Howarth et al. estimate that life-cycle emissions from natural gas-fired generation are significantly less than those from coal-fired generation on a per MMBtu basis. As can be seen in Exhibit 2, our GHG estimate for average U.S. gas based on EPA's 2011 data (72.3 kg/MMBtu) is very similar to the National Energy Technology Laboratory's (NETL) bottom-up estimate for Barnett Shale gas (73.5 kg/MMBtu).

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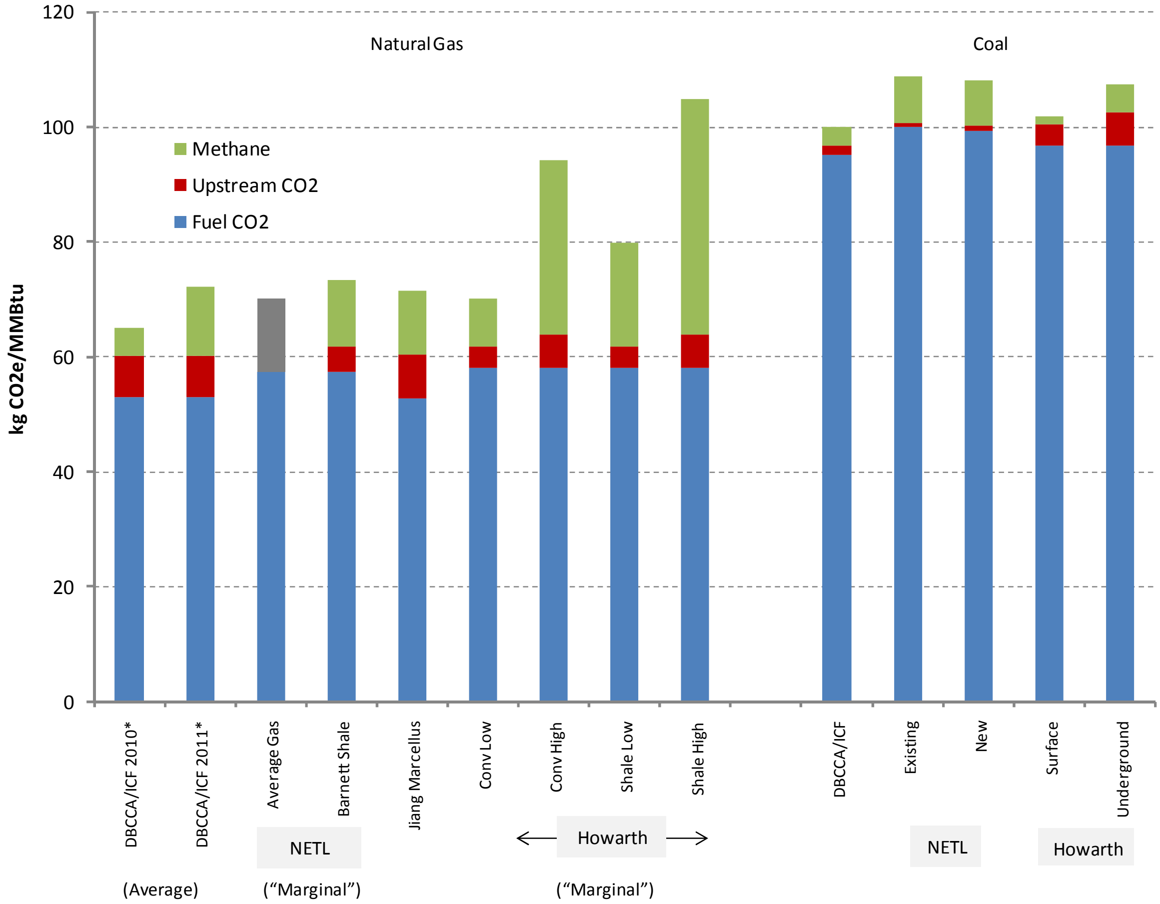
[16] *ORNL, Transportation Energy Data Book, Oak Ridge National Laboratory, U.S. Department of Energy, June 2010, http://cta.ornl.gov/data/index.shtml*

[17] *The results of the top-down life-cycle analysis conducted in the present study are displayed for reference. Bottom-up figures are taken from studies by Skone, et al. 2011 (NETL), Jiang et al. 2011 (Jiang), and Howarth, et al. 2011 (Howarth). All studies are normalized using a 100-year GWP for methane of 25, and given in kg CO_2e per MMBtu of fuel rather than kg CO_2e per MWh of electricity generated. Most studies use MMBtu of fuel produced as their metric; the present study uses MMBtu of fuel consumed, an explanation of which is given on p. 22. .*

Exhibit 2. Comparison of Recent Bottom-Up Life-Cycle Assessments.



Source: DBCCA Analysis, 2011. Note: NETL Average Gas study includes bar shaded grey due to inability to segregate upstream CO2 and methane values, which were both accounted for in the study. *2011 EPA methodology compared to 2010.

Many of these studies draw upon data from the U.S. Environmental Protection Agency's *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (hereafter "Inventory" or "Greenhouse Gas Inventory). The Inventory, published annually, is the official U.S. report on GHG emissions to the UN IPCC and the source for much of the analysis of U.S. emissions.[18] The inventory is developed from a variety of public and private data sources on the many different kinds of GHG emission sources in different sectors. It uses a combination of "bottom-up" analysis, utilizing counts and characteristics of individual facilities, and "top-down" analysis, such as national data on fuel combustion from the Energy Information Administration (EIA) to calculate CO_2 emissions from combustion, to build an estimate for total U.S. GHG annual emissions across a range of sectors.

Greenhouse gas emissions from natural gas and coal production, processing, transport, and distribution are estimated in the Inventory's "Natural Gas Systems" and "Coal Mining." In the EPA's 2011 edition of the Inventory, Natural Gas Systems were estimated to be the largest source of non-combustion, energy-related GHG emissions in the U.S., at 296 million metric tons of CO_2 equivalent (MMT CO_2e) in 2009. Coal mining came in third, with an estimated 85 MMT CO_2e of emissions. Fossil fuel combustion accounted for the vast majority of GHG emissions from the U.S. energy sector, with an estimated 1,747.6 MMT CO_2e coming from coal-fired electricity generation alone, while natural gas-fired electricity generation accounted for an additional 373.1 MMT CO_2e (Exhibit 3).[19]

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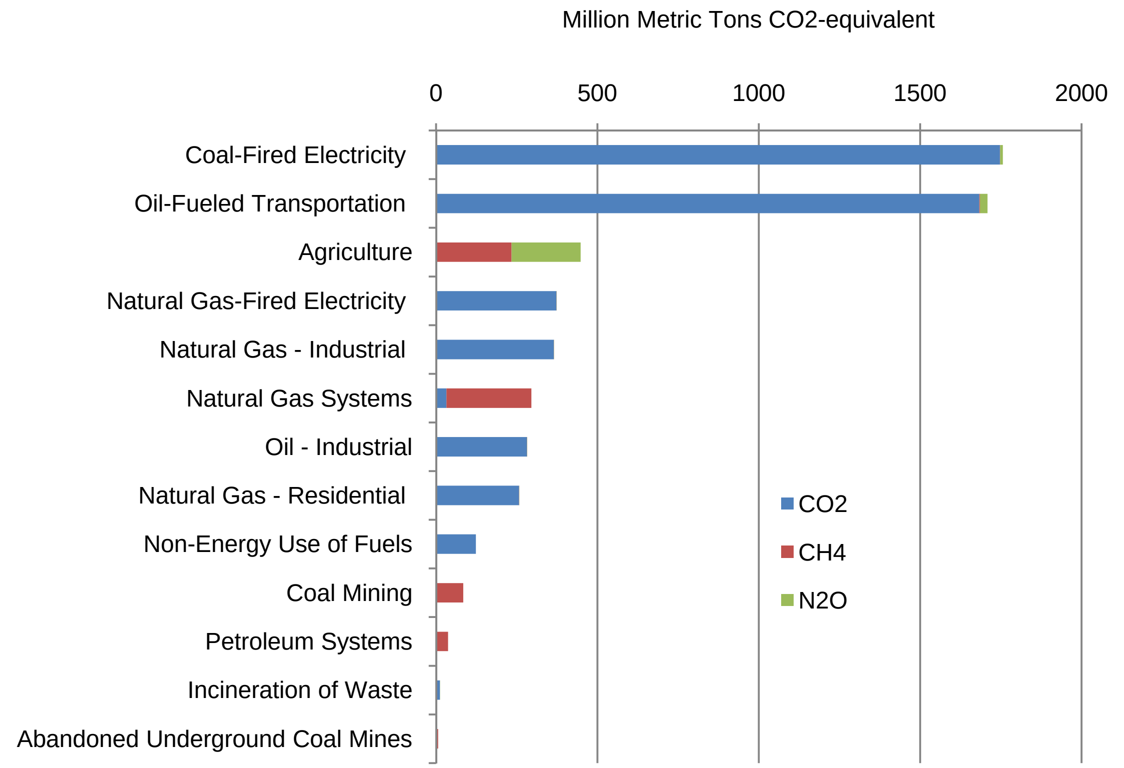
[18] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009* (April 2011), available at http://epa.gov/climatechange/emissions/usinventoryreport.html.

[19] All figures given in CO_2-equivalent here and elsewhere assume a global warming potential of 25 for methane unless otherwise noted. The EPA's Inventory uses a GWP of 21 for reporting purposes, so these numbers were converted to make them consistent with the GWP used for

Exhibit 3. U.S. Greenhouse Gas Emissions by Source Category, 2009.



These are the highest-emitting energy and agriculture sector source categories for 2009. Source: EPA 2011. Data were adjusted to use most recent IPCC GWPs for CH4 and N2O (25 and 298, respectively).

We draw two main conclusions from our survey of recent bottom-up life-cycle assessments. First, **the natural gas industry's practices are evolving rapidly, and better data are essential to ensuring that life-cycle greenhouse gas assessments remain up-to-date and reflect current industry behavior**. All of the bottom-up life-cycle assessments we surveyed identified significant uncertainty around certain segments of the natural gas life cycle stemming from data inadequacy. Among the sources of uncertainty identified were: formation-specific production rates, flaring rates during extraction and processing, construction emissions, transport distance, penetration and effectiveness of green completions and workovers, and formation-specific gas compositions.

Second, because shale gas appears to have a GHG footprint some 8 to 11 percent higher than conventional gas on a life-cycle basis per mmBtu based on these bottom up studies that we reviewed, **increased production of shale gas would tend to increase the average life-cycle GHG footprint from U.S. natural gas production if methane emissions from the upstream portion of the natural gas life are unmitigated**. This fact underlines **the importance of implementing the many existing control technologies and practices that can significantly reduce the overall greenhouse gas footprint of the natural gas industry**. Many companies are already reducing vented and flared methane emissions voluntarily through the EPA's voluntary Natural Gas STAR program. For example, the Inventory estimates that the completion emissions of methane from two thirds of shale gas production are already being mitigated through flaring or reduced emission completion.[20] If this is correct, then bottom-up life-cycle GHG estimates that do not account for reduced emissions completions are likely too high.

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the main analysis in this paper. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009* (April 2011), available at http://epa.gov/climatechange/emissions/usinventoryreport.html.

[20] *Ibid.*

Stronger regulations limiting methane and other air pollutant emissions from oil and natural gas operations are also likely to lead to lower overall GHG emissions. Some states already require the adoption of certain methane controls: Wyoming and Colorado, for example, already require “no-flare” or “green” completions and workovers, which are reported to capture 70 to 90 percent of methane vented during completions and workovers following hydraulic fracturing. Because this methane can then be sold, users of green completions have reported payback times of less than one year.[21] Moreover, the EPA released proposed regulations for the gas production sector on July 28, 2011 that are expected to require mitigation of completion emissions from all wells.[22] This regulation is currently in the comment period and is set to be implemented by court order in 1Q12. If these regulations are adopted, there will be little or no difference between the emissions of hydraulically fractured and conventional gas wells.

Top-Down Life-Cycle Analysis of U.S. Natural Gas and Coal: Impact on the Average

The remainder of this paper develops a top-down life-cycle greenhouse gas analysis of natural gas and coal for the purpose of determining the impact of recent EPA revisions to methane emissions estimation methodologies on the current comparison between U.S. natural gas and coal-fired electricity.

Natural Gas

This analysis for natural gas includes each of the industry steps described in Exhibit 1 above. (See Appendix A for a detailed methodology.) The source of information for methane emissions and non-combustion CO_2 is the EPA’s *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009* (April 2011 release), which includes updated estimates for methane emissions from natural gas production that are approximately twice the level indicated in the previous 2010 edition.[23] This LCA uses the data from both 2010 and 2011 EPA inventory reports to illustrate the effect that the EPA’s latest increase in estimated methane emissions has on the overall LCA for gas (as discussed below), which we estimate to be about an 11 percent increase in the life-cycle emissions.

The U.S. Energy Information Administration (EIA) is the primary source for the data on natural gas consumption and associated CO_2 emissions in the various segments of the gas industry (fuel for gas compressors and gas processing plants).[24] In addition to the natural gas, petroleum is used for drill rigs, trucks and other mobile equipment, such as pumps for hydraulic fracturing. This analysis uses information from the Economic Census to estimate non-natural gas energy consumption and associated CO_2 emissions in the production sector.[25]

Sources of methane emissions are many and vary widely. Apart from EIA there are very few sources of aggregated data in the public domain. As noted earlier, the EPA recently increased its estimates significantly for several processes in natural gas production, and better data availability on methane leakage and venting will be critical going forward given the rapidly evolving gas production landscape. On this score, disclosures and reporting of upstream emissions have historically been voluntary. And while there is evidence that large volumes of GHGs are being captured by industry, the actual penetration rates of these voluntary programs is unknown[26].

For example, the EPA Natural Gas STAR program, a voluntary methane mitigation program, reports that its members reduced methane emissions from natural gas systems by 904 billion cubic feet between 2003 and 2009—equivalent to 365 $MMTCO_2e$.[27] This program has identified and documented many methane mitigation measures that could be applied more widely across both industries and are included in the EPA’s Inventory of US Greenhouse Gas Emissions

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[21] EPA, Natural Gas STAR Program, “Reduced Emissions Completions: Lessons Learned,” available at http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf, viewed 2 August 2011.

[22] *EPA, “Oil and Natural Gas Air Pollution Standards,” http://epa.gov/airquality/oilandgas/, viewed 18 August 2011.*

[23] *The new EPA data have raised questions on two ends, with some believing the estimates are too high and others believing they are too low. Some comments submitted to the EPA from gas producers about the Draft Inventory question the validity of these revisions, believing them too high. While on the other hand, there are environmental advocacy groups that question whether EPA’s “activity factors” used in its methodology accurately represent the preponderance of shale wells being drilled in the Gulf Coast and North East regions, thereby raising the question of whether the emission factors are indeed high enough.*

[24] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*

[25] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*

[26] *Reported 2009 Natural Gas STAR voluntary emission reductions were the equivalent of ~$344 million in revenue (assuming $4/mmBtu gas) and the avoidance of 34.8 mn tonnes CO_2e; http://www.epa.gov/gasstar/accomplishments/index.html#content*

[27] *EPA Natural Gas STAR Program Accomplishments, page 2; http://www.epa.gov/gasstar/accomplishments/index.html*

and Sinks report.[28] Additionally, many mitigation activities are not reported to these programs. It is also possible that the EPA is missing or has underestimated some sources of upstream emissions for both natural gas and coal. Nevertheless, we expect that better information will be available in the spring of 2012 when reporting of data on upstream methane emissions through EPA's GHG Reporting Program commences.

In our LCA, the emission factors for the combustion of natural gas, coal and petroleum includes the CO_2 from complete combustion of the fuel plus the small amounts of nitrous oxide (N_2O) and unburned methane that result from the combustion. The emission factors for fuel combustion are taken from subpart C of the EPA Greenhouse Gas Reporting Program.[29] The N_2O and methane emissions from combustion are less than 1% of the CO_2 emissions. The total emission factors for combustion are:

- Natural gas – 53.07 kg CO_2 e/MMBtu
- Diesel fuel – 74.21 kg CO_2 e/MMBtu
- Coal – 95.11 kg CO_2 e/MMBtu

Exhibit 4 summarizes the data on total upstream GHG emissions calculated for the natural gas sector for the year 2008 using the April 2011 EPA inventory for methane adjusted for a methane GWP of 25 and the EIA data on fuel consumption. According to this inventory, U.S. production, processing, and transport of natural gas emitted 387.0 million tons of CO_2 equivalent ($MMTCO_2e$) in 2008.

Exhibit 4. Baseline U.S. Upstream Gas Emission Data for 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	146.3	11.3	47.2	204.8
Processing	18.7	21.4	19.4	59.5
Transmission	51.5	0.1	35.4	87.1
Distribution	35.6			35.6
Total	252.1	32.8	102.1	387.0

In this analysis, we adjust several factors to more accurately and robustly capture the life-cycle emissions associated with the use of natural gas on a national basis.

First, the emissions estimates account for natural gas production in the United States; however, because 13 percent of natural gas consumed in the U.S. was imported in 2008, we increase the production and processing emissions estimates to account for emissions from gas imports. Of that 13 percent in 2008, 11.7 percent was imported by pipeline from North America, mostly from Canada. The analysis assumes that other North American production operations are similar to those in the United States, so the emissions are increased linearly to account for these imports. In addition, 1.3 percent of the gas supply arrived via liquefied natural gas (LNG) imports. The LNG life cycle includes additional emissions associated with liquefaction, transportation, and regasification from source to use. The LNG portion is escalated by 76 percent to account for these emissions, based on a bottom-up LNG LCA prepared by NETL.[30] These are the most significant modifications made in our analysis, increasing the overall LCA for natural gas by 39 $MMTCO_2e$, or about 10 percent, primarily due to the adjustment for pipeline imports.

A second adjustment relates to methane emissions from distribution lines at local gas distribution companies. Since only 52 percent of the gas used for power generation is delivered by local distribution lines, the methane emissions associated with distribution have been discounted by that amount.[31] This reduces the total emissions by 18 $MMtCO_2e$, or 4 percent.

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[28] *EPA,* Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, April 2011, available at http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Complete_Report.pdf, p. 152.*

[29] *EPA, Greenhouse Gas Reporting Program, Subpart C, U.S. Environmental Protection Agency, http://www.epa.gov/climatechange/emissions/ghgrulemaking.html*

[30] *Skone, T.J., 2010. Life Cycle Greenhouse Gas Analysis of Power Generation Options, National Energy Technology Laboratory, U.S. Department of Energy*

[31] *EIA, EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition", Energy Information Administration, U.S. Department of Energy. http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP1&CFID=5251631&CFTOKEN=51c7f7f0104e329d-3FD56B17-237D-DA68-24412047FB2CE3CB*

A final adjustment is for methane emissions from production of associated gas—gas produced from oil wells. We did this in order to accurately adjust the impact of associated gas in our net import correction. Most oil wells produce some natural gas, and some of this gas is collected and becomes part of the gas supply. The EPA inventory of U.S. GHG emissions estimates that methane emissions from petroleum systems are approximately 30 MMTCO$_2$e per year.[32] Since some domestic natural gas is co-produced with petroleum, these emissions could be considered for inclusion in the LCA of emissions from the natural gas sector.

The associated natural gas produced and the methane emitted during petroleum production, processing, and transport are a byproduct of petroleum production. Methane emissions would occur even if no natural gas were captured and delivered for end-use consumption. In fact, the emissions might actually be higher in that case since there would be no economic incentive to capture the gas. By this assessment it would not be appropriate to count the methane emissions from petroleum production, since they are independent of the production of gas.

On the other hand, associated gas produced from oil wells represents a significant segment of U.S. gross withdrawals of natural gas, and if there are methane emissions associated with that production, it seems appropriate to include them in the LCA, even if the production is incidental to oil production. In that case, we have to evaluate how much of the methane emissions to allocate to gas production versus petroleum production. This calculation is shown in Appendix A and results in an additional 5 MMTCO$_2$e of emissions being added, or a 1.4 percent increase.

Exhibit 5 shows our adjusted total emissions for 2008, which come to 423.8 MMTCO$_2$e compared to the 387.0 baseline. The production segment is the largest contributor to GHG emissions from the natural gas supply chain, accounting for 57 percent of total emissions. Of the different gases, methane accounts for 59 percent of total GHG emissions using a GWP of 25.

Exhibit 5. Adjusted Total Upstream GHG Emissions from Natural Gas, 2008 (MMTCO$_2$e)

	Methane	Non-Combustion CO$_2$	CO$_2$ and N$_2$O from Combustion	**Total**
Production	173.7	12.9	62.2	248.7
Processing	21.3	24.4	22.2	67.9
Transmission	51.5	0.1	37.2	88.8
Distribution	18.3	0.0	0.0	18.3
Total	264.9	37.4	121.5	423.8

To compare emissions from coal and natural gas on an apples-to-apples basis, the emissions are normalized to the amount of GHG per million Btu (MMBtu) of *natural gas delivered to consumers* using EIA data for gas deliveries[33]. Some LCAs normalize to GHG per unit of natural gas *produced*, which includes associated gas that is reinjected into the producing formation as well as natural gas liquids that are removed during gas processing and gas lost through fugitives and venting, in addition to gas actually delivered to consumers such as power plants. Using delivered rather than produced natural gas results in a slightly higher overall figure for life-cycle emissions but depicts more accurately the energy that is actually available to power plants. The total normalized upstream emissions are 19.2 kg CO$_2$e/MMBtu of natural gas delivered. (See Exhibit 6.) As discussed earlier, the emissions for combustion of the natural gas at the power plant are 53.1 kg CO$_2$e/MMBtu, so the total life-cycle GHG emissions at the point of use are 72.3 kg/MMBtu. Of this, the upstream emissions are 30 percent, 60 percent of which are from methane.

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[32] *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2009, EPA 340-R-11-005, April 2011 page, 27*

[33] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*

Exhibit 6. Normalized Life-Cycle GHG Emissions for Natural Gas for 2008, using EPA 2011 Methane Emissions Methodolgy (kg CO$_2$e/MMBtu)

	Methane	Non-Combustion CO$_2$	CO$_2$ and N$_2$O from Combustion	**Total**
Production	7.9	0.6	2.8	11.3
Processing	1.0	1.1	1.0	3.1
Transmission	2.3	0.0	1.7	4.0
Distribution	0.8	0.0	0.0	0.8
Total Upstream	12.0	1.7	5.5	19.2
Fuel Combustion	0	0	53.1	53.1
Total	12.0	1.7	58.6	72.3

Doing the same calculation with the lower methane emissions estimated in the prior year's EPA inventory yields a value of 12.0 kg CO$_2$e/MMBtu for the upstream emissions. (See Exhibit 7) Including the end-use gas consumption, total life-cycle emissions are 65.1 kg CO$_2$/MMBtu, with the upstream portion accounting for 20 percent. In this case, methane makes up only about 40 percent of the upstream gas GHG footprint.

Exhibit 7. Normalized Life-Cycle GHG Emissions for Natural Gas for 2008, using EPA 2010 Methane Emissions Methodology (kg CO$_2$e/MMBtu)

	Methane	Non-Combustion CO$_2$	CO$_2$ and N$_2$O from Combustion	**Total**
Production	1.2	0.4	2.8	4.4
Processing	0.8	1.1	1.0	2.9
Transmission	2.1	0.0	1.7	3.8
Distribution	0.8	0.0	0.0	0.8
Upstream Total	4.9	1.6	5.5	12.0
Fuel Combustion	0	0	53.1	53.1
Total	4.9	1.6	58.6	65.1

Finally, Exhibit 8 applies the most recent EPA data to calculate the life-cycle emissions for 2009 using the 2011 methane emissions methodology. This is the most recent year for which data are available. The 2009 emissions are quite similar to the emissions calculated for 2008 using the same methodology (73.1 vs 72.1 expressed as kg CO2e/MMBtu).

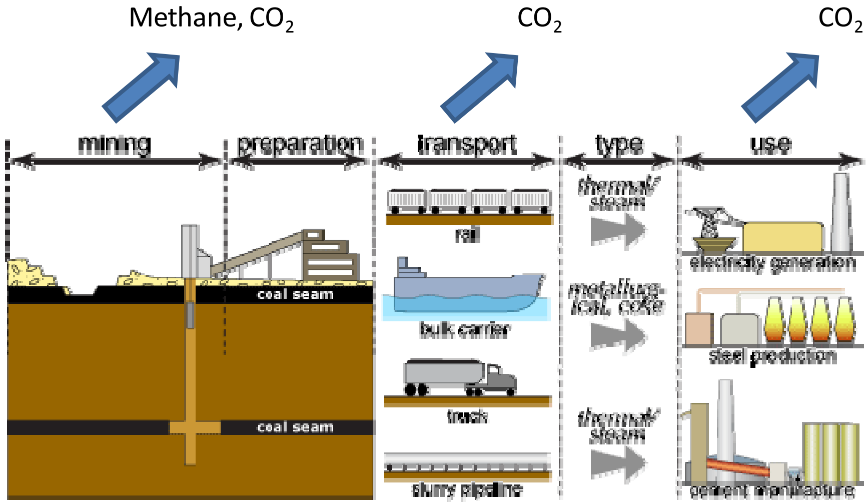
Exhibit 8. Normalized Life-Cycle GHG Emissions for Natural Gas for 2009, using EPA 2011 Methane Emissions Methodology (kg CO$_2$e/MMBtu)

	Methane	Non-Combustion CO$_2$	CO$_2$ and N$_2$O from Combustion	**Total**
Production	8.4	0.6	3.0	12.0
Processing	1.1	1.1	1.0	3.2
Transmission	2.4	0.0	1.6	4.0
Distribution	0.8	0.0	0.0	0.8
Upstream Total	12.8	1.7	5.6	20.1
Fuel Combustion	0.0	0.0	53.1	53.1
Total	12.8	1.7	58.7	73.1

Coal

The production and distribution of coal is simpler to analyze than that of natural gas because there are fewer steps in production and processing (Exhibit 9). Coal is produced in the U.S. from underground mines (40 percent) and surface mines (60 percent). In underground mines, most of the mining equipment is driven by electricity. In surface mines, the equipment runs on diesel fuel or electricity. This analysis estimates the direct and indirect emissions of the mining processes from Economic Census data[34]. (For detailed calculations of the coal LCA, see Appendix A.)

Exhibit 9. Coal Industry Segments and Emission Sources



Source: University of Wyoming

Coal formations contain methane, which is released when the coal is mined. The methane content varies among different coal formations but is generally higher for underground mines than for surface mines. Underground mines use ventilation to remove the methane, which is a safety hazard, and in some cases the methane can be recovered for use or flared to reduce GHG emissions. The U.S. GHG Inventory estimates the methane emissions from coal mining. Coal mines that are no longer active (i.e., are "abandoned") release methane as well: 7.0 MMTCO$_2$e in 2008 (at 25 GWP). This would add an additional 0.4 kg CO$_2$e/MMBtu to the coal LCA but is not included here since we do not have similar data on methane emissions from abandoned gas wells.

Data on coal transportation by mode are available from the Economic Census[35]. More than 90 percent of coal is transported by train, with the remainder transported by barge, truck, or various combinations of these modes. This analysis derives the energy consumption per ton-mile from several sources to calculate CO_2 emissions. (See Appendix A.)

The United States is a net exporter of coal by 4 percent, so the production data are adjusted downward by that amount. Table 6 shows the adjusted upstream GHG emissions for coal, totaling 117.8 MMTCO$_2$e.

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[34] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*

[35] *Ibid.*

Exhibit 10. Adjusted Total Upstream GHG Emissions from Coal for 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	79.9	0.0	14.0	93.9
Transportation	0.0	0.0	23.9	23.9
Total	79.9	0.0	37.9	117.8

As with the natural gas LCA, this analysis “normalizes” total emissions by the energy delivered to coal consumers (more than 90% power of whom are power generators), or 1,147 million short tons of coal in 2008. This yields a normalized upstream emission factor of 4.8 kg CO_2e/MMBtu consumed. (See Exhibit 11.) This value is about 25 percent of the upstream emissions from natural gas. The emission factor for combustion of coal is 95.1 kg/MMBtu, bringing the total end-use life-cycle emissions to 99.9 kg CO_2/MMBtu. In this case, although methane comprises 63 percent of the upstream emissions, the upstream component is only 5 percent of the total, with CO_2 emissions from the combustion of the coal itself being the dominant factor in the total life-cycle emissions.

Exhibit 11. Normalized Life-Cycle GHG Emissions from Coal for 2008 (kg CO_2e/MMBtu)

	Methane	CO_2 and N_2O from Combustion	**Total**
Production	3.3	0.6	3.9
Transportation	0.0	1.0	1.0
Total Upstream	3.3	1.5	4.8
Coal Combustion	0.0	95.1	95.1
End Use Total	3.3	96.6	99.9

Electricity Generation

Finally, life-cycle GHG emissions per MMBtu of fuel delivered to power plants are normalized to GHG emissions per MWh of electricity generated to account for the difference in coal and natural gas power plant efficiencies. In 2008, essentially all coal-fired electricity in the United States was generated by steam-turbine power plants, which combust fuel to boil water and use the resulting steam to drive a turbine.[36] Many coal plants are run almost all the time at full capacity to provide baseload power. Technology has improved over the past several decades and new plants have improved combustion efficiencies, but many active plants in the U.S. fleet were built before 1970 and are less efficient.

By contrast, natural gas is used in a range of power plant technologies, each of which fills a different role in the electricity dispatch. In 2008, only 12 percent of natural gas-fired electricity was generated by steam-turbine plants, most of which were built before 1980 and are relatively inefficient. An additional 9 percent was generated by simple-cycle gas turbines, relatively inefficient plants that are used to provide peaking power during limited periods. Since 2000, a large portion of new natural gas capacity additions have been combined-cycle units, which use waste heat from gas turbines to run steam turbines.

Combined-cycle plants have superior heat rates and may be used to provide baseload or intermediate power, depending on the particular grid and the price of gas. In 2008, 79 percent of gas-fired electricity was generated by combined-cycle plants. Two coal plants in the U.S. currently gasify coal to generate electricity in a combined-cycle configuration, but such plants, called Integrated Gasification Combined Cycle (IGCC) plants, have very low market penetration today.

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[36] *All 2008 generation data from Energy Information Administration (EIA), Form EIA-923, 2008.*

The heat rate (the amount of fuel in Btus needed to generate a kilowatt-hour of electricity) of the electric generator is one of the most significant variables in estimating the GHG emissions per MWh of electricity.[37] Unless otherwise specified, this analysis uses heat rates representing the average efficiency of existing power plants in the U.S. fleet:

- **Average efficiency of existing capital stock:** National average values are based on EIA data for total gas or coal consumption for generation and total generation by each fuel. The heat rates are 8,044 Btu/kWh (41 percent efficiency) for gas generation and 11,044Btu/kWh (31 percent efficiency) for coal generation.

A sensitivity analysis comparing life-cycle emissions results using average heat rates and heat rates representative of new natural gas and coal plants is shown in Appendix A (Exhibit A-12).

- **Efficiency of new plants:** In its *Annual Energy Outlook 2010*[38], EIA provides a value for a new plant in 2009, and for future plants that accounts for future cost reductions from learning and production efficiencies ("nth" plant). The values used here are the average of the two values for a gas combined-cycle plant (6,998 Btu/kWh, 49 percent efficiency) and a new supercritical coal plant (8,970 Btu/kWh, 38 percent efficiency).

Summary of Results and Sensitivity Analysis for Top=Down Analysis

Exhibit 12 compares the calculated LCA emissions (by GHG) for gas delivered to power plants for (a) natural gas using the EPA 2010 methodology, (b) natural gas using the EPA 2011 methodology, and (c) coal. In all cases, the emissions are dominated by CO_2 from final combustion of the fuel at the power plant. The upstream emissions are larger for gas, and the power plant combustion emissions are higher for coal. The LCA for coal is dominated by the CO_2 from the coal combustion itself. The upstream component is larger for natural gas, and methane is a larger component of the emissions. Using the increased methane emission estimate for gas from the 2011 methodology results in the LCA for natural gas being 11 percent higher than with the 2010 estimate. The gas life-cycle value using the 2011 methodology is 28 percent lower than the coal value.

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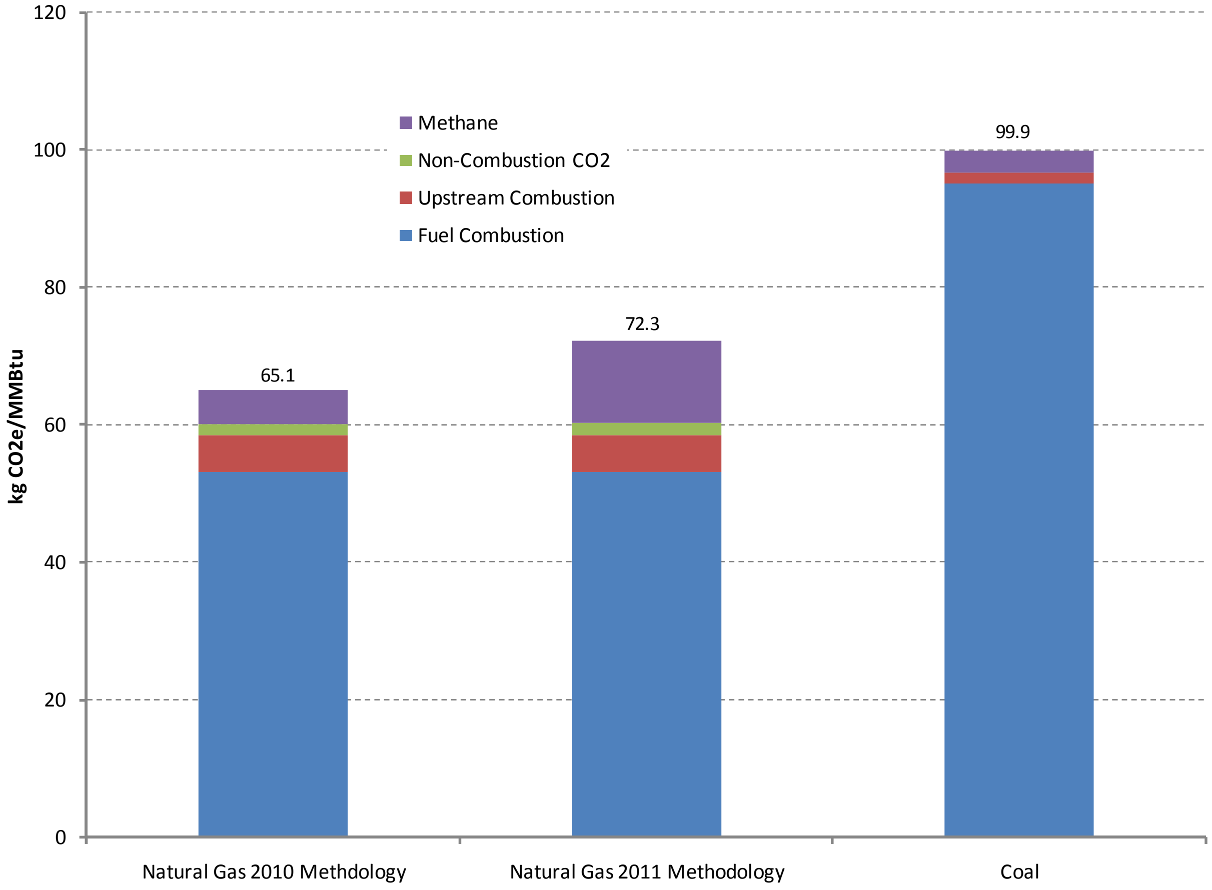
[37] The power industry uses efficiency and heat rate to express power plant efficiency. Heat rate in Btu/kWh = 3413/efficiency. A lower heat rate signifies a higher efficiency.

[38] *EIA, Assumptions to the Annual Energy Outlook 2010 – Table 8-2,* DOE/EIA-0554(2010), *Energy Information Administration, U.S. Department of Energy.* *http://www.eia.gov/oiaf/aeo/assumption/pdf/electricity_tbls.pdf*

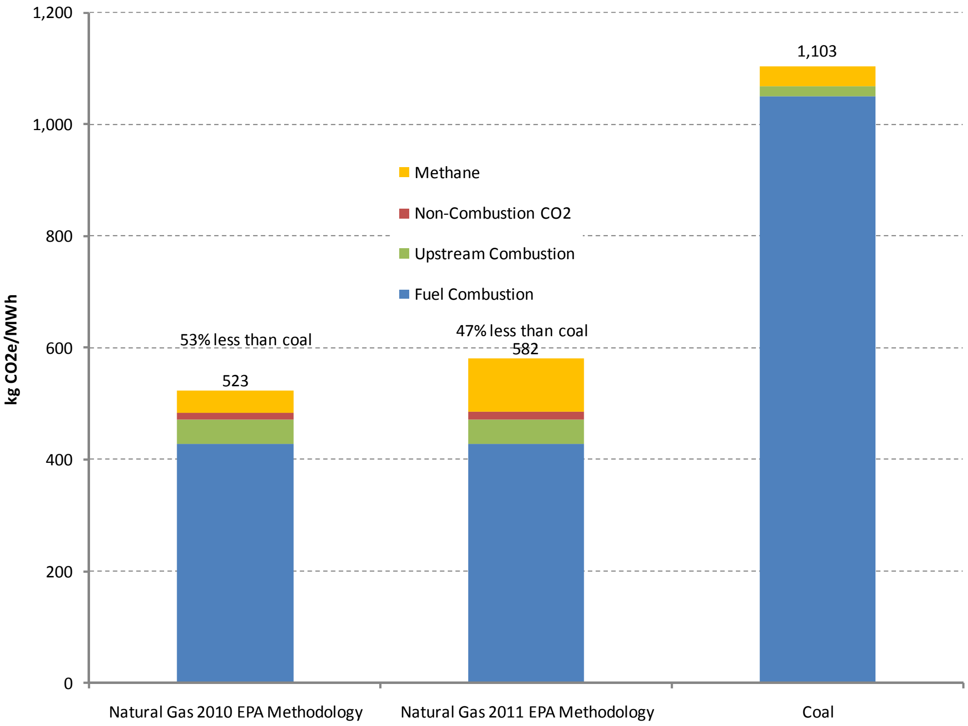
Exhibit 12: Life-Cycle Emissions as Delivered to Power Plants, 2008 (kg CO_2e/MMBtu)



Source: DBCCA Analysis 2011

Exhibit 13 shows the LCA in terms of GHG emissions per megawatt-hour of electricity generated from gas and coal, using the national average power plant efficiencies. The gas value using the 2011 EPA methane emissions estimates is 582 kg CO_2e/MWh—or 11 percent higher than the 523 kg CO_2e/MWh calculated using data for 2010 methodology. The value for coal is 1,103 kg CO_2e/MWh. Because coal plants are on average less efficient than gas plants, the difference between gas and coal is greater than the fuel-only comparison at the burner tip prior to combustion and conversion to electricity. **Natural gas-fired electricity, using the 2011 methodology, has 47 percent lower life-cycle GHG emissions per unit of electricity than coal-fired electricity.**

Exhibit 13: Electric Generating LCA, by Greenhouse Gas, 2008 (kg CO_2e/MWh)



Source: DBCCA Analysis 2011

Conclusions

Our top-down LCA of natural gas and coal-based generation using publicly available data shows that the EPA's recent revision of methane emissions increases the life-cycle GHG emissions for natural gas-fired electricity by about 11 percent from estimates based on the earlier values. Our conclusion is that, on average, natural gas-fired power generation emits significantly fewer GHGs compared to coal-fired power generation. Life-cycle emissions for natural gas generation using new EPA estimates are 47 lower than for coal-based generation when using a GWP of 25. The impact of different GWPs to our LCA can be found in Appendix B.

Nevertheless, methane, despite its shorter lifetime than carbon dioxide, is of concern as a GHG. Compared to coal-fired generation, methane emissions, including a large venting component, comprise a much larger share of natural-gas generation's GHGs. And while measurement of upstream emissions and public disclosure of those emissions still has room for improvement, methane emissions during the production, processing, transport, storage, and distribution of natural gas can be mitigated now at moderately low cost using existing technologies and best practices. Such capture potential presents a commercial and investment opportunity that would further improve the life-cycle GHG footprint of natural gas.

Appendix A
Detailed Methodology and Calculations

Natural Gas

The natural gas LCA addresses emissions from extraction through electricity generation for 2008. The primary data sources are the EPA *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009* and EIA data on natural gas consumption[39]. Exhibit A-1 shows the basic information on total emissions by industry segment for 2008. The methane emissions are from the EPA Inventory and adjusted from a GWP of 21 to a GWP of 25. The non-combustion CO_2 emissions are from the same source and include CO_2 from combustion of flared gas and the formation CO_2 vented from gas processing plants. The CO_2 from combustion is primarily from the EIA data on gas consumption in the gas industry. The gas consumed in the production segment is the “lease gas” reported by EIA, which is gas consumed in the producing areas. EIA also reports “vented and flared gas,” which is assumed here to be all flared but is already included in the EPA category of non-combustion emissions. The “processing” category includes the “plant gas” reported by EIA, and “transmission” includes the pipeline and distribution fuel reported by EIA. The total upstream emissions from these sources are 387.0 $MMTCO_2e$ based on a 100 year GWP of 25.

Detailed data collection and verification, as well as LCA harmonization to common metrics and system boundaries are critical for improving the rigor of LCA analysis. The National Renewable Energy Laboratory’s Joint Institute for Strategic Energy Analysis, www.jisea.org, will be conducting such an evaluation in the coming months, which may improve upon the historical data sets used by EPA.

Exhibit A-1: Basic U.S. Upstream Gas Emission Data for 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	146.3	11.3	47.2	204.8
Processing	18.7	21.4	19.4	59.5
Transmission	51.5	0.1	35.4	87.1
Distribution	35.6			35.6
Total	252.1	32.8	102.1	387.0

There are several additions to this basic information. First, there are some electric driven compressors on the pipeline network. This electricity consumption of 2,936.6 million kWh is from the ORNL *Transportation Data Book*[40]. (That estimate is based on a fixed share of 1.5 percent of the natural gas consumption.) The emission factor for electricity throughout the analysis is 603 kg CO_2/MWh, calculated from EIA data on total generation and CO_2 emissions. This electricity consumption adds 1.8 $MMTCO_2e$ to the pipeline emissions. There is also diesel fuel, gasoline and other petroleum fuel used in gas drilling and production that is not separately reported by EIA. This information is collected by the Economic Census[41]**Error! Bookmark not defined.** but only by NAICS code and only every 10 years (the latest reporting year is 2007). The four relevant NAICS codes are: 211111 (crude petroleum and natural gas extraction); 211112 (natural gas liquid extraction); 213111 (drilling oil and gas wells); and 213112 (support activities for oil and gas operations).

Three of these codes (excepting NGL extraction) combine data for oil and gas operation. The gas portion is calculated based on the gas share of U.S. producing oil and gas wells (55.4 percent) or active drilling rigs (83.2 percent). Also, the Census lists expenditures only by fuel type. The actual consumption is estimated from the expenditures based on average price for each fuel. The consumption is then converted to CO_2 emissions using the emission factors from the EPA GHG Reporting Program. These emissions are then escalated from 2007 to 2008 based on EIA data for production (3.9 percent increase). The calculations are summarized in Exhibit A-2. Total emissions for this segment are 7.2 $MMTCO_2e$.

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[39] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*

[40] *ORNL, Transportation Energy Data Book, Oak Ridge National Laboratory, U.S. Department of Energy, June 2010, http://cta.ornl.gov/data/index.shtml*

[41] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*

Exhibit A-2: Gas Industry Upstream Non-Gas Emissions

Energy Consumption (MMBtu)						
NAICS		Distillate	Gasoline	Other	Residual Oil	Undistributed
211111	Extraction	29,055,998	10,031,608	--	6,539,144	8,502,932
211112	NGL Extraction	288,585	352,861	66,627	--	168,613
213111	Drilling	10,014,334	3,808,638	551,713	3,967,479	5,446,747
213112	Support	20,671,552	13,157,404	893,604	7,166,105	4,389,137

CO_2 Emission Factors		Distillate	Gasoline	Other	Residual Oil	Other
		73.96	70.22	62.98	75.1	62.98

CO_2 Emissions ($MMTCO_2e$)						
211111	Extraction	2.1	0.7	0	0.5	0.5
211112	NGL Extraction	0	0	0	0	0
213111	Drilling	0.7	0.3	0	0.3	0.3
213112	Support	1.5	0.9	0.1	0.5	0.3

Gas Share of Emissions ($MMTCO_2e$)						
21111	Extraction	1.8	0.6	0	0.4	0.4
211112	NGL Extraction	0	0	0	0	0
213111	Drilling	0.4	0.1	0	0.2	0.2
213112	Support	1.3	0.8	0	0.4	0.2

Source: EPA, ORNL, Census Bureau, DBCCA Analysis 2011

Another adjustment is for methane emissions from "associated" gas produced from oil wells. Most oil wells produce gas, much of which is captured and delivered to consumers. The EPA *Inventory of U.S. GHG Emissions* estimates methane emissions from petroleum systems to be approximately 30 $MMTCO_2e$ per year.

Since some domestic natural gas is co-produced with petroleum, one could consider all of these emissions be included in the life-cycle analysis of emissions from the natural gas sector. However, the natural gas produced and the methane emissions are a byproduct of petroleum production. Methane emissions would occur even if no natural gas were captured and delivered for end-use consumption. In fact, the emissions might actually be higher in that case since there would be no economic incentive to capture the gas. One could also therefore maintain that it is not appropriate to count the methane emissions from petroleum production toward gas use, since they are independent of the production of gas and are related to petroleum consumption.

On the other hand, associated gas produced from oil wells is a significant segment of U.S. gross withdrawals of natural gas, and if there are methane emissions associated with that production, it seems appropriate to include them in the life-cycle analysis, even if the production is incidental to oil production. In that case, we have to evaluate how much of the methane emissions to allocate to gas production versus petroleum production.

The EPA inventory separates the methane emissions from petroleum systems at the wellhead oil separator. Methane emitted on the oil side downstream from the separator is allocated to the petroleum side, and methane emitted on the natural gas side is allocated to the natural gas side. The part that must be allocated here is the upstream production emissions, of which the largest components are miscellaneous venting and fugitives and venting from gas-powered pneumatic devices. The approach in this analysis is to simply allocate these emissions based on the energy value of oil versus gas produced from these wells.

According to the EIA, the gross production of natural gas from petroleum wells in 2008 was 5.7 trillion cubic feet (Tcf)[42]. However, much of this gas (3.3 Tcf) was not gathered for sale but was reinjected into the producing formation. Some of the gas is reinjected to push more oil out of the formation. Most of the reinjection (3.0 Tcf) is from Alaska production where there is no pipeline to bring the gas to market. It is reinjected as a means of storage until the time when a pipeline may be built to the lower 48 states. In any case, the associated gas actually produced for potential sale is 2.5 Tcf. On an energy basis, this is 20 percent energy value of the net associated gas plus the 1.8 billion barrels of U.S. oil production in 2008.

Of the methane emission sources in petroleum production, we include pneumatic device venting, combustion and process upsets, miscellaneous venting and fugitives, and wellhead fugitives. Tank venting is not included because it is purely related to oil production. Total methane emissions for these sources in 2008 were 25.6 MMTCO$_2$e, according to the EPA inventory. Taking 20 percent of this total gives 5.0 MMTCO$_2$e of additional methane emissions to allocate to the natural gas LCA, increasing the unadjusted emission baseline by 1.4 percent.

With these additions (electricity, non-gas fuel, and methane from petroleum systems), total upstream gas production emissions are 402.0 MMTCO$_2$e.

The total emissions are then adjusted for imports. The calculations above include emissions for U.S. production, but a net 13 percent of natural gas was imported in 2008. Of this, 11.7 percent was imported by pipeline from Mexico and Canada (mostly the latter). This analysis assumes that production processes are similar throughout North America, so the production emissions are escalated by 11.7 percent to account for the pipeline imports. The remaining 1.3 percent of imports were LNG imports. LNG has a higher LCA than conventional gas due to gasification, liquefaction, and transportation processes. The LCA for LNG is estimated at 176 percent of conventional gas based on the LCA performed by NETL[30] The production emissions for the LNG component are increased by this amount. The adjustment for imports is the largest adjustment, increasing the emissions by about 39 MMTCO$_2$e, or 10 percent.

The other adjustment in this analysis is related to fugitive methane emissions from gas distribution lines at local gas distribution companies (LDCs). Methane emissions from local distribution lines are 35.6 MMTCO$_2$e (at 25 GWP), but many power plants receive gas deliveries directly from interstate pipelines rather than via local distribution lines. Relatively few power plants actually purchase gas from LDCs, but some receive gas deliveries from the LDCs. The EIA-176 survey[43] provides data on deliveries by LDCs to electric generators; however, these reported deliveries total 6.5 Tcf, which is almost equal to total gas consumption for electricity generation. This is because intrastate pipeline deliveries in California, Texas, and Florida are included in the EIA-176 survey. Excluding these three states, 59 percent of gas to electric generators is delivered by LDCs. Based on this, only 59 percent of the distribution company methane emissions are included in the adjusted values. This adjustment decreases the emissions by about 17 MMTCO$_2$e, or 4 percent. Exhibit A-3 shows the adjusted final upstream GHG emissions for natural gas: 423.8 MMTCO$_2$e. Methane emissions account for more than half of the total.

Exhibit A-3: Adjusted Total Upstream GHG Emissions from Natural Gas for 2008, using EPA 2011 Methodology for Methane (MMTCO$_2$e)

	Methane	Non-Combustion CO$_2$	CO$_2$ and N$_2$O from Combustion	**Total**
Production	173.7	12.9	62.2	248.7
Processing	21.3	24.4	22.2	67.9
Transmission	51.5	0.1	37.2	88.8
Distribution	18.3	0.0	0.0	18.3
Total	264.9	37.4	121.5	423.8

These total emissions are then normalized to kg CO$_2$e/MMBtu of delivered natural gas based on the EIA data on natural gas delivered to consumers: 21.4 trillion cubic feet (Tcf). The total normalized upstream emissions are 19.2 kg CO$_2$e/MMBtu. (See Exhibit A-4.) The emissions for combustion of the gas at the point of use are 53.07 kg

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[42] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*

[43] *EIA, EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition", Energy Information Administration, U.S. Department of Energy. http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP1&CFID=5251631&CFTOKEN=51c7f7f0104e329d-3FD56B17-237D-DA68-24412047FB2CE3CB*

CO_2e/MMBtu (including N_2O and unburned methane), so the total life-cycle GHG emissions at the point of use are 70.4 kg CO_2e/MMBtu. Of this, the upstream emissions are 24 percent and methane is slightly over half of the upstream component.

Exhibit A-4: Normalized Life-cycle GHG Emissions for Natural Gas for 2008, using 2011 EPA Methodology for Methane (kg CO_2/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	7.9	0.6	2.8	11.3
Processing	1.0	1.1	1.0	3.1
Transmission	2.3	0.0	1.7	4.0
Distribution	0.8	0.0	0.0	0.8
Total Upstream	12.0	1.7	5.5	19.2
Fuel Combustion	0	0	53.1	53.1
Total	12.0	1.7	58.6	72.3

The same methodology is applied using EPA's 2010 estimate of methane emissions, to show the effect of the updated, increased 2011 methane emission estimate. Exhibits A-5 and A-6 show the total and normalized emissions for this case. The normalized upstream emissions with the old data are 12.0 kg CO_2e/MMBtu. Including the end-use gas combustion; total life-cycle emissions including end-use combustion are 65.1 kg CO_2/MMBtu, with the upstream portion accounting for 20 percent. In this case, methane makes up only about 40 percent of the upstream gas GHG footprint.

Exhibit A-5: Adjusted Total Upstream GHG Emissions from Natural Gas, 2008, using 2010 EPA Methodology for Methane (MMTCO_2e)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	25.9	9.7	62.2	97.8
Processing	17.7	24.4	22.2	64.2
Transmission	46.9	0.1	37.2	84.2
Distribution	18.3	0.0	0.0	18.3
Total	108.8	34.2	121.5	264.6

Exhibit A-6: Normalized Life-cycle GHG Emissions for Natural Gas for 2008, using 2010 EPA Methodology for Methane (kg CO_2/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	1.2	0.4	2.8	4.4
Processing	0.8	1.1	1.0	2.9
Transmission	2.1	0.0	1.7	3.8
Distribution	0.8	0.0	0.0	0.8
Upstream Total	4.9	1.6	5.5	12.0
Fuel Combustion	0	0	53.1	53.1
Total	4.9	1.6	58.6	65.1

Coal LCA

The upstream energy consumption for coal production is calculated using the 2007 Economic Census[44] data on fuel and electricity consumption in the same way as the non-gas fuel for gas production. In this case, there is a separate NAICS code for coal production, so no adjustments are necessary. The same CO_2 emission factors and the emission factor for electricity use are used as for the data on gas production. (See Exhibit A-7.) The values are adjusted from 2007 to 2008 based on the production in each year—a 2.2 percent increase. The total CO_2 emissions from energy consumption for coal production are 14.0 $MMTCO_2e$. Methane emissions from coal mines of 67.1 $MMTCO_2e$ (79.9 at 25 GWP) are taken from the EPA GHG inventory. Methane from abandoned coal mines is not included.

Exhibit A-7: Upstream GHG Calculation for Coal

	Coal	Distillate	Natural Gas	Gasoline	Residual Oil	Other	Electricity (MWh)
MMBtu	3,607,020	52,597,178	2,487,920	4,846,529	25,739,212	2,039,820	11,444,477
kg CO2/MMBtu	94.38	73.96	53.02	70.22	75.10	62.98	603.01
MMTCO2e	0.34	3.89	0.13	0.34	1.93	0.13	6.90

The estimate of transportation emissions is based on the Commodity Flow Summary[45] developed by the U.S. Department of Transportation and Census Bureau, which provides information on ton-miles of coal transported by different modes. Rail is the primary mode of transportation, with rail-only accounting for 91 percent of the ton-miles and rail and other modes (truck and barge) accounting for the remainder. This analysis applies a ton-mile fuel consumption factor[46, 47, 48] to calculate fuel consumption and converts the fuel consumption to CO_2 using the same EPA emission factors used for other sectors. (See Exhibit A-8.) For mixed mode, rail or barge are assumed to account for 75 percent of the ton-miles and truck for 50 percent. Most coal is delivered via dedicated equipment—e.g., a coal unit train travels only to and from the mine to the power plant. Thus, the fuel consumed in returning empty to the mine must be included. This analysis assumes 100-percent empty return as part of the energy consumption, with the empty fuel consumption being one-third of the loaded consumption based on the weight of the empty vehicle. The total consumption calculated is 23.9 $MMTCO_2$.

Exhibit A-8: GHG Calculation for Coal Transportation

Mode	Ton-Miles (million)	Fuel Consumption (ton-mi/gal)	GHG Emissions (MMTCO2)	Round-Trip Emissions (MMTCO2)
Truck	14,002	110.00	1.28	1.67
Rail	773,290	480.00	16.26	21.13
Water	6,548	730.00	0.09	0.12
Truck and rail	785	388.00	0.02	0.03
Truck and water	7,257	575.00	0.13	0.17
Rail and water	26,994	605.00	0.45	0.59
Other multiple modes	4,353	480.00	0.09	0.12
Other and unknown modes	2,567	480.00	0.05	0.07
Total	835,796	-	18.38	23.89

In the case of coal, the U.S. is a net exporter of about 4 percent of its production, so the total production emissions are adjusted downward by this amount to calculate the emissions attributable to coal consumed in the U.S. Exhibit A-9 shows the final adjusted upstream emissions: 117.8 $MMTCO_2e$.

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[44] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*

[45] *U.S. Department of Transportation, Research and Innovative Technology Administration, Bureau of Transportation Statistics and U.S. Census Bureau, 2007 Commodity Flow Survey.*

[46] *Federal Railroad Administration, "Comparative Evaluation of Rail and Truck Fuel Efficiency on Competitive Corridors", November 19, 2009.*

[47] *Army Corps of Engineers, "Waterborne Commerce Statistics Center", http://www.ndc.iwr.usace.army.mil//data/data1.htm*

[48] *American Railroad Association*

Exhibit A-9: Adjusted Total Upstream GHG Emissions from Coal, 2008 (MMTCO$_2$e)

	Methane	Non-Combustion CO$_2$	CO$_2$ and N$_2$O from Combustion	**Total**
Production	79.9	0.0	14.0	93.9
Transportation	0.0	0.0	23.9	23.9
Total	79.9	0.0	37.9	117.8

These values are then normalized by the total 2008 consumption of coal in the U.S. of 1,147 million tons of coal, assuming an average heating value of 10,250 Btu/lb.[49] This yields a normalized upstream emission factor of 4.3 kg CO$_2$/MMBtu consumed. (See Exhibit A-10.) The value is about 25 percent of the upstream emissions from natural gas. The emission factor for combustion of coal is 95.1 kg CO$_2$e/MMBtu, bringing the total end use life-cycle emissions to 99.9 kg CO$_2$/MMBtu. In this case, although methane is still 63 percent of the upstream emissions, the upstream component is only 4 percent of the total, with the CO$_2$ emissions from the coal itself being the dominant factor.

Exhibit A-10: Normalized Upstream GHG Emissions for Coal for 2008 (kg CO$_2$/MMBtu)

	Methane	CO$_2$ and N$_2$O from Combustion	**Total**
Production	3.3	0.6	3.9
Transportation	0.0	1.0	1.0
Total Upstream	3.3	1.5	4.8
Coal Combustion	0.0	95.1	95.1
End Use Total	3.3	96.6	99.9

Electricity Generation
The efficiency[50] of the electric generator is one of the most significant variables in estimating the GHG emissions per MWh of electricity. This analysis looks at two values:

- **National average efficiency values** based on EIA data[51, 52, 53, 54] for total gas or coal consumption for generation and total generation by each fuel. (See Exhibit A-11.)

- **Efficiency[55] for new power plants** assumed by the EIA in its *Annual Energy Outlook 2010*[38]. EIA provides a value for a new plant in 2009 and for subsequent plants ("nth plant") of each type for which the cost may be lower due to learning and production improvement. The values used here are the average of the values for a gas combined-cycle plant (6,998 Btu/kWh, 49 percent efficiency) and a new supercritical coal plant (8,970 Btu/kWh, 38 percent efficiency). (See Exhibit A-12.)

Exhibit A-11: Calculation of Average Power Plant Efficiencies

	Energy Consumption (Quads)	Generation (Billion kWh)	Heat Rate (Btu / kWh)	Efficiency
Gas	7	883.00	8,044.00	0.42
Coal	22	1,986.00	11,044.00	0.31

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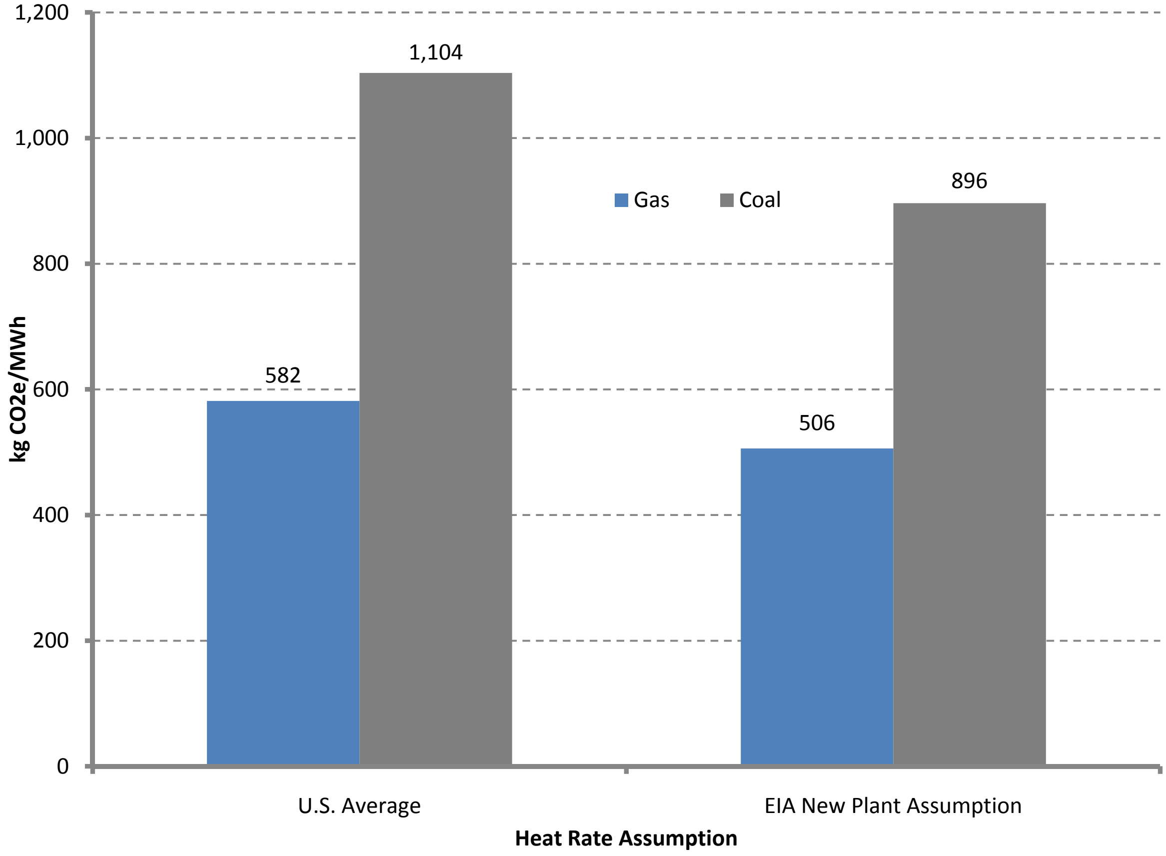
[49] *EIA, Annual Coal Data, Energy Information Administration, U.S. Department of Energy, http://www.eia.gov/totalenergy/data/annual/pdf/sec7_5.pdf*
[50] *The power industry uses efficiency and heat rate to express power plant efficiency. Heat rate is Btu/kWh = 3413/efficiency. A lower heat rate signifies a higher efficiency.*
[51] *EIA, Electric Power Monthly, Energy Information Administration, U.S. Department of Energy, http://www.eia.doe.gov/cneaf/electricity/epm/table2_4_a.html*
[52] *EIA, Electric Power Monthly, Energy Information Administration, U.S. Department of Energy, http://www.eia.doe.gov/aer/txt/ptb0802a.html*
[53] *EIA, Annual Energy Review, Energy Information Administration, U.S. Department of Energy, http://www.eia.doe.gov/cneaf/electricity/epm/table2_1_a.html*
[54] *EIA, Quarterly Coal Report, U.S. Department of Energy, http://www.eia.gov/cneaf/coal/quarterly/html/t32p01p1.pdf*

Exhibit A-12: Effect of Power Plant Heat Rate on Life-Cycle Emissions



Source: DBCCA analysis, 2011.

Appendix B
Effect of Global Warming Potential (GWP)

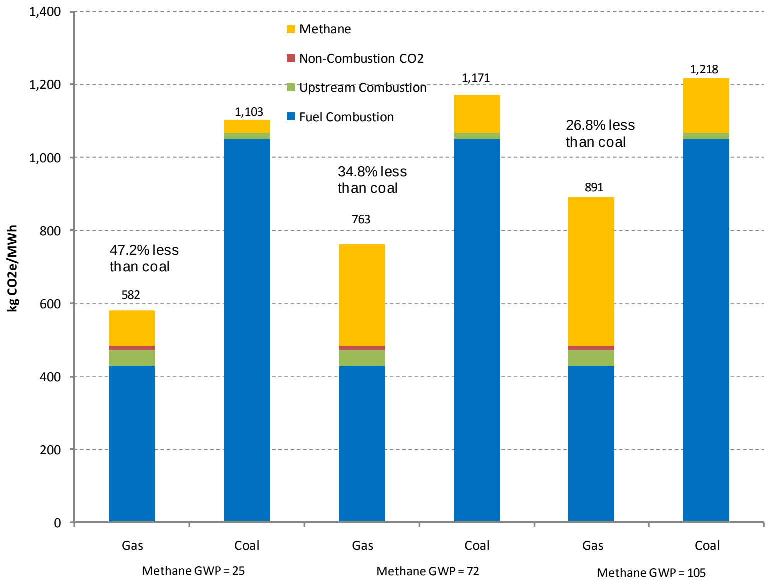
Methane is a potent GHG and its effect varies depending on the lifetime over which it is evaluated. The IPCC uses a 100 year lifetime for its analysis and a 100 year GWP of 25 for methane. Others believe that short-lived GHGs should be evaluated on a 20 year lifetime.

In its recently completed study on natural gas, MIT explains the reasons that a 100 GWP is commonly used:

> *"Because the various GHGs have different lives in the atmosphere (e.g., on the scale of a decade for methane, but centuries for CO_2), the calculation of GWPs depends on the integration period. Early studies calculated this index for 20-, 100- and 500-year integration periods. The IPCC decided to use the 100-year measure, and it is a procedure followed by the U.S. and other countries over several decades. An outlier in this domain is the Cornell study which recommends the application of the 20-year value in inter-fuel comparison. A 20-year GWP would emphasize the near-term impact of methane but ignore serious longer-term risks of climate change from GHGs that will remain in the atmosphere for hundreds to thousands of years, and the 500-year value would miss important effects over the current century. Methane is a more powerful GHG than CO_2, and its combination of potency and short life yields the 100-year GWP used in this study."*[56]

In addition, scientific work continues on the appropriate GWPs for different GHGs. Although the IPCC 20-year GWP for methane is 72, new work by Shindell et al[57] proposes a 20-year GWP of 105 for methane. Exhibit B-1 above shows the effect of different methane GWPs on the LCA using the EPA 2011 methodology. Since methane is a much larger component of the LCA for natural gas, the GWP has a much larger effect on gas than coal. Going from the 100 year GWP to the 20-year GWP of 72 increases life-cycle emissions for natural gas by 31 percent and for coal by only 6 percent. At the GWP of 72, the power plant emissions for natural gas are 35 percent lower than those for coal. At the 105 GWP, the emissions for the gas-fired plant are 27 percent lower than those for coal.

Exhibit B-1: Effect of Methane GWP on Life-Cycle Emissions



Source: DBCCA Analysis 2011

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[56] *The Future of Natural Gas, Moniz, Ernest J.; Jacoby, Henry D.; Meggs, Anthony J.M. (Study co-chairs), MIT Energy Initiative, 2011.*
[57] *Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, Bauer SE (2009) Improved attribution of climate forcing to emissions. Science 326:716–718*

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LETTER

Methane and the greenhouse-gas footprint of natural gas from shale formations

A letter

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Abstract We evaluate the greenhouse gas footprint of natural gas obtained by high-volume hydraulic fracturing from shale formations, focusing on methane emissions. Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of shale gas on shorter time scales, dominating it on a 20-year time horizon. The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.

Keywords Methane · Greenhouse gases · Global warming · Natural gas · Shale gas · Unconventional gas · Fugitive emissions · Lifecycle analysis · LCA · Bridge fuel · Transitional fuel · Global warming potential · GWP

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Many view natural gas as a transitional fuel, allowing continued dependence on fossil fuels yet reducing greenhouse gas (GHG) emissions compared to oil or coal over coming decades (Pacala and Socolow 2004). Development of "unconventional" gas dispersed in shale is part of this vision, as the potential resource may be large, and in many regions conventional reserves are becoming depleted (Wood et al. 2011). Domestic production in the U.S. was predominantly from conventional reservoirs through the 1990s, but by 2009 U.S. unconventional production exceeded that of conventional gas. The Department of Energy predicts that by 2035 total domestic production will grow by 20%, with unconventional gas providing 75% of the total (EIA 2010a). The greatest growth is predicted for shale gas, increasing from 16% of total production in 2009 to an expected 45% in 2035.

Although natural gas is promoted as a bridge fuel over the coming few decades, in part because of its presumed benefit for global warming compared to other fossil fuels, very little is known about the GHG footprint of unconventional gas. Here, we define the GHG footprint as the total GHG emissions from developing and using the gas, expressed as equivalents of carbon dioxide, per unit of energy obtained during combustion. The GHG footprint of shale gas has received little study or scrutiny, although many have voiced concern. The National Research Council (2009) noted emissions from shale-gas extraction may be greater than from conventional gas. The Council of Scientific Society Presidents (2010) wrote to President Obama, warning that some potential energy bridges such as shale gas have received insufficient analysis and may aggravate rather than mitigate global warming. And in late 2010, the U.S. Environmental Protection Agency issued a report concluding that fugitive emissions of methane from unconventional gas may be far greater than for conventional gas (EPA 2010).

Fugitive emissions of methane are of particular concern. Methane is the major component of natural gas and a powerful greenhouse gas. As such, small leakages are important. Recent modeling indicates methane has an even greater global warming potential than previously believed, when the indirect effects of methane on atmospheric aerosols are considered (Shindell et al. 2009). The global methane budget is poorly constrained, with multiple sources and sinks all having large uncertainties. The radiocarbon content of atmospheric methane suggests fossil fuels may be a far larger source of atmospheric methane than generally thought (Lassey et al. 2007).

The GHG footprint of shale gas consists of the direct emissions of CO_2 from end-use consumption, indirect emissions of CO_2 from fossil fuels used to extract, develop, and transport the gas, and methane fugitive emissions and venting. Despite the high level of industrial activity involved in developing shale gas, the indirect emissions of CO_2 are relatively small compared to those from the direct combustion of the fuel: 1 to 1.5 g C MJ^{-1} (Santoro et al. 2011) vs 15 g C MJ^{-1} for direct emissions (Hayhoe et al. 2002). Indirect emissions from shale gas are estimated to be only 0.04 to 0.45 g C MJ^{-1} greater than those for conventional gas (Wood et al. 2011). Thus, for both conventional and shale gas, the GHG footprint is dominated by the direct CO_2 emissions and fugitive methane emissions. Here we present estimates for methane emissions as contributors to the GHG footprint of shale gas compared to conventional gas.

Our analysis uses the most recently available data, relying particularly on a technical background document on GHG emissions from the oil and gas industry (EPA 2010) and materials discussed in that report, and a report on natural gas losses on federal lands from the General Accountability Office (GAO 2010). The

EPA (2010) report is the first update on emission factors by the agency since 1996 (Harrison et al. 1996). The earlier report served as the basis for the national GHG inventory for the past decade. However, that study was not based on random sampling or a comprehensive assessment of actual industry practices, but rather only analyzed facilities of companies that voluntarily participated (Kirchgessner et al. 1997). The new EPA (2010) report notes that the 1996 “study was conducted at a time when methane emissions were not a significant concern in the discussion about GHG emissions” and that emission factors from the 1996 report “are outdated and potentially understated for some emissions sources.” Indeed, emission factors presented in EPA (2010) are much higher, by orders of magnitude for some sources.

1 Fugitive methane emissions during well completion

Shale gas is extracted by high-volume hydraulic fracturing. Large volumes of water are forced under pressure into the shale to fracture and re-fracture the rock to boost gas flow. A significant amount of this water returns to the surface as flow-back within the first few days to weeks after injection and is accompanied by large quantities of methane (EPA 2010). The amount of methane is far more than could be dissolved in the flow-back fluids, reflecting a mixture of fracture-return fluids and methane gas. We have compiled data from 2 shale gas formations and 3 tight-sand gas formations in the U.S. Between 0.6% and 3.2% of the life-time production of gas from wells is emitted as methane during the flow-back period (Table 1). We include tight-sand formations since flow-back emissions and the patterns of gas production over time are similar to those for shale (EPA 2010). Note that the rate of methane emitted during flow-back (column B in Table 1) correlates well to the initial production rate for the well following completion (column C in Table 1). Although the data are limited, the variation across the basins seems reasonable: the highest methane emissions during flow-back were in the Haynesville, where initial pressures and initial production were very high, and the lowest emissions were in the Uinta, where the flow-back period was the shortest and initial production following well completion was low. However, we note that the data used in Table 1 are not well documented, with many values based on PowerPoint slides from EPA-sponsored workshops. For this paper, we therefore choose to represent gas losses from flow-back fluids as the mean value from Table 1: 1.6%.

More methane is emitted during “drill-out,” the stage in developing unconventional gas in which the plugs set to separate fracturing stages are drilled out to release gas for production. EPA (2007) estimates drill-out emissions at 142×10^3 to 425×10^3 m^3 per well. Using the mean drill-out emissions estimate of 280×10^3 m^3 (EPA 2007) and the mean life-time gas production for the 5 formations in Table 1 (85×10^6 m^3), we estimate that 0.33% of the total life-time production of wells is emitted as methane during the drill-out stage. If we instead use the average life-time production for a larger set of data on 12 formations (Wood et al. 2011), 45×10^6 m^3, we estimate a percentage emission of 0.62%. More effort is needed to determine drill-out emissions on individual formation. Meanwhile, in this paper we use the conservative estimate of 0.33% for drill-out emissions.

Combining losses associated with flow-back fluids (1.6%) and drill out (0.33%), we estimate that 1.9% of the total production of gas from an unconventional shale-gas

Table 1 Methane emissions during the flow-back period following hydraulic fracturing, initial gas production rates following well completion, life-time gas production of wells, and the methane emitted during flow-back expressed as a percentage of the life-time production for five unconventional wells in the United States

	(A) Methane emitted during flow-back (10^3 m^3)[a]	(B) Methane emitted per day during flow-back (10^3 m^3 day^{-1})[b]	(C) Initial gas production at well completion (10^3 m^3 day^{-1})[c]	(D) Life-time production of well (10^6 m^3)[d]	(E) Methane emitted during flow-back as % of life-time production[e]
Haynesville (Louisiana, shale)	6,800	680	640	210	3.2
Barnett (Texas, shale)	370	41	37	35	1.1
Piceance (Colorado, tight sand)	710	79	57	55	1.3
Uinta (Utah, tight sand)	255	51	42	40	0.6
Den-Jules (Colorado, tight sand)	140	12	11	?	?

Flow-back is the return of hydraulic fracturing fluids to the surface immediately after fracturing and before well completion. For these wells, the flow-back period ranged from 5 to 12 days

[a] Haynesville: average from Eckhardt et al. (2009); Piceance: EPA (2007); Barnett: EPA (2004); Uinta: Samuels (2010); Denver-Julesburg: Bracken (2008)

[b] Calculated by dividing the total methane emitted during flow-back (column A) by the duration of flow-back. Flow-back durations were 9 days for Barnett (EPA 2004), 8 days for Piceance (EPA 2007), 5 days for Uinta (Samuels 2010), and 12 days for Denver-Julesburg (Bracken 2008); median value of 10 days for flow-back was assumed for Haynesville

[c] Haynesville: http://shale.typepad.com/haynesvilleshale/2009/07/chesapeake-energy-haynesville-shale-decline-curve.html1/7/2011 and http://oilshalegas.com/haynesvilleshalestocks.html; Barnett: http://oilshalegas.com/barnettshale.html; Piceance: Kruuskraa (2004) and Henke (2010); Uinta: http://www.epmag.com/archives/newsComments/6242.htm; Denver-Julesburg: http://www.businesswire.com/news/home/20100924005169/en/Synergy-Resources-Corporation-Reports-Initial-Production-Rates

[d] Based on averages for these basins. Haynesville: http://shale.typepad.com/haynesvilleshale/decline-curve/); Barnett: http://www.aapg.org/explorer/2002/07jul/barnett_shale.cfm and Wood et al. (2011); Piceance: Kruuskraa (2004); Uinta: http://www.epmag.com/archives/newsComments/6242.htm

[e] Calculated by dividing column (A) by column (D)

Table 2 Fugitive methane emissions associated with development of natural gas from conventional wells and from shale formations (expressed as the percentage of methane produced over the lifecycle of a well)

	Conventional gas	Shale gas
Emissions during well completion	0.01%	1.9%
Routine venting and equipment leaks at well site	0.3 to 1.9%	0.3 to 1.9%
Emissions during liquid unloading	0 to 0.26%	0 to 0.26%
Emissions during gas processing	0 to 0.19%	0 to 0.19%
Emissions during transport, storage, and distribution	1.4 to 3.6%	1.4 to 3.6%
Total emissions	1.7 to 6.0%	3.6 to 7.9%

See text for derivation of estimates and supporting information

well is emitted as methane during well completion (Table 2). Again, this estimate is uncertain but conservative.

Emissions are far lower for conventional natural gas wells during completion, since conventional wells have no flow-back and no drill out. An average of 1.04×10^3 m^3 of methane is released per well completed for conventional gas (EPA 2010), corresponding to 1.32×10^3 m^3 natural gas (assuming 78.8% methane content of the gas). In 2007, 19,819 conventional wells were completed in the US (EPA 2010), so we estimate a total national emission of 26×10^6 m^3 natural gas. The total national production of onshore conventional gas in 2007 was 384×10^9 m^3 (EIA 2010b). Therefore, we estimate the average fugitive emissions at well completion for conventional gas as 0.01% of the life-time production of a well (Table 2), three orders of magnitude less than for shale gas.

2 Routine venting and equipment leaks

After completion, some fugitive emissions continue at the well site over its lifetime. A typical well has 55 to 150 connections to equipment such as heaters, meters, dehydrators, compressors, and vapor-recovery apparatus. Many of these potentially leak, and many pressure relief valves are designed to purposefully vent gas. Emissions from pneumatic pumps and dehydrators are a major part of the leakage (GAO 2010). Once a well is completed and connected to a pipeline, the same technologies are used for both conventional and shale gas; we assume that these post-completion fugitive emissions are the same for shale and conventional gas. GAO (2010) concluded that 0.3% to 1.9% of the life-time production of a well is lost due to routine venting and equipment leaks (Table 2). Previous studies have estimated routine well-site fugitive emissions as approximately 0.5% or less (Hayhoe et al. 2002; Armendariz 2009) and 0.95% (Shires et al. 2009). Note that none of these estimates include accidents or emergency vents. Data on emissions during emergencies are not available and have never, as far as we can determine, been used in any estimate of emissions from natural gas production. Thus, our estimate of 0.3% to 1.9% leakage is conservative. As we discuss below, the 0.3% reflects use of best available technology.

Additional venting occurs during “liquid unloading.” Conventional wells frequently require multiple liquid-unloading events as they mature to mitigate water intrusion as reservoir pressure drops. Though not as common, some unconventional wells may also require unloading. Empirical data from 4 gas basins indicate that 0.02

to 0.26% of total life-time production of a well is vented as methane during liquid unloading (GAO 2010). Since not all wells require unloading, we set the range at 0 to 0.26% (Table 2).

3 Processing losses

Some natural gas, whether conventional or from shale, is of sufficient quality to be "pipeline ready" without further processing. Other gas contains sufficient amounts of heavy hydrocarbons and impurities such as sulfur gases to require removal through processing before the gas is piped. Note that the quality of gas can vary even within a formation. For example, gas from the Marcellus shale in northeastern Pennsylvania needs little or no processing, while gas from southwestern Pennsylvania must be processed (NYDEC 2009). Some methane is emitted during this processing. The default EPA facility-level fugitive emission factor for gas processing indicates a loss of 0.19% of production (Shires et al. 2009). We therefore give a range of 0% (i.e. no processing, for wells that produce "pipeline ready" gas) to 0.19% of gas produced as our estimate of processing losses (Table 2). Actual measurements of processing plant emissions in Canada showed fourfold greater leakage than standard emission factors of the sort used by Shires et al. (2009) would indicate (Chambers 2004), so again, our estimates are very conservative.

4 Transport, storage, and distribution losses

Further fugitive emissions occur during transport, storage, and distribution of natural gas. Direct measurements of leakage from transmission are limited, but two studies give similar leakage rates in both the U.S. (as part of the 1996 EPA emission factor study; mean value of 0.53%; Harrison et al. 1996; Kirchgessner et al. 1997) and in Russia (0.7% mean estimate, with a range of 0.4% to 1.6%; Lelieveld et al. 2005). Direct estimates of distribution losses are even more limited, but the 1996 EPA study estimates losses at 0.35% of production (Harrison et al. 1996; Kirchgessner et al. 1997). Lelieveld et al. (2005) used the 1996 emission factors for natural gas storage and distribution together with their transmission estimates to suggest an overall average loss rate of 1.4% (range of 1.0% to 2.5%). We use this 1.4% leakage as the likely lower limit (Table 2). As noted above, the EPA 1996 emission estimates are based on limited data, and Revkin and Krauss (2009) reported "government scientists and industry officials caution that the real figure is almost certainly higher." Furthermore, the IPCC (2007) cautions that these "bottom-up" approaches for methane inventories often underestimate fluxes.

Another way to estimate pipeline leakage is to examine "lost and unaccounted for gas," e.g. the difference between the measured volume of gas at the wellhead and that actually purchased and used by consumers. At the global scale, this method has estimated pipeline leakage at 2.5% to 10% (Crutzen 1987; Cicerone and Oremland 1988; Hayhoe et al. 2002), although the higher value reflects poorly maintained pipelines in Russia during the Soviet collapse, and leakages in Russia are now far less (Lelieveld et al. 2005; Reshetnikov et al. 2000). Kirchgessner et al. (1997) argue against this approach, stating it is "subject to numerous errors including gas theft, variations in temperature and pressure, billing cycle differences, and meter inaccuracies." With the exception of theft, however, errors should be randomly distributed and should not bias the leakage estimate high or low. Few recent data on lost and unaccounted gas are publicly available, but statewide data for Texas averaged 2.3% in 2000 and 4.9% in 2007 (Percival 2010). In 2007, the State of Texas passed new legislation to regulate lost and unaccounted for gas; the legislation originally proposed a 5% hard cap which was dropped in the face of industry opposition (Liu 2008; Percival 2010). We take the mean of the 2000 and 2007 Texas data for missing and unaccounted gas (3.6%) as the upper limit of downstream losses (Table 2), assuming that the higher value for 2007 and lower value for 2000 may potentially reflect random variation in billing cycle differences. We believe this is a conservative upper limit, particularly given the industry resistance to a 5% hard cap.

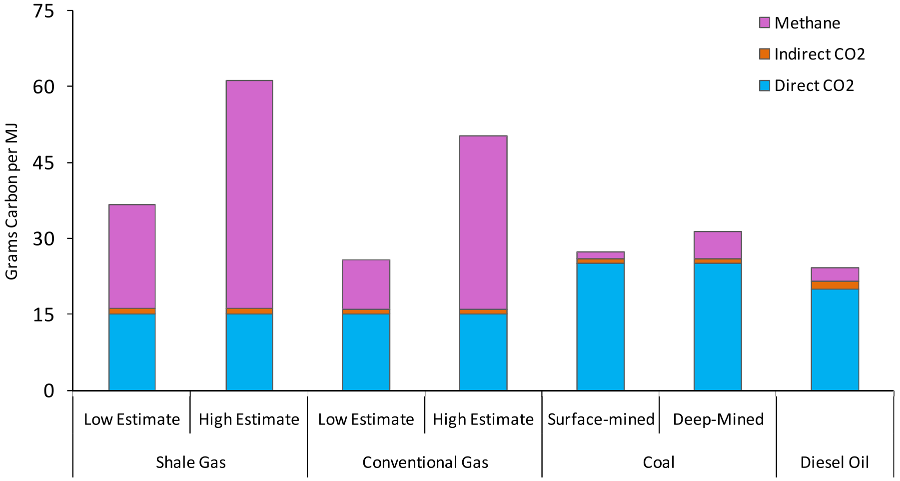
Our conservative estimate of 1.4% to 3.6% leakage of gas during transmission, storage, and distribution is remarkably similar to the 2.5% "best estimate" used by Hayhoe et al. (2002). They considered the possible range as 0.2% and 10%.

5 Contribution of methane emissions to the GHG footprints of shale gas and conventional gas

Summing all estimated losses, we calculate that during the life cycle of an average shale-gas well, 3.6 to 7.9% of the total production of the well is emitted to the atmosphere as methane (Table 2). This is at least 30% more and perhaps more than twice as great as the life-cycle methane emissions we estimate for conventional gas, 1.7% to 6%. Methane is a far more potent GHG than is CO_2, but methane also has a tenfold shorter residence time in the atmosphere, so its effect on global warming attenuates more rapidly (IPCC 2007). Consequently, to compare the global warming potential of methane and CO_2 requires a specific time horizon. We follow Lelieveld et al. (2005) and present analyses for both 20-year and 100-year time horizons. Though the 100-year horizon is commonly used, we agree with Nisbet et al. (2000) that the 20-year horizon is critical, given the need to reduce global warming in coming decades (IPCC 2007). We use recently modeled values for the global warming potential of methane compared to CO_2: 105 and 33 on a mass-to-mass basis for 20 and 100 years, respectively, with an uncertainty of plus or minus 23% (Shindell et al. 2009). These are somewhat higher than those presented in the 4th assessment report of the IPCC (2007), but better account for the interaction of methane with aerosols. Note that carbon-trading markets use a lower global-warming potential yet of only 21 on the 100-year horizon, but this is based on the 2nd IPCC (1995) assessment, which is clearly out of date on this topic. See Electronic Supplemental Materials for the methodology for calculating the effect of methane on GHG in terms of CO_2 equivalents.

Methane dominates the GHG footprint for shale gas on the 20-year time horizon, contributing 1.4- to 3-times more than does direct CO_2 emission (Fig. 1a). At this time scale, the GHG footprint for shale gas is 22% to 43% greater than that for conventional gas. When viewed at a time 100 years after the emissions, methane emissions still contribute significantly to the GHG footprints, but the effect is diminished by the relatively short residence time of methane in the atmosphere. On this time frame, the GHG footprint for shale gas is 14% to 19% greater than that for conventional gas (Fig. 1b).

A. 20-year time horizon



B. 100-year time horizon

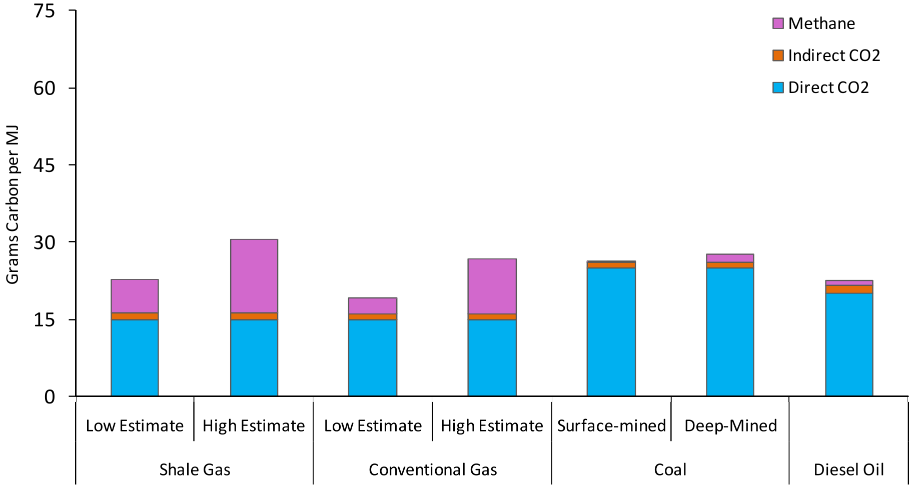


Fig. 1 Comparison of greenhouse gas emissions from shale gas with low and high estimates of fugitive methane emissions, conventional natural gas with low and high estimates of fugitive methane emissions, surface-mined coal, deep-mined coal, and diesel oil. **a** is for a 20-year time horizon, and **b** is for a 100-year time horizon. Estimates include direct emissions of CO_2 during combustion (*blue bars*), indirect emissions of CO_2 necessary to develop and use the energy source (*red bars*), and fugitive emissions of methane, converted to equivalent value of CO_2 as described in the text (*pink bars*). Emissions are normalized to the quantity of energy released at the time of combustion. The conversion of methane to CO_2 equivalents is based on global warming potentials from Shindell et al. (2009) that include both direct and indirect influences of methane on aerosols. Mean values from Shindell et al. (2009) are used here. Shindell et al. (2009) present an uncertainty in these mean values of plus or minus 23%, which is not included in this figure

6 Shale gas versus other fossil fuels

Considering the 20-year horizon, the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal when expressed per quantity of energy available during combustion (Fig. 1a; see Electronic Supplemental Materials for derivation of the estimates for diesel oil and coal). Over the 100-year frame, the GHG footprint is comparable to that for coal: the low-end shale-gas emissions are 18% lower than deep-mined coal, and the high-end shale-gas emissions are 15% greater than surface-mined coal emissions (Fig. 1b). For the 20 year horizon, the GHG footprint of shale gas is at least 50% greater than for oil, and perhaps 2.5-times greater. At the 100-year time scale, the footprint for shale gas is similar to or 35% greater than for oil.

We know of no other estimates for the GHG footprint of shale gas in the peer-reviewed literature. However, we can compare our estimates for conventional gas with three previous peer-reviewed studies on the GHG emissions of conventional natural gas and coal: Hayhoe et al. (2002), Lelieveld et al. (2005), and Jamarillo et al. (2007). All concluded that GHG emissions for conventional gas are less than for coal, when considering the contribution of methane over 100 years. In contrast, our analysis indicates that conventional gas has little or no advantage over coal even over the 100-year time period (Fig. 1b). Our estimates for conventional-gas methane emissions are in the range of those in Hayhoe et al. (2002) but are higher than those in Lelieveld et al. (2005) and Jamarillo et al. (2007) who used 1996 EPA emission factors now known to be too low (EPA 2010). To evaluate the effect of methane, all three of these studies also used global warming potentials now believed to be too low (Shindell et al. 2009). Still, Hayhoe et al. (2002) concluded that under many of the scenarios evaluated, a switch from coal to conventional natural gas could aggravate global warming on time scales of up to several decades. Even with the lower global warming potential value, Lelieveld et al. (2005) concluded that natural gas has a greater GHG footprint than oil if methane emissions exceeded 3.1% and worse than coal if the emissions exceeded 5.6% on the 20-year time scale. They used a methane global warming potential value for methane from IPCC (1995) that is only 57% of the new value from Shindell et al. (2009), suggesting that in fact methane emissions of only 2% to 3% make the GHG footprint of conventional gas worse than oil and coal. Our estimates for fugitive shale-gas emissions are 3.6 to 7.9%.

Our analysis does not consider the efficiency of final use. If fuels are used to generate electricity, natural gas gains some advantage over coal because of greater efficiencies of generation (see Electronic Supplemental Materials). However, this does not greatly affect our overall conclusion: the GHG footprint of shale gas approaches or exceeds coal even when used to generate electricity (Table in Electronic Supplemental Materials). Further, shale-gas is promoted for other uses, including as a heating and transportation fuel, where there is little evidence that efficiencies are superior to diesel oil.

7 Can methane emissions be reduced?

The EPA estimates that ’green’ technologies can reduce gas-industry methane emissions by 40% (GAO 2010). For instance, liquid-unloading emissions can be greatly reduced with plunger lifts (EPA 2006; GAO 2010); industry reports a 99% venting reduction in the San Juan basin with the use of smart-automated plunger lifts (GAO 2010). Use of flash-tank separators or vapor recovery units can reduce dehydrator emissions by 90% (Fernandez et al. 2005). Note, however, that our lower range of estimates for 3 out of the 5 sources as shown in Table 2 already reflect the use of best technology: 0.3% lower-end estimate for routine venting and leaks at well sites (GAO 2010), 0% lower-end estimate for emissions during liquid unloading, and 0% during processing.

Methane emissions during the flow-back period in theory can be reduced by up to 90% through Reduced Emission Completions technologies, or REC (EPA 2010). However, REC technologies require that pipelines to the well are in place prior to completion, which is not always possible in emerging development areas. In any event, these technologies are currently not in wide use (EPA 2010).

If emissions during transmission, storage, and distribution are at the high end of our estimate (3.6%; Table 2), these could probably be reduced through use of better storage tanks and compressors and through improved monitoring for leaks. Industry has shown little interest in making the investments needed to reduce these emission sources, however (Percival 2010).

Better regulation can help push industry towards reduced emissions. In reconciling a wide range of emissions, the GAO (2010) noted that lower emissions in the Piceance basin in Colorado relative to the Uinta basin in Utah are largely due to a higher use of low-bleed pneumatics in the former due to stricter state regulations.

8 Conclusions and implications

The GHG footprint of shale gas is significantly larger than that from conventional gas, due to methane emissions with flow-back fluids and from drill out of wells during well completion. Routine production and downstream methane emissions are also large, but are the same for conventional and shale gas. Our estimates for these routine and downstream methane emission sources are within the range of those reported by most other peer-reviewed publications inventories (Hayhoe et al. 2002; Lelieveld et al. 2005). Despite this broad agreement, the uncertainty in the magnitude of fugitive emissions is large. Given the importance of methane in global warming, these emissions deserve far greater study than has occurred in the past. We urge both more direct measurements and refined accounting to better quantify lost and unaccounted for gas.

The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming. We do not intend that our study be used to justify the continued use of either oil or coal, but rather to demonstrate that substituting shale gas for these other fossil fuels may not have the desired effect of mitigating climate warming.

Finally, we note that carbon-trading markets at present under-value the greenhouse warming consequences of methane, by focusing on a 100-year time horizon and by using out-of-date global warming potentials for methane. This should be corrected, and the full GHG footprint of unconventional gas should be used in planning for alternative energy futures that adequately consider global climate change.

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Life cycle greenhouse gas emissions of Marcellus shale gas

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Abstract

This study estimates the life cycle greenhouse gas (GHG) emissions from the production of Marcellus shale natural gas and compares its emissions with national average US natural gas emissions produced in the year 2008, prior to any significant Marcellus shale development. We estimate that the development and completion of a typical Marcellus shale well results in roughly 5500 t of carbon dioxide equivalent emissions or about 1.8 g CO_2e/MJ of gas produced, assuming conservative estimates of the production lifetime of a typical well. This represents an 11% increase in GHG emissions relative to average domestic gas (excluding combustion) and a 3% increase relative to the life cycle emissions when combustion is included. The life cycle GHG emissions of Marcellus shale natural gas are estimated to be 63–75 g CO_2e/MJ of gas produced with an average of 68 g CO_2e/MJ of gas produced. Marcellus shale natural gas GHG emissions are comparable to those of imported liquefied natural gas. Natural gas from the Marcellus shale has generally lower life cycle GHG emissions than coal for production of electricity in the absence of any effective carbon capture and storage processes, by 20–50% depending upon plant efficiencies and natural gas emissions variability. There is significant uncertainty in our Marcellus shale GHG emission estimates due to eventual production volumes and variability in flaring, construction and transportation.

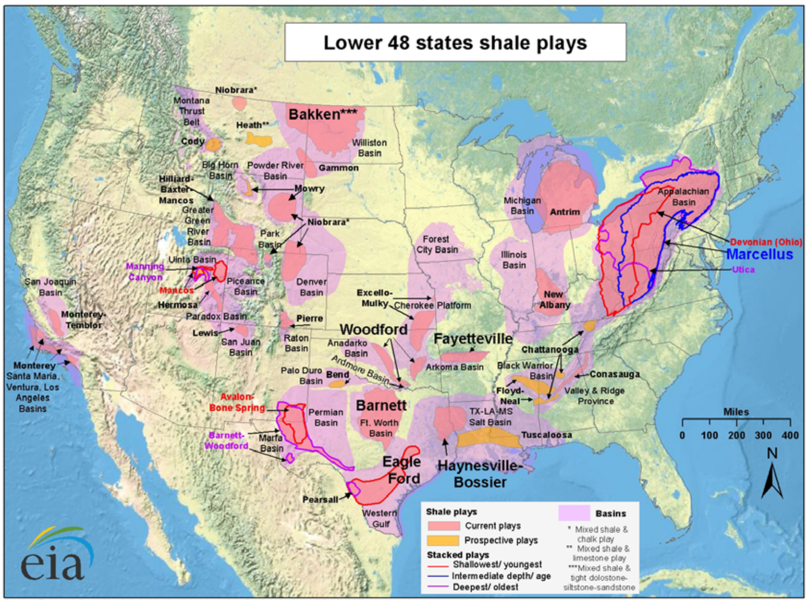
Keywords: life cycle assessment, greenhouse gases, Marcellus shale, natural gas

S Online supplementary data available from stacks.iop.org/ERL/6/034014/mmedia

1. Introduction

Marcellus shale is a rapidly developing new source of US domestic natural gas. The Appalachian Basin Marcellus shale extends from southern New York through the western portion of Pennsylvania and into the eastern half of Ohio and northern West Virginia (Kargbo *et al* 2010). The estimated basin area is between 140 000 and 250 000 km^2 (Kargbo *et al* 2010), and has a depth ranging from 1200 to 2600 m (US DOE 2009). The shale seam's net thickness ranges from 15 to 60 m (US DOE 2009) and is generally thicker from west to east (Hill *et al* 2004). Figure 1 shows the location of the Marcellus and other shale gas formations in the continental United States.

Shale gas has become an important component of the current US natural gas production mix. In 2009, shale gas was 16% of the 21 trillion cubic feet (Tcf) or 600 million cubic meters (Mm^3) total dry gas produced (US EIA 2011a, 2011b). In 2035, the EIA expects the share to increase to 47% (12 Tcf or 340 Mm^3) of total gas production. The prospect of rapid shale gas development has resulted in interest in expanding



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Figure 1. Shale gas plays and basins in the 48 states (source: US Energy Information Administration 2011a, available at http://www.eia.gov/oil_gas/rpd/shale_gas.jpg).

natural gas use including increased natural gas fired electricity generation, use as an alternative transportation fuel, and even exporting as liquefied natural gas. To date most shale gas activity has been in the Barnett shale in Texas. However, the immense potential of the Marcellus shale has stimulated increased attention. The shale play has an estimated gas-in-place of 1500 Tcf or 42 000 Mm^3, of which 262–500 Tcf or 7400–14 000 Mm^3 are thought to be recoverable (Hill *et al* 2004, US DOE 2009).

Advancements in horizontal drilling and hydraulic fracturing, demonstrated successfully in the Barnett shale and first applied in the Marcellus shale in 2004, have enabled the recovery of economical levels of Marcellus shale gas. After vertical drilling reaches the depth of the shale, the shale formation is penetrated horizontally with lateral lengths extending thousands of feet to ensure maximum contact with the gas-bearing seam. Hydraulic fracturing is then used to increase permeability that in turn increases the gas flow.

In this study, life cycle greenhouse gas (GHG) emissions associated with the Marcellus shale gas production are estimated. The difference between GHG emissions of natural gas production from unconventional Marcellus gas wells and average domestic wells is considered to help determine the environmental impacts of the development of shale gas resources. The results of this analysis are compared with life cycle GHG emissions of average domestic natural gas pre-Marcellus and imported liquefied natural gas. In addition domestic coal and Marcellus shale for electricity generation are compared. Other environmental issues may also be of concern in the Marcellus shale development, including disruption of natural habitats, the use of water and creation of wastewater as well as the impacts of truck transport in rural areas. However these environmental issues are outside the scope of our analysis and are not addressed in this paper.

In estimating GHG emissions, we include GHG emissions of carbon dioxide, methane and nitrous oxide. We converted the GHG emissions to carbon dioxide equivalents according to the global warming potential (GWP) factors reported by IPCC. We use the 100-year GWP factor, in which methane has a global warming potential (GWP) 25 times higher than carbon dioxide (IPCC 2007).

2. Marcellus shale gas analysis boundaries and functional unit

The boundary of our analysis and the major process steps included in our estimates are shown in figure 2. Final life cycle emission estimates are reported in grams of carbon dioxide equivalent emissions per megajoule of natural gas ($\mathrm{g\ CO_2e/MJ}$) produced. Each of the individual processes in the natural gas life cycle has an associated upstream supply chain and is included in this study to provide a full assessment of GHG emissions associated with Marcellus shale gas. The sources of GHG emissions considered in the LCA include: emissions from the production and transportation of material involved in the well development activities (such as trucking water); emissions from fuel consumption for powering the drilling and fracturing equipment; methane leaks and fuel combustion emissions associated with gas production, processing, transmission, distribution, and natural gas combustion.

The life cycle of Marcellus shale natural gas begins with a ‘preproduction phase’ that includes the well site investigation, preparation of the well pad including grading and construction of the well pad and access roads, drilling, hydraulic fracturing, and well completion (Soeder and Kappel 2009). After this preproduction phase is completed, the well becomes operational and starts producing natural gas. This natural gas can require additional processing to remove water, CO_2 and/or

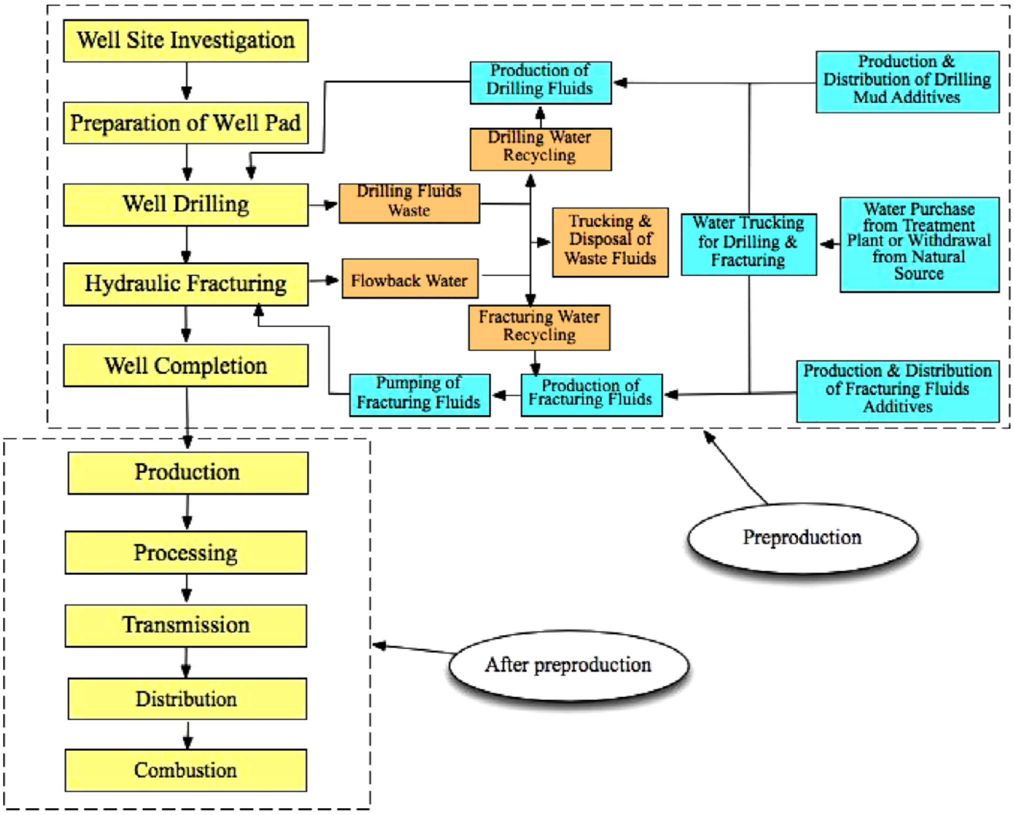


Figure 2. Analysis boundaries and gas production processes.

natural gas liquids before it enters the natural gas transmission and distribution system, which delivers it to final end users. For this work we assume that the GHG emissions for production, transmission, distribution and combustion of Marcellus shale natural gas are similar to average domestic gas sources as estimated by Jaramillo *et al* (2007) and further developed and updated by Venkatesh *et al* (2011).

Finally, natural gas has many current and potential uses including electricity generation, chemical feedstock, and as a transportation fuel. Modeling these uses allows comparisons of different primary energy sources. Here we model its use for power generation since it is the largest single use of natural gas in the US (US EIA 2011a, 2011b).

As previously mentioned, this study integrates GHG emissions from the life cycle of water associated with Marcellus shale gas production. Large amounts of water are consumed in the drilling and hydraulic fracturing processes (preproduction phase). Hydraulic fracturing uses fluid pressure to fracture the surrounding shale. The fracturing fluid consists of water mixed with a number of additives necessary to successfully fracture the shale seam. The source of the water varies and can be surface or ground water, purchased from a local public water supplier, or reused fracturing water. In this study we assume 45% of the water is reused on site and the original sources are surface water (50%) and purchased from a local water treatment plant (50%). Regardless of the water source used to produce the hydraulic fracturing fluid, trucks transport the water for impoundment at the well pad. In addition, flowback water (hydraulic fracturing fluid that returns to the surface) and produced water must be trucked to the final disposal site. This water is assumed to be disposed of via deep well injection. A detailed description of the method and data sources used to estimate the GHG emissions associated with all these stages is presented in section 3.

Marcellus shale gas production is in its infancy. Thus, industry practice is evolving and even single well longevity is unknown. Assumptions related to production rates and ultimate recovery have considerable uncertainty. Below, we include a sensitivity analysis for a wide range of inputs parameters.

This study does not consider any GHG emissions outside of the Marcellus shale gas preproduction and production processes. Natural processes or development actions such as hydraulic fracturing might lead to emissions of the shale gas external to a well, particularly in the case of poorly installed well casings (Osborn *et al* 2011). Any such external leaks are not included in this study.

3. Methods for calculating life cycle greenhouse gas emissions

Our study used a hybrid combination of process activity emission estimates and economic input–output life cycle assessment estimates to estimate the preproduction GHG emission estimates (Hendrickson *et al* 2006, CMU GDI 2010). Emissions from production, processing and transport were adapted from the literature. We include emissions estimates based on different data sources and reasonable

Table 1. Greenhouse gas estimation approaches and data sources.

Process	Estimation approaches	Data sources
Preparation of Well Pad:		
Vegetation clearing	Estimated area cleared multiplied by vegetative carbon storage to obtain carbon loss due to land use change	NY DEC (2009), Tilman *et al* (2006)
Well pad construction	Detailed cost estimate and EIO-LCA model	RSMeans (2005), CMU GDI (2010)
Well drilling:		
Drilling energy consumption	(1) Energy required and emission factor, and (2) cost estimate and EIO-LCA model	Harper (2008), Sheehan *et al* (2000), CMU GDI (2010)
Drilling mud production	(1) Cost estimate and EIO-LCA and (2) emission factors multiplied by quantity.	Shaker (2005), PRé Consultants (2007), CMU GDI (2010)
Drilling water consumption	Trucking emissions plus water treatment emissions multiplied by quantity	Wang and Santini (2009), URS Corporation (2010), PA DEP (2010), Stokes and Horvath (2006)
Hydraulic fracturing:		
Pumping	Pumping energy multiplied by emission factor	URS Corporation (2010), Kargbo *et al* (2010), Currie and Stelle (2010), Sheehan *et al* (2000)
Additives production	Additive quantities cost and EIO-LCA model	URS Corporation (2010), CMU GDI (2010)
Water consumption	Trucking emissions	Wang and Santini (2009), URS Corporation (2010), Stokes and Horvath (2006), PA DEP (2010)
Well completion:	If flaring, gas flow emission factor multiplied by flaring time	NY DEC (2009), PA DEP (2010)
Wastewater disposal:		
Deep well injection	Deep well injection costs and EIO-LCA model	US ACE (2006), CMU GDI (2010)
Production, processing, transmission and storage, and combustion	Assumed comparable to national average	Venkatesh *et al* (2011)

ranges of process parameters. Table 1 summarizes estimation approaches used in this study, while calculation details appear in the supplementary information (available at stacks.iop.org/ERL/6/034014/mmedia).

In section 3.1, we report point estimates of GHG emissions for a base case. In section 5, we report range estimates and consider the sensitivity of point estimates to particular assumptions. Table 2 summarizes important parameter assumptions and possible ranges. Uniform or triangular distributions are assigned to these parameters based on whether we had two (uniform) or three (triangular) data points. When more data was available, parameters of probability distributions that best fit the data were estimated. A Monte Carlo analysis was performed using these distributions, to estimate the emissions from the various activities considered in our life cycle model.

3.1. *Emissions from Marcellus shale gas preproduction*

Horizontal wells are drilled on a multi-well pad to achieve higher cost-effectiveness. It is reported that a Marcellus well pad might have as few as one well per pad and as many as 16, but more typically 6–8 (ICF International 2009, NY DEC 2009, Currie and Stelle 2010). As a base case scenario, we chose to analyze the typical pad with six wells, each producing 2.7 Bcf (3.0×10^9 MJ), representing an average of 0.3 MMcf per day of gas for 25 years. Other production estimates are higher. EQT (2011), for example, provides a production estimate of 7.3 Bcf (8.1×10^9 MJ) and Range Resources at 4.4 Bcf (4.9×10^9 MJ) (Ventura 2009). Within the LCA framework the impacts are distributed across the total volume of gas produced during the lifetime of the well. Thus, the choice of using the low end ultimate recovery as the base case should be considered conservative. With Marcellus shale gas production currently in its infancy, the average production characteristics have significant uncertainty, so we perform an

Table 2. Parameter assumptions and ranges. (Note: sources for base case and range values are in table 1 and discussed in the supplementary material (available at stacks.iop.org/ERL/6/034014/mmedia).)

Parameter	Base case	Range
Area of access road (acres)	1.43	0.1–2.75
Wells per pad (number)	6	1–16
Area of well pad (acres)	5	2–6
Vertical drilling depth (ft)	8500	7000–10 000
Horizontal drilling length (ft)	4000	2000–6000
Fracturing water (MMgal/well)	4	2–6
Flowback fraction (%)	37.5	35–40
Recycling fraction (%)	45	30–60
Trucking distance between well site and water source (miles)	5	0–10
Trucking distance between well site and deep well injection facility (miles)	80	3–280
Well completion time with collection system in place (h)	18	12–24
Well completion time without collection system in place (days)	9.5	4–15
Fraction of flaring (%)	76	51–100
Initial 30 day gas flow rate (MMscf/day)	4.1	0.7–10
Average well production rate (MMscf/day)	0.3	0.3–10
Well lifetime (years)	25	5–25

extensive sensitivity analysis over a range of flow rates and well lifetimes, as discussed below.

The EIO-LCA (CMU GDI 2010) model was used to estimate GHG emissions from the construction of the access road and the multi-well pad. These costs were estimated using the utility price cost estimation method (RSMeans 2005). The size of an average Marcellus well pad is reported as being between 2 and 6 acres and typically between 4 and 5 acres (16 000 and 20 000 m^2) during drilling and fracturing phase (NY DEC 2009, Columbia University 2009). The costs of constructing this pad are estimated to be \$3.0–\$3.3 million per well pad in 2002 dollars (see the supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for detail). Using these costs as input, GHG emissions associated with well pad construction are estimated with the EIO-LCA (CMU GDI 2010) model.

Greenhouse gas emissions associated with drilling operations were calculated by two methods; (1) using the drilling energy intensity (table 1) and the life cycle diesel engine emissions factor of 635 g CO_2e per hp–hr output (Sheehan *et al* 2000), and (2) using drilling cost data and the EIO-LCA model (CMU GDI 2010). The EIA estimated the average drilling cost for natural gas wells in 2002 to be \$176 per foot (including the cost for drilling and equipping the wells and for surface producing facilities) (US EIA 2008). Emissions associated with the production of the drilling mud components were based on data from the SimaPro life cycle tool and the EIO-LCA economic model (PRé Consultants 2007, CMU GDI 2010).

Hydraulic fracturing associated GHG emissions result from the operation of the diesel compressor used to move and compress the fracturing fluid to high pressure, the emissions associated with the production of the hydraulic fracturing fluid, and from fugitive methane emissions as flowback water is captured. The last category of emissions is discussed separately below. Energy and emissions associated with the hydraulic fracturing process were modeled by using vendor specific diesel data along with the emission factor described above. The emissions of hydraulic fracturing fluid production are estimated with EIO-LCA model, based on the price of additives and fracturing fluid composition (see supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for detail).

There may be significant GHG emissions as a result of flaring and venting activities that occur during well casing and gathering equipment installation. The natural gas associated with the hydraulic fracturing flowback water is flared and vented. Flaring is used for testing the well gas flow prior to the construction of the gas gathering system which transport the gas to the sales line. Well completion emissions depend on the flaring/venting time, gas flow rate during well completion, the ratio of flaring to venting, and flaring efficiency. Uncertainty/variability analysis was conducted to investigate the effect of flaring/venting time, gas flow rate during fracturing water flowback, and flaring per cent on the well completion emissions. For those well completions with the collection facilities in place, gas is flared for between 12 and 24 h, due to necessary flowback operations. In wells where the appropriate gas gathering system as a tie to the gas sales line is not available for the gas during fracturing water flowback, the flaring or venting can occur for between 4 and 15 days as shown in table 2 (NY DEC 2009). In our model, we assumed the gas release rate during well completion equals the initial 30 day gas production rate for the base case and considered a scenario with both venting and flaring (see supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for details).

3.2. Emissions from Marcellus shale gas production to combustion

GHG emissions for production, processing, transmission, distribution and combustion of Marcellus shale natural gas are assumed to be similar to the US average domestic gas system that have been estimated previously (Jaramillo *et al* 2007). Jaramillo *et al* (2007) estimates were updated to include the uncertainty and variability in life cycle estimates and recalculated with recent and/or more detailed information by Venkatesh *et al* (2011). The GHG emissions from these life cycle stages consist of vented methane (gas release during operation), fugitive methane (unintentional leaks) and CO_2 emissions from the processing plants and from fuel consumption. Methane leakage rates throughout the natural gas system (excluding the preproduction processes previously discussed) are a major concern and our analysis has an implied fugitive emissions rate of 2%, consistent with the EPA natural gas industry study (US EPA 1996, 2010).

Venkatesh *et al* (2011) estimated the mean emission factors used in this study: 9.7 g CO_2e/MJ of natural gas in production; 4.3 g CO_2e MJ for processing; 1.4 g CO_2e/MJ for transmission and storage; 0.8 g CO_2e/MJ for distribution; and 50 g CO_2e/MJ for combustion.

3.3. Emissions associated with the life cycle of water used for drilling and hydraulic fracturing

Water resource management is a critical component of the production of Marcellus shale natural gas. Chesapeake Energy (2010) indicates that 100 000 gallons of water are used for drilling mud preparation. Two to six million gallons of water per well are required for the hydraulic fracturing process (Staaf and Masur 2009). About 85% of the drilling mud is reused (URS Corporation 2010). The flowback and recycling rates are used to estimate the total volume of water required. About 60–65% of this hydrofracturing fluid is recovered (URS Corporation 2010). For the flowback water, a recycle rate from 30 to 60% can be achieved (Agbaji *et al* 2009). The rest of the flowback water is temporarily stored in the impoundment and transported off site for disposal. Base case assumptions for these parameters are shown in table 2.

Emissions associated with drilling water use and hydraulic fracturing water use result from water taken from surface water resources or a local public water system; truck transport to the well pad, and then from the pad to disposal via deep well injection. It is assumed that no GHG emissions are related

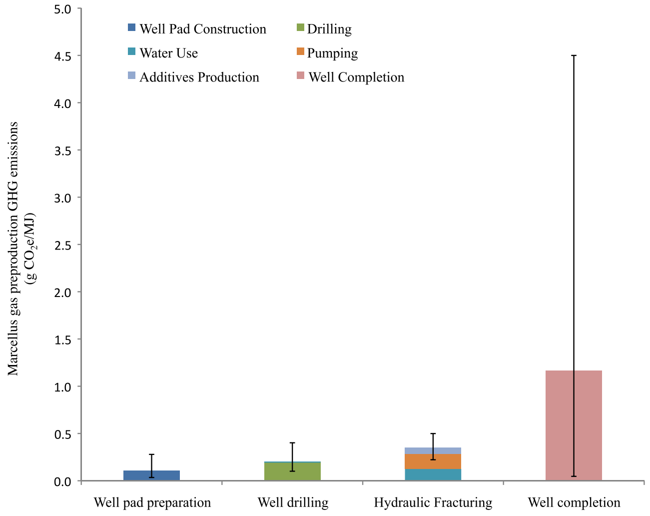


Figure 3. GHG emissions from different stages of Marcellus shale gas preproduction.

with producing water if it comes from surface water resources. For the water purchased from a local public water system, the emission factor for water treatment is used, which is estimated to be 3.4 g CO_2e/gallon of water generated according to Stokes and Horvath (2006). The energy intensity for transportation of liquids via truck is assumed to be 1028 Btu/ton mile for both forward and back-haul trips, as given in the GREET model (Wang and Santini 2009). In this study we assume that separate round trips are needed to transport the freshwater to the pad and to remove wastewater to the disposal site. This is to say that trucks bring in the freshwater from the source and return to the source empty; trucks also collect the wastewater from the well site and return to the well site empty. The life cycle emission factor (wells to wheels) for diesel as a transportation fuel is 93 g CO_2e/MJ (Wang and Santini 2009).

To estimate transport emissions associated with water taken from surface streams and water purchased from the local public water system, we used spatial analysis (ArcGIS) to estimate the distance from the surface water source to the well pad using well operational data and geographical information from Pennsylvania Department of Environmental Protection (2010). We depicted the overall distribution pattern of Marcellus wells under drilling and production in PA and NY in June 2010 by GIS. The distance from the well site to the surface water source is assumed to be 5 miles or 8 km in the base case of the model and the same transportation distance is also assumed for the water purchased from local public water system. We assumed an equal probability for sourcing water between surface water and the local public water system.

The trucking distance between well site and deep well injection facility was also estimated by GIS (PA DEP 2010). The average value of 80 miles or 130 km as determined by GIS was used in the base case.

4. Results for the base case

A total of 5500 t CO_2e is emitted during 'preproduction' per well. This is equivalent to 1.8 g CO_2e/MJ of natural gas produced over the lifetime of the well. Figure 3 depicts the GHG emissions by preproduction stage and by source. As can be seen, the completion stage has the largest GHG emissions, which result from flaring and/or venting. The error bars represent the limits of the 90% confidence interval of the emissions from each stage based on the uncertainty analysis.

A recent EPA report addressing emissions from the natural gas industry reported that 177 t of CH_4 is released during the completion of an unconventional gas well (US EPA 2010). This estimate is consistent with the analysis here and falls within the range estimated by our study, 26–1000 t of CH_4 released per completion and a mean value of 400 t of CH_4 released per completion. In our model, this methane released during the well completion is either flared with a combustion efficiency of 98% or vented without recovery.

Adding the preproduction emissions estimate to the downstream emission estimated by Venkatesh *et al* (2011) results in an overall GHG emissions factor of 68 g CO_2e/MJ of gas produced (figure 4). The life cycle emissions are dominated by combustion that accounts for 74% of the total emissions.

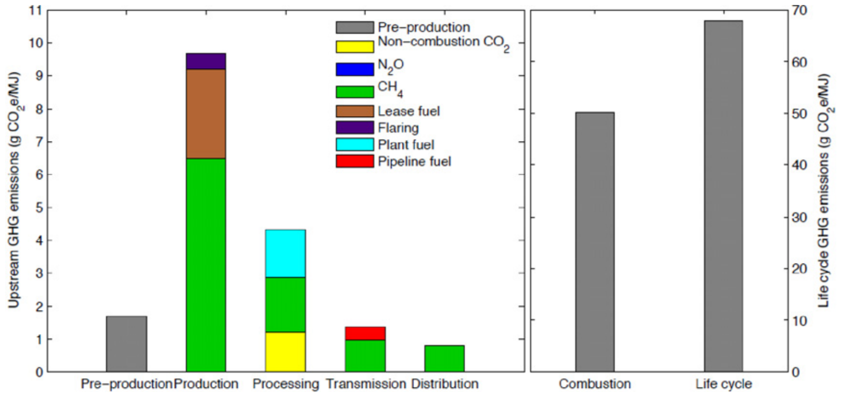


Figure 4. GHG emissions through the life cycle of Marcellus shale gas. (Preproduction through distribution emissions are on left scale; combustion and total life cycle emissions are on right scale. No carbon capture is included after combustion.)

Table 3. Uncertainty analysis on Marcellus gas preproduction.

Life cycle stage	Mean ($g\ CO_2e/MJ$)	Standard deviation ($g\ CO_2e/MJ$)	COV	90% CI-L (%)	90% CI-U (%)
Well pad preparation	0.13	0.1	0.72	58	131
Drilling	0.21	0.1	0.50	51	95
Hydraulic fracturing	0.35	0.1	0.24	37	42
Completion	1.15	1.8	1.53	96	287
Total	1.84	1.8	0.96	67	179

Table 4. Sensitivity of emissions from wells with different production rates and lifetimes. (Source: author calculations.)

Average gas flow (MMscf/day)	Lifetime (years)	Emissions from preproduction ($g\ CO_2e/MJ$)	Preproduction % contribution to life cycle emissions of Marcellus shale gas (%)	Total life cycle emissions ($g\ CO_2e/MJ$)
10	25	0.1	0.1	65.3
10	10	0.1	0.2	65.3
10	5	0.3	0.4	65.5
3	25	0.2	0.3	65.4
3	10	0.5	0.7	65.7
3	5	0.9	1.4	66.1
1	25	0.6	0.8	65.8
1	10	1.4	2.1	66.6
1	5	2.8	4.1	68.0
0.3	25	1.8	2.7	67.0
0.3	10	5	6.6	69.8
0.3	5	9.2	12.4	74.4

5. Sensitivity and uncertainty

Our results are subject to considerable uncertainty, particularly for the production rates and well lifetime. Table 3 summarizes the uncertainty analysis on the emission estimates for preproduction based on the distribution of parameters used.

Table 4 addresses model sensitivity to different estimates of ultimate gas recovery from wells, investigating the impact of different production rates and lifetimes. At high production rates and long well lifetimes the preproduction GHG emissions are normalized over higher volumes of natural gas than when using low flow rates and short well lifetimes. Comparing the case of 10 MMscf/day with a 25-year well lifetime to 0.3 MMscf/day with a 5-year well lifetime, table 4 shows that the emissions go from 0.1 to 9.2 g CO_2e/MJ. The overall life cycle emissions change from 65 to 74 g CO_2e/MJ. However, the preproduction emissions are less than 15% of the total life cycle emissions in all cases.

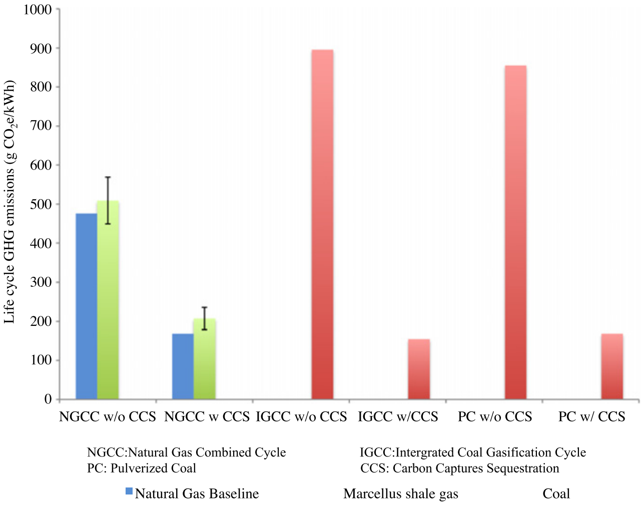


Figure 5. Comparison of life cycle GHG emissions from current domestic natural gas, Marcellus shale gas and coal for use in electricity production.

6. Comparison with coal for power generation

Marcellus shale gas emissions can be compared to alternative energy sources and processes when using a common metric such as electricity generated. Currently coal power plants are used to generate base load. Natural gas power plants, especially inefficient ones, are used to provide regulation services to balance supply and demand at times when base load power plants are insufficient or there is high-frequency variability in load or from renewable resources. Natural gas combined cycle (NGCC) plants could be used to generate base load thus competing directly with coal to provide this service. For this reason our comparison includes the emissions associated with using Marcellus shale gas in a NGCC power plant (efficiency of 50%) and the emissions from using coal in pulverized coal (PC) plants (efficiency of 39%) and integrated gasification combined cycle (IGCC) plants (efficiency of 38%). The results of these comparisons can be seen in figure 5. For this comparison point values are used for the life cycle GHG emissions of coal-based electricity. The error bars found in figure 5 represent the low and high emissions values for Marcellus shale gas, based on the assumptions of well production rate and well lifetime. The high-emission scenario assumes a 5-year well with 0.3 MMscf/day production rate while the low-emission scenario, assumes a 25-year well with 10 MMscf/day production rate. Also shown in figure 5 are the life cycle emissions of electricity generated in power plants with carbon capture and sequestration (CCS) capabilities (efficiency of 43% for NGCC with CCS; efficiency of 30% for PC with CCS; efficiency of 33% for ICGG with CCS).

In general, natural gas provides lower greenhouse emission for all cases studied whether the gas is derived from Marcellus shale or the average 2008 domestic natural gas system. When advanced technologies are used with CSS then the emissions are similar and coal provides slightly less emissions. This implies that the upstream emissions for natural gas life cycle are higher than the upstream emissions from coal, once efficiencies of power generation are taken into account (Jaramillo *et al* 2007).

The comparison of natural gas and coal for electricity allows us to investigate the impact of three additional model uncertainty components including the choice of leakage rate, GWP values, and re-refracking of a Marcellus gas well. This study assumes a 2% production phase leakage rate based on the volume of gas produced (US EPA 2010, Venkatesh *et al* 2011). Assuming the average efficiency of 43% for natural gas fired electricity generation and 32% for coal fired plants the fugitive emissions rate would need to be 14% (resulting in a life cycle emission factor for Marcellus gas of 125 g CO_2e/MJ) before the overall life cycle emissions including those of electricity generation would be greater than coal. This is an exorbitantly high leakage rate and to put it into perspective, using 2009 dry natural gas production estimates and the average wellhead price, we calculate that the economic losses a would total around $11 billion. If we convert our data to the 20-year GWP the break-even point is reduced to 7% because of the higher impacts attributed to methane. Finally, we modeled a single hydraulic fracturing event occurring during well preproduction (figure 3). Above we calculated that the break-even emission factor that would make coal and natural electricity generation the same is 125 g CO_2e/MJ of natural gas. With the current emissions estimate for Marcellus gas of 68 g CO_2e/MJ, and a hydraulic fracturing event (and its associated flaring and venting emissions) contributing 1.5 g CO_2e/MJ to this estimate, more than 25 fracturing events would need to occur in a single well before the decision between coal and natural gas would change.

7. Comparison with liquefied natural gas as a future source

In 2005 EIA suggested that domestic natural gas production and Canadian imports would decline as natural gas consumption increased. EIA predicted that liquefied natural gas (LNG) imports would grow to offset the deficits in North American production (US EIA 2011a, 2011b). As a result of the development of unconventional natural gas reserves, EIA has changed their projections. The Annual Energy Outlook 2011 reference case (US EIA 2011a, 2011b) predicts that increases in shale gas production, including Marcellus, will more than offset the decline in conventional natural gas and decreasing imports from Canada and will allow for increases in natural gas consumption. Since shale gas is projected to be the largest component of the unconventional sources of future natural gas production, it seem appropriate to compare its emissions to those of the gas that would be used if shale gas were not produced. Venkatesh *et al* (2011) estimated the life cycle GHG from LNG imported to the US to have a mean of 70 g CO_2e/MJ, These results are based on emissions due to production and liquefaction in the countries of origin, shipping the gas to the US by ocean tanker, regasification in the US and its transmission, distribution and subsequent combustion. On average, the emissions of Marcellus shale gas were about 3% lower than LNG. As with the overall Marcellus gas results, there is considerable uncertainty to the comparisons. However, we conclude that as these unconventional sources of natural gas supplant LNG imports, overall emissions will not rise.

8. Conclusion

The GHG emission estimates shown here for Marcellus gas are similar to current domestic gas. Other shale gas plays could generate different results considering regional environmental variability and reservoir heterogeneity. Green completion and capturing the gas for market that would otherwise be flared or vented, could reduce the emissions associated with completion and thus would significantly reduce the largest source of emissions specific to Marcellus gas preproduction. These preproduction emissions, however, are not substantial contributors to the life cycle estimates, which are dominated by the combustion emissions of the gas. For comparison purposes, Marcellus shale gas adds only 3% more emissions to the average conventional gas, which is likely within the uncertainty bounds of the study. Marcellus shale gas has lower GHG emissions relative to coal when used to generate electricity.

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NATIONAL ENERGY TECHNOLOGY LABORATORY

Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States

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Office of Strategic Energy Analysis and Planning

May 12, 2011

Presented at: Cornell University Lecture Series

U.S. DEPARTMENT OF ENERGY

Overview

1. Who is NETL?
2. What is the role of natural gas in the United States?
3. Who uses natural gas in the U.S.?
4. Where does natural gas come from?
5. What is the life cycle GHG footprint of domestic natural gas extraction and delivery to large end-users?
6. How does natural gas power generation compare to coal-fired power generation on a life cycle GHG basis?
7. What are the opportunities for reducing GHG emissions?

<u>Question #1:</u>

Who is NETL?

National Energy Technology Laboratory

MISSION
Advancing energy options to fuel our economy, strengthen our security, and improve our environment

Oregon

Pennsylvania

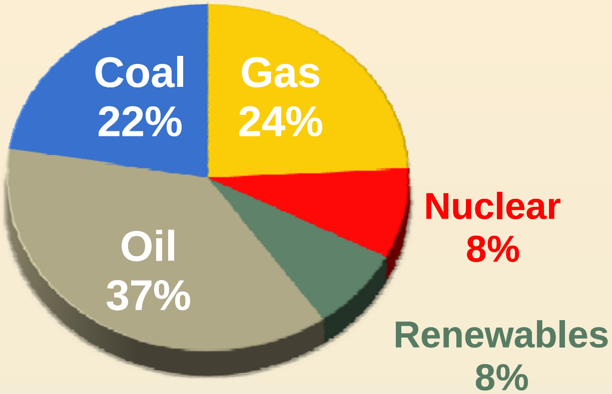
West Virginia

Question #2:

What is the role of natural gas in the United States?

Energy Demand 2008

100 QBtu / Year
84% Fossil Energy



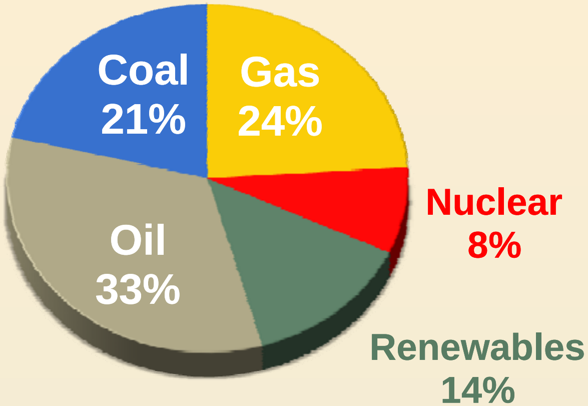
5,838 mmt CO_2

+ 14%

United States

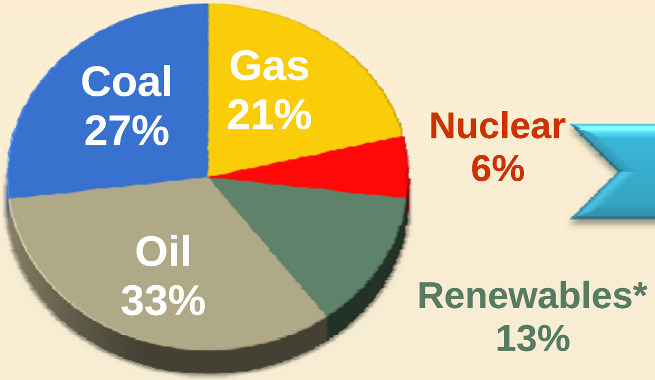
Energy Demand 2035

114 QBtu / Year
78% Fossil Energy



6,311 mmt CO_2

487 QBtu / Year
81% Fossil Energy

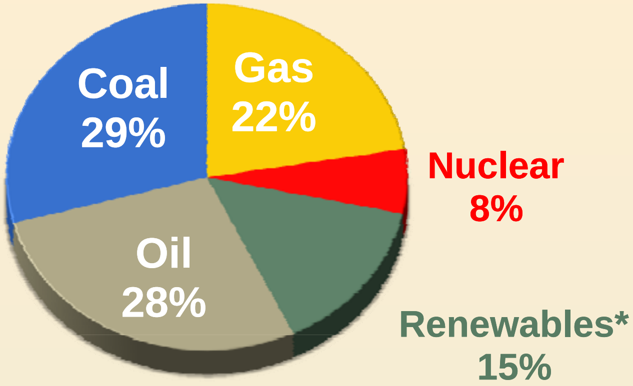


29,259 mmt CO_2

+ 47%

World

716 QBtu / Year
79% Fossil Energy



42,589 mmt CO_2

Sources: U.S. data from EIA, Annual Energy Outlook 2011; World data from IEA, World Energy Outlook 2010, Current Policies Scenario

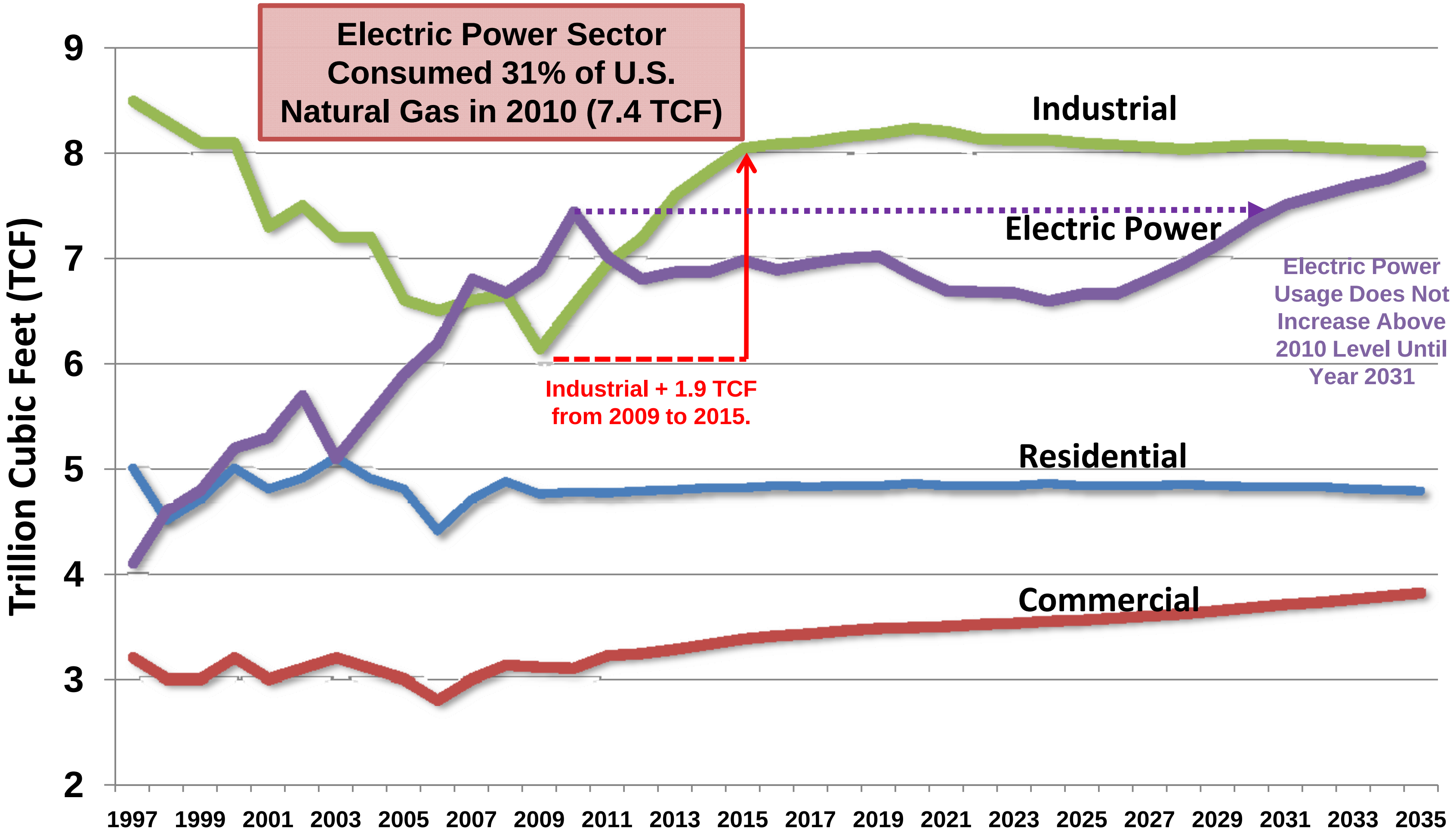
* Primarily traditional biomass, wood, and waste.

Question #3:

Who uses natural gas in the United States?

Domestic Natural Gas Consumption

Sectoral Trends and Projections: 2010 Total Consumption = 23.8 TCF



Electric Power Sector Consumed 31% of U.S. Natural Gas in 2010 (7.4 TCF)

Industrial + 1.9 TCF from 2009 to 2015.

Electric Power Usage Does Not Increase Above 2010 Level Until Year 2031

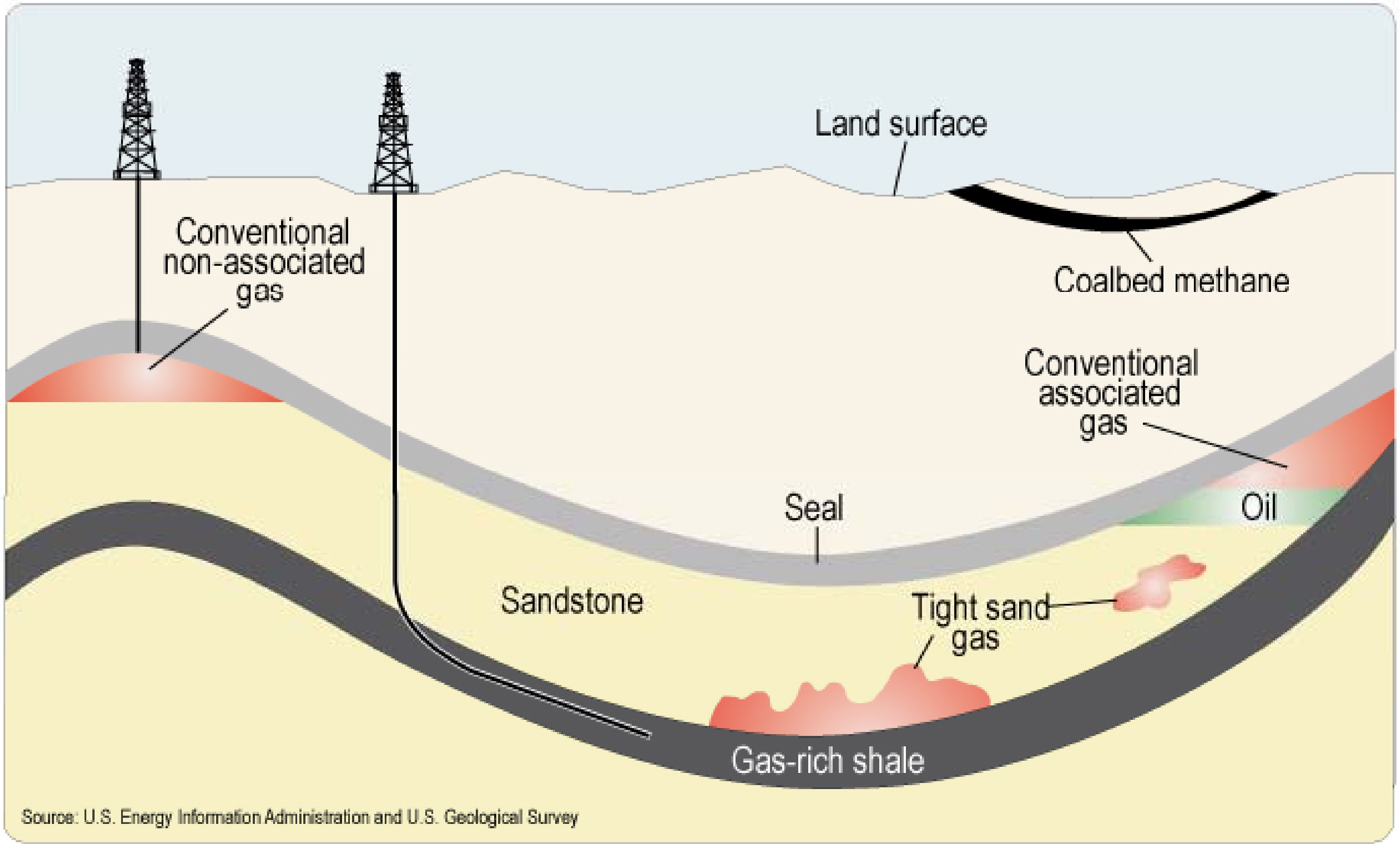
+1.9 TCF Resurgence in Industrial Use of Natural Gas by 2015 Exceeds the Net Incremental Supply; No Increase in Natural Gas Use for Electric Power Sector Until 2031

Source: EIA Annual Energy Review 2009 and Annual Energy Outlook 2011

Question #4:

Where does natural gas come from?

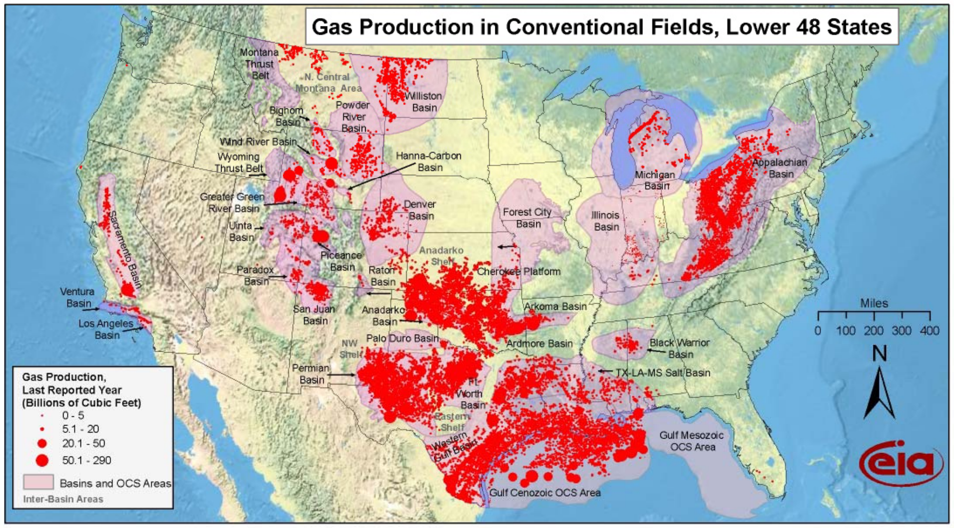
Schematic Geology of Onshore Natural Gas Resources



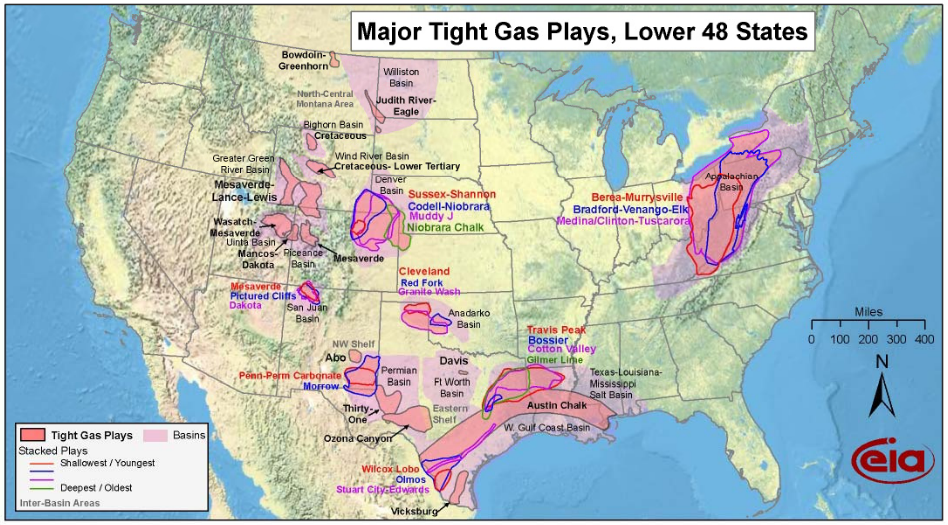
Source: U.S. Energy Information Administration and U.S. Geological Survey

Source: EIA, Today in Energy, February 14, 2011; Modified USGS Figure from Fact Sheet 0113-01; www.eia.doe.gov/todayinenergy/detail.cfm?id=110 Last Accessed May 5, 2011.

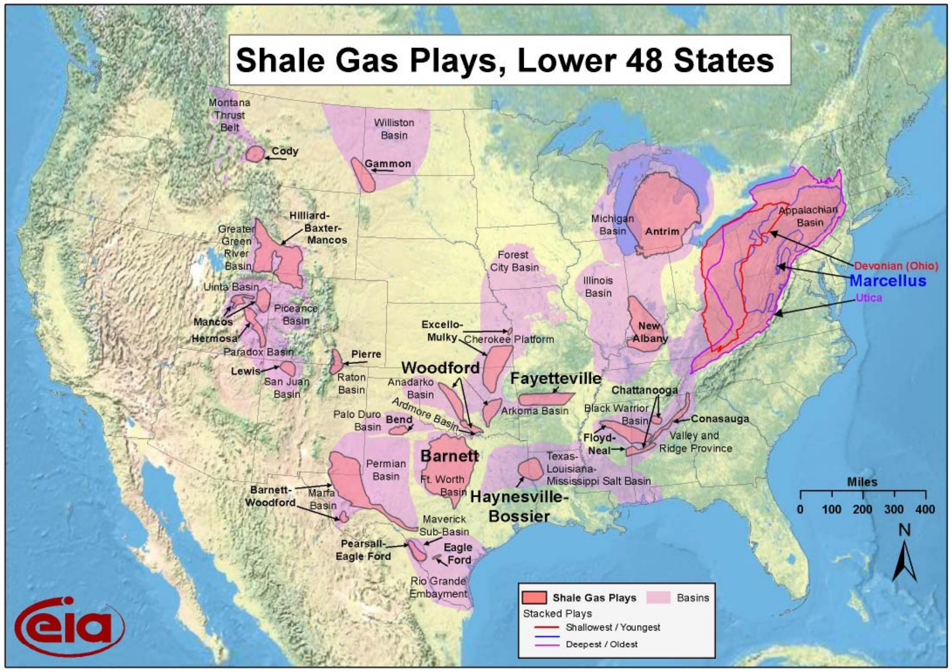
EIA Natural Gas Maps



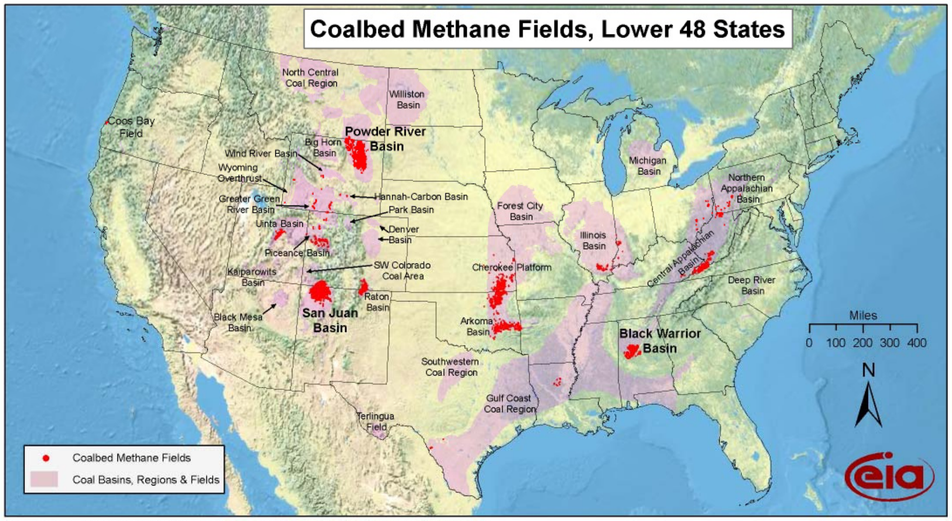
Source: Energy Information Administration based on data from HPDI, IN Geological Survey, USGS
Updated: April 8, 2009



Source: Energy Information Administration based on data from various published studies
Updated: June 6, 2010



Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010

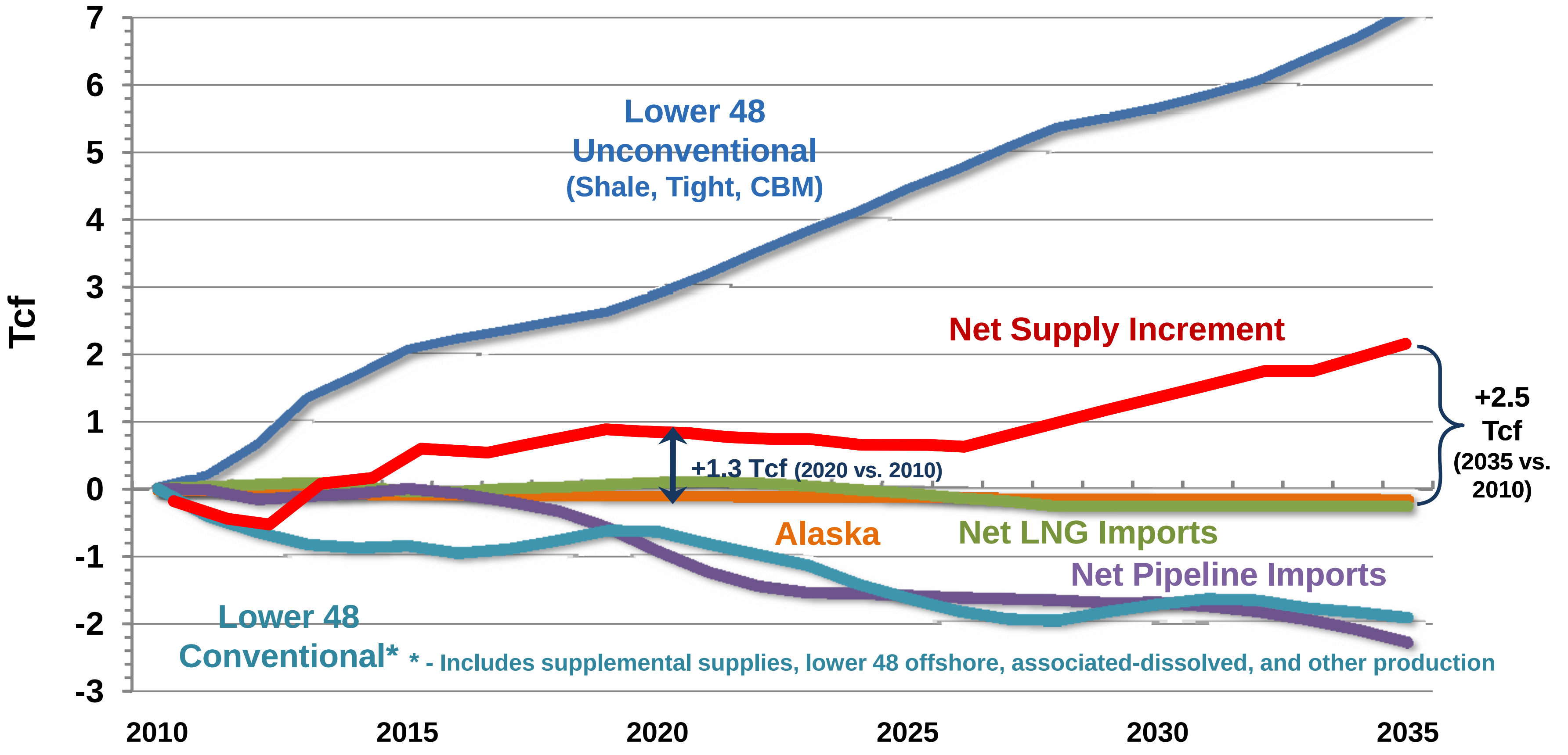


Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

Source: EIA, Natural Gas Maps, http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm Last Accessed May 5, 2011.

Sources of Incremental Natural Gas Supply

(Indexed to 2010)



* - Includes supplemental supplies, lower 48 offshore, associated-dissolved, and other production

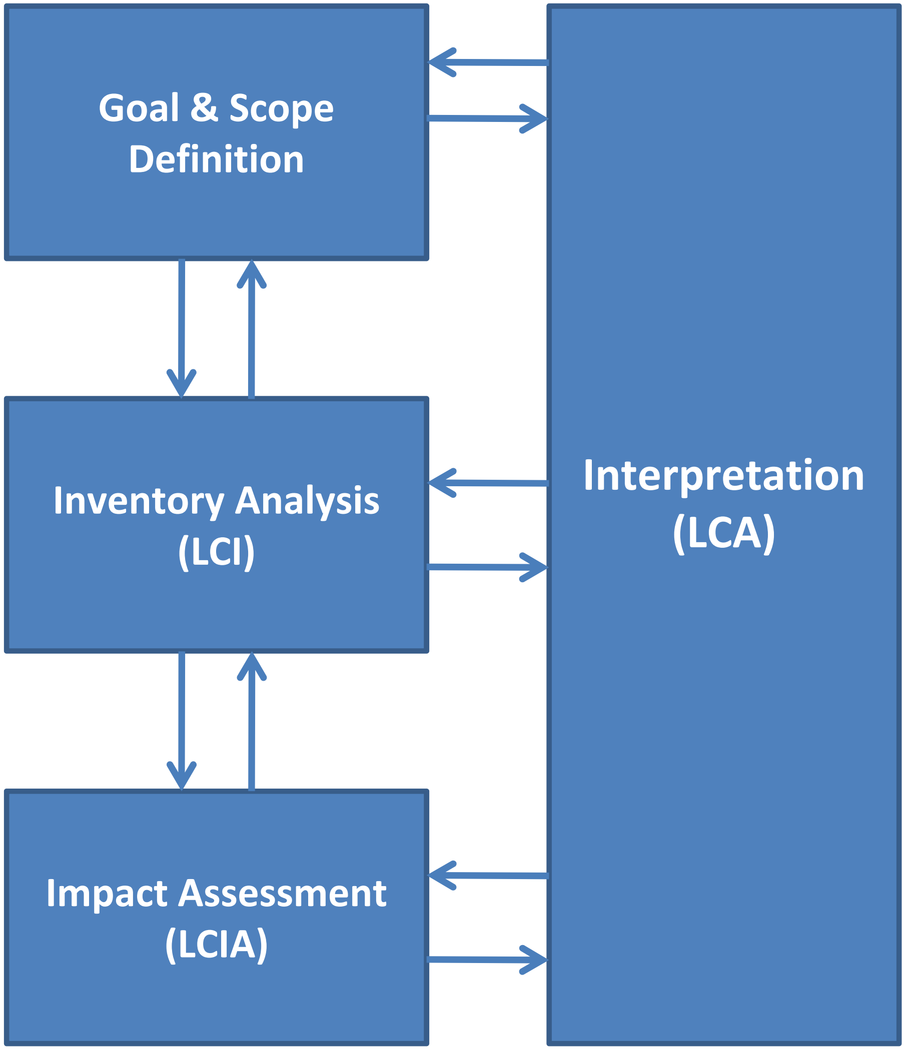
Unconventional Production Growth Offset by Declines in Conventional Production and Net Pipeline Imports; 1.3 Tcf Increment by 2020 Does Not Support Significant Coal Generation Displacement

Source: EIA, Annual Energy Outlook 2011

Question #5:

What is the life cycle GHG footprint of domestic natural gas extraction and delivery to large end-users?

Overview: Life Cycle Assessment Approach



Goal & Scope Definition

Inventory Analysis (LCI)

Impact Assessment (LCIA)

Interpretation (LCA)

Source: ISO 14040:2006, Figure 1 – Stages of an LCA (reproduced)

The Type of LCA Conducted Depends on Answers to these Questions:

1. What Do You Want to Know?

2. How Will You Use the Results?

International Organization for Standardization (ISO) for LCA

- ISO 14040:2006 Environmental Management – Life Cycle Assessment – Principles and Framework
- ISO 14044 Environmental Management – Life Cycle Assessment – Requirements and Guidelines
- ISO/TR 14047:2003 Environmental Management – Life Cycle Impact Assessment – Examples of Applications of ISO 14042
- ISO/TS 14048:2002 Environmental Management – Life Cycle Assessment – Data Documentation Format

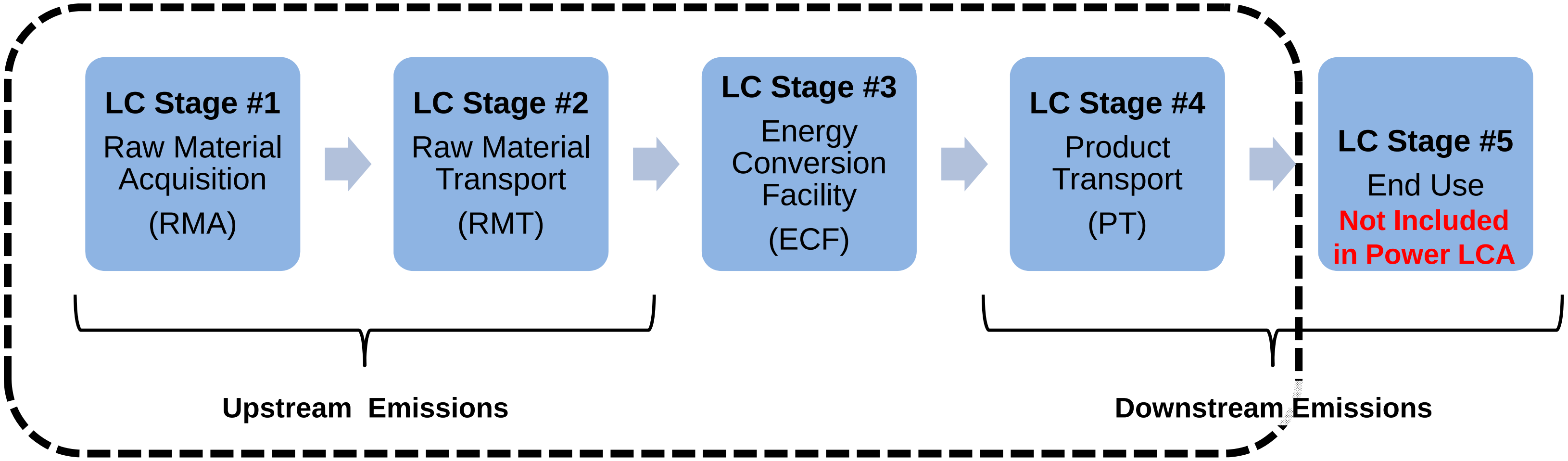
Overview: Life Cycle Assessment Approach

The Type of LCA Conducted Depends on Answers to these Questions :

1. What Do You Want to Know?
   - ☐ The GHG footprint of natural gas, lower 48 domestic average, extraction, processing, and delivery to a large end-user (e.g., power plant)
   - ☐ The comparison of natural gas used in a baseload power generation plant to baseload coal-fired power generation on a lbs CO_2e/MWh basis
2. How Will You Use the Results?
   - ☐ Inform research and development activities to reduce the GHG footprint of both energy feedstock extraction and power production in existing and future operations

NETL Life Cycle Analysis Approach

- **Compilation and evaluation of the inputs, outputs, and the potential environmental impacts of a product or service throughout its life cycle, from raw material acquisition to the final disposal**



LC Stage #1
Raw Material Acquisition
(RMA)

LC Stage #2
Raw Material Transport
(RMT)

LC Stage #3
Energy Conversion Facility
(ECF)

LC Stage #4
Product Transport
(PT)

LC Stage #5
End Use
Not Included in Power LCA

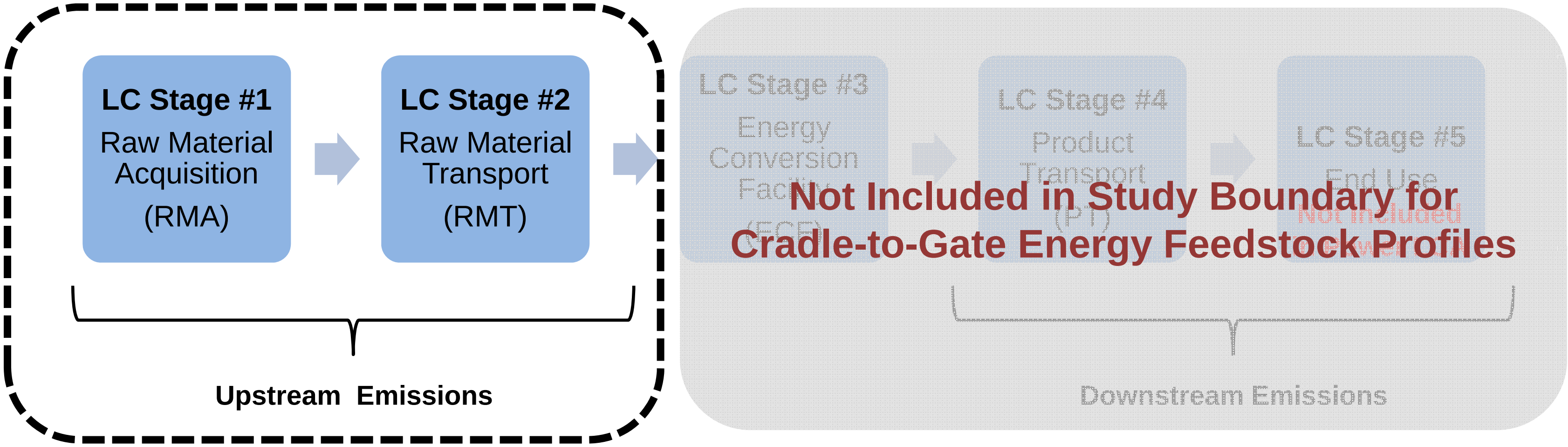
Upstream Emissions

Downstream Emissions

- **The ability to compare different technologies depends on the functional unit (denominator); for power LCA studies:**
  - 1 MWh of electricity delivered to the end user

NETL Life Cycle Analysis Approach for Natural Gas Extraction and Delivery Study

- **The study boundary for “domestic natural gas extraction and delivery to large end-users” is represented by Life Cycle (LC) Stages #1 and #2 only.**



LC Stage #1
Raw Material Acquisition
(RMA)

LC Stage #2
Raw Material Transport
(RMT)

Upstream Emissions

LC Stage #3
Energy Conversion Facility
(ECF)

LC Stage #4
Product Transport
(PT)

LC Stage #5
End Use
Not included

Downstream Emissions

Not Included in Study Boundary for Cradle-to-Gate Energy Feedstock Profiles

- **Functional unit (denominator) for energy feedstock profiles is:**
  - 1 MMBtu of feedstock delivered to end user

    (MMBtu = million British thermal units)

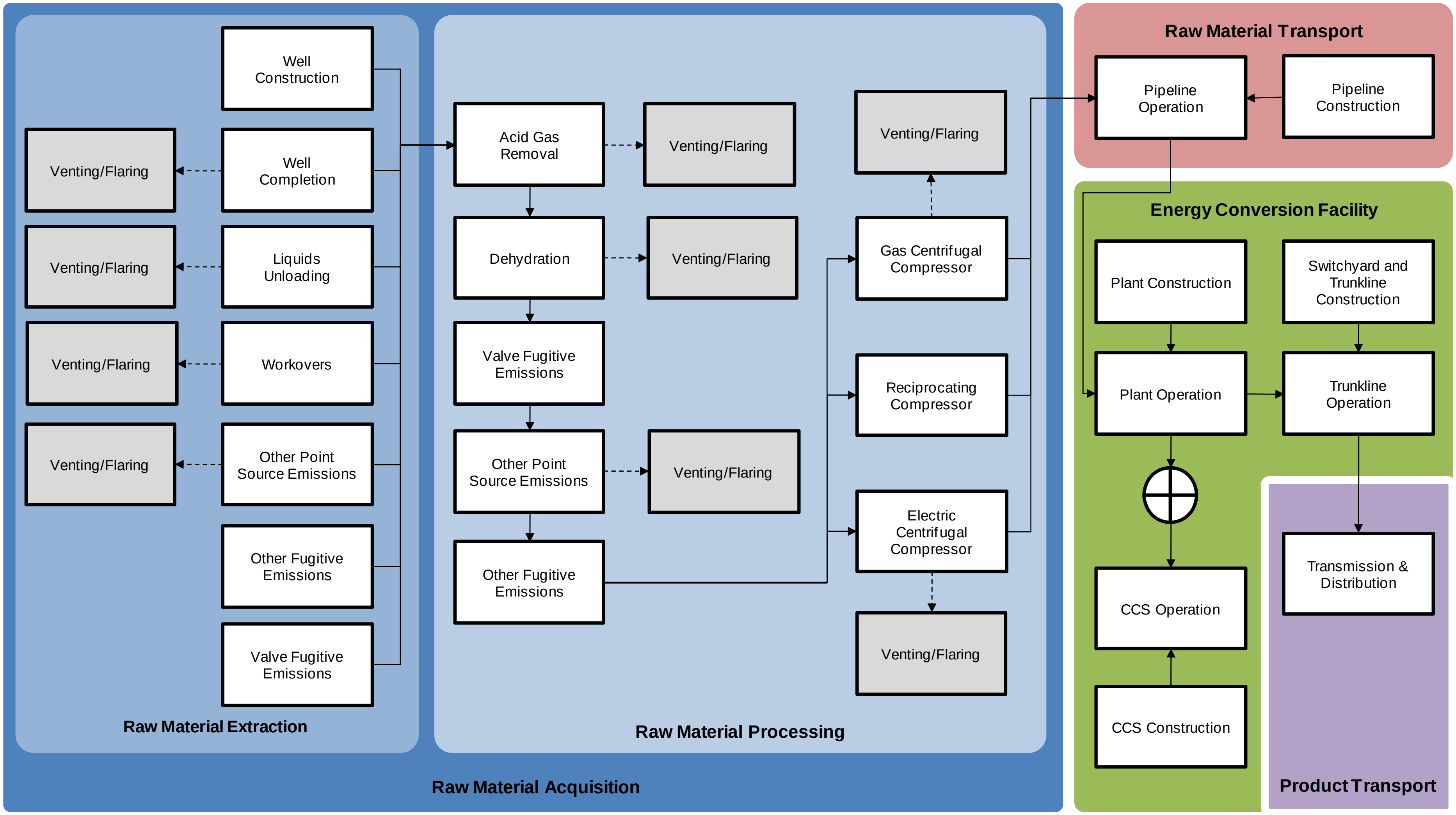
NETL Life Cycle Study Metrics

- **Greenhouse Gases**
  - CO_2, CH_4, N_2O, SF_6
- **Criteria Air Pollutants**
  - NO_X, SO_X, CO, PM10, Pb
- **Air Emissions Species of Interest**
  - Hg, NH_3, radionuclides
- **Solid Waste**
- **Raw Materials**
  - Energy Return on Investment
- **Water Use**
  - Withdrawn water, consumption, water returned to source
  - Water Quality
- **Land Use**
  - Acres transformed, greenhouse gases

Converted to Global Warming Potential using IPCC 2007 100-year CO_2 equivalents

CO_2 = 1
CH_4 = 25
N_2O = 298
SF_6 = 22,800

NETL Life Cycle Model for Natural Gas



Raw Material Extraction

Well Construction

Well Completion

Liquids Unloading

Workovers

Other Point Source Emissions

Other Fugitive Emissions

Valve Fugitive Emissions

Venting/Flaring

Venting/Flaring

Venting/Flaring

Venting/Flaring

Raw Material Processing

Acid Gas Removal

Dehydration

Valve Fugitive Emissions

Other Point Source Emissions

Other Fugitive Emissions

Venting/Flaring

Venting/Flaring

Venting/Flaring

Gas Centrifugal Compressor

Reciprocating Compressor

Electric Centrifugal Compressor

Venting/Flaring

Venting/Flaring

Raw Material Acquisition

Raw Material Transport

Pipeline Operation

Pipeline Construction

Energy Conversion Facility

Plant Construction

Switchyard and Trunkline Construction

Plant Operation

Trunkline Operation

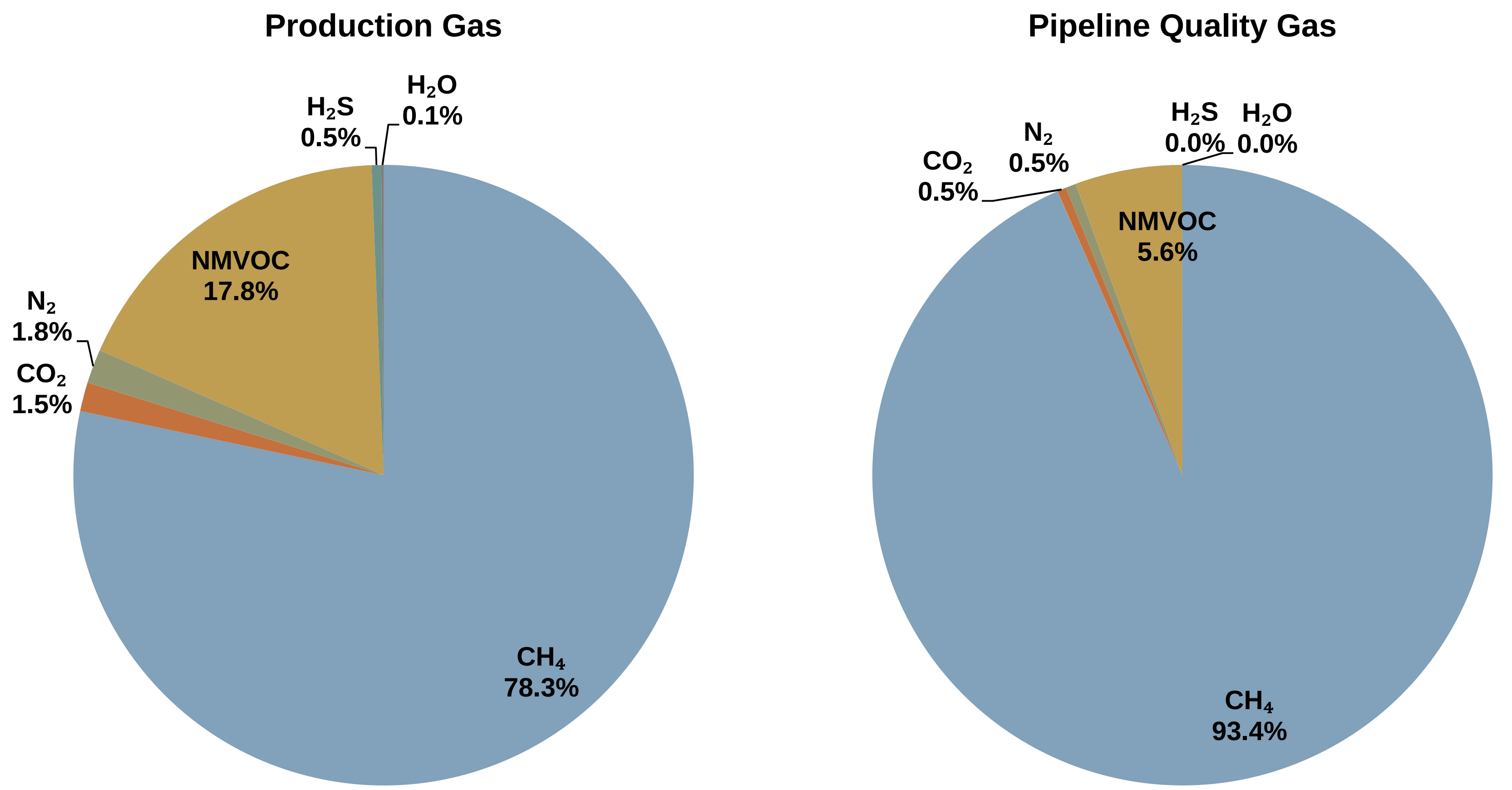
CCS Operation

CCS Construction

Product Transport

Transmission & Distribution

Natural Gas Composition by Mass



Carbon content (75%) and energy content (1,027 btu/cf) of pipeline quality gas is very similar to raw production gas (within 99% of both values)

Natural Gas Extraction Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Source							
Contribution to 2009 Natural Gas Mix	Percent	23%	7%	13%	32%	16%	9%
Estimated Ultimate Recovery (EUR), Production Gas	BCF/well	8.6	4.4	67.7	1.2	3.0	0.2
Production Rate (30-yr average)	MCF/day	782	399	6,179	110	274	20
Natural Gas Extraction Well							
Flaring Rate at Extraction Well Location	Percent	51%	51%	51%	15%	15%	51%
Well Completion, Production Gas (prior to flaring)	MCF/completion	47	47	47	4,657	11,643	63
Well Workover, Production Gas (prior to flaring)	MCF/workover	3.1	3.1	3.1	4,657	11,643	63
Well Workover, Number per Well Lifetime	Workovers/well	1.1	1.1	1.1	3.5	3.5	3.5
Liquids Unloading, Production Gas (prior to flaring)	MCF/episode	23.5	n/a	23.5	n/a	n/a	n/a
Liquids Unloading, Number per Well Lifetime	Episodes/well	930	n/a	930	n/a	n/a	n/a
Pneumatic Device Emissions, Fugitive	lb CH_4/MCF	0.05	0.05	0.01	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/MCF	0.003	0.003	0.002	0.003	0.003	0.003
Other Sources of Emissions, Fugitive	lb CH_4/MCF	0.043	0.043	0.010	0.043	0.043	0.043

Natural Gas Processing Plant Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Acid Gas Removal (AGR) and CO_2 Removal Unit							
Flaring Rate for AGR and CO_2 Removal Unit	Percent	100%					
Methane Absorbed into Amine Solution	lb CH_4/MCF	0.04					
Carbon Dioxide Absorbed into Amine Solution	lb CO_2/MCF	0.56					
Hydrogen Sulfide Absorbed into Amine Solution	lb H_2S/MCF	0.21					
NMVOC Absorbed into Amine Solution	lb NMVOC/MCF	6.59					
Glycol Dehydrator Unit							
Flaring Rate for Dehydrator Unit	Percent	100%					
Water Removed by Dehydrator Unit	lb H_2O/MCF	0.045					
Methane Emission Rate for Glycol Pump & Flash Separator	lb CH_4/MCF	0.0003					
Pneumatic Devices & Other Sources of Emissions							
Flaring Rate for Other Sources of Emissions	Percent	100%					
Pneumatic Device Emissions, Fugitive	lb CH_4/MCF	0.05					
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/MCF	0.02					
Other Sources of Emissions, Fugitive	lb CH_4/MCF	0.03					

Natural Gas Processing Plant Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Compression at Gas Plant							
Compressor, Gas-powered Combustion, Reciprocating	Percent	100%	100%		100%	75%	100%
Compressor, Gas-powered Turbine, Centrifugal	Percent			100%			
Compressor, Electrical, Centrifugal	Percent					25%	

Natural Gas Transmission Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Emissions on Transmission Infrastructure							
Pipeline Transport Distance (national average)	Miles	450					
Transmission Pipeline Infrastructure, Fugitive	lb CH_4/MCF-Mile	0.0003					
Transmission Pipeline Infrastructure, Fugitive (per 450 miles)	lb CH_4/MCF	0.15					
Natural Gas Compression on Transmission Infrastructure							
Distance Between Compressor Stations	Miles	75					
Compression, Gas-powered Reciprocating	Percent	29%					
Compression, Gas-powered Centrifugal	Percent	64%					
Compression, Electrical Centrifugal	Percent	7%					

Uncertainty Analysis Modeling Parameters

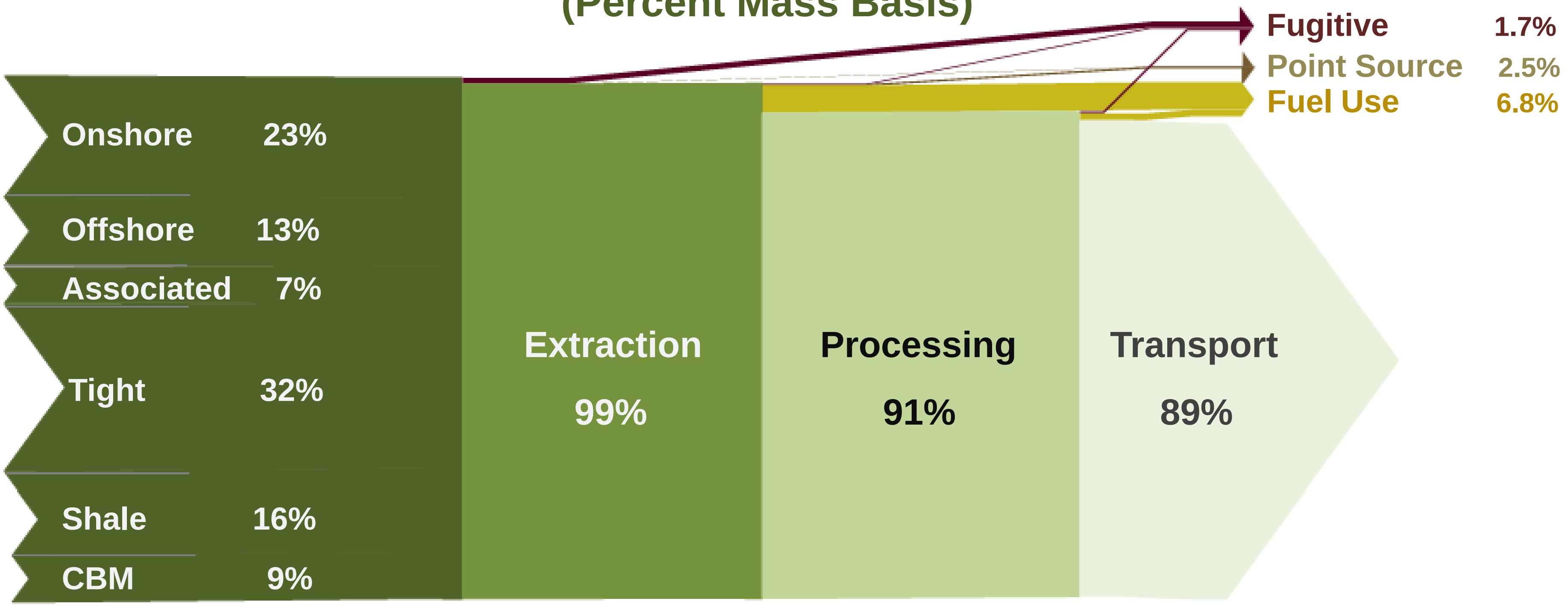
Parameter	Units	Scenario	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Production Rate	MCF/day	Low	403 (-49%)	254 (-36%)	3,140 (-49%)	77 (-30%)	192 (-30%)	14 (-30%)
		Nominal	**782**	**399**	**6,179**	**110**	**274**	**20**
		High	1,545 (+97%)	783 (+96%)	12,284 (+99%)	142 (+30%)	356 (+30%)	26 (+30%)
Flaring Rate at Well	%	Low	41% (-20%)	41% (-20%)	41% (-20%)	12% (-20%)	12% (-20%)	41% (-20%)
		Nominal	**51%**	**51%**	**51%**	**15%**	**15%**	**51%**
		High	61% (+20%)	61% (+20%)	61% (+20%)	18% (+20%)	18% (+20%)	61% (+20%)
Pipeline Distance	miles	Low	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)
		Nominal	**450**	**450**	**450**	**450**	**450**	**450**
		High	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)

Error bars reported are based on setting each of the three parameters above to the values that generate the lowest and highest result.

Note: “Production Rate” and “Flaring Rate at Well” have an inverse relationship on the effect of the study result. For example to generate the lower bound on the uncertainty range both “Production Rate” and “Flaring Rate Well” were set to “High” and “Pipeline Distance” was set to “Low”.

Accounting for Natural Gas from Extraction thru Delivery to a Large End-User

(Percent Mass Basis)



Onshore 23%

Offshore 13%

Associated 7%

Tight 32%

Shale 16%

CBM 9%

Extraction 99%

Processing 91%

Transport 89%

Fugitive 1.7%

Point Source 2.5%

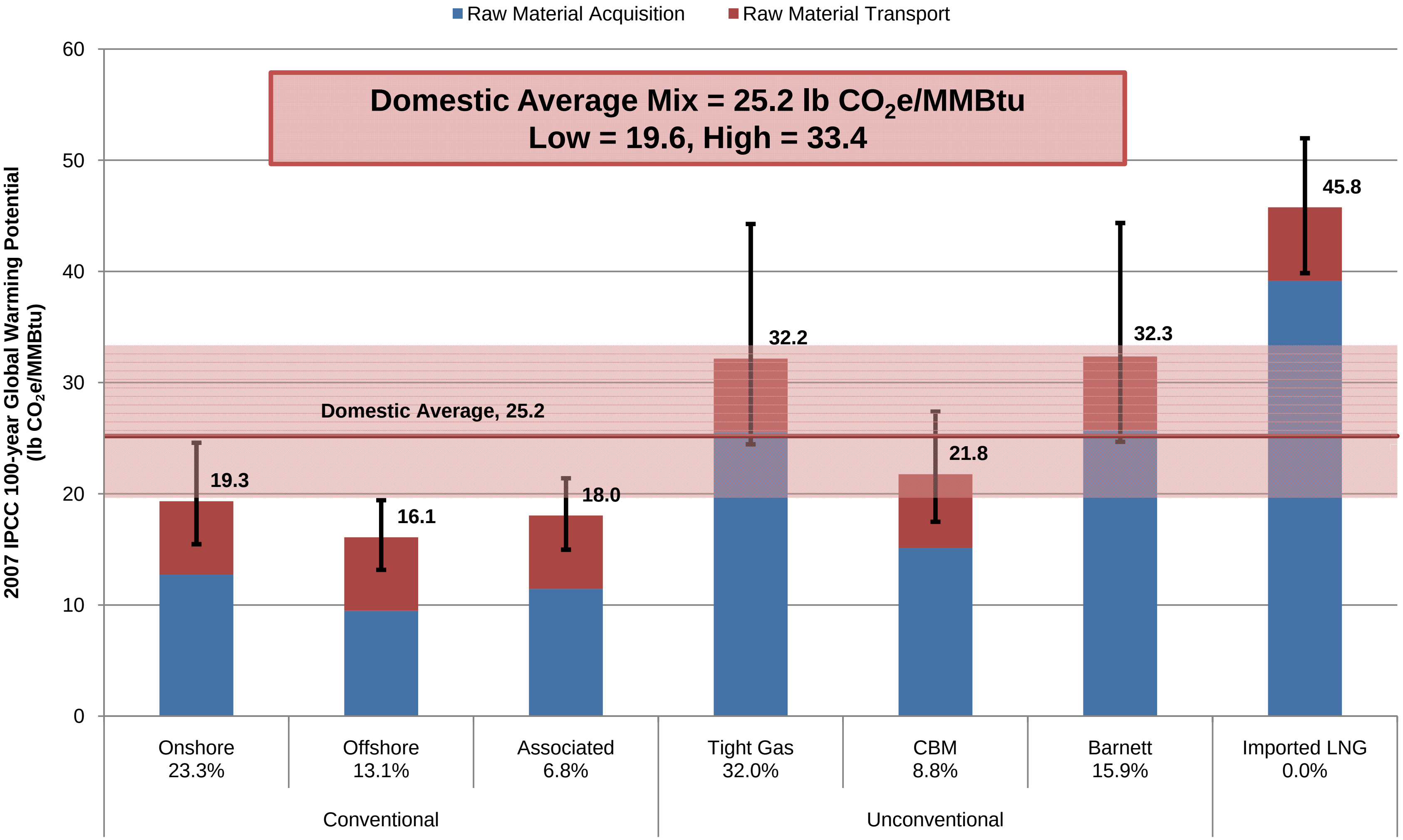
Fuel Use 6.8%

Natural Gas Resource Table	Raw Material Acquisition		Raw Material Transport	Cradle-to-Gate Total:
	Extraction	Processing		
Extracted from Ground	100%	N/A	N/A	100%
Fugitive Losses	1.1%	0.2%	0.4%	1.7%
Point Source Losses (Vented or Flared)	0.1%	2.4%	0.0%	2.5%
Fuel Use	0.0%	5.3%	1.6%	6.8%
Delivered to End User	N/A	N/A	89.0%	89.0%

11% of Natural Gas Extracted from the Earth is Consumed for Fuel Use, Flared, or Emitted to the Atmosphere (point source or fugitive)

Of this, 62% is Used to Power Equipment

Life Cycle GHG Results for Average Natural Gas Extraction and Delivery to a Large End-User

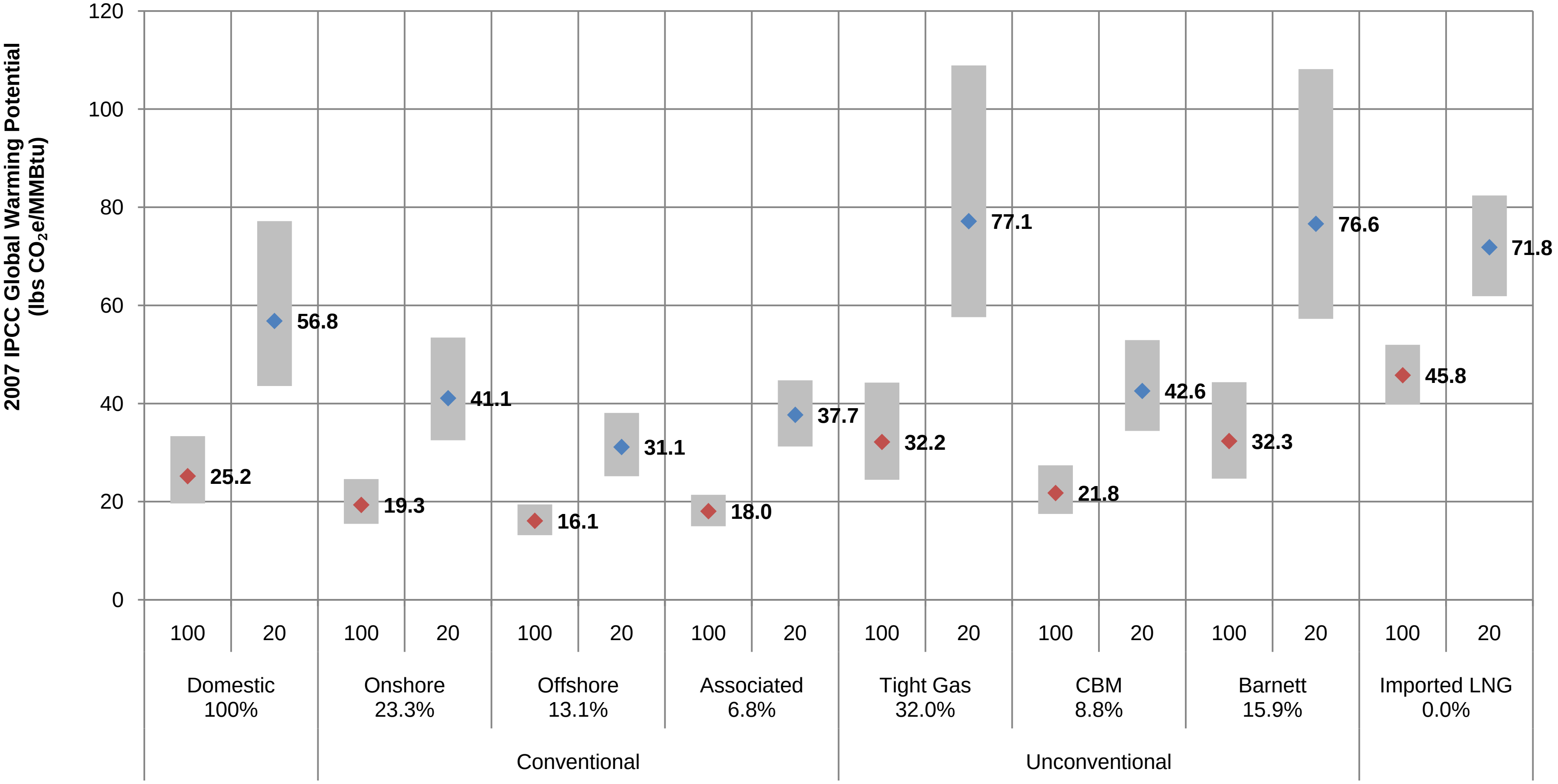


Life Cycle GHG Results for Average Natural Gas Extraction and Delivery to a Large End-User

<u>***Comparison of 2007 IPCC GWP Time Horizons:***</u>

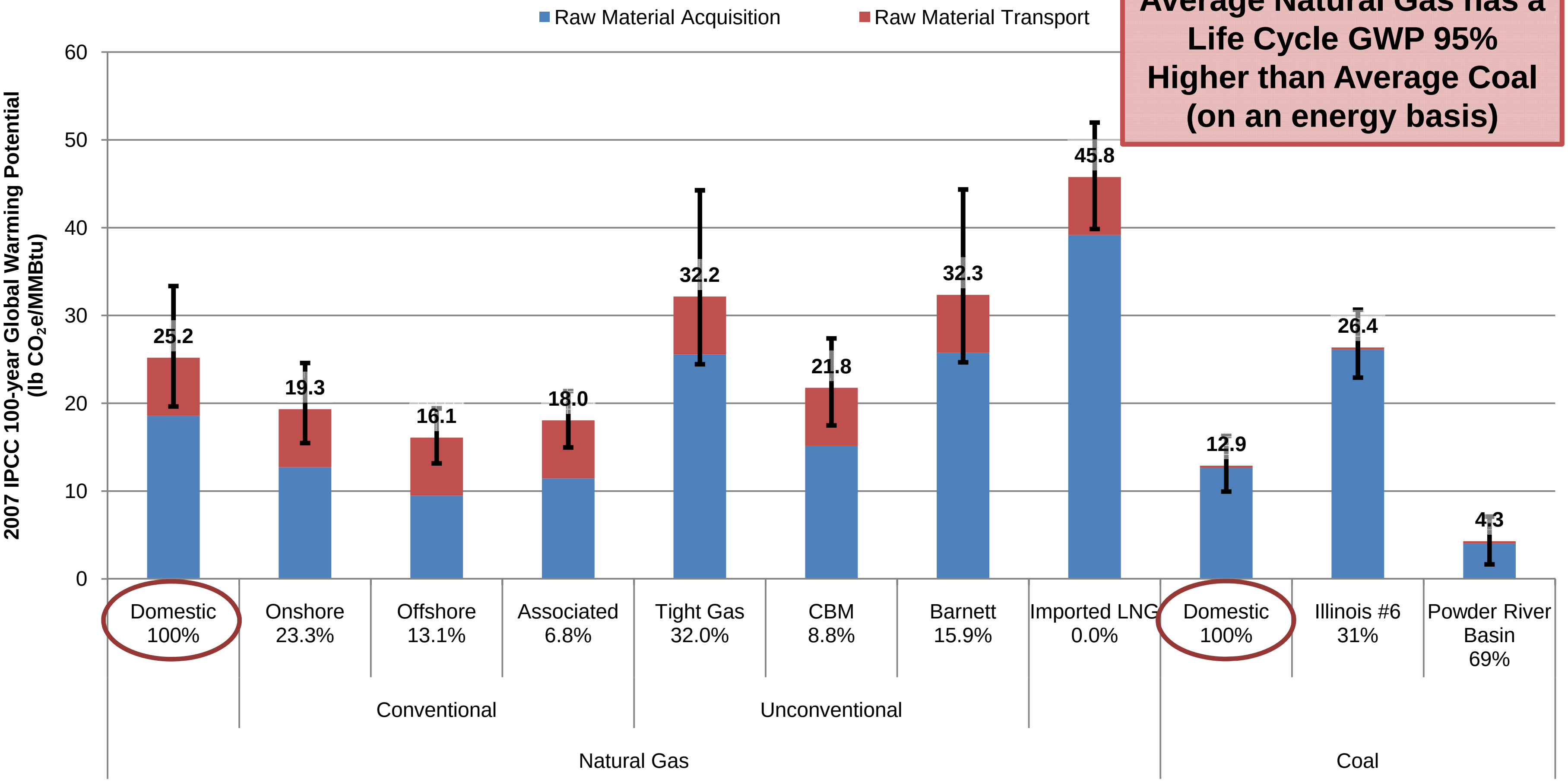
100-year Time Horizon: CO_2 = 1, CH_4 = 25, N_2O = 298

20-year Time Horizon: CO_2 = 1, CH_4 = 72, N_2O = 289



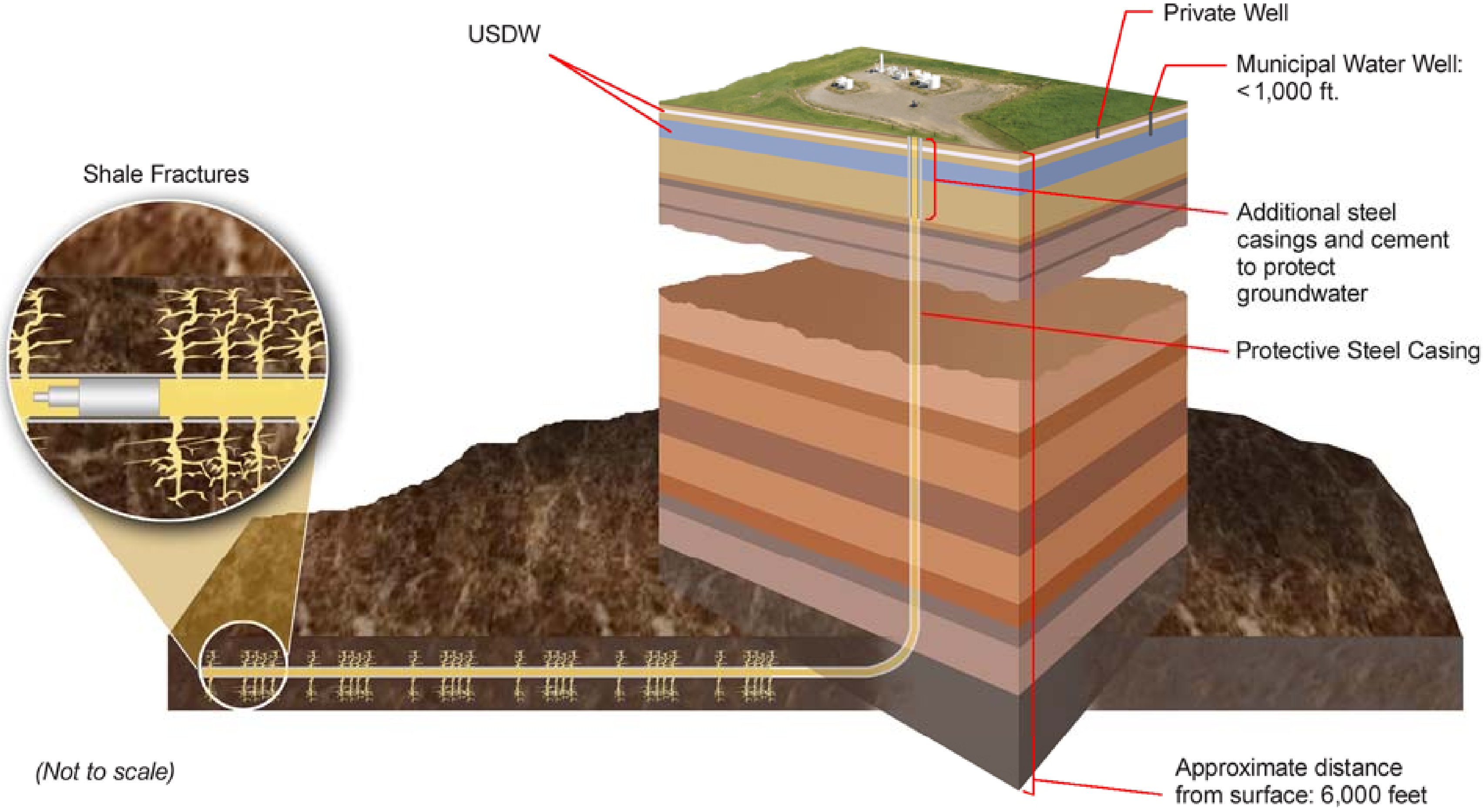
Life Cycle GHG Results for “Average” Natural Gas Extraction and Delivery to a Large End-User

Comparison of Natural Gas and Coal Energy Feedstock GHG Profiles



Average Natural Gas has a Life Cycle GWP 95% Higher than Average Coal (on an energy basis)

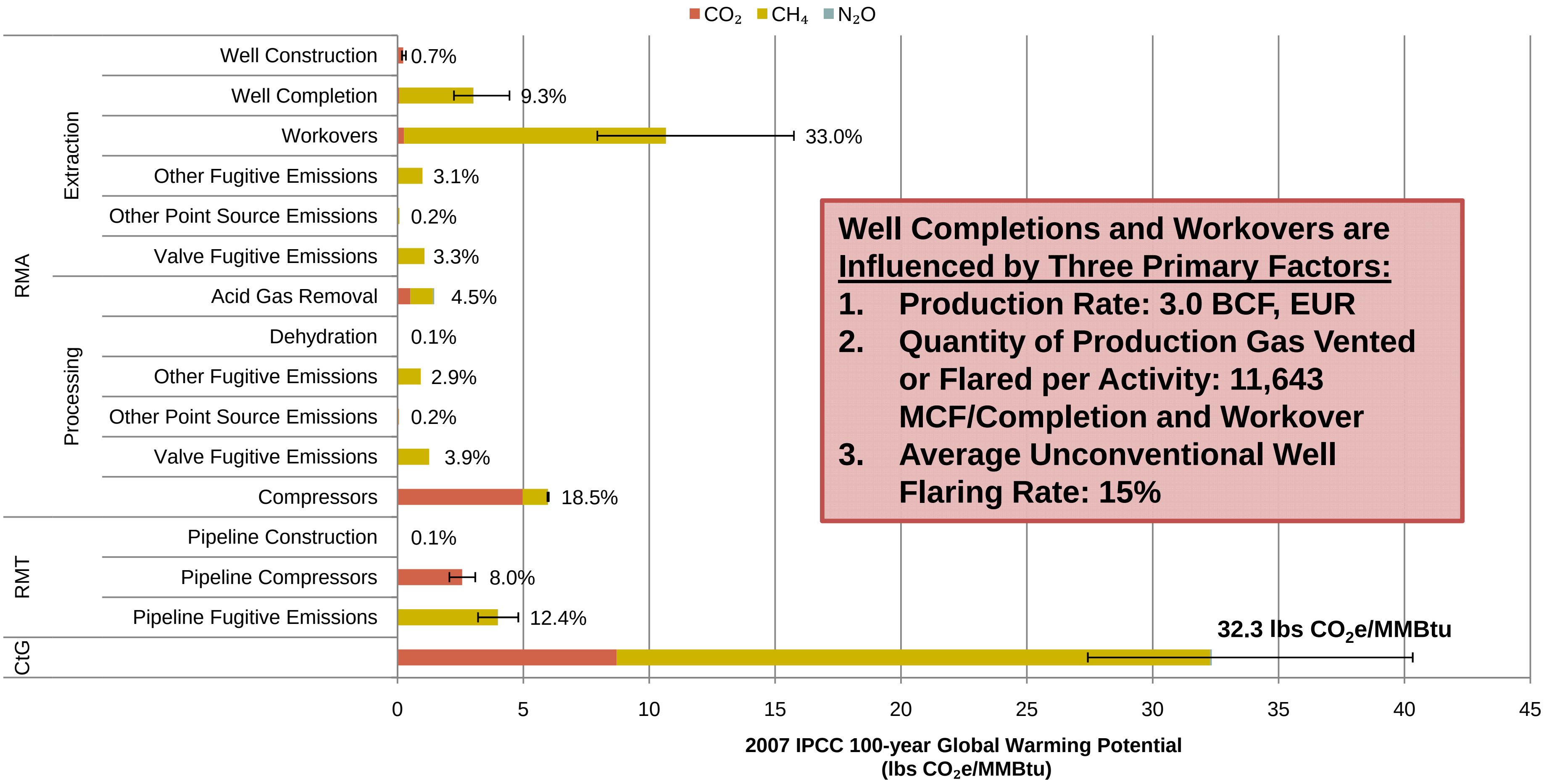
A Deeper Look at Unconventional Natural Gas Extraction via Horizontal Well, Hydraulic Fracturing (*the Barnett Shale Model*)



Source: NETL, *Shale Gas: Applying Technology to Solve America's Energy Challenge*, January 2011

NETL Upstream Natural Gas Profile:
Barnett Shale: Horizontal Well, Hydraulic Fracturing

GWP Result: IPCC 2007, 100-yr (lb CO_2e/MMBtu)



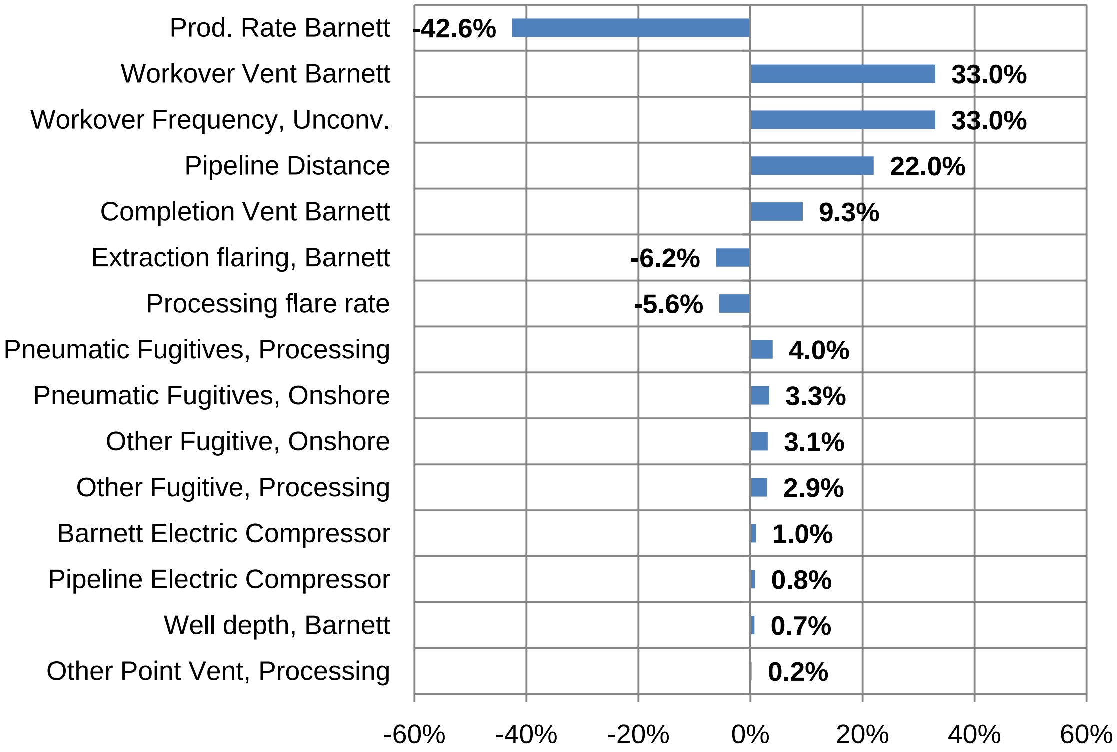
Well Completions and Workovers are
<u>Influenced by Three Primary Factors:</u>

1. **Production Rate: 3.0 BCF, EUR**
2. **Quantity of Production Gas Vented or Flared per Activity: 11,643 MCF/Completion and Workover**
3. **Average Unconventional Well Flaring Rate: 15%**

NETL Upstream Natural Gas Profile:

Barnett Shale: Horizontal Well, Hydraulic Fracturing

Sensitivity Analysis



“0%” = 32.3 lb CO_2e/MMBtu Delivered; IPCC 2007, 100-yr Time Horizon

Default Value	Units
11,508	lb/day
489,023	lb/episode
0.118	episodes/yr
450	miles
489,023	lb/episode
15.0	%
100	%
0.001480	lb fugitives/lb processed gas
0.001210	lb fugitives/lb extracted gas
0.001119	lb fugitives/lb extracted gas
0.001089	lb fugitives/lb processed gas
25	%
7	%
13,000	feet
0.0003940	lb fugitives/lb processed gas

Example: A 1% increase in production rate from 11,508 lb/day to 11,623 lb/day results in a 0.426% decrease in cradle-to-gate GWP, from 32.3 to 32.2 lbs CO_2e/MMBtu

Question #6:

How does natural gas power generation compare to coal-fired power generation on a life cycle GHG basis?

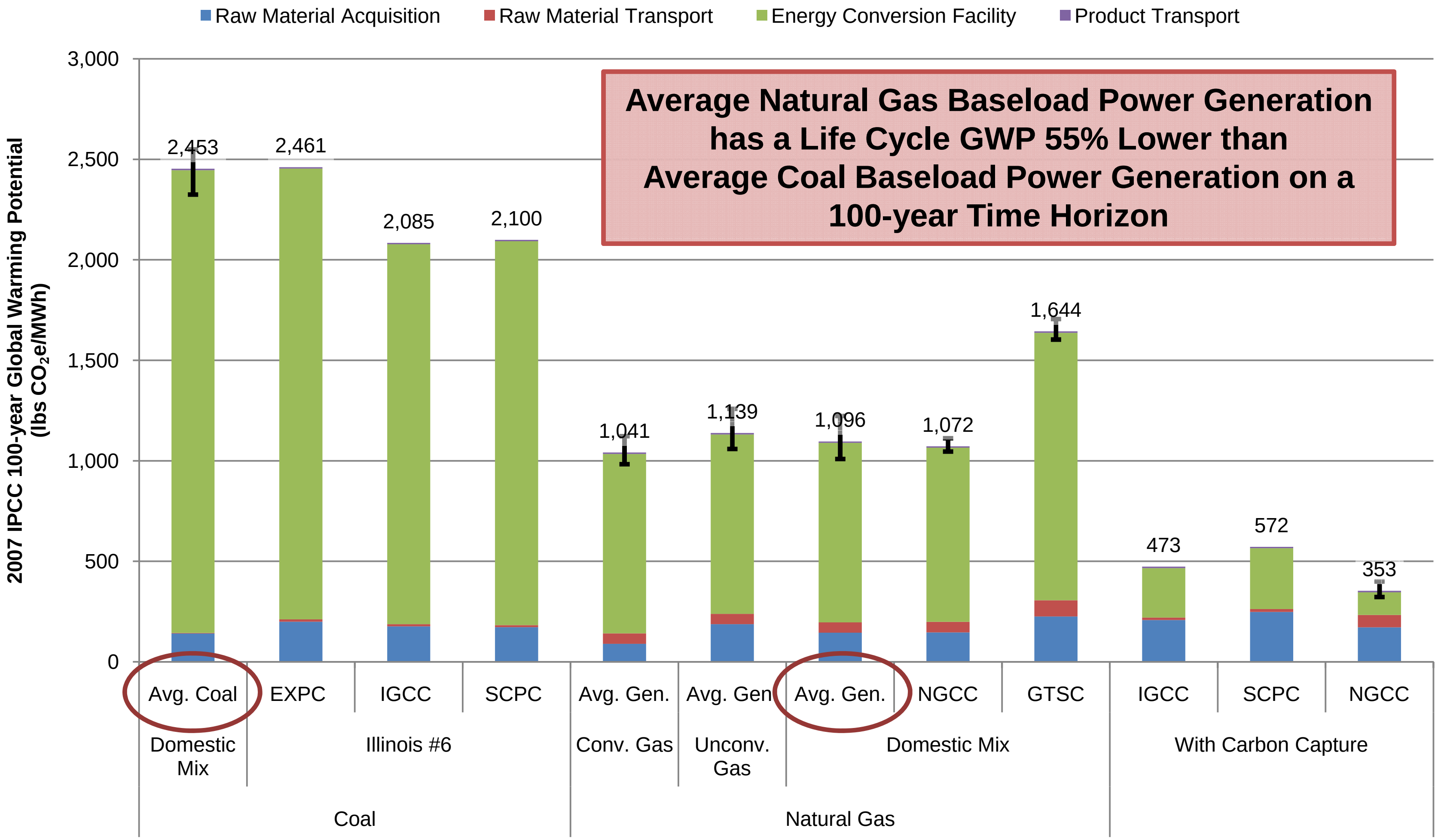
Power Technology Modeling Properties

Plant Type	Plant Type Abbreviation	Fuel Type	Capacity (MW)	Capacity Factor	Net Plant HHV Efficiency
2009 Average Coal Fired Power Plant[a]	Avg. Coal	Domestic Average	Not Calculated	Not Calculated	33.0%
Existing Pulverized Coal Plant	EXPC	Illinois No. 6	434	85%	35.0%
Integrated Gasification Combined Cycle Plant	IGCC	Illinois No. 6	622	80%	39.0%
Super Critical Pulverized Coal Plant	SCPC	Illinois No. 6	550	85%	36.8%
2009 Average Baseload (> 40 MW) Natural Gas Plant[a]	Avg. Gen.	Domestic Average	Not Calculated	Not Calculated	47.1%
Natural Gas Combined Cycle Plant	NGCC	Domestic Average	555	85%	50.2%
Gas Turbine Simple Cycle	GTSC	Domestic Average	360	85%	32.6%
Integrated Gasification Combined Cycle Plant with 90% Carbon Capture	IGCC/CCS	Illinois No. 6	543	80%	32.6%
Super Critical Pulverized Coal Plant with 90% Carbon Capture	SCPC/CCS	Illinois No. 6	550	85%	26.2%
Natural Gas Combined Cycle Plant with 90% Carbon Capture	NGCC/CCS	Domestic Average	474	85%	42.8%

[a] **Net plant higher heating value (HHV) efficiency reported is based on the weighted mean of the 2007 fleet as reported by U.S. EPA, eGrid (2010).**

Comparison of Power Generation Technology Life Cycle GHG Footprints

Raw Material Acquisition thru Delivery to End Customer (lb CO_2e/MWh)



Average Natural Gas Baseload Power Generation has a Life Cycle GWP 55% Lower than Average Coal Baseload Power Generation on a 100-year Time Horizon

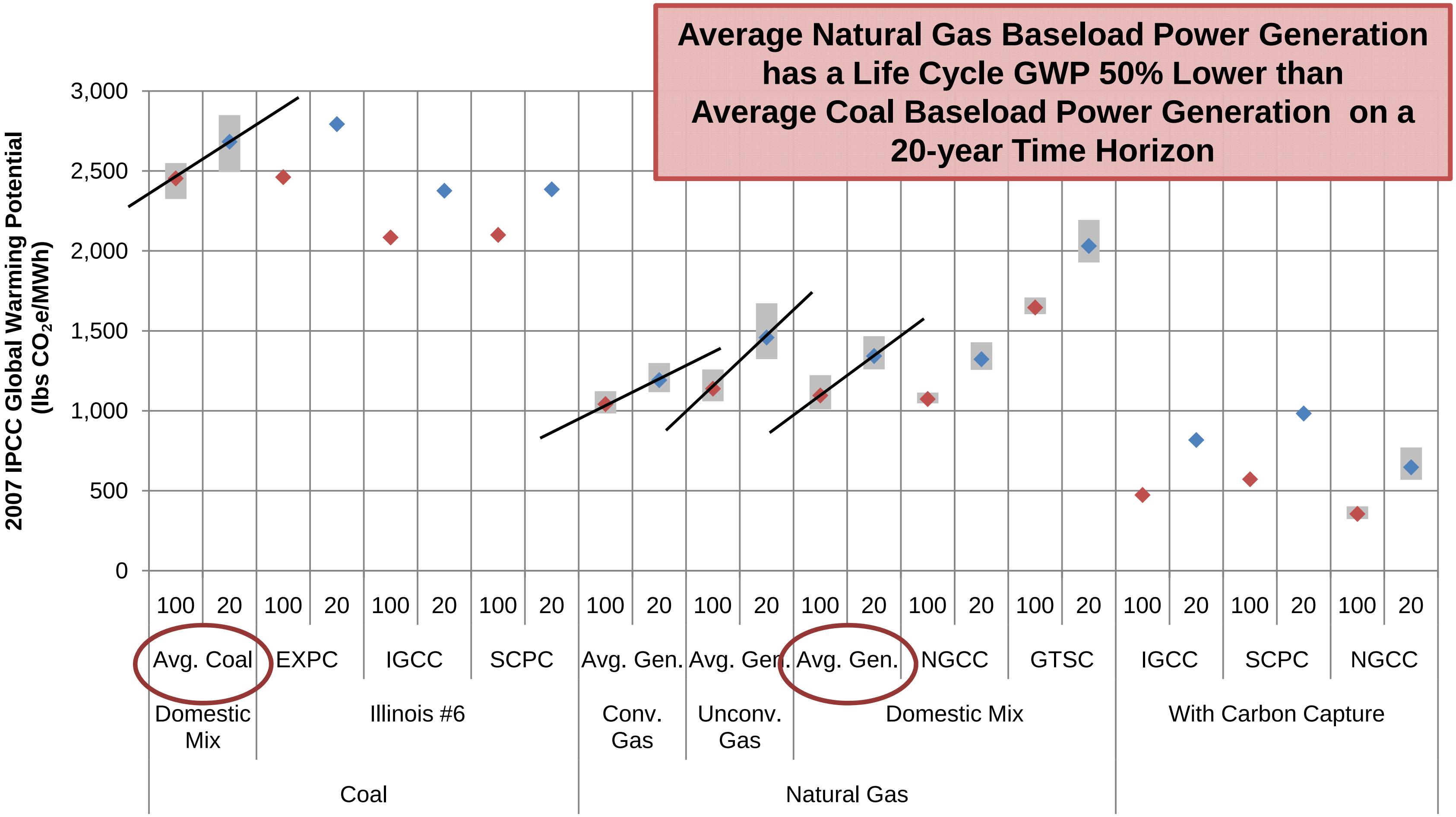
Note: EXPC, IGCC, SCPC, and NGCC (combustion) results, with and without CCS, are based on scenario specific modeling parameters; not industry average data.

Comparison of Power Generation Technology Life Cycle GHG Footprints (lbs CO_2e/MWh)

<u>Comparison of 2007 IPCC GWP Time Horizons:</u>

100-year Time Horizon: $CO_2 = 1$, $CH_4 = 25$, $N_2O = 298$

20-year Time Horizon: $CO_2 = 1$, $CH_4 = 72$, $N_2O = 289$


Average Natural Gas Baseload Power Generation has a Life Cycle GWP 50% Lower than Average Coal Baseload Power Generation on a 20-year Time Horizon

Note: EXPC, IGCC, SCPC, and NGCC (combustion) results, with and without CCS, are based on scenario specific modeling parameters; not industry average data.

Study Data Limitations

- **Data Uncertainty**
  - Episodic emission factors
  - Formation-specific production rates
  - Flaring rates (extraction and processing)
  - Natural gas pipeline transport distance

- **Data Availability**
  - Formation-specific gas compositions (including CH_4, H_2S, NMVOC, and water)
  - Effectiveness of green completions and workovers
  - Fugitive emissions from around wellheads (between the well casing and the ground)
  - GHG emissions from the production of fracing fluid
  - Direct and indirect GHG emissions from land use from access roads and well pads
  - Gas exploration
  - Treatment of fracing fluid
  - Split between venting and fugitive emissions from pipeline transport

Question #7:

What are the opportunities for reducing GHG emissions?

Technology Opportunities

- **Opportunities for Reducing the GHG Footprint of Natural Gas Extraction and Delivery**
  - Reduce emissions from unconventional gas well completions and workovers
    - Better data is needed to properly characterize this opportunity based on basin type, drilling method, and production rate
  - Improve compressor fuel efficiency
  - Reduce pipeline fugitive emissions thru technology and best management practices (collaborative initiatives)

- **Opportunities for Reducing the GHG Footprint of Natural Gas and Coal-fired Power Generation**
  - Capture the CO_2 at the power plant and sequester it in a saline aquifer or oil bearing reservoir (CO_2-EOR)
  - Improve existing power plant efficiency
  - Invest in advanced power research, development, and demonstration

All Opportunities Need to Be Evaluated on a Sustainable Energy Basis: Environmental Performance, Economic Performance, and Social Performance (e.g., energy reliability and security)

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NATIONAL ENERGY TECHNOLOGY LABORATORY

Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production

October 24, 2011

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U.S. DEPARTMENT OF ENERGY

Disclaimer

Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production

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Final Report

October 24, 2011

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Acronyms and Abbreviations

AGR	Acid gas removal
API	American Petroleum Institute
bbl	Barrel
Bcf	Billion cubic feet
BOE	Barrel of oil equivalent
Btu	British thermal unit
CBM	Coal bed methane
CCS	Carbon capture and sequestration
cf	Cubic feet
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
DOE	Department of Energy
eGRID	Emissions & Generation Resource Integrated Database
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
EUR	Estimated ultimate recovery
EXPC	Existing pulverized coal
g	Gram
gal	Gallon
Gg	Gigagram
GHG	Greenhouse gas
GTSC	Gas turbine simple cycle
GWP	Global warming potential
H_2S	Hydrogen sulfide
hp-hr	Horsepower-hour
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
km	Kilometer
kWh	Kilowatt-hour
lb, lbs	Pound, pounds
LCA	Life cycle assessment, analysis
LNG	Liquefied natural gas
m	Meter
m^3	Meters cubed
Mbbl	Thousand barrels
Mcf	Thousand cubic feet
MJ	Megajoule
MMbbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
MW	Megawatt
MWh	Megawatt-hour
N_2O	Nitrous oxide
NETL	National Energy Technology Laboratory
NG	Natural gas
NGCC	Natural gas combined cycle
NMVOC	Non-methane volatile organic compound
NREL	National Renewable Energy Laboratory
PRB	Powder River Basin
psig	Pounds per square inch gauge
PT	Product transport
RMA	Raw material acquisition
RMT	Raw material transport
SCPC	Super critical pulverized coal
T&D	Transmission and distribution
Tcf	Trillion cubic feet
ton	Short ton (2,000 lb)
tonne	Metric ton (1,000 kg)
UP	Unit process

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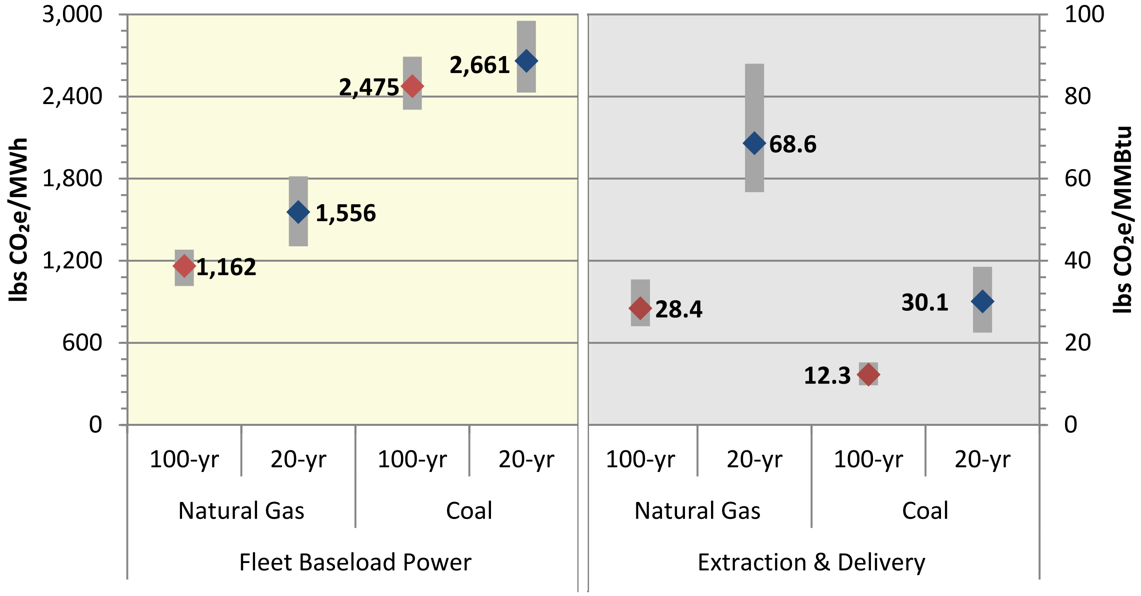
Executive Summary

Natural gas-fired baseload power production has life cycle greenhouse gas emissions 42 to 53 percent lower than those for coal-fired baseload electricity, after accounting for a wide range of variability and compared across different assumptions of climate impact timing. The lower emissions for natural gas are primarily due to differences in the current fleets' average efficiency – 53 percent for natural gas versus 35 percent for coal, and a higher carbon content per unit of energy for coal than natural gas. Even using unconventional natural gas, from tight sands, shale and coal beds, and compared with a 20-year global warming potential (GWP), natural gas-fired electricity has 39 percent lower greenhouse gas emissions than coal per delivered megawatt-hour (MWh) using current technology.

In a life cycle analysis (LCA), comparisons must be based on providing an equivalent service or function, which in this study is the delivery of 1 MWh of electricity to an end user. This life cycle greenhouse gas inventory also developed upstream (from extraction to delivery to a power plant) emissions for delivered energy feedstocks, including six different domestic sources of natural gas, of which three are unconventional gas, and two types of coal, and then combines them both into domestic mixes. These are important characterizations for the LCA community, and can be used as inputs into a variety of processes. However, these upstream, or cradle-to-gate, results are not appropriate to compare when making energy policy decisions, since the two uncombusted fuels do not provide an equivalent function. These results highlight the importance of specifying an end-use basis—not necessarily power production—when comparing different fuels.

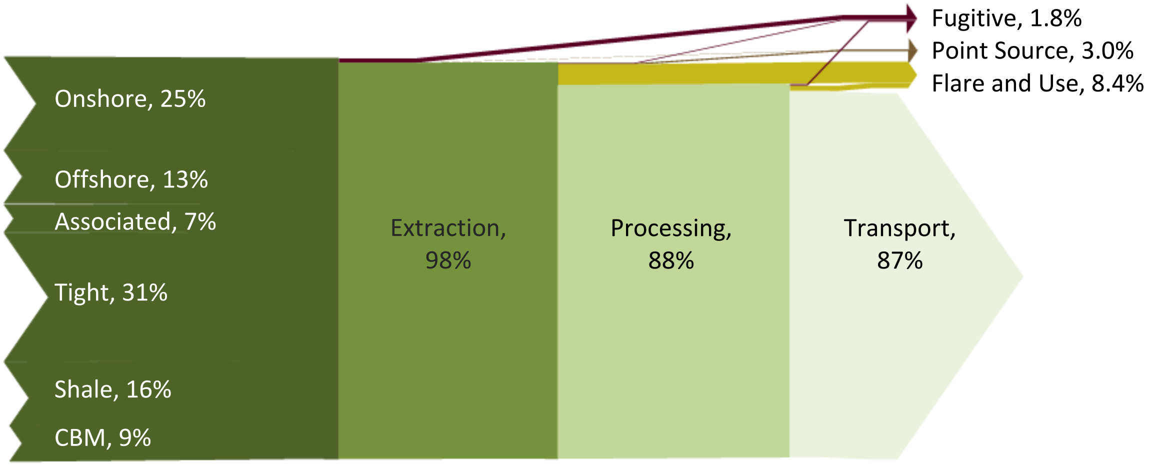
Figure ES-1: Natural Gas and Coal GHG Emissions Comparison



Despite the conclusion that natural gas has lower greenhouse gases than coal on a delivered power basis, the extraction and delivery of the gas has a large climate impact —32 percent of U.S. methane emissions and 3 percent of U.S. greenhouse gases (EPA, 2011b). As **Figure ES-2** shows, there are significant emissions and use of natural gas—13 percent at the city or plant gate—even without considering final distribution to small end-users. The vast majority of the reduction in extracted natural gas —64 percent cradle-to-gate—are not emitted to the atmosphere, but can be attributed to the use of the natural gas as fuel for extraction and transport processes such as compressor operations. Increasing compressor efficiency would lower both the rate of use and the CO_2 emissions associated with the combustion of the gas for energy. Note that this figure accounts for the total mass of natural gas extracted from the earth, including water, acid gases, and other non-methane content.

But, with methane making up 75 to 95 percent of the natural gas flow, there are many opportunities for reducing the climate impact associated with direct venting to the atmosphere. A further 24 percent of the natural gas losses can be characterized as point source, and have the potential to be flared—essentially a conversion of GWP-potent methane to carbon dioxide.

Figure ES-2: Cradle-to-Gate Reduction in Delivered Natural Gas for 2009



The conclusions drawn from this analysis are robust to a wide array of assumptions. However, as with any inventory, they are dependent on the underlying data, and there are many opportunities to enhance the information currently being collected. This analysis shows that the results are both sensitive to and impacted by the uncertainty of a few key parameters: use and emission of natural gas along the pipeline transmission network; the rate of natural gas emitted during unconventional gas extraction processes such as well completion and workovers; and the lifetime production of wells, which determine the denominator over which lifetime emissions are placed.

Table ES-1: Average and Marginal Upstream Greenhouse Gas Emissions (lbs CO_2e/MMBtu)

Source		Average	Marginal	Percent Change
Conventional	Onshore	34.2	20.1	-41.2%
	Offshore	14.3	14.1	-1.4%
	Associated	18.5	18.4	-0.8%
Unconventional	Tight	32.4	32.4	0.0%
	Shale	32.5	32.5	0.0%
	Coal Bed Methane	19.1	19.3	1.4%
Liquefied Natural Gas		42.8	42.5	-0.6%

This analysis inventoried both average and marginal production rates for each natural gas type, with results shown in **Table ES-1**. The average represents natural gas produced from all wells, including older and low productivity stripper wells. The marginal production rate represents natural gas from newer, higher productivity wells. The largest difference was for onshore conventional natural gas, which had a 41 percent reduction in upstream greenhouse gas emissions from 20.1 to 34.2 lbs CO_2e/MMBtu when going from marginal to average production rates. This change has little impact on emissions from power production.

This inventory and analysis are for greenhouse gases only, and there are many other factors that must be considered when comparing energy options. A full inventory of conventional and toxic air emissions, water use and quality, and land use is currently under development, and will allow comparison of these fuels across multiple environmental categories. Further, all options need to be evaluated on a sustainable energy basis, considering full environmental performance, as well as economic and social performance, such as the ability to maintain energy reliability and security. There are many opportunities for decreasing the greenhouse gas emissions from natural gas and coal extraction, delivery and power production, including reducing fugitive methane emissions at wells and mines, and implementing advanced combustion technologies and carbon capture and storage.

1 Introduction

Natural gas is seen as a cleaner burning and flexible alternative to other fossil fuels, and is used in residential, commercial, industrial, and transportation applications in addition to an expanding role in power production. However, the primary component of natural gas by mass is methane, which is also a powerful greenhouse gas—8 to 72 times as potent as carbon dioxide (Forster et al., 2007). Losses of this methane to the atmosphere during the extraction, transmission, and delivery of natural gas to end users made up 32 percent of U.S. 2009 total methane emissions, and 3 percent of all greenhouse gases (EPA, 2011b). The rate of loss, and the associated emissions, varies with the source of natural gas—both the geographic location of the formation, as well as the technology used to extract the gas.

This report expands upon previous life cycle assessments (LCA) performed by the National Energy Technology Laboratory (NETL) of natural gas power generation technologies by describing in detail the greenhouse gas emissions due to extracting, processing and transporting various sources of natural gas to large end users, and the combustion of that natural gas to produce electricity. Emissions inventories are created for the 2009 average natural gas production, but also for natural gas produced from the next highly-productive well for each source of natural gas. This context allows analysis of what the emissions are, and also what they could be in the future.

This analysis also includes an expanded system which compares the life cycle greenhouse gases (GHGs) from baseload natural gas-fired power plants with the GHGs generated by coal-fired plants, including extraction and transportation of the respective fuels. This comparison provides perspective on the scale of fuel extraction and delivery emissions relative to subsequent emissions from power generation and electricity transmission.

Beyond presenting the inventory, the goal of this report is to provide a clear presentation of NETL's natural gas model, including documentation of key assumptions, data sources, and model sensitivities. Further, areas of large uncertainty in the inventory are highlighted, along with areas for potential improvement for both data collection and greenhouse gas reductions.

This greenhouse gas inventory and analysis are part of a larger comprehensive life cycle assessment being performed on the same natural gas system. That assessment effort includes new sources of shale gas and expands the inventory beyond greenhouse gases to include criteria and hazardous air pollutants, water use and quality, direct and indirect land use and greenhouse gases from land use change.

2 Inventory Method, Assumptions, and Data

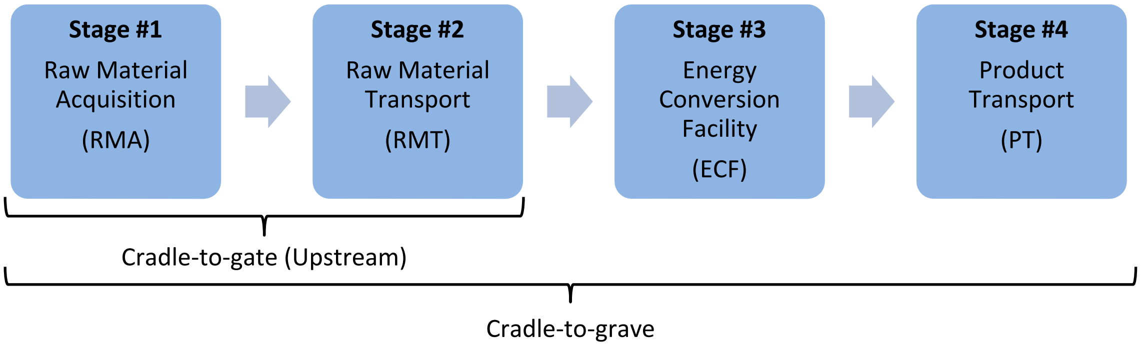
This ISO 14040-compliant inventory and analysis applies the LCA framework to determine the greenhouse gas burdens of natural gas extraction, transport and use in the U.S. The boundaries, basis of comparison, model structure, and data used by this analysis are discussed below. Further detail is available in the Appendix to this document.

2.1 Boundaries

The first piece of this analysis is a cradle-to-gate greenhouse gas inventory that focuses on raw material acquisition and transport; as such, it is also referred to as an upstream inventory, upstream being a relative term (relative, in this case, to the power plant). As shown in **Figure 2-1**, and in more detail in **Figure 2-2**, the boundary of Stage #1 includes all construction and operation activities necessary to extract fuel from the earth, and ends when fuel is extracted, prepared, and ready for final transport to the power plant. Stage #2 includes all construction and operation activities necessary to move fuel from the extraction and processing point to the power plant, and ends at the power plant gate. The boundary of the upstream inventory of natural gas does not include the distribution system of natural gas to small end users, but rather is representative of delivery to a large end user such as a power plant or even a city gate.

The second piece of this analysis is a cradle-to-grave context to compare the greenhouse gas emissions of natural gas extraction and transport with those of electricity production and transmission. Neither piece of analysis includes the use of the produced product, but rather ends when the product is delivered. Coal-fired power systems are used as a further point of comparison.

Figure 2-1: Life Cycle Stages and Boundary Definitions



2.2 Basis of Comparison (Functional Unit)

To establish a basis for comparison, the LCA method requires specification of a functional unit, the goal of which is to define an equivalent service provided by the systems of interest. Within the cradle-to-gate boundary of this analysis, the functional unit is 1 MMBtu of fuel delivered to the gate of an energy conversion facility or other large end user. When the boundaries of the analysis are expanded to include power production, the functional unit is the delivery of 1 MWh of electricity to the consumer. In both contexts, the period over which the service is provided is 30 years.

2.2.1 Global Warming Potential

Greenhouse gases in this inventory are reported on a common mass basis of carbon dioxide equivalents (CO_2e) using the global warming potentials (GWP) of each gas from the 2007 Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (Forster, et al., 2007). The default GWP used is the 100-year time frame, but in some cases, results for the 20-year time frame are presented as well. Selected results comparing all three time frames are included in the Appendix. **Table 2-1** shows the GWPs used for the greenhouse gases inventoried in this study.

Table 2-1: IPCC Global Warming Potentials (Forster, et al., 2007)

GHG	20-year	100-year (Default)	500-year
CO_2	1	1	1
CH_4	72	25	7.6
N_2O	289	298	153
SF_6	16,300	22,800	32,600

2.3 Representativeness of Inventory Results

This inventory uses data gathered from a variety of sources, each of which represents a particular temporal period, geographic location, and state of technology. Since the results of this study are the combination of each of those sources, this section discusses what the results of this study represent in each of those categories.

2.3.1 Temporal

The natural gas upstream inventory results best represent the year 2009, because of the use of the 2009 EIA natural gas production data to create the mix of natural gas sources in the domestic average result and well production rates for each source of natural gas. The year-over-year change to that mix of natural gas sources is small, and the results could represent a period from 2004 to 2012.

This study does not attempt to forecast technological advances or market shifts that might significantly change production rates or emissions of less mature formations.

The inventory results through the conversion of fuel to electricity represent the year 2010 for NETL system study-based technologies and the year 2007 for the fleet average values for coal and natural gas, since this is the vintage of the latest eGRID data release (EPA, 2010). Again, there would be little year-over-year change to the information, and so this LCA could reasonably represent a longer time period, from 2004 to 2015.

Some information included in this inventory pre-dates the temporal period stated above, but was determined to be the latest or highest quality available data.

The time frame of this study is 30 years, but that does not accurately represent a well drilled 30 years from now and operating 60 years into the future. An assumption is made about resource availability based on current estimated ultimate recovery values, and forecasts from the Energy Information Administration (EIA).

2.3.2 Geographic

The results of this inventory are representative of the lower 48 United States. Natural gas from Alaska is neither explicitly included nor excluded, nor are imports and exports. In some situations, source data may not break out information about geographic location, and so is implicitly included in this inventory. However, the error associated with this type of inclusion—or exclusion—is small.

2.3.3 Technological

The natural gas upstream inventory results include two distinct technological representations. The first is a baseline result which represents average 2009 natural gas production, including production from older, less productive wells. Production data from that year is used to create an average domestic mix of natural gas sources, and the production rate of each source well is generally based on 2009 well count and production data. The second set of results is representative of a new marginal unit of natural gas produced in 2009; these results use a variety of methods to create production rates for wells which would create the next unit of natural gas.

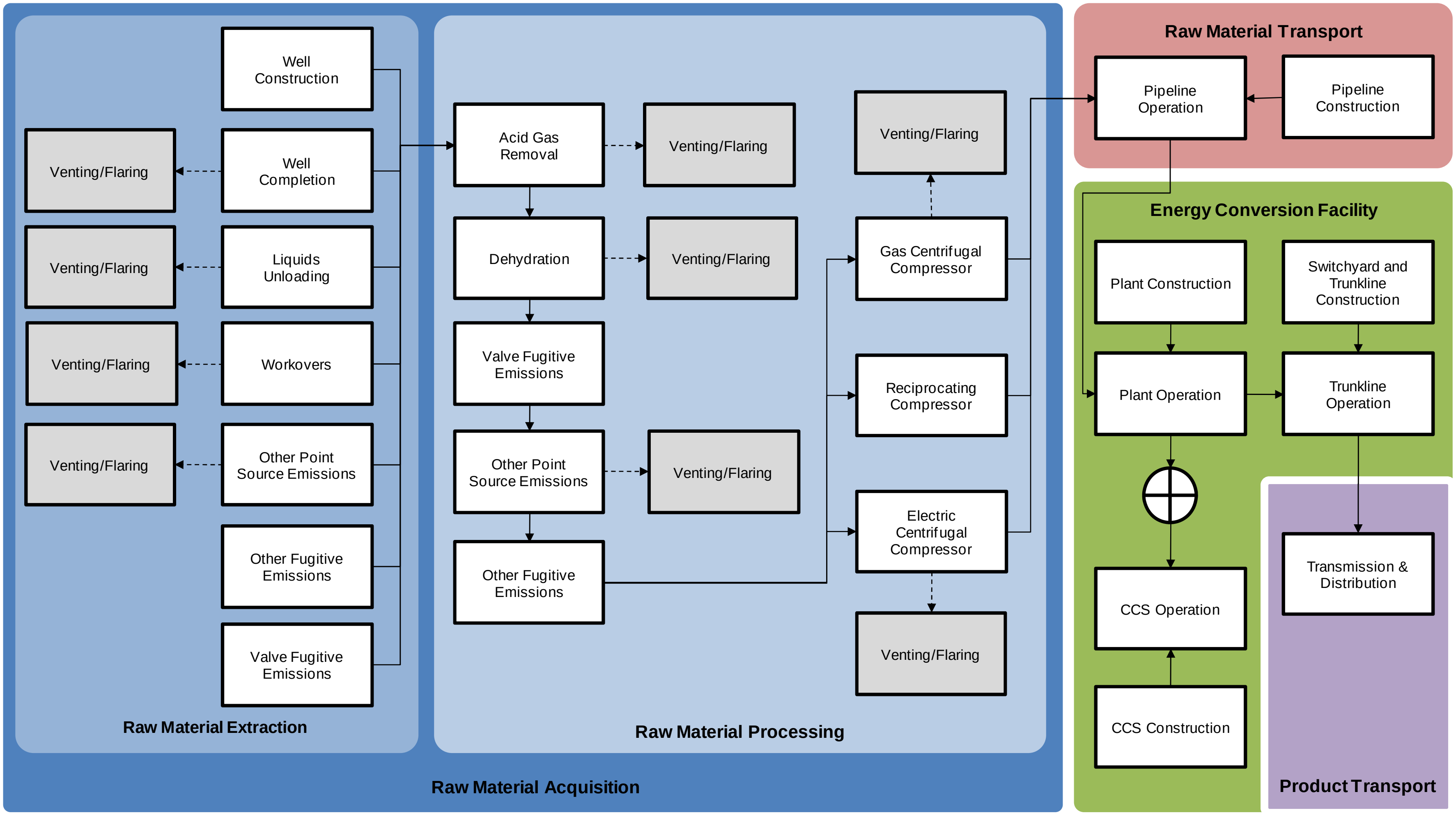
The results of this inventory are representative of currently installed technology as of 2011. This installed base is different from current technology because it includes much older equipment that is still operating.

2.4 Model Structure

All results for this inventory were calculated by NETL's LCA model for natural gas power systems. This model is an interconnected network of operation and construction blocks. Each block in the model, referred to as a unit process, accounts for the key inputs and outputs of an activity. The inputs of a unit process include the purchased fuels, resources from nature (fossil feedstocks, biomass, or water), and man-made raw materials. The outputs of a unit process include air emissions, water effluents, solid waste, and product(s). The role of an LCA model is to converge on the values for all intermediate flows within the interconnected network of unit processes and then scale the flows of all unit processes to a common basis, or functional unit.

The network of unit processes used for the modeling of natural gas power is shown in **Figure 2-2**. Note that only the RMA and RMT portions of the model are necessary to determine the upstream environmental burdens of natural gas; a broader scope—from raw material acquisition through delivery of electricity—is necessary to determine the cradle-to-grave environmental burdens of natural gas power. For simplicity, the following figure shows the extraction and delivery for a generic natural gas scenario; NETL's actual model uses six parallel modules to arrive at the life cycle results for a mix of six types of natural gas. This figure also shows a breakdown of the RMA stage into extraction and processing sub-stages.

Figure 2-2: Natural Gas LCA Modeling Structure



2.5 Data

The primary unit processes of this model are based on data compiled by NETL. Secondary unit processes, such as production of construction materials besides steel, are based on third party data. A full description of data sources is available in the Appendix.

Where data for the inventory is available, high and low values are collected, along with a nominal value. When results are presented, three cases are shown: a nominal case, a high case and a low case. The high and low results (error bars on the results) are a deterministic representation of the variability on the data and not indicative of an underlying distribution or likelihood.

2.5.1 Sources of Natural Gas

This inventory and analysis includes results for natural gas domestically extracted from six sources in the lower 48 states:

1. Conventional onshore
2. Associated
3. Conventional offshore
4. Tight sands
5. Shale formations (Barnett)
6. Coal bed methane

This is not a comprehensive list of natural gas extracted or consumed in the United States. Natural gas extracted in Alaska, 2 percent of domestically extracted natural gas, is included as conventional onshore production. The Haynesville shale play makes up a large portion of unconventional shale production, but it is assumed here that the Barnett play is representative of all shale production. Imported natural gas (18 percent of 2009 total consumption, 88 percent of which is imported via pipeline from Canada) is not included. About 12 percent of imports in 2009 were brought in as liquefied natural gas (LNG) from a variety of countries of origin. While this inventory includes a profile for LNG from offshore extraction in Trinidad and Tobago, this natural gas is not included in the domestic production mix.

Table 2-2 shows the makeup of the domestic production mix in the United States in 2009 and the mix of conventional and unconventional extraction. Note that in 2009 unconventional natural gas sources make up 56 percent of production and the majority of consumption in the Unites States (EIA, 2011a).

Table 2-2: Mix of U.S. Natural Gas Sources (EIA, 2011a)

Source	Conventional			Unconventional		
	Onshore	Associated	Offshore	Tight	Shale	CBM
Domestic Mix	25%	13%	7%	31%	16%	9%
Type Mix	44%			56%		
	56%	15%	29%	56%	28%	15%

The characteristics of these six sources of natural gas are summarized next, including a description of the extraction technologies.

2.5.1.1 Onshore

Conventional onshore natural gas is recovered by vertical drilling techniques. Once a conventional onshore natural gas well has been discovered, the natural gas reservoir does not require significant preparation or stimulation for natural gas recovery. Compressors are used to move natural gas through all process equipment and pressurize it for pipeline transport. Approximately 25 percent (5.2 TCF) of U.S. natural gas production is from conventional onshore gas wells (EIA, 2011a).

An intermittent procedure called liquids unloading is performed at mature onshore conventional natural gas wells to remove water and other liquids from the wellbore; if these liquids are not removed, the flow of natural gas is impeded. Another intermittent activity is a well workover, which is necessary to repair damage to the wellbore and replace downhole equipment, if necessary.

Natural gas is lost through intentional venting, which may be necessary for safety reasons, during well completion when natural gas recovery equipment or gathering lines have not yet been installed, or when key process equipment is offline for maintenance. When feasible, vented natural gas can be recovered and flared, which reduces the global warming potential of the vented natural gas by converting methane to carbon dioxide. Losses of natural gas also result from fugitive emissions due to the opening and closing of valves, and processes where it is not feasible to use vapor recovery equipment.

2.5.1.2 Offshore

Conventional offshore natural gas is recovered by vertical drilling techniques, similar to onshore. Once a conventional offshore natural gas well has been discovered, the natural gas reservoir does not require significant preparation or stimulation for natural gas recovery. A natural gas reservoir must be large in order to justify the capital outlay for the completion of the well and construction of an offshore drilling platform, so production rates tend to be very high. Approximately 13 percent (2.7 TCF) of the United States natural gas supply in 2009 was from the conventional extraction from offshore natural gas wells (EIA, 2011a).

2.5.1.3 Associated

Associated natural gas is co-extracted with crude oil. The extraction of onshore associated natural gas is similar to the extraction methods for conventional onshore natural gas (discussed above). Similar to conventional onshore and offshore natural gas wells, associated natural gas extraction includes losses due to well completion, workovers, and fugitive emissions. Since the natural gas is co-produced with petroleum, the use of oil/gas separators is necessary to recover natural gas from the mixed product stream. Another difference between associated natural gas and other conventional natural gas sources is that liquid unloading is not necessary for associated natural gas wells because the flow of petroleum prevents the accumulation of liquids in the well. Approximately 7 percent (1.4 TCF) of U.S. natural gas production is from conventional onshore oil wells (EIA, 2011a). The majority of these wells are in Texas and Louisiana (EIA, 2010).

2.5.1.4 Tight Gas

The largest single source of domestically produced natural gas, and the largest share of unconventional natural gas, is tight gas. From naturalgas.org, tight gas is defined as follows:

> …trapped in unusually impermeable, hard rock, or in a sandstone or limestone formation that is unusually impermeable and non-porous (tight sand). In a conventional natural gas deposit, once drilled, the gas can usually be extracted quite readily, and easily. A great deal more effort has to be put into extracting gas from a tight formation. Several techniques exist that allow natural gas to be extracted, including fracturing and acidizing. However, these techniques are also very costly. Like all unconventional natural gas, the economic incentive must be there to incite

> companies to extract this costly gas instead of more easily obtainable, conventional natural gas (NGSA, 2010).

Approximately 31 percent (6.6 TCF) of natural gas produced domestically is from tight deposits. This analysis assumes tight gas wells are vertically drilled and hydraulically fractured.

2.5.1.5 Shale

Natural gas is also dispersed throughout shale formations, such as the Barnett Shale region in northern Texas. Shale gas cannot be recovered using conventional extraction technologies, but is recovered through the use of horizontal drilling and hydraulic fracturing (hydrofracking). Horizontal drilling creates a wellbore that runs the length of a shale formation, and hydrofracking uses high pressure fluid (a mixture of water, surfactants, and proppants) for breaking apart the shale formation and facilitating the flow of natural gas. Hydrofracking is performed during the original completion of a shale gas well, but due to the steeply declining production curves of shale gas wells, hydrofracking is also performed during the workover of shale gas wells. Unlike conventional natural gas wells, shale gas wells do not require liquid unloading because wellbore liquids are reduced during workover operations. Natural gas from shale formations accounts for approximately 16 percent (3.3 TCF) of the U.S. natural gas production (EIA, 2011a).

2.5.1.6 Coal Bed Methane

Natural gas can be recovered from coal seams through the use of shallow horizontal drilling. The development of a well for coal bed methane requires horizontal drilling followed by a depressurization period during which naturally-occurring water is discharged from the coal seam. Coal bed methane (CBM) wells do not require liquid unloading and the emissions from CBM workovers are similar to those for shale gas wells. The production of natural gas from CBM wells accounts for approximately 9 percent (1.8 TCF) of the U.S. natural gas production (EIA, 2011a).

2.5.2 Natural Gas Composition

Relevant to all phases of the life cycle, the composition of natural gas varies considerably depending on source, and even within a source. For simplicity, a single assumption regarding natural gas composition is used, although that composition is modified as the natural gas is prepared for the pipeline (EPA, 2011a). **Table 2-3** shows the composition on a mass basis of production and pipeline quality natural gas. The pipeline quality natural gas has had water and acid gases (CO_2 and H_2S) removed, and non-methane VOCs either flared or separated for sale. The pipeline quality natural gas has higher methane content per unit mass. The energy content does not change significantly.

Table 2-3: Natural Gas Composition on a Mass Basis

Component	Production	Pipeline Quality
CH_4 (Methane)	78.3%	92.8%
NMVOC (Non-methane VOCs)	17.8%	5.54%
N_2 (Nitrogen)	1.77%	0.55%
CO_2 (Carbon dioxide)	1.51%	0.47%
H_2S (Hydrogen Sulfide)	0.50%	0.01%
H_2O (Water)	0.12%	0.01%

2.5.3 Data for Natural Gas Extraction

This analysis models the extraction of natural gas by characterizing key construction and operation activities at the natural gas wellhead. A summary of each unit process of NETL's model of natural gas extraction is provided below. **Appendix A** includes comprehensive documentation of the data sources and calculations for these unit processes.

2.5.3.1 Well Construction

Data for the construction and installation of natural gas wellheads are based on the energy requirements and linear drill speed of diesel-powered drilling rigs, the depths of wells, and the casing materials required for a wellbore. Construction and installation are one-time activities that are apportioned to each unit of natural gas operations by dividing all construction and installation emissions by the lifetime in years and production in million cubic feet of a typical well.

2.5.3.2 Well Completion

The data for well completion describe the emission of natural gas that occurs during the development of a well, before natural gas recovery and other equipment have been installed at the wellhead. Well completion is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from an event that occurs one time in the life of a well.

The methane emissions from the completion of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells produce 36.65 Mcf/completion and unconventional wells produce 9,175 Mcf/completion (EPA, 2011a).

Within the unconventional well category, NETL adjusted EPA's completion emission factors to account for the different reservoir pressures of unconventional wells. NETL used EPA's emission factor of 9,175 Mcf of methane per completion for Barnett Shale gas wells. NETL adjusted this emission factor downward for tight gas in order to account for the lower reservoir pressures of tight gas wells. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor. The production rate of tight gas wells is 40 percent of that for Barnett Shale wells (with EURs of 1.2 BCF for tight gas vs. 3.0 BCF for Barnett Shale), and thus NETL assumes that the completion emission factor for tight gas wells is 3,670 Mcf of methane per completion (40 percent × 9,175 = 3,670).

CBM wells also involve unconventional extraction technologies, but have lower reservoir pressures than shale gas or tight gas wells. The corresponding emission factor of CBM wells is 49.57 Mcf of methane per completion, which is the well completion factor that EPA reports for low pressure wells (EPA, 2011a).

The analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. For instance, when factoring for the density of natural gas, a conventional completion emission of 36.65 Mcf is equivalent to 1,540 lbs. CH_4/completion.

2.5.3.3 Liquid Unloading

The data for liquids unloading describe the emission of natural gas that occurs when water and other condensates are removed from a well. These liquids impede the flow of natural gas from the well, and thus producers must occasionally remove the liquids from the wellbore. Liquid unloading is necessary for conventional gas wells—it is not necessary for unconventional wells or associated gas wells. Liquid unloading is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from the occasional maintenance of a well.

The methane emissions from liquids unloading are based on the total unloading emissions from conventional wells in 2007, the number of active conventional wells in 2007, and the average frequency of liquids unloading (EPA, 2011a). The resulting emission factor for liquids unloading is 776 lb CH_4/episode.

2.5.3.4 Workovers

Well workovers are necessary for cleaning wells and, in the case of shale and tight gas wells, use hydraulic fracturing to re-stimulate natural gas formations. The workover of a well is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from the occasional maintenance of a well. As stated in EPA's technical support document of the petroleum and natural gas industry (EPA, 2011a), conventional wells produce 2.454 Mcf of methane per workover. EPA assumes that the emissions from unconventional well workovers are equal to the emission factors for unconventional well completion (EPA, 2011a). Thus, for unconventional wells, this analysis uses the same emission factors for well completion (discussed above) and well workovers.

Unlike well completions, well workovers occur more than one time during the life of a well. For conventional wells, there were approximately 389,000 wells and 14,600 workovers in 2007 (EPA, 2011a), which translates to 0.037 workovers per well-year. Similarly, for unconventional wells, there were approximately 35,400 wells and 4,180 workovers in 2007 (EPA, 2011a), which translates to 0.118 workovers per well-year.

2.5.3.5 Other Point Source Emissions

Routine emissions from natural gas extraction include gas that is released from wellhead and gathering equipment. These emissions are referred to as "other point source emissions." This analysis assumes that a portion of these emissions are flared, while the balance is vented to the atmosphere. For conventional wells, 51 percent of other point source emissions are flared, while for unconventional wells, a 15 percent flaring rate is used (EPA, 2011a).

Data for the other point source emissions from natural gas extraction are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for onshore and offshore wells. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas production rate in 2006. The emission factors for other point source emissions from natural gas extraction are shown in **Table 2-4**.

2.5.3.6 Other Fugitive Emissions

Routine emissions from natural gas extraction include fugitive emissions from equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other fugitive emissions," and cannot be captured for flaring. Data for other fugitive emissions from natural gas extraction are based on EPA data for onshore and offshore natural gas wells (EPA, 2011a). EPA's data is based on 2006 production (EPA, 2011a) and shows the annual methane emissions for specific extraction activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas production rate in 2006. The emission factors for other fugitive emissions from natural gas extraction are included in **Table 2-4**.

2.5.3.7 Valve Fugitive Emissions

The extraction of natural gas uses pneumatic devices for the opening and closing of valves and other control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas extraction site, and thus the pneumatic operation of valves results in the emission of fugitive gas.

Data for the fugitive emissions from valves (and other pneumatically-operated devices) are based on EPA data for onshore and offshore gas wells (EPA, 2011a). EPA's data are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific extraction activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas production rate. The emission factors for fugitive valve emissions from natural gas extraction are included in **Table 2-4**.

Table 2-4: Other Point Source and Fugitive Emissions from Natural Gas Extraction

NG Extraction Emission Source	Onshore Extraction	Offshore Extraction	Units
Other Point Source Emissions	7.49E-05	3.90E-05	lb CH_4/lb NG extracted
Other Fugitive Emissions	1.02E-03	2.41E-04	lb CH_4/lb NG extracted
Valve Fugitive Emissions (including pneumatic devices)	2.63E-03	1.95E-06	lb CH_4/lb NG extracted

2.5.3.8 Venting and Flaring

Venting and flaring are necessary in situations where a natural gas (or other hydrocarbons) stream cannot be safely or economically recovered. Venting and flaring may occur when a well is being prepared for operations and the wellhead has not yet been fitted with a valve manifold, when it is not financially preferable to recover the associated natural gas from an oil well or during emergency operations when the usual systems for gas recovery are not available.

The combustion products of flaring at a natural gas well include carbon dioxide, methane, and nitrous oxide. The mass composition of unprocessed natural gas (referred to as "production natural gas") is 78.3 percent CH_4, 1.51 percent CO_2, 1.77 percent nitrogen, and 17.8 percent non-methane hydrocarbons (NMVOCs) (EPA, 2011a). This composition is used to model flaring at the natural gas processing plant. Flaring has a 98 percent destruction efficiency (98 percent of carbon in the flared gas is converted to CO_2), the methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2, and N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

2.5.4 Data for Natural Gas Processing

This analysis models the processing of natural gas by developing an inventory of key gas processing operations, including acid gas removal, dehydration, and sweetening. Standard engineering calculations were applied to determine the energy and material balances for the operation of key natural gas equipment. A summary of NETL's natural gas processing data is provided below. **Appendix A** includes comprehensive documentation of the data sources and calculations for NETL's natural gas processing data.

2.5.4.1 Acid Gas Removal

Raw natural gas contains hydrogen sulfide (H_2S), a toxic gas that reduces the heat content of natural gas. Amine-based processes are the predominant technologies for acid gas removal (AGR). The energy consumed by an amine reboiler accounts for the majority of energy consumed by the AGR process. Reboiler energy consumption is a function of the amine flow rate, which, in turn, is related to the amount of H_2S removed from natural gas. The H_2S content of raw natural gas is highly variable, with concentrations ranging from one part per million on a mass basis to 16 percent by mass in extreme cases. An H_2S concentration of 0.5 percent by mass of raw natural gas (Foss, 2004) is modeled in this analysis.

In addition to absorbing H_2S, the amine solution also absorbs a portion of methane from the natural gas. This methane is released to the atmosphere during the regeneration of the amine solvent. The venting of methane from natural gas sweetening is based on emission factors developed by the Gas Research Institute; natural gas sweetening releases 0.000971 lb of methane per lb of natural gas sweetened (API, 2009).

Raw natural gas contains naturally-occurring CO_2 that contributes to the acidity of natural gas. A mass balance around the AGR unit, which balances the mass of gas input with the mass of gas venting and natural gas product, shows that 0.013 lb of naturally-occurring CO_2 is vented per lb of processed natural gas.

Non-methane volatile organic compounds (NMVOCs) are a co-product of AGR. A mass balance shows that 84 percent of the vented gas from the AGR process is NMVOC. They are separated and sold as a high value product on the market. Co-product allocation based on the energy content of the natural gas stream exiting the AGR unit and the NMVOC stream was used to apportion life cycle emissions and other burdens between the natural gas and NMVOC products.

2.5.4.2 Dehydration

Dehydration is necessary to remove water from raw natural gas, which makes it suitable for pipeline transport and increases its heating value. The configuration of a typical dehydration process includes an absorber vessel in which glycol-based solution comes into contact with a raw natural gas stream, followed by a stripping column in which the rich glycol solution is heated in order to drive off the water and regenerate the glycol solution. The regenerated glycol solution (the lean solvent) is recirculated to the absorber vessel. The methane emissions from dehydration operations include combustion and venting emissions. This analysis estimates the fuel requirements and venting losses of dehydration in order to determine total methane emissions from dehydration.

NETL's data for natural gas dehydration accounts for the reboiler used by the dehydration process, the flow rate of glycol solvent, and the methane vented from the regeneration of glycol solvent. All of these activities depend on the concentrations of gas and water that enter and exit the dehydration process. The typical water content for untreated natural gas is 49 lbs. per million cubic feet (MMcf). In order to meet pipeline requirements, the water vapor must be reduced to 4 lbs./MMcf of natural gas (EPA, 2006). The flow rate of glycol solution is three gallons per pound of water removed (EPA, 2006), and the heat required to regenerate glycol is 1,124 Btu/gallon (EPA, 2006).

2.5.4.3 Valve Fugitive Emissions

The processing of natural gas uses pneumatic devices for the opening and closing of valves and other process control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas processing plant, and thus the pneumatic operation of valves results in the emission of fugitive gas.

Data for the fugitive emissions from pneumatic devices are based on EPA data for gas processing plants (EPA, 2011a). EPA's data is based on 2006 production (EPA, 2011a) and shows the annual methane emissions for specific processing activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for valve fugitive emissions from natural gas processing is included in **Table 2-5**.

2.5.4.4 Other Point Source Emissions

Routine emissions from natural gas processing include gas that is released from processing equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other point source emissions." This analysis assumes that 100 percent of other point source emissions from natural gas processing are captured and flared.

Data for the other point source emissions from natural gas processing are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific gas processing activities. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for other point source emissions from natural gas processing is included in **Table 2-5**.

2.5.4.5 Other Fugitive Emissions

Routine emissions from natural gas processing include fugitive emissions from processing equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other fugitive emissions." and cannot be captured for flaring.

Data for the other fugitive emissions from natural gas processing are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific gas processing activities. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for other fugitive emissions from natural gas processing is included in **Table 2-5**.

Table 2-5: Other Point Source and Fugitive Emissions from Natural Gas Processing

NG Processing Emission Source	Value	Units
Other Point Source Emissions	3.68E-04	lb CH_4/lb NG processed
Other Fugitive Emissions	8.25E-04	lb CH_4/lb NG processed
Valve Fugitive Emissions (including pneumatic devices)	6.33E-06	lb CH_4/lb NG processed

2.5.4.6 Venting and Flaring

The venting and flaring process for natural gas processing is similar to that of natural gas extraction, described in **Section 2.5.3.8**, except all of the other point source emissions at the natural gas processing plant are flared. The combustion products of flaring at a natural gas processing plant include carbon dioxide, methane, and nitrous oxide. The mass composition of pipeline quality natural gas is 92.8 percent CH_4, 0.47 percent CO_2, 0.55 percent nitrogen, and 5.5 percent NMVOCs; this composition is used to model flaring at the natural gas processing plant. Flaring has a 98 percent destruction efficiency (98 percent of carbon in the flared gas is converted to CO_2); the methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2; and N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

2.5.4.7 Natural Gas Compression

Compressors are used to increase the natural gas pressure for pipeline distribution. This analysis assumes that the inlet pressure to compressors at the natural gas extraction and processing site is 50 psig and the outlet pressure is 800 psig. Three types of compressors are used at natural gas processing plants: gas-powered reciprocating compressors, gas-powered centrifugal compressors, and electrically-powered centrifugal compressors.

Reciprocating compressors used for industrial applications are driven by a crankshaft that can be powered by 2- or 4-stroke diesel engines. Reciprocating compressors are not as efficient as centrifugal compressors and are typically used for small scale extraction operations that do not justify the increased capital requirements of centrifugal compressors. The natural gas fuel requirements for a gas-powered, reciprocating compressor used for natural gas extraction are based on a compressor survey conducted for natural gas production facilities in Texas (Burklin & Heaney, 2006).

Gas-powered centrifugal compressors are commonly used at offshore natural gas extraction sites. The amount of natural gas required for gas powered centrifugal compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures).

If the natural gas extraction site is near a source of electricity, it has traditionally been financially preferable to use electrically-powered equipment instead of gas-powered equipment. This is the case for extraction sites for Barnett Shale located near Dallas-Fort Worth. The use of electric equipment is also an effective way of reducing the noise of extraction operations, which is encouraged when an extraction site is near a populated area. An electric centrifugal compressor uses the same compression principles as a gas-powered centrifugal compressor, but its shaft energy is provided by an electric motor instead of a gas-fired turbine.

Centrifugal compressors (both gas-powered and electrically-powered) lose natural gas through a process called wet seal degassing, which involves the regeneration of lubricating oil that is circulated between the compressor shaft and housing. This analysis uses an EPA study that sampled venting emissions from 15 offshore platforms (Bylin et al., 2010) and implies a wet seal degassing emission factor of 0.0069 lb of natural gas/lb of processed natural gas.

2.5.5 Data for Natural Gas Transport

This analysis models the transport of natural gas by characterizing key construction and operation activities for pipeline transport. A summary of NETL's natural gas transport data is provided below. **Appendix A** includes comprehensive documentation of the data sources and calculation methods for NETL's natural gas transport data.

2.5.5.1 Natural Gas Transport Construction

The construction of a natural gas pipeline is based on the linear density, material requirements, and length for pipeline construction. A typical natural gas transmission pipeline is 32 inches in diameter and is constructed of carbon steel. Construction is a one-time activity that is apportioned to each unit of natural gas transport by dividing all construction burdens by the book life in years and throughput in million cubic feet of the pipeline.

2.5.5.2 Natural Gas Transport Operations

Data for the operation of a natural gas pipeline are based on national inventory data for methane emissions from natural gas transmission (EPA, 2011b) and a national pipeline compressor survey compiled by EIA (Gaul, 2011). Air emissions from pipeline operations are calculated by applying AP-42 emission factors to the portion of pipeline natural gas that is combusted for compressor power. Seven percent of U.S. natural gas pipeline compressors rely on electric power, and thus the emission profile of the U.S. electricity grid is used to model the emissions associated with electric compressor operations. Finally, the estimated transport capacity of U.S. national gas pipelines (in ton-miles) is applied to the other pipeline variables in order to correlate pipeline emissions with pipeline distance.

2.5.6 Data for Other Energy Sources

The overall goal of this analysis is to understand the greenhouse gas burdens of natural gas extraction and transport. However, the modeling of the conversion of natural gas energy to electricity and electricity transmission is necessary in order to understand how significant extraction and transport are in the cradle-to-grave life cycle context. Additionally, including a comparison both to the upstream greenhouse gases from coal extraction and transport, and the conversion of coal to electricity allows comparison of the fuels on a common basis.

Coal was chosen as a comparable fossil energy source to natural gas that will be used for power production. Because a mix of natural gas sources is developed to represent a domestic production average, a similar method was followed for developing an average domestic coal extraction and transport profile. Two sources of coal are used in the mix, and a wide range of uncertainty is applied to sensitive parameters to ensure the domestic average is captured. The two coal sources are:

- Illinois No. 6 Underground-mined Bituminous
- Powder River Basin Surface-mined Sub-bituminous

Table 2-6 shows the properties used for each type of coal, as well as the proportion of U.S. supply used to create the average profile. The methane content is indicative of what is emitted to the atmosphere during the mining process, not the methane contained in the coal in the formation or after mining.

Table 2-6: Coal Properties

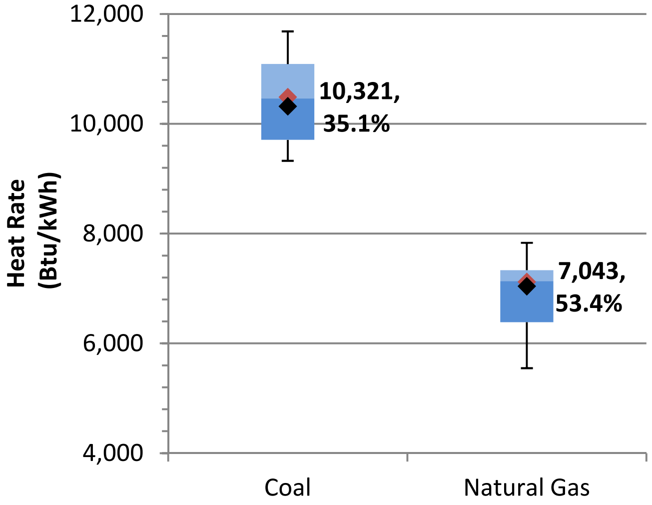
Coal Type	U.S. Supply Share (% by energy)	Energy Content (Btu/lb)	Carbon Content (% by mass)	Methane Emissions (cf CH_4/ton)
Sub-bituminous	69%	8,564	50.1%	8 – 98 (51)
Bituminous	31%	11,666	63.8%	360 – 500 (422)
Average		9,526	54.3%	

Additional information for the Illinois No. 6 profile can be found in the appendix and in the NETL document, *Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant (NETL, 2010e).* Additional information for the Powder River Basin coal extraction and transport profile can be found in the appendix to this document.

2.5.7 Data for Energy Conversion Facilities

The simplest way to compare the full life cycle of coal and natural gas is to produce electricity, although there are alternative uses for both feedstocks. To compare inputs of coal and natural gas on a common basis, production of baseload electricity was chosen. Seven different power plant options are used – three for natural gas and four for coal. Three of the options include carbon capture technology and sequestration infrastructure. Two of the options are U.S. fleet averages based on eGRID data, while the remainder are NETL baseline models. For the U.S. fleet average power plants, **Figure 2-3** shows the distribution of heat rates and associated efficiencies from eGRID. To arrive at the samples shown below, plants smaller than 200MW, with capacity factors lower than 60 percent, and with primary feedstock percentages below 85 percent were cut. The boxes are the first and third quartiles, and the whiskers the 5th and 95th percentiles. The division in the boxes is the median value. The black diamond is the mean, and the orange diamond is the production-weighted mean.

Figure 2-3: Fleet Baseload Heat Rates for Coal and Natural Gas (EPA, 2010)



2.5.7.1 Natural Gas Combined Cycle (NGCC)

The NGCC power plant is based a 555-MW thermoelectric generation facility with two parallel, advanced F-Class gas fired combustion turbines. Each combustion turbine is followed by a heat recovery steam generator that produces steam that is fed to a single steam turbine. The NGCC plant consumes natural gas at a rate of 75,900 kg/hr and has an 85 percent capacity factor. Other details on the fuel consumption, water withdrawal and discharge, and emissions to are detailed in NETL's bituminous baseline (NETL, 2010a). The carbon capture scenario for NGCC is configured a Fluor Econamine carbon dioxide capture system that recovers 90 percent of the CO_2 in the flue gas

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant (NETL, 2010d).*

2.5.7.2 Gas Turbine Simple Cycle (GTSC)

The GTSC plant uses two parallel, advanced F-Class natural gas-fired combustion turbines/generators. The performance of the GTSC plant was adapted from NETL baseline of NGCC power by considering only the streams that enter and exit the combustion turbines/generators and not accounting for any process streams related to the heat recovery systems used by combined cycles. The net output of the GTSC plant is 360 MW and it has an 85 percent capacity factor.

2.5.7.3 U.S. 2007 Average Baseload Natural Gas

The average baseload natural gas plant was developed using data from eGRID on plant efficiency (EPA, 2010). The most recent eGRID data is representative of 2007 electricity production. The average heat rate was calculated for plants with a capacity factor over 60 percent and a capacity greater than 200MW to represent those plants performing a baseload role. The average efficiency (weighted by production, so the efficiency of larger, more productive plants had more weight) was 53.4 percent. This heat rate is applied to the energy content of natural gas (which ranges from 990 and 1,030 Btu/cf) in order to determine the feed rate of natural gas per average U.S. natural gas power. Similarly, the carbon content of natural gas (which ranges from 72 percent to 80 percent) is factored by the feed rate of natural gas, 99 percent oxidation efficiency, and a molar ratio of 44/12 to determine the CO_2 emissions per unit of electricity generation.

2.5.7.4 Integrated Gasification Combined Cycle (IGCC)

The plant modeled is a 640 MW IGCC thermoelectric generation facility located in southwestern Mississippi utilizing an oxygen-blown gasifier equipped with a radiant cooler followed by a water quench. A slurry of Illinois No. 6 coal and water is fed to two parallel, pressurized, entrained flow gasifier trains. The cooled syngas from the gasifiers is cleaned before being fed to two advanced F-Class combustion turbine/generators. The exhaust gas from each combustion turbine is fed to an individual heat recovery steam generator where steam is generated. All of the net steam generated is fed to a single conventional steam turbine generator. A syngas expander generates additional power.

This facility has a capacity factor of 80 percent. For the carbon capture case, the plant is a 556 MW facility with a two-stage Selexol solvent process to capture both sulfur compounds and CO_2 emissions. The captured CO_2 is compressed and transported 100 miles to an undefined geographical storage formation for permanent sequestration, in a saline formation.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Integrated Gasification Combined Cycle (IGCC) Power Plant (NETL, 2010c).*

2.5.7.5 Supercritical Pulverized Coal (SCPC)

This plant is a 550 MW facility located at a greenfield site in southeast Illinois utilizing a single-train supercritical steam generator. Illinois No. 6 pulverized coal is conveyed to the steam generator by air from the primary air fans. The steam generator supplies steam to a conventional steam turbine generator. Air emission control systems for the plant include a wet limestone scrubber that removes sulfur dioxide, a combination of low-nitrogen oxides burners and overfire air, and a selective catalytic reduction unit that removes nitrogen oxides, a pulse jet fabric filter that removes particulates, and mercury reductions via co-benefit capture.

The carbon capture case is a 546 MW plant configured with 90 percent CCS utilizing an additional sulfur polishing step to reduce sulfur content and a Fluor Econamine FG Plus process. The captured CO_2 is compressed and transported 100 miles to an undefined geographical storage formation for permanent sequestration, in a saline formation.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant (NETL, 2010e).*

2.5.7.6 Existing Pulverized Coal (EXPC)

This case is an existing pulverized coal power plant that fires coal at full load without capturing carbon dioxide from the flue gas. This case is based on a 434 MW plant with a subcritical boiler that fires Illinois No. 6 coal, has been in commercial operation for more than 30 years, and is located in southern Illinois. The net efficiency of this power plant is 35 percent.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Existing Pulverized Coal (EXPC) Power Plant (NETL, 2010b).*

2.5.7.7 U.S. 2007 Average Baseload Coal

Using a similar method to the fleet average natural gas baseload plant, a mean and weighted average efficiency of 35.1 percent were pulled from eGRID. Using the coal characteristics detailed in **Table 2-6**, a feed rate and emissions rate were created.

For each option, the transmission and distribution (T&D) of electricity incurs a 7 percent loss, resulting in the production of additional electricity and extraction of necessary fuel to overcome this loss. All upstream life cycle stages scale according to this loss factor.

Construction is included in the four NETL developed models. It accounts for less than 1 percent of overall greenhouse gas impact, and so was excluded from the total for the fleet average plants.

The performance characteristics of the power plants modeled in this analysis are summarized in **Table 2-7**. Note that for the average natural gas and coal power plants, low, nominal and high values are indicated.

Table 2-7: Power Plant Performance Characteristics

Property			**Natural Gas**			**Coal**					
			NGCC	**GTSC**	**Avg. NG**	**IGCC**	**IGCC (w/ CCS)**	**SCPC**	**SCPC (w/ CCS)**	**EXPC**	**Avg. Coal**
Performance											
Net Output	MW		555	360	> 200	640	556	550	546	434	> 200
Heat Rate[1]	Btu/kWh	L			7,334						11,090
		N	6,798	11,323	7,043	8,756	10,458	8,687	12,002	9,749	10,321
		H			6,387						9,708
Efficiency	%	L			46.5%						30.8%
		N	50.2%	30.1%	48.4%	39.0%	32.6%	39.3%	28.4%	35.0%	33.1%
		H			53.4%						35.1%
Capacity Fac.	%		85%	85%	> 60%	80%	80%	85%	85%	85%	> 60%
Feedstocks											
Natural Gas	cf/MWh		6,619	11,025	6,858	-	-	-	-	-	-
Ill. No. 6 Coal	lb/MWh		-	-	-	730	876	745	1,036	734	649
PRB Coal	lb/MWh		-	-	-	-	-	-	-	-	355
Air Emissions											
CO_2	lb/MWh		804	1,100	817	1,723	206	1,768	244	2,075	1,999
CO_2 Capture	%		n/a	n/a	n/a	n/a	90%	n/a	90%	n/a	n/a

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[1] L, N, H indicated Low, Nominal (default), and High values, respectively.

2.5.8 Summary of Key Model Parameters

The following table summarizes the key parameters that affect the life cycle results for the extraction of natural gas. This includes the amounts of methane emissions from routine activities, frequency and emission rates from non-routine operations, depths of different well types, flaring rates of vented gas, production rates, and domestic supply shares.

Table 2-8: Key Parameters for Six Types of Natural Gas Sources

Property (Units)	Onshore	Associated	Offshore	Tight Sands	Shale	CBM
Natural Gas Source						
Production Rate (Mcf/day) (Range)	66 (46 - 86)	121 (85 - 157)	2,800 (1,960 - 3,641)	110 (77 - 143)	274 (192 - 356)	105 (73 - 136)
Natural Gas Extraction Well						
Flaring Rate (%)	51% (41 - 61%)			15% (12 - 18%)		
Well Completion (Mcf/episode)	47			4,657	11,643	63
Well Workover (Mcf/episode)	3.1			4,657	11,643	63
Well Workover Frequency (Episode/well/yr)	1.1			3.5		
Liquids Unloading (Mcf/episode)	23.5	n/a	23.5	n/a	n/a	n/a
Liquids Unloading Frequency (Episodes/well)	930	n/a	930	n/a	n/a	n/a
Valve Emissions, Fugitive (lb CH_4/Mcf)	0.11		0.0001	0.11		
Other Sources, Point Source (lb CH_4/Mcf)	0.003		0.002	0.003		
Other Sources, Fugitive (lb CH_4/Mcf)	0.043		0.01	0.043		
Acid Gas Removal (AGR) and CO_2 Removal Unit						
Flaring Rate (%)	100%					
CH_4 Absorbed (lb CH_4/Mcf)	0.04					
CO_2 Absorbed (lb CO_2/Mcf)	0.56					
H_2S Absorbed (lb H_2S/Mcf)	0.21					
NMVOC Absorbed (lb NMVOC/Mcf)	6.59					
Glycol Dehydrator Unit						
Flaring Rate (%)	100%					
Water Removed (lb H_2O/Mcf)	0.045					
CH_4 Emission Rate (lb CH_4/Mcf)	0.0003					
Valves & Other Sources of Emissions						
Flaring Rate (%)	100%					
Valve Emissions, Fugitive (lb CH_4/Mcf)	0.0003					
Other Sources, Point Source (lb CH_4/Mcf)	0.02					
Other Sources, Fugitive (lb CH_4/Mcf)	0.03					
Natural Gas Compression at Gas Plant						
Compressor, Gas-powered Reciprocating (%)	100%	100%		100%	75%	100%
Compressor, Gas-powered Centrifugal (%)			100%			
Compressor, Electrical, Centrifugal (%)					25%	
Natural Gas Emissions on Transmission Infrastructure						
Pipeline Transport Distance (mi.)	604 (483 - 725)					
Pipeline Emissions, Fugitive (lb CH_4/Mcf-mi.)	0.0003					
Natural Gas Compression on Transmission Infrastructure						
Distance Between Compressors (mi.)	75					
Compressor, Gas-powered Reciprocating (%)	78%					
Compressor, Gas-powered Centrifugal (%)	19%					
Compressor, Electrical, Centrifugal (%)	3%					

3 Inventory Results

This section includes upstream results for the average production case, marginal upstream results, and results after conversion to electricity.

3.1 Average Upstream Inventory Results

This analysis defines upstream activities as the raw material acquisition and transport activities that are necessary for the delivery of fuel to a power plant. The results of this analysis include the upstream GHG emissions for natural gas. For the natural gas supply chain, upstream includes well operations and natural gas processing activities, as well as the pipeline transport of natural gas from the extraction site to a power plant.

Figure 3-1: Upstream Cradle-to-gate Natural Gas GHG Emissions by Source

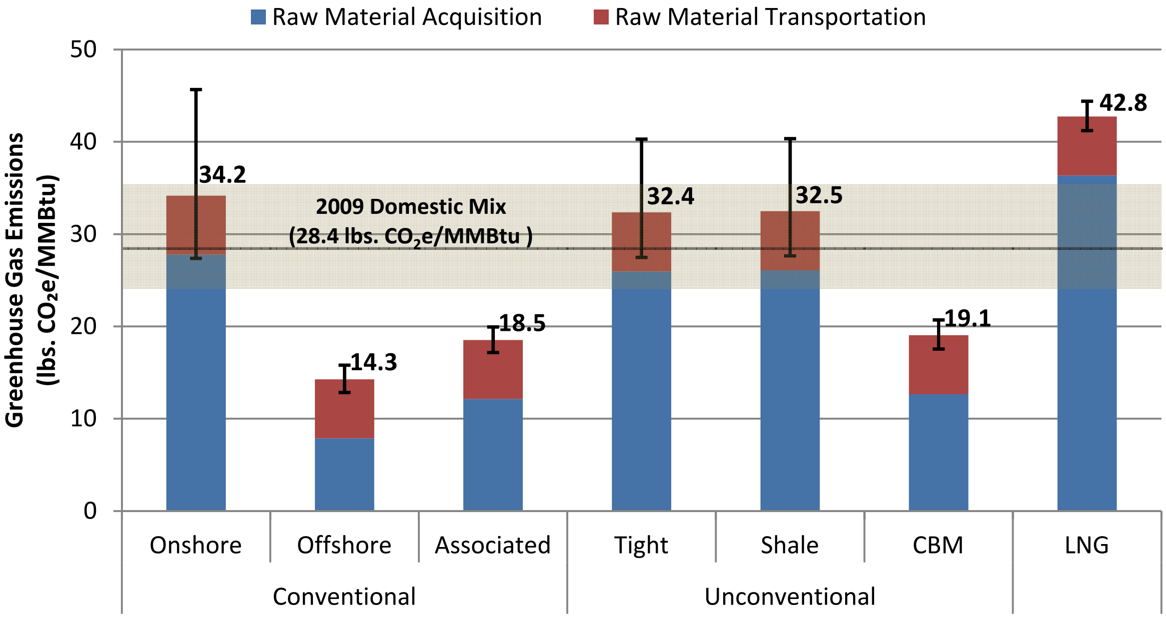


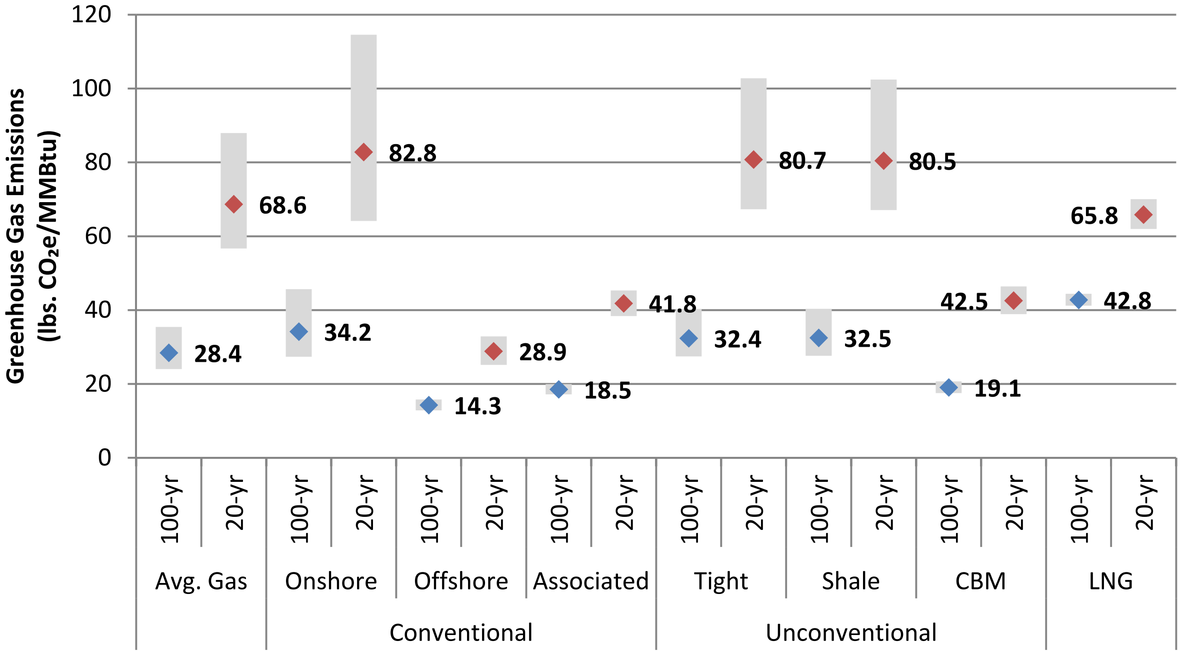
Figure 3-1 shows the comparative upstream greenhouse gases of the six sources of domestic gas, imported liquefied natural gas, and the 2009 mix of all of those sources, broken out by life cycle stage. These results are based on IPCC 100-year GWP. The domestic average of 28.4 lbs. CO_2e/MMBtu and its associated uncertainty are shown overlaying the results for the other types of gas. This average is calculated using the percentages shown in **Table 2-2**. It is worth noting here that the RMT result is the same for all types of natural gas. It is assumed in this study that natural gas is a commodity that is indistinguishable once put on the transport network, so the distance traveled is the same for all types of natural gas. The distance parameter is adjustable, so if a natural gas type with a short distance to markets were evaluated, the RMT value would be smaller.

Offshore sourced natural gas has the lowest greenhouse gases of any source. This is due to the very high production rate of offshore wells and an increased emphasis on controlling methane emissions for safety and risk-mitigation reasons.

Imported gas has a significantly higher greenhouse gases than even domestic unconventional extraction. It is fundamentally an offshore extraction process, which has the lowest GHGs of all the sources. The additional impact is due to the refrigeration, ocean transport and liquefaction processes. Uncertainty is highest for the unconventional sources due to high episodic emissions (well completions, workovers, etc.) and a wide range of observed production rates to allocate those emissions.

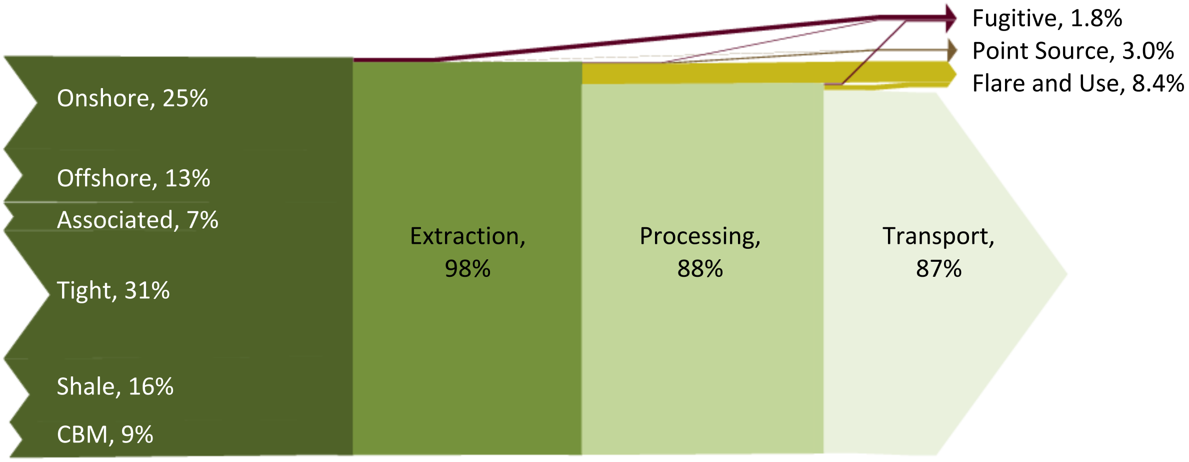
The key sources of GHG emissions in the natural gas supply chain are the combustion of fossil fuels and the venting of methane from natural gas processing and compression equipment.

Figure 3-2: Upstream Cradle-to-gate Natural Gas GHG Emissions by Source and GWP



The results in **Figure 3-2** compare the basic results from **Figure 3-1** across two sets of global warming potentials (detailed in **Table 2-1**). Converting the inventory of greenhouse gases to 20-year GWP, where methane's factor increases from 25 to 72, magnifies the difference between conventional and unconventional sources of natural gas, and the importance of methane losses to the cradle-to-gate GHG results.

Figure 3-3: Cradle-to-Gate Reduction in Extracted Natural Gas



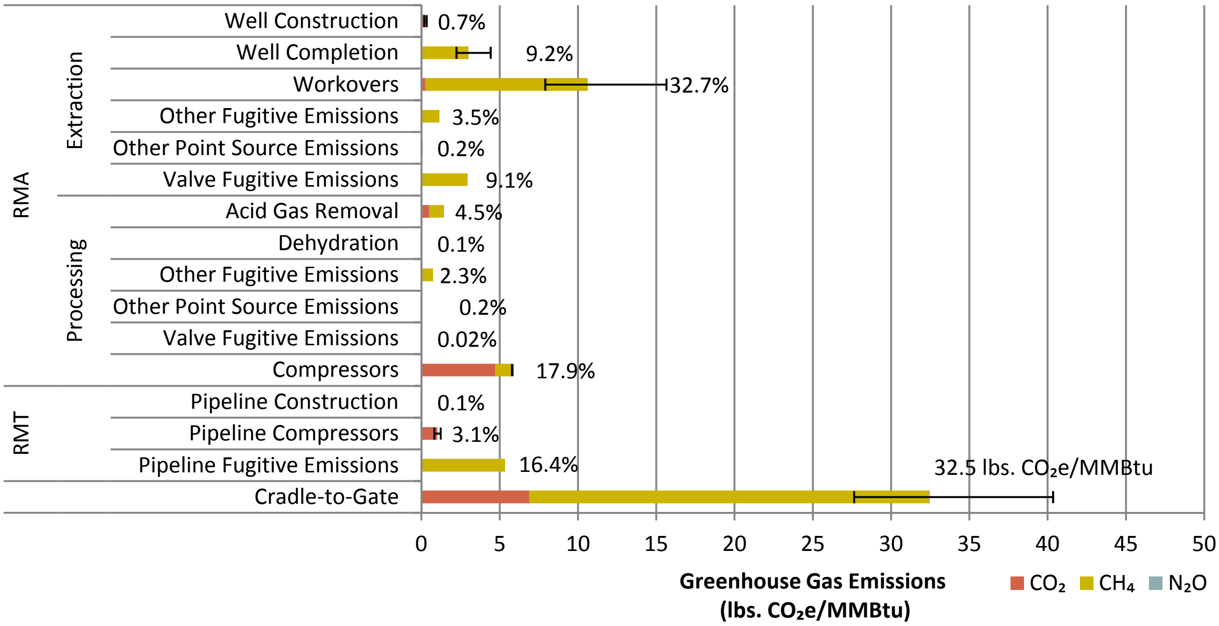
The Sankey diagram shown in **Figure 3-3** shows the reduction in natural gas (not solely methane) from extraction to delivery at the plant gate. This information is also not weighted by global warming potential. **Table 3-1** shows the same information in table form. Of the natural gas extracted from the ground, only 87 percent is delivered to the plant or city gate; 13 percent is either used internally for power, released at a point source and then flared – if applicable, or lost as a fugitive emission. It is important to recognize that not all of this gas is emitted to the atmosphere. In fact, 64 percent of the reduction in natural gas is used to power various processing equipment, most significantly compressors providing motive force for the natural gas. Further, 23 percent are point source emissions, generally concentrated enough to be flared; this, importantly from a climate change perspective, converts the methane to carbon dioxide. Only 13 percent of emissions are considered fugitive: spatially separated emissions difficult to capture or control.

Table 3-1: Natural Gas Losses from Extraction and Transportation

Process	Raw Material Acquisition		Transport	Total
	Extraction	Processing		
Extracted from Ground	100.0%			100.0%
Fugitive Losses	1.2%	0.1%	0.5%	1.8%
Point Source Losses (Vented or Flared)	0.8%	2.2%	0.0%	3.0%
Flare and Fuel Use	0.0%	7.6%	0.8%	8.4%
Delivered to End User				86.9%

By expanding the underlying data in NETL's model, a better understanding of the key contributions to natural gas emissions can be achieved. **Figure 3-4** shows the GHG contribution of specific extraction and transport activities for the Barnett Shale profile. This figure further shows the contribution of methane (CH_4), nitrous oxide (N_2O) and carbon dioxide (CO_2) to the total greenhouse gases. Similar data exists for each source of natural gas, as well as for the domestic average.

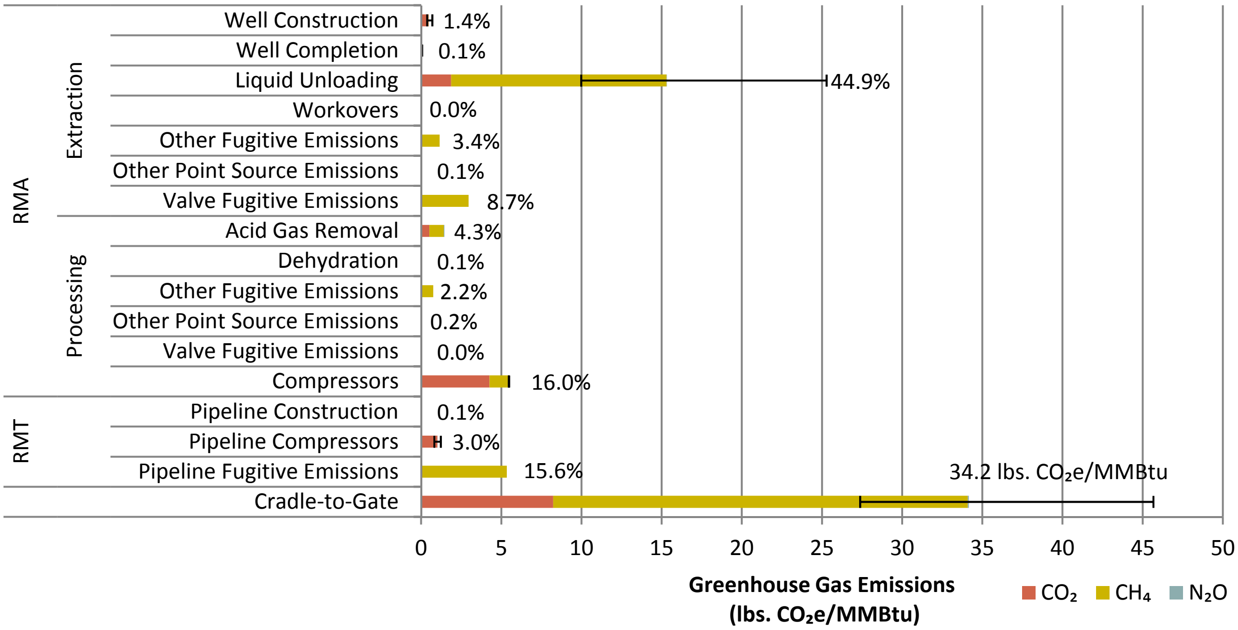
Figure 3-4: Expanded Greenhouse Gas Results for Barnett Shale Gas



This figure shows clearly how important methane is to the total greenhouse gas emissions. In most energy systems, carbon dioxide is the primary concern, but for natural gas extraction, processing and transport, the methane drives the result, and most of the uncertainty. With this unconventional gas, the importance (and associated uncertainty) associated with episodic emissions such as well completion and workover can be seen as well. Well construction, on the other hand, contributes less than 1 percent to the total. Moreover, from the compressors at the last stage of the processing step along with the compressor operations and fugitive emissions on the pipeline, the importance of transport can be seen from these results.

Figure 3-5 shows similar cradle-to-gate results for the natural gas extracted from conventional onshore wells. As with the shale profile, the major contributors are the fuel use and fugitive emissions from the transport, and episodic emissions like liquid unloading. Liquid unloading along contributes 45 percent to the total emissions, and the majority of the uncertainty as well. The uncertainty indicated here is due to a wide range in production rate, not the emission factor for liquids unloading. As discussed in the modeling method, production rate is used to apportion episodic emissions.

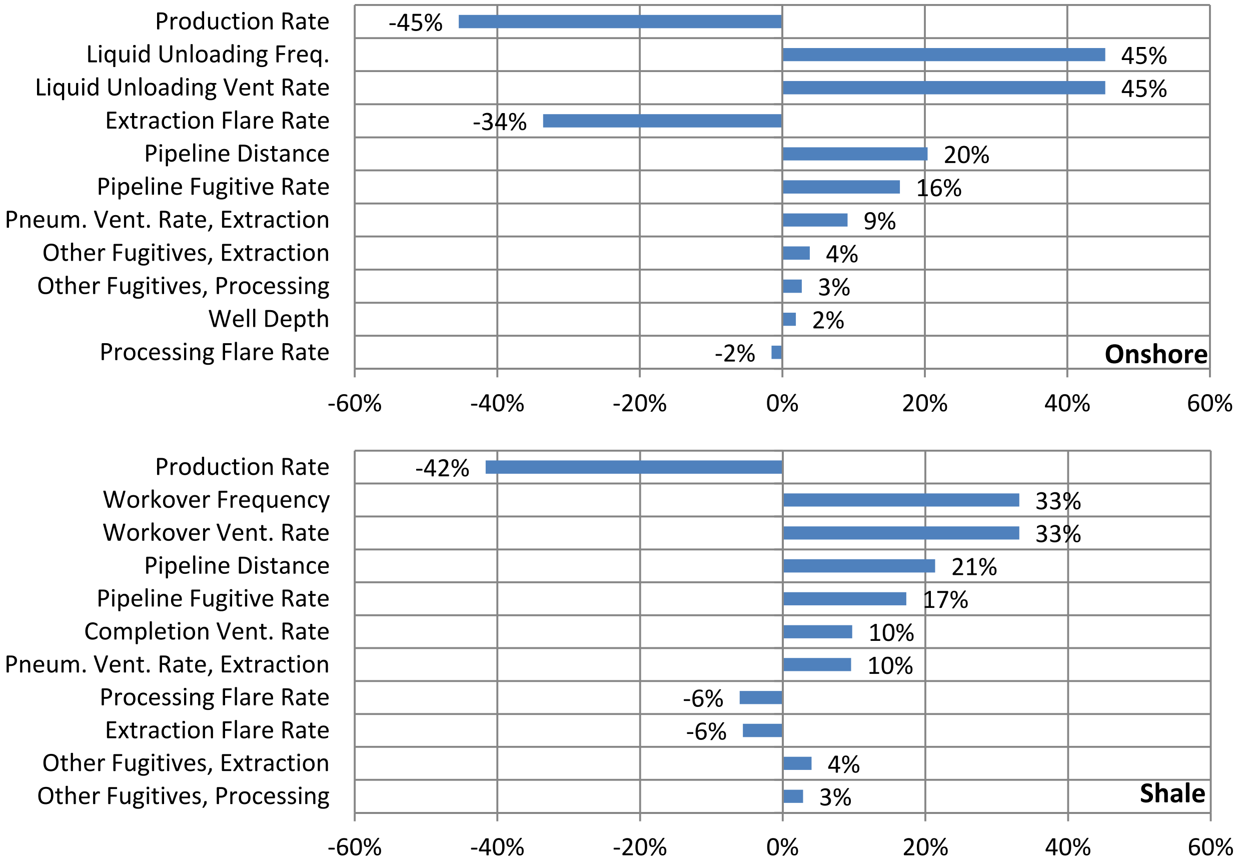
Figure 3-5: Expanded Greenhouse Gas Results for Onshore Natural Gas



This analysis uses a parameterized modeling approach that allows the alteration and subsequent analysis of key variables. Doing so allows the identification of variables that have the greatest effect on results. Sensitivity results are shown in **Figure 3-6**. Parameters were adjusted and displayed regardless of whether uncertainty information was collected for that parameter. Percentages above are relative to a unit change in parameter value; all parameters are changed by the same percentage, allowing comparison of the magnitude of change to the result across all parameters. Positive results indicate that an increase in the parameter leads to an increase in the result. A negative value indicates an inverse relationship; an increase in the parameter would lead to a decrease in the overall result.

For example, a 5 percent increase in shale Production Rate would result in a 2.1 percent (5 percent of 42 percent) decrease in cradle-to-gate GHGs, from 32.5 to 31.8 lbs. CO_2e/MMBtu. A corresponding 5 percent increase in onshore Production rate results in a 2.3 percent decrease to 33.4 lbs. CO_2e/MMBtu. Thus, onshore is more sensitive to changes in production rate than shale gas.

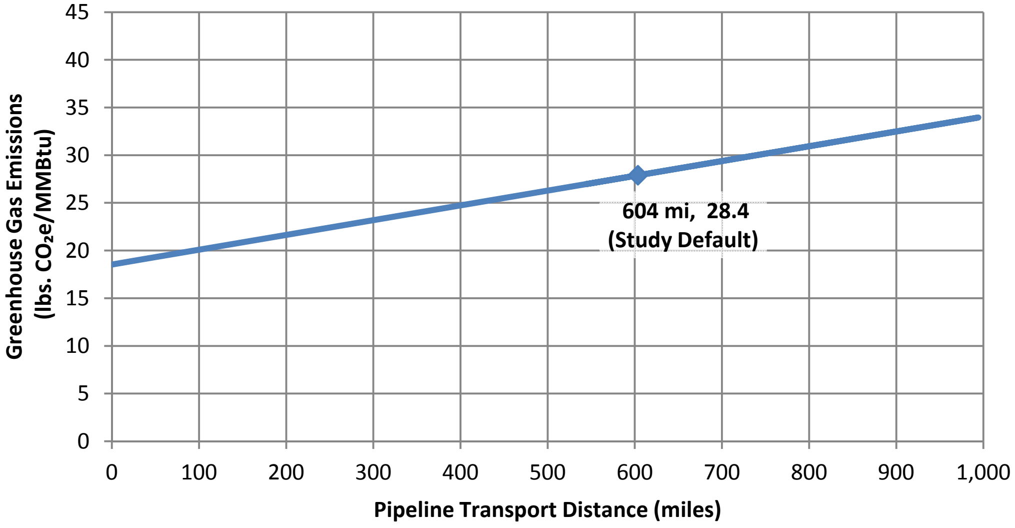
Figure 3-6: Sensitivity of Onshore and Shale GHGs to Changes in Parameters



The results in **Figure 3-6** show that both the onshore and shale profiles are sensitive to changes in pipeline distance, which is currently set to 604 miles for all profiles. As more unconventional sources like Marcellus shale which is close to major demand centers (New York, Boston, Toronto) come on the market, the average distance natural gas has to travel will go down, decreasing the overall impact.

The pipeline transport of natural gas is inherently energy intensive because compressors are required to continuously alter the physical state of the natural gas in order to maintain adequate pipeline pressure. Further, the majority of compressors on the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline. **Figure 3-7** shows the sensitivity of natural gas losses to pipeline distance. The study default for domestic sources of natural gas is 604 miles, which was determined by solving for the distance at which the per-mile emissions were equivalent to the U.S. annual natural gas transmission methane emissions in 2009. See **Appendix A** for full discussion on determining a default distance.

Figure 3-7: Sensitivity of GHGs Results to Pipeline Distance



3.2 Results for Marginal Production

Marginal production is defined here as the next unit of natural gas produced not included in the average, presumably from a new, highly productive well for each type of natural gas. Since older, less productive wells are ignored as part of these results, the production rate per well is much higher, episodic emissions are spread across more produced gas, and the corresponding GHG inventory is lower. **Table 3-2** shows the production rate assumptions used for both the average and marginal cases.

Table 3-2: Production Rate Assumptions for Average and Marginal Cases

Source	Well Count	Dry Production (Tcf)	Production Rate (Mcf/day)					
			Average			Marginal		
			N	L (-30%)	H (+30%)	N	L (-30%)	H (+30%)
Onshore	216,129	5.2	66	46	86	593	297	1,186
Offshore	2,641	2.7	2,801	1,961	3,641	6,179	3,090	12,358
Associated	31,712	1.4	121	85	157	399	200	798
Tight Sands	162,656	6.6	111	78	144	110	77	143
Shale	32,797	3.3	274	192	356	274	192	356
CBM	47,165	1.8	105	73	136	105	73	136

Results are shown below in **Table 3-3**. The marginal and average production rates for the unconventional sources (tight, shale and CBM) were identical, and so there is no change shown below. There was a significant change in the production rate for all the mature conventional sources. Large numbers of the wells from each of these sources are nearing the end of the useful life, and have dramatically lower production rates, bringing the average far below what would be expected of a new well of each type.

Table 3-3: Average and Marginal Upstream Greenhouse Gas Emissions (lbs CO_2e/MMBtu)

Source		Average	Marginal	Percent Change
Conventional	Onshore	34.2	20.1	-41.2%
	Offshore	14.3	14.1	-1.4%
	Associated	18.5	18.4	-0.8%
Unconventional	Tight	32.4	32.4	0.0%
	Shale	32.5	32.5	0.0%
	Coal Bed Methane	19.1	19.3	1.4%
Liquefied Natural Gas		42.8	42.5	-0.6%

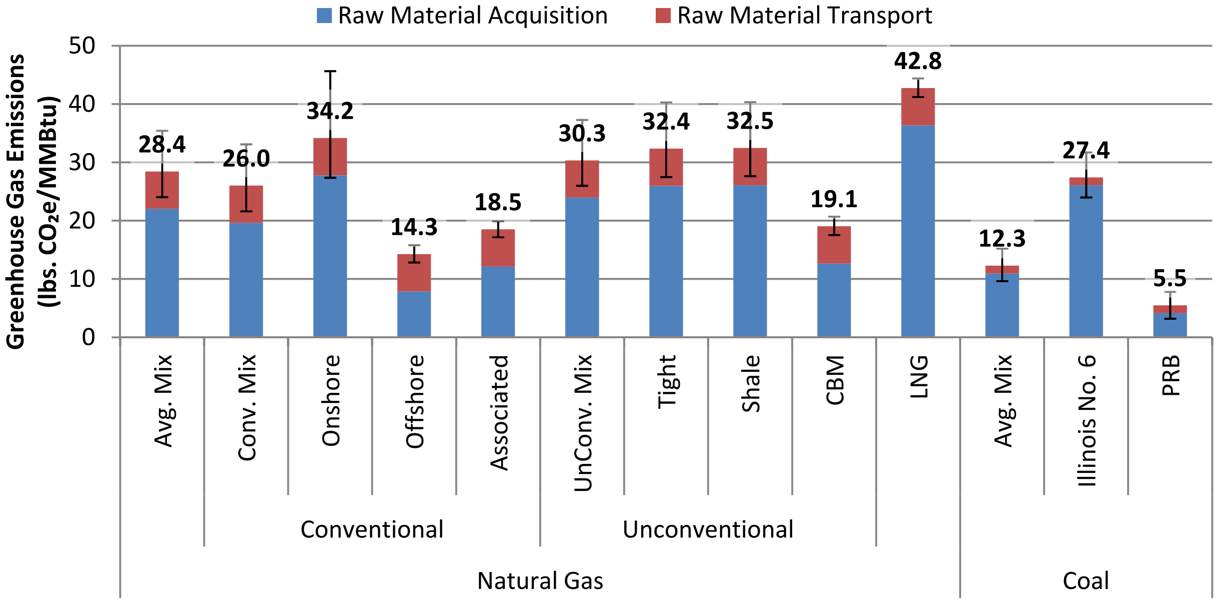
Interestingly, although the production rates for both associated gas and offshore gas change significantly, there is little change to the upstream value: a drop of 0.8 percent and 1.4 percent respectively. This has to do with the characteristics of these types of wells; the flow of natural gas in offshore wells is so strong that there is no need to periodically perform liquids unloading, and for associated wells, the petroleum co-product is constantly removing any liquid in the well. This means the only episodic emission (one which would need to be allocated by lifetime production of the well) is the construction or completion of the well, which is small in both cases, as a percentage of overall emissions.

That leaves onshore conventional production as the only source which shows a significant difference (a drop of 41.2 percent) between the average and marginal production. There are over 200,000 active onshore conventional wells, over 80 percent of which have daily production below the average rate of 138 Mcf/day (EIA, 2010). Yet, when this marginal natural gas is run through electricity generation, there is only a 7 percent drop in greenhouse gas emissions.

3.3 Comparison to Other Fossil Energy Sources

Additional insight can be gained by comparing the life cycle of natural gas power to those of coal. The upstream GHG emissions for various fuels are shown in **Figure 3-8**.

Figure 3-8: Comparison of Upstream GHG Emissions for Various Feedstocks

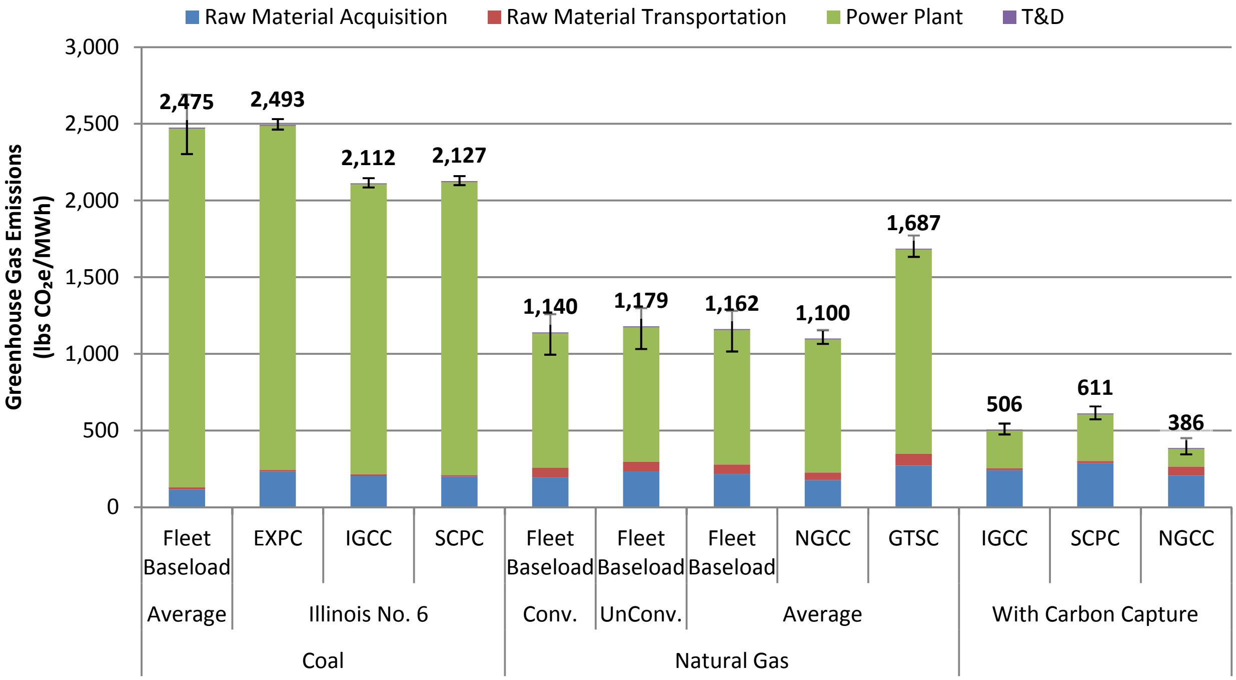


Compared on an upstream energy basis, natural gas has higher GHG emissions than coal. Comparing the domestic mixes from **Figure 3-8**, natural gas is nominally 116 percent more greenhouse gas intense than coal. Gassier bituminous coal such as Illinois No. 6 is more comparable, but only makes up 31 percent of domestic consumption on an energy basis.

3.4 Role of Energy Conversion

The per unit energy upstream emissions comparisons shown above are somewhat misleading in that a unit of coal and natural gas often provide different services. If they do provide the same service, they often do so with different efficiencies—it is more difficult to get useful energy out of coal than it is out of natural gas. To provide a common basis of comparison, different types of natural gas and coal are run through various power plants and converted to electricity. Note that there are alternative uses of both fuels, and as such, different bases on which they could be compared. However, in the United States, the vast majority of coal is used for power production, and so provides the most relevant comparison. **Figure 3-9** compares results for natural gas and coal power on the basis of 1 MWh of electricity delivered to the consumer. In addition to the NETL baseline fossil plants with and without carbon capture and sequestration, these results include a simple cycle gas turbine (GTSC) and representations of fleet average baseload coal and natural gas plants, as described in **Section 2.5.7**.

Figure 3-9: Life Cycle GHG Emissions for Electricity Production



In contrast to the upstream results, which showed a significantly higher GHGs for natural gas than coal, these results show that natural gas power, on a 100-year GWP basis, has a much lower impact than coal power without capture, even when using unconventional natural gas. Even when using less efficient simple cycle turbines, which provide peaking power to the grid, there are far fewer greenhouse gases emitted than for coal-fired power. Because of different the different roles played by these plants, the fairest comparison is the domestic mix of coal run through an average baseload coal power plant with the domestic mix of natural gas run through the average baseload natural gas plant. In that case, the coal-fired plant has emissions of 2,475 lbs. CO_2e/MWh, more than double the emissions of the natural –gas fired plant at 1,162 lbs. CO_2e/MWh.

Figure 3-10 shows the same results but applying and comparing 100- and 20-year IPCC global warming potentials to the inventoried greenhouse gases.

Figure 3-10: Comparison of Power Production GHG Emissions on 100- and 20-year GWPs

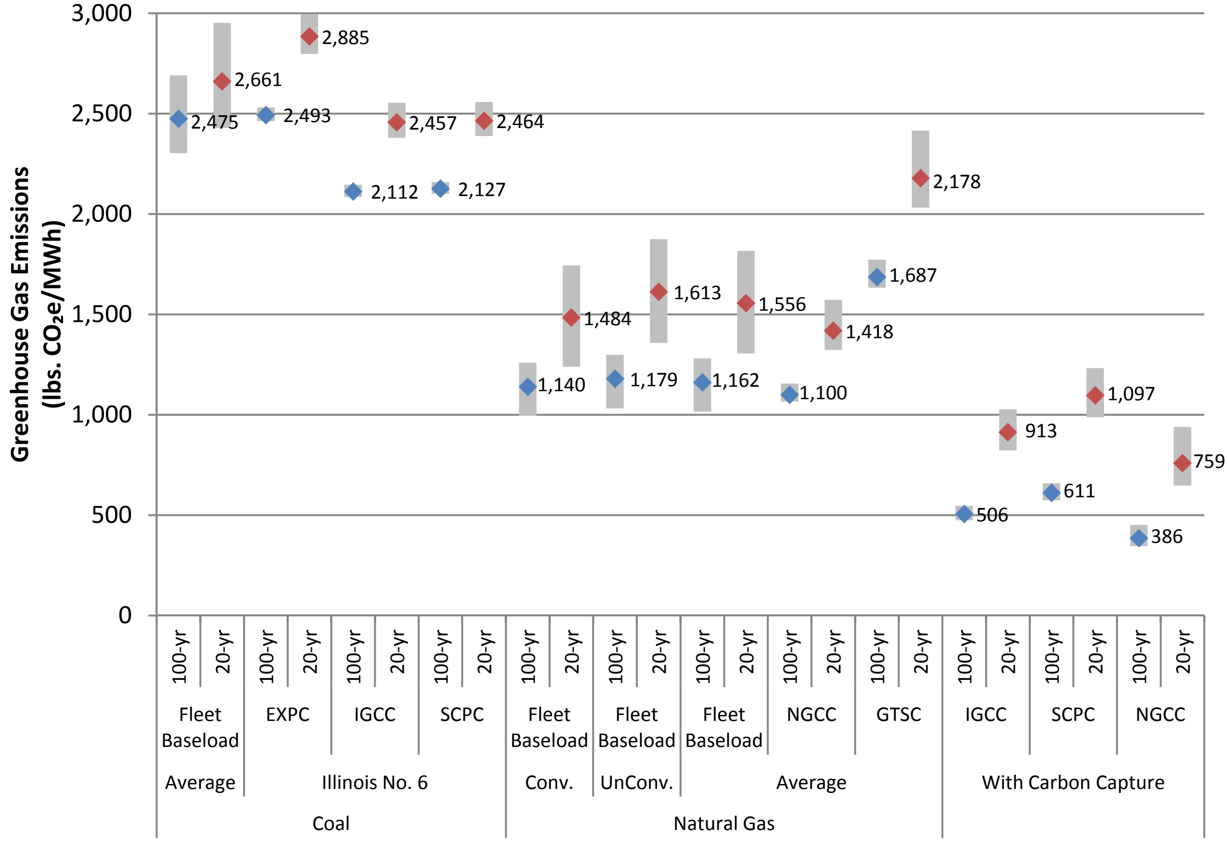


Figure 3-10 shows that even when using a GWP of 72 for CH_4 to increase the relative impact of upstream methane from natural gas, gas-fired power still has lower GHGs than coal-fired power. This conclusion holds across a range of fuel sources (conventional vs. unconventional for natural gas, bituminous vs. average for coal) and a range of power plants (GTSC, NGCC, average for natural gas, and IGCC, SCPC, EXPC, and average for coal). The one situation where this conclusion changed is the use of unconventional natural gas in an NGCC unit with carbon capture compared to an IGCC unit with carbon capture. The high end of the range overlaps the nominal value for IGCC in this situation.

4 Discussion

The following section contains a comparison of the results of this analysis to other natural gas LCAs, a discussion on data limitations, recommendations for improvement and final conclusions.

4.1 Comparison to Other Natural Gas LCAs

Authors at universities and other government labs have conducted research on the natural gas life cycle. The methods and conclusions of three such papers are summarized below.

Life Cycle Assessment of a Natural Gas Combined Cycle Power Generation System (Spath & Mann, 2000)

This NREL study is somewhat dated, having been published in 2000, but using data from the 1990s. It is a high quality study, which makes solid assumptions and tests those assumptions with documented sensitivity analysis. It uses national, annual, top-down information to develop the upstream emissions for natural gas extraction and transportation. Because of this, there are no data specific to unconventional extraction. This study includes not only greenhouse gases but select criteria air emissions and an energy balance. A qualitative impact assessment is performed as well.

Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation (Jaramillo, Griffin, & Matthews, 2007)

This widely cited paper is the most recent publicly available, peer-reviewed study that directly compares life cycle greenhouse gas emissions of power generated from natural gas and coal. Due to concerns regarding gas price volatility at the time the paper was being written, it also includes a comparison of LNG and synthetic natural gas (SNG) from coal. Rather than attempting to represent the next megawatt-hour generated by using best available technology, it looks at average current megawatt-hours generated, so plant efficiencies tend to be lower and emission factors higher. It mixes technologies (NGCC vs. GTSC) and roles (baseload vs. peaking). Like the NREL study, the upstream emissions for both natural gas and coal are top-down numbers. These values are somewhat dated, and represent a homogeneous gas supply rather than breaking out unconventional extraction.

Development of a Top Down Screening Model Using 2011 EPA Greenhouse Gas Inventory

Although this study uses emission factors from the EPA that went into building the 2011 U.S. Greenhouse Gas Inventory, it did not use the annual emissions estimates to generate a top-down value. Rather, some of the EPA emission factors were applied against specific activities, combined with other data sources and standard engineering calculations in a comprehensive hybrid bottom-up approach.

For comparison purposes, NETL performed a top-down analysis of 2009 domestic natural gas production using EPA's 2011 GHG inventory. This top-down approach was not a comprehensive LCA, but was a screening method that resulted in an aggregated, national-level estimate of GHG emissions. The top-down approach gave a GHG result of 36.6 lbs. CO_2e/MMBtu of delivered natural gas to a large end user, with +30 percent and -19 percent uncertainty. NETL's comprehensive LCA model of natural gas gives a GHG result of 28.4 lbs. CO_2e/MMBtu of delivered natural gas, which is 24 percent lower than the top-down value derived from EPA's national inventory. The nominal top-down number from EPA's inventory is within NETL's uncertainty range, but NETL and EPA use many of the same emission factors for natural gas production, and thus an explanation of the 24 percent difference is necessary.

An overarching reason for the difference between EPA's national inventory and NETL's natural gas life cycle analysis model is that EPA's inventory is based on the emissions reported for an entire industry sector over one year, while NETL's model accounts for the operating characteristic of six types of natural gas extraction technologies over a 30-year period and then mixes the six types according to the 2009 U.S. natural gas supply profile. Three specific examples of this fundamental difference between modeling approaches are as follows:

1. A difference in method between activity-based scaling to the national level vs. well-specific production rates that scale results to each of six extraction types.
2. Differences in episodic emission factors for tight gas and the contribution of tight gas to the national inventory.
3. Time series discrepancies inherent in EPA's episodic emission factors.

Clarification on these differences is provided below.

For each type of natural gas well, NETL apportions episodic emission factors based on the production rate of a single well. These apportioned emissions are then compiled according to the relative contribution of each well type to the domestic mix to arrive at the domestic average emissions. EPA's national GHG inventory, on the other hand, does not use well production rates, but uses well activity counts for conventional and unconventional wells to scale up the episodic emission factors to a national level. It is possible that the production rates of the wells that were sampled during the development of EPA's episodic emission factors do not align with the average well production rates applied by NETL. Or the activity counts used by EPA do not align with the contribution of the six natural gas types to the national mix as modeled by NETL.

When modeling tight gas, NETL made adjustments to EPA's emission factors for well completions and workovers. A close look at EPA's documentation (EPA, 2011a) indicates that its unconventional completion and workover emission factors are representative of high-pressure, tight gas wells in the San Juan and Piceance Basins that were completed using a horizontal hydraulic fracturing method and have a high, for tight gas basins, EUR of approximately 2 to 4 BCF. NETL's survey of tight gas production in the U.S. determined that an EUR of 1.2 BCF is more representative of average U.S. tight gas production. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor for tight gas well completion and workovers. NETL uses an emission factor of 3,670 Mcf CH_4 per episode for the completion and workover of tight gas wells. It is worth noting that EPA does not distinguish between tight sands and shale gas in the annual inventory, a general category of unconventional natural gas is characterized by low and high pressure formations. NETL applied EPA's unconventional completion and workover emission factor for low pressure formations (49.57 Mcf CH_4) reported in Subpart W Technical Support Document (EPA, 2011a) to the coal bed methane well profile and the corresponding high pressure well emission factor to shale gas based on the correlation of representative EUR of 3 BCF for Barnett Shale and the San Juan and Piceance Basin EUR's representing a range of 2 to 4 BCF. While the EPA Subpart W Technical Support Document detailed the results for unconventional well completions and workovers for low pressure formations, the annual inventory (EPA, 2011a) discusses unconventional well activity as a single category assumed to be completed by hydraulic fracture, for the purposes of the inventory, and applies the high pressure formation emission factor of 9,175 Mcf CH_4 for all unconventional well completions and workovers in the annual activity count.

The differences between the top-down and comprehensive approaches is further influenced by whether or not EPA explicitly accounts for tight gas production or simply includes tight gas within its conventional onshore natural gas activity factors. Tight gas represents 31 percent of the 2009 U.S. domestic natural gas supply, and thus the results for NETL's domestic mix are sensitive to changes in the tight gas results (the extent of this sensitivity is demonstrated by the tornado chart for the domestic natural gas mix). It is not clear if EPA includes tight gas within its conventional or unconventional category. If EPA accounts for tight gas in its conventional category, then liquids unloading would be incorrectly assigned to tight gas production, which would result in an overstated result. Alternatively, if EPA accounts for tight gas in its unconventional category, then a well completion and workover emission factor based on high production tight gas formations using horizontal hydraulic fracture was applied, which would result in an overstated result. This difference is only relevant in the comparative context between the two modeling approaches (screening versus comprehensive life cycle analysis). With respect to the purpose of the EPA national inventory approach, the effects are minimized based on the granularity of the overall analysis and the comparison of results at the national sector level. As described above, NETL adjusted the episodic emission factors for tight gas and coal bed methane based on well completion method and production profile.

EPA's documentation of unconventional emission factors are provided in its Subpart W document, which is the basis for its national inventory results (EPA, 2011a). EPA's 2009 GHG inventory is representative of 2009 natural gas production; however, a close look at EPA's Subpart W document reveals that the episodic emission factors are based on relatively small samples of natural gas wells from 2006 and 2007. It is common for LCAs to use data from a broad range of years. However, the behavior of the natural gas industry was especially volatile between 2007 and 2009. The imposition of emission factors that are representative of 2006 and 2007 upon other natural gas data that are representative of anomalous activity in 2009 creates a time-series lag that introduces uncertainty to the emission factor.

Figure 4-1: Natural Gas Well Development vs. Natural Gas Production (EIA, 2011b, 2011c)

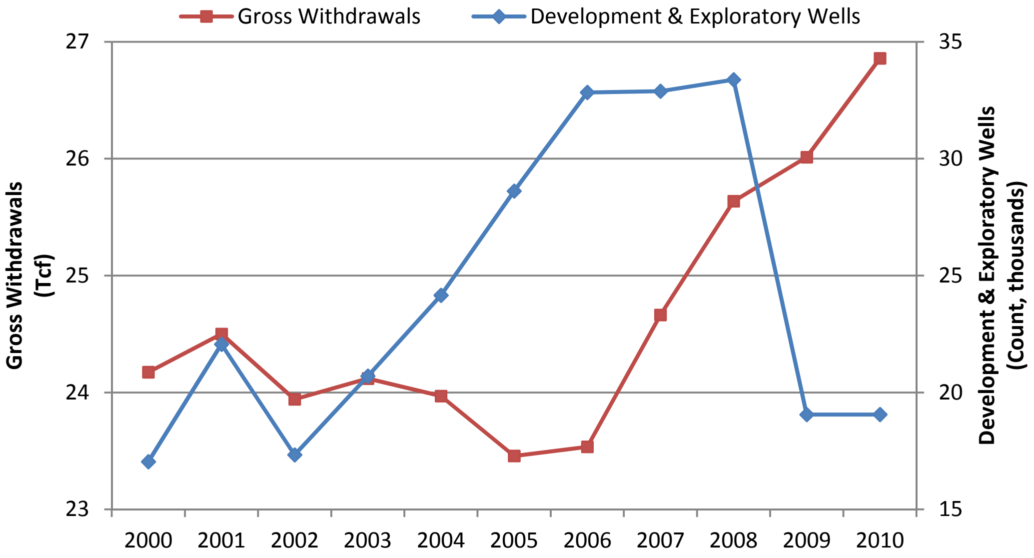


Figure 4-1 shows how increases in natural gas withdrawals lag between five and six years behind the increase in natural gas well drilling activity. Using a numerator with 2006 to 2007 data for well

activity, and 2009 data for withdrawals for the numerator could cause an undefined level of uncertainty in the emission factor. The modeling approaches used by EPA and NETL (as described in the first item above) react differently to this time-series lag. It is possible that NETL's model diminishes these effects because it amortizes the emissions over a 30-year operating period. **Table 4-1** shows the differences among key parameters of the NETL and EPA models.

Table 4-1: Parameter Comparison between NETL and EPA Natural Gas Modeling

Property[1]	Units	NETL						EPA	
		Onshore	Assoc.	Offshore	Tight Sands[2]	Barnett Shale	CBM[3]	Conv.	Unconv.
Contribution to 2009 Mix	Percent	25%	7%	13%	31%	16%	9%	n/a	n/a
Production Rate (30-yr average)	Mcf/day	66	121	2,800	110	274	105	n/a	n/a
Active Wells (2007)	Count	n/a	n/a	n/a	n/a	n/a	n/a	431,035	41,790
Flaring Rate at Well	Percent	51%	51%	51%	15%	15%	51%	51%	15%
Completion Emissions	Mcf CH_4/episode	36.7	36.7	36.7	3,670	9,175	49.6	36.7	9,175
Workover Emissions	Mcf CH_4/episode	2.5	2.5	2.5	3,670	9,175	49.6	2.5	9,175
Workover Frequency	Episodes/year	0.04	0.04	0.04	0.12	0.12	0.12	0.04	0.12
Liquids Unloading Emissions	Mcf CH_4/episode	18.5	n/a	18.5	n/a	n/a	n/a	18.5	n/a
Liquids Unloading Frequency	Episodes/year	31	n/a	31	n/a	n/a	n/a	31	31

Figure 4-2 shows comparative greenhouse gas emissions from the three studies reviewed above. Results from each study were converted to a common basis of 100-year Global Warming Potential in pounds CO_2e per MMBtu gas delivered. The NREL study did not have an explicit range of values, so the central estimate is shown. For Jaramillo et al., the central estimate is the average of the high and low values.

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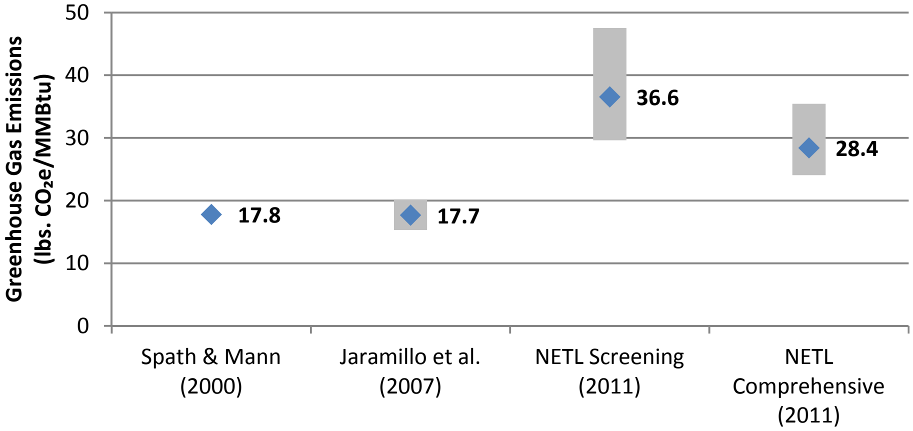
[1] All emission rates are prior to flaring.

[2] The tight sands emission factor for well completions and workovers was calculated by NETL by reducing EPA's completion and workover factor (3,670 Mcf CH_4) for unconventional wells. The emission rates for completions and workovers are associated with the production rates and reservoir pressures of a well.

[3] The CBM emission factor for well completions and workovers (49.57 Mcf CH_4) is from EPA's documentation of low pressure wells. While CBM wells are an unconventional source of natural gas, they have a low reservoir pressure and thus have lower emission rates from completions and workovers.

Figure 4-2: Comparison of Natural Gas Upstream GHGs from Other Studies



4.2 Data Limitations

A key objective of an LCA is to normalize all data to a common basis (the functional unit). Like all LCAs, this analysis is limited by data uncertainty and data limitations. Key instances of data uncertainty and limitation are summarized below.

4.2.1 Data Uncertainty

Episodic emissions, natural gas production rates, flaring rates, and pipeline distance are four areas of data uncertainty in this analysis and represented within the study results.

Episodic emission factors include the non-routine release of natural gas during well completion, workovers, and liquid unloading. The results of this analysis are sensitive to these episodic emissions. The data for episodic emissions from natural gas wells is limited to a relatively small sample of wells and includes data going back as far as 1996 (EPA, 2011a). These emission factors are not necessarily applicable to all natural gas wells. For instance, it is likely that some unconventional wells have been completed using best practices and thus have low completion emissions, while some conventional wells have been completed with poor practices and thus have high completion emissions. However, there is no basis for claiming that a more recent, larger sampling of natural gas wells would increase or decrease these emission factors.

This analysis uses the production rate for each type of natural gas well for apportioning episodic emissions to a unit of natural gas production. The production rates of unconventional natural gas wells (Barnett Shale, tight gas, and CBM wells) are based on estimated ultimate recovery (EUR) data that are specific to each formation and have specific geographical constraints (Lyle, 2011). Representativeness of unconventional production rate data provides a reasonable confidence range of +/-30 percent. Production data for conventional wells is more variable, exhibiting a 200 percent increase from the low to high production rates. This variability is due to the broad range in age, reservoir, and technology characteristics for conventional wells, making it difficult to define a "typical" conventional natural gas well.

Flaring rate is the portion of vented natural gas that is combusted; the unflared portion is released directly to the atmosphere. Conventional wells flare 51 percent of vented gas, while unconventional wells flare 15 percent of vented natural gas (EPA, 2011a). The natural gas processing plant is modeled at a 100 percent flaring rate. While technology is available to capture and flare virtually all of the vented natural gas from extraction and processing, economics and other practical concerns often prevent the implementation of such technologies. To account for uncertainty, this analysis varied the default values for flaring rates by +/-20 percent. It is likely that there are natural gas wells that fall outside of this range; however, based on professional judgment, we expect this range to account for average natural gas production.

The transmission of natural gas by pipeline involves the combustion of a portion of the natural gas in compressors as well as fugitive losses of natural gas. The total natural gas combustion and fugitive emissions is a function of pipeline distance, which was estimated at an average distance of 604 miles. This distance is based on the characteristics of the entire transmission network and delivery rate for natural gas in the U.S. It is possible that some natural gas sources are located significantly closer to their final markets than other sources of natural gas. To account for this uncertainty, this analysis varies the average pipeline distance by +/- 20 percent, which is an uncertainty range based on professional judgment.

4.2.2 Data Availability

Most data required for this analysis were readily available. However, there are several instances for which more detailed data would enhance the functionality of the LCA model and allow further discernment among natural gas types.

- Formation-specific gas compositions (CH_4, H_2S, NMVOC, and water) for each natural gas type would allow the assignment of specific venting emissions for natural gas extraction and processing. It would also allow the calculation of the specific heat load required for natural gas processing equipment (acid gas removal and dehydration).
- The effectiveness of green completions and workovers would allow further scrutiny of the episodic emissions at wells and, possibly, further data granularity among the three unconventional well types (Barnett Shale, tight gas, and CBM wells).
- No data are available for the fugitive emissions from around wellheads (between the well casing and the ground). This is a possible emission source that could present a significant opportunity for reductions in natural gas losses at a specific wellhead or site, but is not expected to be a significant contribution from an average natural gas perspective.
- Data for water sourcing and production of other fluids used for hydraulic fracturing would expand the boundaries of this analysis further and provide more details on the activities that contribute most to the environmental burdens of unconventional natural gas production and delivery.
- Direct and indirect GHG emissions from land use from access roads and well pads would expand the scope of this analysis further and provide more details on the activities that contribute most to the environmental burdens of unconventional natural gas production and delivery.
- Data for the energy requirements of natural gas exploration would allow further comparisons between conventional and unconventional natural gas. Historically, conventional natural gas fields have been difficult to find, but relatively easy to develop once they are located (NGSA, 2010). In contrast, unconventional gas fields are easy to find, but require significant preparation before natural gas is recovered.

- The energy requirements for the treatment of flowback water from the hydraulic fracturing of unconventional wells would represent an environmental burden that could allow further differentiation among natural gas extraction types.
- The current EPA GHG inventory data for natural gas pipeline emissions includes methane emissions in one category. A split between venting and fugitive emissions from pipeline transport would facilitate recommendations for reducing pipeline losses. Vented emissions may present opportunities for recovery, while fugitive emissions may not represent feasible opportunities for recovery.

4.3 Recommendations for Improvement

Creating a greenhouse gas inventory from a life cycle perspective gives not only a more complete picture of the impact of the process in question, but also allows for identification for the areas of largest impact, and those with the greatest opportunity for improvement. Since this inventory is presented on two different bases, opportunities were identified in both the extraction and delivery of natural gas as well as the production of electricity from natural gas and coal.

4.3.1 Reducing the GHG Emissions of Natural Gas Extraction and Delivery

Unconventional gas sources (shale, tight sands, coal bed methane, etc.) now make up the majority of natural gas extraction. As such, the emissions released during well completion and periodic well workovers are a major contributor to the overall greenhouse gas footprint, and a large opportunity for reduction. However, due to the relatively recent development of unconventional resources, better data is needed to characterize this opportunity based on basin type, drilling method, and production in order to better identify the potential for reductions.

Transportation of processed natural gas to the point at which it is consumed – in this inventory, large end users such as power plants – makes up a large portion of the overall upstream impact. There are two components to this impact: the first is the use of energy to compress the natural gas – the initial compression to put the natural gas on the pipeline, and then periodic compression as the motive force to push the natural gas along the transmission system. The second component is fugitive emissions from joints in the pipeline and other equipment. Improving compressor efficiency not only increases the amount of sellable product, but reduces the greenhouse gases emitted delivering that product. Pipeline fugitive emissions could be reduced with both technology and best management practices.

4.3.2 Reducing the GHG Emissions of Natural Gas and Coal-fired Electricity

Although efforts to reduce methane emissions from natural gas and coal extraction and transportation are important and should be continued, most GHG emissions from their extraction, transportation and use comes in the form of post-combustion carbon dioxide. Three high-level opportunities for reducing these emissions include:

- Capture the CO_2 at the power plant and sequester it in a saline aquifer or oil bearing reservoir
- Improve existing power plant efficiency
- Invest in advanced power research, development, and demonstration

Further, all opportunities need to be evaluated on a sustainable energy basis, considering full environmental performance, as well as economic and social performance, such as the ability to maintain energy reliability and security.

4.4 Conclusions

This greenhouse gas (GHG) analysis inventories six different sources of natural gas, including three types of unconventional gas, combines them into a domestic mix, and then compares the inventory on both a delivered feedstock and delivered electricity basis to a similar domestic mix of coal. The results show that average coal, across a wide range of variability, and compared across different assumptions of climate impact timing, has lower greenhouse gas emissions than domestically produced natural gas when compared as a delivered energy feedstock—over 50 percent less than natural gas per unit of energy.

However, the conclusion that coal is the cleaner fuel flips once the fuels are converted to electricity in power plants with different efficiencies—53 percent for natural gas versus 35 percent for coal. Natural gas-fired electricity has a 42 percent to 53 percent lower climate impact than coal-fired electricity. Even when fired on 100 percent unconventional natural gas, from tight sands, shale and coal beds, and compared on a 20-year GWP, natural gas-fired electricity has 39 percent lower greenhouse gases than coal. This shifting conclusion based on a change in the basis of comparison highlights the importance of specifying an end-use basis—not necessarily power production—when comparing different fuels.

Despite the conclusion that natural gas has lower greenhouse gases than coal on a delivered power basis, the extraction and delivery of the gas has a large climate impact —32 percent of U.S. methane emissions and 3 percent of U.S. greenhouse gases. There are significant emissions and use of natural gas—13 percent at the city or plant gate—even without considering final distribution to small end-users. The vast majority of the reduction in extracted natural gas —70 percent cradle-to-gate—are not emitted to the atmosphere, but can be attributed to the use of the natural gas as fuel for extraction and transport processes such as compressor operations. Increasing compressor efficiency would lower both the rate of use and the CO_2 emissions associated with the combustion of the gas for energy.

But, with methane making up 75 to 95 percent of the natural gas flow, there are many opportunities for reducing the climate impact associated with direct venting to the atmosphere. A further 17 percent of the natural gas losses can be characterized as point source, and have the potential to be flared—essentially a conversion of GWP-potent methane to carbon dioxide.

The conclusions drawn from this inventory and the associated analysis are robust to a wide array of assumptions. However, as with any inventory, they are dependent on the underlying data, and there are many opportunities to enhance the information currently being collected. This analysis shows that the results are both sensitive to and impacted by the uncertainty of a few parameters: use and emission of natural gas along the pipeline transmission network; the rate of natural gas emitted during unconventional gas extraction processes such as well completion and workovers; and the lifetime production of wells, which determine the denominator over which lifetime emissions are placed.

This inventory and analysis are for greenhouse gases only, and there are many other factors that must be considered when comparing energy options. A full inventory of conventional and toxic air emissions, water use and quality, and land use is currently under development, and will allow comparison of these fuels across multiple environmental categories. Further, all opportunities need to be evaluated on a sustainable energy basis, considering full environmental performance, as well as economic and social performance, such as the ability to maintain energy reliability and security.

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Appendix A:
Data and Calculations for Greenhouse Gas Inventory

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The energy and material flows tracked by NETL's life cycle analysis (LCA) method in support of this study are used to quantify emissions of greenhouse gases (CO_2, CH_4, and N_2O, SF_6) that would result from natural gas extraction and transport, and from coal extraction and transport. The methods for calculating these flows for the raw material acquisition (RMA) and raw material transport (RMT) of natural gas and coal are provided below.

Some common engineering conversions used in this study are:

- 1 tonne = 1,000 kg
- 1 kg = 2.205 lb
- 1 m^3 = 35.3 cf
- Natural Gas Density: 1 cf of natural gas = 0.042 lb natural gas
- Natural Gas Energy Content: 1,027 Btu/cf natural gas
- The molar ratio of CO_2 to carbon is 44/12

A.1 Raw Material Acquisition: Natural Gas

In this analysis, the boundary of the RMA for natural gas begins with the extraction of natural gas from nature and ends with processed natural gas ready for pipeline delivery. Key activities in the RMA of natural gas are as follows:

- Well construction and installation
- Natural gas sweetening (acid gas removal)
- Natural gas dehydration
- Natural gas venting and flaring
- Natural gas compression
- Well decommissioning

The data sources and assumptions for calculating the greenhouse gas (GHG) emissions from each RMA activity are provided below. In most cases, the methane emissions are calculated by using standard engineering calculations around key gas field equipment, followed by the application of the Environmental Protection Agency (EPA) AP-42 emission factors as necessary.

Well Construction and Installation

NETL's LCA model of natural gas extraction includes the construction and installation activities for natural gas wells. Construction is defined as the cradle-to-gate burdens of key materials that embody key equipment and structures. Installation is defined as the activity of preparing a site, erecting buildings or other structures, and putting equipment in place.

The construction of natural gas wells requires a well casing that provides strength to the well bore and prevents contamination of the geological formations that surround the gas reservoir. In the case of offshore extraction, a large platform is also required. A well is lined with a carbon steel casing that is held in place with concrete. A typical casing has an inner diameter of 8.6 inches, is 0.75 inches thick, and weighs 24 pounds per foot (NaturalGas.org, 2004). The weight of concrete used by the well walls is assumed to be equal to the weight of the steel casing. The total length of a natural gas well is variable, based on the natural gas extraction profile under consideration. The well lengths considered in this study are as follows: conventional onshore: 1,990 m; conventional offshore: 2,660 m; conventional onshore associated: 1,500 m; shale gas: 3,980 m; coal bed methane: 3,980 m; and tight gas: 2,525 m. The total weight of materials for the construction of a well bore is estimated by factoring the total well length by the linear weight of carbon steel and concrete.

The installation of natural gas wells includes the drilling of the well, followed by the installation of the well casing. Horizontal drilling is used for unconventional natural gas reserves where hydrocarbons are dispersed throughout a matrix of shale or coal. An advanced drilling rig has a drilling speed of 17.8 meters per hour, which translates to the drilling of a 7,000 foot well in approximately 10 days (NaturalGas.org, 2004). A typical diesel engine used for oil and gas exploration has a power of 700 horsepower and a heat rate of 7,000 Btu/hp-hr (EPA, 1995). The methane emissions from well installation is the product of the following three variables: heat rate of drilling engine (7,000 Btu/hp-hr), methane emission factor (EPA, 1995) for diesel combustion in stationary industrial engines (6.35E-05 lb/hp-hr), and the total drilling time (in hours).

The daily production rate of a natural gas well is an important factor in apportioning one-time construction activities or intermittent operations to a unit of natural gas production. Typical production rates vary considerably based on well type. Production rates also vary based on well specific factors, such as the age of the natural gas well. For instance, the average daily production rate for new, horizontal shale gas wells in the Barnett Shale region is as high as 2.5 million standard cubic feet (MMcf) per day, but declines at a rapid rate (Hayden & Pursell, 2005). The observed production rates in the Barnett Shale region decline 55 percent during the first year, 25 percent during the second year, 15 percent during the third year, and 10 percent each following year (Hayden & Pursell, 2005). The production rates for each type of natural gas well are shown in **Table A-12**. These production rates include the average production of natural gas wells in 2009 (the basis year of this analysis), as marginal production rates. Marginal production rates exclude poorly performing, mature wells that will likely be removed from service within a couple of years.

The construction and material requirements are apportioned to one kilogram of natural gas product by dividing them by the lifetime production of the well. The natural gas wells considered in this study are presumed to produce natural gas at the rates discussed above, with a lifetime of 30 years. Thus, construction and material requirements, and associated GHG emissions, are apportioned over the lifetime production rate specific to each type of natural gas well, based on average well production rates.

Natural Gas Sweetening (Acid Gas Removal)

Raw natural gas contains varying levels of hydrogen sulfide (H_2S), a toxic gas that reduces the heat content of natural gas and causes fouling when combusted in equipment. The removal of H_2S from natural gas is known as sweetening. Amine-based processes are the predominant technologies for the sweetening of natural gas.

The H_2S content of raw natural gas is highly variable, with concentrations ranging from one part per million on a mass basis to 16 percent by mass in extreme cases. An H_2S concentration of 0.5 percent by mass is modeled in this analysis. This H_2S concentration is based on raw gas composition data compiled by the Gas Processors Association (Foss, 2004).

The energy consumed by the amine reboiler accounts for the majority of energy consumed by the sweetening process. Reboiler energy consumption is a function of the amine flow rate, which, in turn, is related to the amount of H_2S removed from natural gas. Approximately 0.30 moles of H_2S are removed per 1 mole of circulated amine solution (Polasek, 2006), the reboiler duty is approximately 1,000 Btu per gallon of amine (Arnold, 1999), and the reboiler has a thermal efficiency of 92 percent. The molar mass of amine solution is assumed to be 83 g/mole, which is estimated by averaging the molar mass of monoethanolamine (61 g/mole) and diethanolamine (105 g/mole). The density of the amine is assumed to be 8 lb/gal (3.62 kg/gal). The calculation of energy input per kilogram of natural gas product is shown in **Equation 1**.

$$\frac{0.005\ kg\ H_2S}{kg\ NG\ product} * \frac{1\ kg\ mol\ \ H_2S}{34\ kg\ H_2S} * \frac{1\ kg\ mol\ amine}{0.30 kg\ mol\ H_2S} * \frac{83\ kg\ amine}{kg\ mol\ amine} * \frac{1\ gal\ amine}{3.62\ kg\ amine} * \\ \frac{1{,}000\ Btu\ reboiler\ duty}{gal\ amine} * \frac{1\ Btu\ energy\ input}{0.92\ Btu\ reboiler\ duty} = \frac{12.2\ Btu}{kg\ NG\ product} = \frac{26.9\ Btu}{lb\ NG\ product}$$

(Equation 1)

The amine reboiler combusts natural gas to generate heat for amine regeneration. This analysis applies EPA emission factors for industrial boilers (EPA, 1995) to the energy consumption rate discussed in the above paragraph in order to estimate the combustion emissions from amine reboilers.

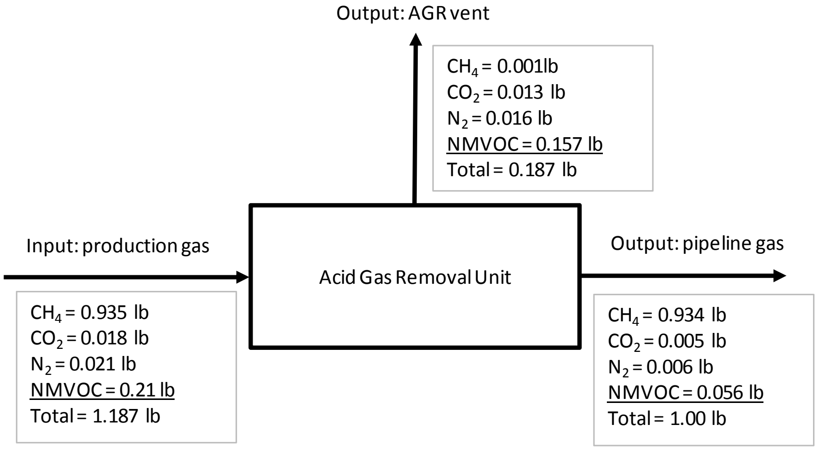
The sweetening of natural gas is also a source of vented methane emissions. In addition to absorbing H_2S, the amine solution also absorbs a portion of methane from the natural gas. This methane is released to the atmosphere during the regeneration of the amine solvent. The venting of methane from natural gas sweetening is based on emission factors developed by the Gas Research Institute; natural gas sweetening releases 0.000971 lb of methane per lb per natural gas sweetened (API, 2009). The calculation of methane released by amine reboiler venting is shown in **Equation 2**.

$$\frac{0.0185\ tonne\ CH_4}{10^6\ cf\ NG} * \frac{1{,}000\ kg}{tonne} * \frac{2.205\ lb}{kg} * \frac{1cf}{0.042\ lb} = \frac{9.71 \times 10^{-4}\ lb\ CH_4}{lb\ NG}$$

(Equation 2)

Raw natural gas contains naturally-occurring CO_2 that contributes to the acidity of natural gas. Most of this CO_2 is absorbed by the amine solution during the sweetening of natural gas and is ultimately released to the atmosphere when the amine is regenerated. This analysis calculates the mass of naturally-occurring CO_2 emissions from the acid gas recovery (AGR) unit by balancing the composition of production gas (natural gas that has been extracted but has not undergone significant processing) and pipeline-quality gas. Production gas contains 1.52 mass percent CO_2 and pipeline-quality natural gas contains 0.47 mass percent CO_2. A mass balance around the AGR unit, which balances the mass of gas input with the mass of gas venting and gas product, shows that 0.013 lb of naturally-occurring CO_2 is vented per lb of processed natural gas. The key constraints of this mass balance are the different compositions of input gas (production gas) and output gas (pipeline-quality gas) and the methane venting rate from amine regeneration. The mass balance around the AGR unit is illustrated by **Figure A-1.**

Figure A-1: Mass Balance for Acid Gas Removal



As shown by the mass balance around the AGR unit, the majority (84 percent by mass) of the AGR vent stream is NMVOC. At this concentration, NMVOCs are a high-value energy product. Thus, from an LCA perspective, NMVOCs are a valuable co-product of the AGR process. Co-product allocation is used to apportion life cycle emissions and other burdens between the natural gas and NMVOC products.

In this analysis, the relative energy contents of the natural gas and NMVOC outputs from the AGR process are used as the basis for co-product allocation. The heating value of pipeline-quality natural gas is 24,452 Btu/lb (which is calculated from the default study value of 1,027 Btu/cf). The heating value of NMVOCs is 21,025 Btu/lb, which is calculated from the composition of the vent stream from the AGR unit and the heating values of each NMVOC component (The Engineering Toolbox, 2011); the calculation of the heating value of NMVOC is shown in **Table A-1**. As shown by the mass balance (**Figure A-1**), 0.157 lbs of NMVOC are produced for every lb of natural gas produced. When these mass flows are converted to an energy basis using the above heating values, 88.1 percent of the product leaving the AGR process is natural gas and 11.9 percent is NMVOCs. Thus, the natural gas model allocates 88.1 percent of the energy requirements and environmental emissions of acid gas removal to the natural gas product.

Table A-1: Heating Value of NMVOC Co-Product from AGR Process

NMVOC Component	Percent Mass	Heating Value (Btu/lb)
CH_4	0%	23,811
Ethane	44.1%	20,525
Propane	26.7%	21,564
Iso-Butane	5.9%	21,640
n-Butane	10.4%	21,640
iso-Pentane	3.0%	20,908
n-Pentane	3.9%	20,908
Hexanes	3.0%	20,526
Heptanes Plus	2.9%	21,000
Other (N_2 and CO_2)	0%	0
	Composite Heating Value	21,025

The following table shows the energy consumption and GHG emissions for acid gas removal. These energy and emission factors do not account for the co-product allocation between natural gas and NMVOCs. The co-product allocation between natural gas and NMVOC is performed within the modeling software (GaBi).

For **Table A-2**, the energy used for acid gas removal is based on a 0.005 kg H_2S per of raw natural gas, a molar loading of 0.30 mol H2S per mole of amine solution, and a reboiler duty of 1,000 Btu/gal of regenerated amine, and a reboiler efficiency of 92 percent. The CH_4 venting factor assumes that the reboiler vent is not flared.

Table A-2: Acid Gas Removal (Sweetening)

Flow Name	Value	Units	Reference
Air Emission Factors			
CO_2	2.86	lb CO_2/lb NG fuel	API 2009
N_2O	1.52E-05	lb N_2O/lb NG fuel	API 2009
CH_4 (combustion)	5.48E-05	lb CH_4/lb NG fuel	API 2009
Energy Inputs and Outputs			
Reboiler energy	26.9	Btu/lb NG product	calculated
Reboiler fuel	2.26E-04	lb NG fuel/lb NG product	calculated
Air Emissions			
CO_2 (combustion)	6.47E-04	lb CO_2/lb NG product	calculated
CO_2 (vented)	0.013	lb CO_2/lb NG product	calculated
N_2O	3.54E-06	lb N_2O/lb NG product	calculated
CH_4 (combustion)	1.27E-05	lb CH_4/lb NG product	calculated
CH_4 (vented)	9.71E-04	lb CH_4/lb NG product	API 2009
NMVOC (vented)	0.157	lb NMVOC/lb NG product	calculated

Natural Gas Dehydration

Dehydration is necessary to remove water from raw natural gas, which makes it suitable for pipeline transport and increases its heating value. The configuration of a typical dehydration process includes an absorber vessel in which glycol-based solution comes into contact with a raw natural gas stream, followed by a stripping column in which the rich glycol solution is heated in order to drive off the water and regenerate the glycol solution. The regenerated glycol solution (the lean solvent) is recirculated to the absorber vessel. The methane emissions from dehydration operations include combustion and venting emissions. This analysis estimates the fuel requirements and venting losses of dehydration in order to determine total methane emissions from dehydration.

The fuel requirements of dehydration are a function of the reboiler duty. Due to the heat integration of the absorber and stripper streams, the reboiler, which is heated by natural gas combustion, is the only equipment in the dehydration system that consumes fuel. The reboiler duty (the heat requirements for the reboiler) is a function of the flow rate of glycol solution, which, in turn, is a function of the difference in water content between raw and dehydrated natural gas. The typical water content for untreated natural gas is 49 lbs/MMcf. In order to meet pipeline requirements, the water vapor must be reduced to 4 lbs/MMcf of natural gas (EPA, 2006). The flow rate of glycol solution is 3 gallons per pound of water removed (EPA, 2006), and the heat required to regenerate glycol is 1,124 Btu/gal (EPA, 2006). By factoring the change in water content, the glycol flow rate, and boiler heat requirements, the energy requirements for dehydration are 152,000 Btu/MMcf of dehydrated natural gas (as shown by **Equation 3** and **Equation 4** below). Assuming that the reboiler is fueled by natural gas, this translates to 1.48E-04 lb of natural gas combusted per lb of dehydrated natural gas (as shown by the equations below). The emission factor for the combustion of natural gas in boiler equipment produces 2.3 lb CH_4/million cf natural gas (API, 2009). After converting to common units, the above fuel consumption rate and methane emission factor translate to 8.09E-09 lb CH_4/lb NG treated.

$$\frac{3.00\ gal\ glycol}{lb\ water} * \frac{1{,}124\ Btu}{gal\ glycol} * \frac{(49-4)\ lb\ water}{MMCF\ NG} = \frac{152{,}000\ Btu}{MMcf\ NG} \qquad \textbf{(Equation 3)}$$

$$\frac{152{,}000\ Btu}{MMcf\ NG} * \frac{MMcf\ NG}{10^6 cf\ NG} * \frac{1\ cf\ NG}{1027\ Btu} = \frac{1.48\times10^{-4}\ lb\ NG\ fuel}{lb\ NG\ product} \qquad \textbf{(Equation 4)}$$

In addition to absorbing water, the glycol solution also absorbs methane from the natural gas stream. This methane is lost to evaporation during the regeneration of glycol in the stripper column. Flash separators are used to capture most of methane emissions from glycol strippers; nonetheless, small amounts of methane are vented from dehydrators. The emission of methane from glycol dehydration is based on emission factors developed by the Gas Research Institute (API, 2009). Based on this emission factor, 8.06E-06 lb of methane is released for every pound of natural gas that is dehydrated.

For **Table A-3**, the energy used for dehydration is based on 3 gallons of glycol per pound of water removed, a reboiler duty of 1,124 Btu per gallon of glycol regenerated, and 45 pounds of water removed per MMcf of natural gas produced. The methane venting factor assumes that no flash separator is used to control venting emissions.

Table A-3: Natural Gas Dehydration

Flow Name	Value	Units	Reference
Air Emission Factors			
CO_2	2.86	lb CO_2/lb NG fuel	API 2009
N_2O	1.52E-05	lb N_2O/lb NG fuel	API 2009
CH_4 (combustion)	5.48E-05	lb CH_4/lb NG fuel	API 2009
Energy Inputs and Outputs			
Reboiler energy	1.52E-01	Btu/cf NG product	API 2009
Reboiler fuel	1.48E-04	lb NG fuel/lb NG product	calculated
Air Emissions			
CO_2	4.24E-04	lb CO_2/lb NG product	calculated
N_2O	2.26E-09	lb N_2O/lb NG product	calculated
CH_4 (combustion)	8.10E-09	lb CH_4/lb NG product	calculated
CH_4 (venting)	8.06E-06	lb CH_4/lb NG product	API 2009

Natural Gas Venting and Flaring

Venting and flaring are necessary in situations where a natural gas (or other hydrocarbons) stream cannot be safely or economically recovered. Venting and flaring may occur when a well is being prepared for operations and the wellhead has not yet been fitted with a valve manifold, when it is not financially preferable to recover the associated natural gas from an oil well, or during emergency operations when the usual systems for gas recovery are not available.

The combustion products of flaring include carbon dioxide, methane, and nitrous oxide. The flaring emission factors published by the American Petroleum Institute (API, 2009) are based on the following recommendations by the Intergovernmental Panel on Climate Change (IPCC):

- If measured data are not available, assume flaring has a 98 percent destruction efficiency. Destruction efficiency is a measure of how much carbon in the flared gas is converted to CO_2 (API, 2009).
- The CO_2 emissions from flaring are the product the destruction efficiency, carbon content of the flared gas, the molar ratio of CO_2 to carbon (44/12). Methane is 75 percent carbon by mass, and the other hydrocarbons in natural gas are approximately 81 percent carbon by mass

(Foss, 2004); the composite carbon content of natural gas is calculated by factoring these carbon compositions with the natural gas composition.

- Methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2 (API, 2009).
- N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

The mass composition of unprocessed natural gas (referred to as "production natural gas") is 78.8 percent CH_4, 1.5 percent CO_2, 1.78 percent nitrogen, and 17.9 percent non-methane hydrocarbons (NMVOCs) (EPA, 2011a). The mass composition of pipeline quality natural gas is 93.4 percent CH_4, 0.47 percent CO_2, 0.55 percent nitrogen, and 5.6 percent NMVOCs. The composition of production natural gas to model flaring during natural gas extraction, and the composition of pipeline quality natural gas is used to model flaring at the natural gas processing plant. The above method for estimating flaring emissions was applied to these gas compositions to develop flaring emission factors for production and pipeline natural gas. The following table summarizes the mass composition and flaring emissions for these two gas compositions.

Table A-4: Natural Gas Flaring

Emission	Production NG	Pipeline NG	Units	Reference
Natural Gas Composition				
CH_4	78.8%	93.4%	% mass	(EPA, 2011a)
CO_2	1.52%	0.47%	% mass	(EPA, 2011a)
Nitrogen	1.78%	0.55%	% mass	(EPA, 2011a)
NMVOC	17.90%	5.57%	% mass	(EPA, 2011a)
Flaring Emissions				
CO_2	2.67	2.69	lb CO_2/lb flared NG	API, 2009
N_2O	8.95E-05	2.79E-05	lb N_2O/lb flared NG	API, 2009
CH_4	1.53E-02	1.81E-02	lb CH_4/lb flared NG	API, 2009

The venting rate of natural gas is necessary to apply the above emission factors to a unit of natural gas production. Venting rates are highly variable and depend more on the production practices and condition of equipment at an extraction site that the type of natural gas reservoir. Thus, venting rates have been parameterized in the model to allow uncertainty analysis.

Recent data indicate that only 51 percent of vented natural gas from conventional natural gas extraction operations is flared and the remaining 49 percent is released to the atmosphere (EPA, 2011a). The flaring rate is even lower for unconventional wells, which flare 15 percent of vented natural gas (EPA, 2011a). The flaring rate at natural gas processing plants is assumed to be 100 percent.

Venting from Well Completion

The methane emissions from the completion of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells produce 36.65 Mcf/completion and unconventional wells produce 9,175 Mcf/completion (EPA, 2011a). Barnett Shale and tight gas wells are high pressure wells, and thus have higher completion venting than coal bed methane and conventional wells (EPA, 2011a).

When modeling tight gas, adjustments were made to EPA's emission factors for well completions and workovers. EPA's documentation (EPA, 2011a) indicates that its unconventional completion and workover emissions are representative of high-pressure, tight gas wells in the San Juan and Piceance basins, which are horizontal wells that were completed using hydraulic fracturing and have an estimated ultimate recovery of 3 Bcf. A survey of tight gas production in the U.S. determined that an estimated ultimate recovery of 1.2 Bcf is more representative of U.S. tight gas production. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor for tight gas well completion and workovers. An emission factor of 3,670 Mcf CH_4 per episode for the completion and workover of tight gas wells is used.

Tight gas emissions are not the only emission factor adjusted for the model. While coal bed methane (CBM) wells are an unconventional source of natural gas, they have a low reservoir pressure and thus have relatively low emission rates from completions and workovers. The CBM emission factor used for the completion and workover of CBM wells is 49.57 Mcf CH_4 (EPA, 2011a). This is much lower than the completion and workover emission factor that EPA recommends for unconventional wells (9,175 Mcf CH_4).

The analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. Using a natural gas density of 0.042 lb/cf (API, 2009) the methane emissions from conventional well completions are 1,538 lb/completion (698 kg/completion). For unconventional wells the venting rates are 386,000 lb/completion (175,000 kg/completion) for Barnett Shale, 2,090 lb/completion (946 kg/completion) for coal bed methane, and 154,000 lb/completion (70,064 kg/completion) for tight gas (EPA, 2011a).

Venting from Well Workovers

The methane emissions from the workover of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells produce 2.454 Mcf/workover and unconventional wells produce 9,175 Mcf/workover. (Note that the workover emission factor for unconventional wells is the same as the completion emission factor for unconventional wells.) This analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. Using a natural gas density of 0.042 lb/cf (API, 2009) and the conversion factor of 2.205 lb/kg, the methane emissions from well workovers are 103 lb/workover (46.7 kg/workover) for conventional wells. The workover venting rates for unconventional wells are assumed to be equal to their completion venting rates (EPA, 2011a).

Unlike well completions, well workovers occur more than one time during the life of a well. The frequency of well workovers was calculated using EPA's accounting of the total number of natural gas wells in the U.S. and the total number of workovers performed per year (all data representative of 2007). For conventional wells, there were approximately 389,000 wells and 14,600 workovers in 2007 (EPA, 2011a), which translates to 0.037 workovers per well-year. Similarly, for unconventional wells, there were approximately 35,400 wells and 4,180 workovers in 2007 (EPA, 2011a), which translates to 0.118 workovers per well-year.

Venting from Liquid Unloading

Liquid unloading is necessary for conventional gas wells. It is not necessary for unconventional wells or associated gas wells.

The methane emissions from the unloading of liquid from conventional wells are based on emission factors developed by EPA. In 2007, conventional wells produced 223 Bcf/year (EPA, 2011a), which is 4.25 million metric tons per year using a natural gas density of 0.042 lb/cf. There were approximately 389,000 unconventional wells in 2007. When the annual emissions are divided by the total number of wells, the resulting emission factor is 10.9 metric tons per well-year.

Liquid unloading is a routine operation for conventional gas wells. The frequency of liquid unloading was calculated using EPA's assessment of two producers and the unloading activities for their wells (EPA, 2011a). From this sampling, EPA calculated that there are 31 liquid unloading episodes per well-year (EPA, 2011a).

When the emission factor for liquid unloading is divided by the average number of unloading episodes, the resulting methane emission factor is 776 lb/episode (352 kg/episode).

Venting from Wet Seal Degassing

The emission factor for wet seal degassing accounts for the natural gas lost during the regeneration of wet seal oil, which is used for centrifugal compressors. This analysis uses an EPA study that sampled venting emissions from 15 offshore platforms (Bylin et al., 2010). According to EPA's sampling of these platforms, the emissions from wet seal oil degassing are 33.7 million m^3 of methane annually. These platforms produce 4.88 billion m^3 of natural gas annually. When the emission rate for this category is divided by the production rate, the resulting emission factor is 0.00690 m^3 of vented gas per m^3 of produced gas. Assuming the emissions have the same density as the produced gas, this emission factor is 0.00690 lb of natural gas/lb produced natural gas.

Fugitive Emissions from Pneumatic Devices

The extraction and processing of natural gas uses pneumatic devices for the opening and closing of valves and other process control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas extraction or processing site. Thus, this analysis assumes that the operation of pneumatic systems result in the emission of fugitive natural gas emissions.

Data for the fugitive emissions from pneumatic devices are based on EPA data for offshore wells, onshore wells, and gas processing plants (EPA, 2011a). EPA’s data is based on 2006 production (EPA, 2011a) and shows the methane emissions for specific wellhead and processing activities. This analysis translated EPA’s data to a basis of lb methane per lb of natural gas production by dividing the methane emission rate by the natural gas production rate. For example, the annual emissions from pneumatic devices used for offshore production are 7 MMcf of methane; when divided by the annual offshore production rate of 3,584,190 MMcf, this translates to an emission factor of 1.95E-06 lb of methane per lb of natural gas produced (this calculation assumes that the volumetric densities of methane and natural gas are the same). The fugitive emissions from pneumatic devices used by offshore wells, onshore wells, and natural gas processing plants are shown in the following table.

Table A-5: Fugitive Emissions from Pneumatic Devices

Location	MMcf/yr (EPA, 2011a)		Emission Factor
	CH_4 emission	NG Production	lb CH_4/lb NG
Onshore	52,421	19,950,828	2.63E-03
Offshore	7.0	3,584,190	1.95E-06
Processing	93	14,682,188	6.33E-06

Other Point Source and Fugitive Emissions

The emissions described above account for natural gas emissions from specific processes, including the episodic releases of natural gas during well completion, workovers, and liquid unloading, as well as routine releases from wet seal degassing, AGR, and dehydration. Natural gas is also released by other extraction and processing equipment. To account for these other emissions, NETL's model includes two additional emission categories: other point source emissions and other fugitive emissions. Other point source emissions account for natural gas emissions that are not accounted for elsewhere in model and can be recovered for flaring. Other fugitive emissions include emissions that are not accounted for elsewhere in the model and cannot be recovered for flaring.

EPA's Background Technical Support Document - Petroleum and Natural Gas Industry (EPA, 2011a) was used for quantifying the other point source and fugitive emissions from natural gas extraction and processing. A three-step process was used to filter EPA's venting and flaring data so that it is consistent with the boundary assumptions of this analysis:

1. Emissions that are accounted for by NETL's existing natural gas unit processes were not included in the categories for other point source and fugitive emissions. For example, EPA provides emission rates for well construction, well completion, dehydration, and pneumatic devices. The emissions from these activities are accounted for elsewhere in NETL's model and thus, to avoid double counting, are not included in the emission factors for other point and fugitive emissions.
2. Emissions that fall within NETL's boundary definitions for natural gas processing were moved from the natural gas extraction category to the natural gas processing category.
3. The EPA data (EPA, 2011a) does not discern between point source and fugitive emissions, so emissions were assigned to the point source or fugitive emission categories based on another EPA reference that provides more details on point source and fugitive emissions (Bylin, et al., 2010).

Other Point Source and Fugitive Emissions from Onshore Extraction

The data for other point source and fugitive emissions from onshore extraction are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from construction, dehydration, compressors, well completion, and pneumatic devices; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Additionally, emissions from Kimray pumps, condensate tanks, and compressor blowdowns are re-categorized as natural gas *processing* emissions in NETL's model, and are thus not included in the emission factors for natural gas *extraction*. Based on EPA's data (EPA, 2011a) and NETL's boundary assumptions, the emission factors for point source and fugitive emissions from onshore gas extraction are 7.49E-05 lb CH_4/lb NG extracted and 1.02E-03 lb CH_4/lb NG extracted, respectively. The data for these calculations are shown in **Table A-6**.

Table A-6: Other Point Source and Fugitive Emissions from Onshore NG Extraction

Emission Source	Emissions (MMcf/year)	Location (UP)	Point Source	Fugitive
Normal Fugitives				
Gas Wells	2,751	Construction		
Heaters	1,463		1,463	
Separators	4,718			4,718
Dehydrators	1,297	Dehydrator		
Meters/Piping	4,556			4,556
Small Reciprocating Compressor	2,926	Reciprocating Compressor		
Large Reciprocating Compressor	664	Reciprocating Compressor		
Large Reciprocating Stations	45	Reciprocating Compressor		
Pipeline Leaks	8,087			8,087
Vented and Combusted				
Completion Flaring	0	Well Completion V&F		
Well Drilling	96	Well Completion		
Coal Bed Methane	3,467	Well Completion		
Pneumatic Device Vents	52,421	Pneumatic Devices		
Chemical Injection Pumps	2,814			2,814
Kimray Pumps	11,572	In NG processing boundary		
Dehydrator Vents	3,608	Dehydrator V&F		
Condensate Tanks without Control Devices	1,225	In NG processing boundary		
Condensate Tanks with Control Devices	245	In NG processing boundary		
Gas Engines, Compressor Exhaust Vented	11,680	Gas Compressor		
Well Workovers				
Well Workovers, Gas Wells	47	Well Workovers		
Well Workovers, Well Clean Ups (Low Pressure Gas Wells)	9,008	Well Workovers		
Blowdowns				
Blowdowns, Vessel	31		31	
Blowdowns, Pipeline	129			129
Blowdowns, Compressors	113	In NG processing boundary		
Blowdowns, Compressor Starts	253	In NG processing boundary		
Upsets				
Pressure Relief Valves	29			29
Mishaps	70			70
Total Emissions	123,315		1,494	20,403
Total NG Extracted	19,950,828			
Emission Rate (lb CH_4/lb NG extracted)			**7.49E-05**	**1.02E-03**

Other Venting and Fugitive Emissions from Offshore Extraction

The data for other point source and fugitive emissions from offshore extraction are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from drilling rigs, flares, centrifugal seals, glycol dehydrators, gas engines and turbines, and pneumatic pumps; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Based on EPA's data (EPA, 2011a) and NETL's boundary assumptions, the emission factors for point source and fugitive emissions from offshore gas extraction are 3.90E-05 lb CH_4/lb NG extracted and 2.41E-04 lb CH_4/lb NG extracted, respectively. The data for these calculations are shown in **Table A-7.**

Table A-7: Other Point Source and Fugitive Emissions from Offshore NG Extraction

Emission Source	Emissions (MMcf/year)	Location (UP)	Point Source	Fugitive
Amine gas sweetening unit	0.2	AGR and CO_2 removal		
Boiler/heater/burner	0.8		0.80	
Diesel or gasoline engine	0.01		0.01	
Drilling Rig	3	Construction		
Flare	24	Venting and Flaring		
Centrifugal Seals	358	Centrifugal Compressor		
Connectors	0.8			0.80
Flanges	2.4			2.38
Open Ended Line	0.1			0.10
Other	44			44.0
Pump Fugitive	0.5			0.50
Valves	19			19.00
Glycol Dehydrator	25	Dehydrator		
Loading Operation	0.1			0.10
Separator	796			796
Mud Degassing	8.0		8.00	
Natural Gas Engines	191	Reciprocating compressor		
Natural Gas Turbines	3.0	Centrifugal compressor		
Pneumatic Pumps	7.0	Pneumatic Devices		
Pressure Level Controls	2.0			2.00
Storage Tanks	7.0		7.00	
Variable Exhaust Nozzle Exhaust Gas	124		124	
Total Emissions	1616		140	865
Total Processed NG	3,584,190			
Emission Rate (lb CH_4/lb NG extracted)			**3.90E-05**	**2.41E-04**

Other Venting and Fugitive Emissions from Natural Gas Processing

The data for other point source and fugitive emissions from natural gas processing are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from reciprocating compressors, centrifugal compressors, AGR units, dehydrators, and pneumatic devices; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Based on EPA's data (EPA, 2011a) and NETL's boundary assumptions, the emission factors for point source and fugitive emissions from natural gas processing are 3.68E-04 lb CH_4/lb NG extracted and 8.25E-04 lb CH_4/lb NG extracted, respectively. The data for these calculations are shown in **Table A-8**.

Table A-8: Other Point Source and Fugitive Emissions from NG Processing

Emission Source	Emissions (MMcf/year)	Location (UP)	Point Source	Fugitive
Normal Fugitives				
Plants	1,634		3,104	
Recip Compressors	17,351	Reciprocating Compressor		
Centrifugal Compressors	5,837	Centrifugal Compressor		
Vented and Combusted (Normal Operations)				
Compressor Exhaust, Gas Engines	6,913	Reciprocating Compressor		
Compressor Exhaust, Gas Turbines	195	Centrifugal Compressor		
AGR Vents	643	AGR and CO_2 removal		
Kimray Pumps (Glycol Pump for Dehydrator)	177			11,749
Dehydrator Vents	1,088	Dehydrator venting & flaring		
Pneumatic Devices	93	Pneumatic Device		
Routine Maintenance				
Blowdowns/Venting	2,299		2,299	366
Total Emissions	36,230		5,403	12,115
Total Production	14,682,188			
Emissions Rate (lb CH_4/lb NG processed)			**3.68E-04**	**8.25E-04**

Natural Gas Compression

Compressors are used to increase the gas pressure for pipeline distribution. This analysis assumes that the inlet pressure to compressors at the natural gas extraction and processing site is 50 psig and the outlet pressure is 800 psig. The inlet pressure depends on the pressure of the natural gas reservoir and pressure drop during gas processing and thus introduces uncertainty to the model. The outlet pressure of 800 psig is a standard pressure for pipeline transport of natural gas.

The energy required for compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures). A two-stage compressor with an inlet pressure of 50 psig and an outlet pressure of 800 psig has a power requirement of 187 horsepower per MMcf of natural gas (GE Oil and Gas, 2005). Using a natural gas density of 0.042 lb/cf and converting to kilograms gives a compression energy intensity of 1.76E-04 MWh per kg of natural gas. This energy rate represents the required *output* of the compressor shaft; the *input* fuel requirements for compression vary according to compression technology. The two types of compressors used for natural gas operations are reciprocating compressors and centrifugal compressors. These two compressor types are discussed below.

Reciprocating compressors account for an estimated 75 percent of wellhead compression in the Barnett Shale gas play, and are estimated to accounted for all wellhead compression at conventional onshore, conventional onshore associated, and coal bed methane wells. Reciprocating compressors used for industrial applications are driven by a crankshaft that can be powered by 2- or 4-stroke diesel engines. Reciprocating compressors are not as efficient as centrifugal compressors and are typically used for small scale extraction operations that do not justify the increased capital requirements of centrifugal compressors. The natural gas fuel requirements for a gas-powered, reciprocating compressor used for natural gas extraction are based on a compressor survey conducted for natural gas production facilities in Texas (Houston Advanced Research Center, 2006). The average energy intensity of a gas-powered turbine is 8.74 Btu/hp-hr (Houston Advanced Research Center, 2006). Using a natural gas heating value of 1,027 Btu/cf (API, 2009), a natural gas density of 0.042 lb/cf (API, 2009), and converting to kilograms translates to 217 kg of natural gas per MWh of centrifugal, gas-powered turbine output. This fuel factor represents the mass of natural gas that is combusted per compressor energy output. The carbon dioxide emissions from a gas-powered, 4-stroke reciprocating compressor are 110 lb/MMBtu of fuel input. Similarly, the methane emissions from the same type of reciprocating compressor are 1.25 lb/MMBtu of fuel input (EPA, 1995); these methane emissions result from leaks in compressor rod packing systems and are based on measurements conducted by the EPA on a sample of 22 compressors (EPA, 1995).

The emissions for the operation of wellhead compressors are shown in **Table A-9** below.

Table A-9: Gas-Powered Reciprocating Compressor Operations

Air Emission Factors			
CO_2	110 lb/MMBtu fuel	0.047 kg/MJ fuel	EPA 1995
CH_4	1.25 lb/MMBtu fuel	5.37E-04 kg/MJ fuel	EPA 1995
Energy Inputs and Outputs			
Output shaft energy	7.39E-05 MWh/lb	1.63E-04 MWh/kg	GE 2005
Heat rate	478 lb NG/MWh	217 kg NG/MWh	HARC 2006
Fuel input	3.54E-02 lb NG/lb NG	3.54E-02 kg NG/kg NG	calculated
Air Emissions			
CO_2	0.095 lb/lb NG	0.095 kg/kg NG	calculated
CH_4	1.08E-03 lb/lb NG	1.08E-03 kg/kg NG	calculated

Gas powered centrifugal compressors are commonly used at offshore natural gas extraction sites. The amount of natural gas required for gas powered centrifugal compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures). A two-stage centrifugal compressor with an inlet pressure of 50 psig and an outlet pressure of 800 psig has a power requirement of 187 horsepower per MMcf of natural gas (GE Oil and Gas, 2005). Using a natural gas density of 0.042 lb/cf and converting to kilograms gives a compression energy intensity of 1.76E-04 MWh per kg of natural gas.

Table A-10: Gas-Powered Centrifugal Compressor Operations

Air Emission Factors			
CO_2	110 lb/MMBtu fuel	0.047 kg/MJ fuel	EPA 1995
CH_4	8.60E-03 lb/MMBtu fuel	3.70E-06 kg/MJ fuel	EPA 1995
N_2O	3.00E-03 lb/MMBtu fuel	1.29E-06 kg/MJ fuel	EPA 1995
Energy Inputs and Outputs			
Output shaft energy	7.39E-05 MWh/lb	1.63E-04 MWh/kg	GE 2005
Heat rate	443 lb NG/MWh	201 kg NG/MWh	API 2009
Fuel input	3.28E-02 lb NG/lb NG	3.28E-02 kg NG/kg NG	calculated
Air Emissions			
CO_2	0.088 lb/lb NG	0.088 kg/kg NG	calculated
CH_4	6.89E-06 lb/lb NG	6.89E-06 kg/kg NG	calculated
N_2O	2.40E-06 lb/lb NG	2.40E-06 kg/kg NG	calculated

Electrically-powered centrifugal compressors account for an estimated 25 percent of wellhead compression in the Barnett Shale gas play, but were not found to be utilized in substantial numbers outside of the Barnett Shale. If the natural gas extraction site is near a source of electricity, it has traditionally been financially preferable to use electrically-powered equipment instead of gas-powered equipment. This is the case for extraction sites for Barnett Shale located near Dallas-Fort Worth. The use of electric equipment is also an effective way of reducing the noise of extraction operations, which is encouraged when an extraction site is near a city.

An electric centrifugal compressor uses the same compression principles as a gas-powered centrifugal compressor, but its shaft energy is provided by an electric motor instead of a gas-fired turbine. The average power range of electrically-driven compressor in the U.S. natural gas transmission network is greater than 500 horsepower. This analysis assumes that compressors of this size have an efficiency of 95 percent (DOE, 1996). This efficiency is the ratio of mechanical power output to electrical power input. Thus, approximately 1.05 MWh of electricity is required per MWh of compressor energy output. The upstream emissions associated with the generation of electricity are modeled with the fuel mix of the Electric Reliability Council of Texas (ERCOT) grid, which is representative of electricity generation in Texas (the location of Barnett Shale). The air emissions from electricity generation are based on the 2005 fuel mix for the ERCOT region (Texas) and are modeled by NETL's LCA model for power generation. Electric compressors have negligible methane emissions because they do not require a fuel line for the combustion of product natural gas and incomplete combustion of natural gas is not an issue (EPA, 2011c). Electric compressors are also recommended by EPA’s Natural Gas STAR program as a strategy for reducing system emissions of methane (EPA, 2011c).

Table A-11: Electrically-Powered Centrifugal Compressor Operations

Air Emissions from Electricity Generation			
CO_2	1,784 lb/MWh	809 kg/MWh	calculated
N_2O	2.29E-02 lb/MWh	1.04E-02 kg/MWh	calculated
CH_4	2.36 lb/MWh	1.07 kg/MWh	calculated
SF_6	2.23E-09 lb/MWh	1.01E-09 kg/MWh	calculated
Energy Inputs and Outputs			
Output shaft energy	7.39E-05 MWh/lb NG	1.63E-04 MWh/kg	GE 2005
Heat rate	1.053 MWh/MWh	1.053 MWh/MWh	API 2009
Electricity input	7.80E-05 MWh/lb NG	1.72E-04 MWh/kg NG	calculated
Air Emissions			
CO_2	0.139 lb/lb NG	0.139 kg/kg NG	calculated
N_2O	1.78E-06 lb/lb NG	1.78E-06 kg/kg NG	calculated
CH_4	1.84E-04 lb/lb NG	1.84E-04 kg/kg NG	calculated
SF_6	1.73E-13 lb/lb NG	1.73E-13 kg/kg NG	calculated

Well Decommissioning

This analysis assumes that the de-installation of a natural gas well incurs ten percent of the energy requirements and emissions as the original installation of the well.

Compilation of Natural Gas Processes

All energy and emissions data for the extraction of natural gas are described above. The compilation of these data into a model for natural gas extraction involves the connection of all unit processes into an interdependent network.

To model the extraction of natural gas from different sources (onshore, offshore, unconventional, etc.) it is necessary to tune each unit process within this network with a set of source-specific parameters. The assumptions used to adjust the unit processes into profiles of specific natural gas types are shown in **Table A-12**.

Table A-12: Natural Gas Modeling Parameters

Property	Units	Onshore	Associated	Offshore	Tight Sands	Barnett Shale	Coal Bed Methane
Natural Gas Source							
Contribution to 2009 Natural Gas Mix	Percent	23%	7%	13%	32%	16%	9%
2009 Production Rate	Mcf/day	65.6	121	2,795	110	273	104
Marginal Production Rate	Mcf/day	592	398	6,165	110	273	76.2
Natural Gas Extraction Well							
Flaring Rate at Extraction Well Location	Percent	51%	51%	51%	15%	15%	51%
Well Completion, Production Gas (prior to flaring)	Mcf/completion	47	47	47	4,657	11,643	63
Well Workover, Production Gas (prior to flaring)	Mcf/workover	3.1	3.1	3.1	4,657	11,643	63
Well Workover, Number per Well Lifetime	Workovers/well	1.1	1.1	1.1	3.5	3.5	3.5
Liquids Unloading, Production Gas (prior to flaring)	Mcf/episode	23.5	n/a	23.5	n/a	n/a	n/a
Liquids Unloading, Number per Well Lifetime	Episodes/well	930	n/a	930	n/a	n/a	n/a
Pneumatic Device Emissions, Fugitive	lb CH_4/Mcf	0.05	0.05	0.01	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/Mcf	0.003	0.003	0.002	0.003	0.003	0.003
Other Sources of Emissions, Fugitive	lb CH_4/Mcf	0.043	0.043	0.01	0.043	0.043	0.043
Natural Gas Processing Plant							
AGR and CO_2 Removal Unit							
Flaring Rate for AGR and CO_2 Removal Unit	Percent	100%	100%	100%	100%	100%	100%
Methane Absorbed into Amine Solution	lb CH_4/Mcf	0.04	0.04	0.04	0.04	0.04	0.04
Carbon Dioxide Absorbed into Amine Solution	lb CO_2/Mcf	0.56	0.56	0.56	0.56	0.56	0.56
Hydrogen Sulfide Absorbed into Amine Solution	lb H_2S/Mcf	0.21	0.21	0.21	0.21	0.21	0.21
NMVOC Absorbed into Amine Solution	lb NMVOC/Mcf	6.59	6.59	6.59	6.59	6.59	6.59
Glycol Dehydrator Unit							
Flaring Rate for Dehydrator Unit	Percent	100%	100%	100%	100%	100%	100%
Water Removed by Dehydrator Unit	lb H_2O/Mcf	0.045	0.045	0.045	0.045	0.045	0.045
Methane Emission Rate for Glycol Pump & Flash Separator	lb CH_4/Mcf	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
Pneumatic Devices and Other Sources of Emissions							
Flaring Rate for Other Sources of Emissions	Percent	100%	100%	100%	100%	100%	100%
Pneumatic Device Emissions, Fugitive	lb CH_4/Mcf	0.05	0.05	0.05	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/Mcf	0.02	0.02	0.02	0.02	0.02	0.02
Other Sources of Emissions, Fugitive	lb CH_4/Mcf	0.03	0.03	0.03	0.03	0.03	0.03
Natural Gas Compression at Gas Plant							
Compressor, Gas-powered Combustion, Reciprocating	Percent	100%	100%		100%	75%	100%
Compressor, Gas-powered Turbine, Centrifugal	Percent			100%			
Compressor, Electrical, Centrifugal	Percent					25%	

Production Rates for Conventional Onshore Natural Gas Wells

The purpose of this discussion is to describe the data sources and calculations used to determine the typical production rate of conventional onshore natural gas wells. The population of conventional onshore wells is a lot more diverse that other types of natural gas wells, and thus it is necessary to distinguish between the large population of wells with low production rates and the relatively small population of wells with high production rates.

The Energy Information Administration (EIA) collects production data for oil and gas wells in the U.S. and organizes it according to production rates. The EIA data for total U.S. production is shown in **Table A-13**. The data in **Table A-13** are copied directly from EIA (EIA, 2010b) and show 22 production rate brackets. The lowest bracket includes wells that produce less than one barrel of oil equivalent (BOE) per day, and the highest bracket represents wells that produce more than 12,800 BOE per day. The EIA data have separate groups for oil wells and gas wells; from these data, we know that in 2009 the U.S. had 363,459 oil wells and 461,388 gas wells. These data also show the co-production of oil at gas wells as well as the average per well production rate within each production rate bracket.

The goal of this discussion is to focus on conventional onshore gas extraction. The data in **Table A-13** includes offshore production, and to develop a more accurate representation of onshore gas production, it is necessary to remove offshore data from the total U.S. profile. The EIA also has data for offshore production, as shown by **Table A-14**. By subtracting the offshore data from the total U.S. well profile, production data exclusive to onshore wells can be determined, as shown in **Table A-15**.

Table A-13: U.S. Total 2009 Distribution of Wells by Production Rate Bracket (EIA, 2010b)

Prod. Rate Bracket (BOE/Day)	Oil Wells							Gas Wells						
	# of Oil Wells	% of Oil Wells	Annual Oil Prod. (MMbbl)	% of Oil Prod.	Oil Rate per Well (bbl/Day)	Annual Gas Prod. (Bcf)	Gas Rate per Well (Mcf/Day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (Bcf)	% of Gas Prod.	Gas Rate per Well (Mcf/Day)	Annual Oil Prod. (MMbbl)	Oil Rate per Well (bbl/Day)
0-1	127,734	35.1	15.4	0.9	0.4	4.8	0.1	91,005	19.7	73.4	0.3	2.4	0.7	0.0
1-2	45,649	12.6	21.8	1.3	1.4	9.5	0.6	45,034	9.8	131.1	0.5	8.3	1.3	0.1
2-4	47,803	13.2	45.3	2.8	2.7	22.3	1.3	60,930	13.2	358.3	1.5	16.6	3.6	0.2
4-6	27,625	7.6	43.6	2.7	4.4	29.4	3.0	43,009	9.3	428.4	1.8	28.0	4.4	0.3
6-8	21,816	6.0	48.3	2.9	6.2	36.7	4.7	32,564	7.1	457.8	1.9	39.4	4.5	0.4
8-10	15,482	4.3	42.9	2.6	7.7	40.0	7.2	24,829	5.4	451.1	1.9	50.8	4.3	0.5
10-12	12,642	3.5	43.8	2.7	9.7	33.5	7.4	18,967	4.1	420.5	1.8	62.1	4.1	0.6
12-15	11,801	3.2	50.3	3.1	11.9	37.3	8.8	21,718	4.7	591.1	2.5	76.2	5.7	0.7
15-20	13,895	3.8	75.1	4.6	15.2	60.8	12.3	23,974	5.2	841.3	3.5	98.5	7.7	0.9
20-25	8,157	2.2	56.6	3.4	19.6	46.2	16.1	16,539	3.6	744.2	3.1	126.5	7.5	1.3
25-30	6,276	1.7	52.3	3.2	23.7	46.5	21.1	11,638	2.5	644.9	2.7	156.7	5.1	1.2
30-40	7,207	2.0	75.3	4.6	30.0	69.0	27.5	16,083	3.5	1,122.3	4.7	197.4	9.5	1.7
40-50	3,684	1.0	49.0	3.0	39.1	42.1	33.5	9,959	2.2	895.6	3.7	255.6	7.1	2.0
50-100	7,934	2.2	159.7	9.7	59.4	171.4	63.7	22,546	4.9	3,156.6	13.2	402.7	22.4	2.9
100-200	3,070	0.8	119.1	7.3	118.3	115.9	115.1	13,444	2.9	3,520.4	14.7	782.4	30.8	6.8
200-400	1,469	0.4	109.9	6.7	233.9	122.3	260.3	5,528	1.2	2,572.2	10.7	1,545.1	22.3	13.4
400-800	663	0.2	92.3	5.6	447.9	128.5	623.6	2,038	0.4	1,708.3	7.1	3,007.9	22.2	39.0
800-1,600	264	0.1	77.8	4.7	900.8	114.4	1,325.0	816	0.2	1,342.4	5.6	6,039.3	25.0	112.6
1,600-3,200	145	0.0	86.8	5.3	1,770.4	121.8	2,485.6	460	0.1	1,633.2	6.8	11,907.5	35.8	261.0
3,200-6,400	66	0.0	88.1	5.4	3,950.0	92.9	4,167.6	247	0.1	1,913.3	8.0	22,917.6	46.1	552.0
6,400-12,800	47	0.0	112.4	6.8	7,428.9	132.1	8,729.2	51	0.0	725.3	3.0	46,468.5	9.9	635.0
> 12,800	30	0.0	176.5	10.7	18,162.2	136.8	14,083.1	9	0.0	227.5	0.9	84,081.9	3.3	1,204.3
Total	**363,459**	**100.0**	**1,642.3**	**100.0**	**12.9**	**1,614.4**	**12.7**	**461,388**	**100.0**	**23,959.1**	**100.0**	**148.5**	**283.2**	**1.8**

Table A-14: Federal Gulf 2009 Distribution of Wells by Production Rate Bracket (EIA, 2010a)

Prod. Rate Bracket (BOE/Day)	Oil Wells							Gas Wells						
	# of Oil Wells	% of Oil Wells	Annual Oil Prod. (Mbbl)	% of Oil Prod.	Oil Rate per Well (bbl/Day)	Annual Gas Prod. (MMcf)	Gas Rate per Well (Mcf/Day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (MMcf)	% of Gas Prod.	Gas Rate per Well (Mcf/Day)	Annual Oil Prod. (Mbbl)	Oil Rate per Well (bbl/Day)
0-1	46	1.5	3.1	0.0	0.3	4.8	0.4	116	4.4	52.2	0.0	1.9	0.7	0.0
1-2	23	0.8	6.5	0.0	1.2	10.2	1.9	55	2.1	112.1	0.0	8.2	1.7	0.1
2-4	40	1.3	30.4	0.0	2.5	43.0	3.5	70	2.7	278.2	0.0	15.8	4.2	0.2
4-6	37	1.2	41.6	0.0	4.0	71.0	6.8	74	2.8	538.6	0.0	27.4	8.1	0.4
6-8	43	1.4	66.9	0.0	5.4	108.4	8.8	51	1.9	499.7	0.0	37.8	8.2	0.6
8-10	46	1.5	101.6	0.0	7.0	169.0	11.7	43	1.6	609.0	0.0	50.0	6.4	0.5
10-12	32	1.1	89.2	0.0	9.2	111.5	11.5	35	1.3	547.3	0.0	56.6	14.5	1.5
12-15	65	2.2	229.0	0.0	11.3	267.8	13.2	51	1.9	1,041.6	0.1	69.9	28.1	1.9
15-20	99	3.3	448.9	0.1	14.1	676.8	21.2	89	3.4	2,557.3	0.1	93.8	43.2	1.6
20-25	101	3.4	625.5	0.1	18.6	792.3	23.5	84	3.2	3,023.3	0.2	121.1	56.3	2.3
25-30	111	3.7	856.6	0.2	23.1	937.8	25.3	77	2.9	3,140.6	0.2	146.8	59.5	2.8
30-40	216	7.2	2,107.2	0.4	28.5	2,821.7	38.2	126	4.8	7,456.0	0.4	191.8	109.5	2.8
40-50	189	6.3	2,403.6	0.4	37.1	2,952.2	45.6	108	4.1	7,788.0	0.4	240.3	175.6	5.4
50-100	638	21.3	13,471.4	2.5	60.5	16,722.2	75.1	351	13.3	42,876.5	2.3	394.8	718.7	6.6
100-200	506	16.9	21,060.9	3.9	118.8	23,817.1	134.4	388	14.7	99,838.2	5.3	815.0	1,272.4	10.4
200-400	303	10.1	23,902.4	4.4	234.2	27,232.1	266.9	357	13.5	171,637.2	9.1	1,587.1	2,113.7	19.5
400-800	157	5.2	24,319.8	4.5	465.6	28,928.2	553.8	281	10.6	267,687.1	14.2	3,139.7	3,352.2	39.3
800-1,600	124	4.1	37,018.6	6.8	911.9	51,361.6	1,265.2	155	5.9	297,842.7	15.8	6,179.4	5,209.8	108.1
1,600-3,200	86	2.9	53,804.6	9.9	1,901.4	73,151.5	2,585.1	72	2.7	281,825.9	15.0	12,283.7	5,179.9	225.8
3,200-6,400	58	1.9	79,016.7	14.5	4,001.7	81,878.3	4,146.6	34	1.3	259,606.8	13.8	24,584.0	4,941.2	467.9
6,400-12,800	45	1.5	107,626.0	19.8	7,472.5	126,500.1	8,782.9	16	0.6	234,073.5	12.4	53,797.6	909.8	209.1
> 12,800	30	1.0	176,482.4	32.5	18,162.2	136,845.3	14,083.1	8	0.3	200,795.6	10.7	85,773.4	2,324.5	992.9
Total	**2,995**	**100.0**	**543,712.9**	**100.0**	**541.3**	**575,403.0**	**572.8**	**2,641**	**100.0**	**1,883,827.2**	**100.0**	**2,396.7**	**26,538.1**	**33.8**

Table A-15: U.S. 2009 Distribution of Onshore Gas Wells (EIA, 2010a, 2010b)

Prod. Rate Bracket (BOE/day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (Bcf)	% of Gas Prod.	Gas Rate per Well (Mcf/day)	Annual Oil Prod. (MMbbl)	Oil Rate per Well (bbl/day)	Gas Energy Equivalent (MMBtu/day)	Oil Energy Equivalent (MMBtu/day)	% of Energy from Gas	Adjusted Gas Rate per Well, (Mcf/Day)[1]
0-1	90,889	19.8%	73.4	0.3%	2.2	0.7	0.0	2.3	0.1	94.9%	2.3
1-2	44,979	9.8%	131.0	0.6%	8.0	1.3	0.1	8.2	0.5	94.7%	8.4
2-4	60,860	13.3%	358.0	1.6%	16.1	3.6	0.2	16.6	0.9	94.6%	17.0
4-6	42,935	9.4%	427.9	1.9%	27.3	4.4	0.3	28.0	1.6	94.5%	29.0
6-8	32,513	7.1%	457.3	2.1%	38.5	4.5	0.4	39.6	2.2	94.7%	41.0
8-10	24,786	5.4%	450.5	2.0%	49.8	4.3	0.5	51.1	2.8	94.9%	52.0
10-12	18,932	4.1%	420.0	1.9%	60.8	4.1	0.6	62.4	3.4	94.8%	64.0
12-15	21,667	4.7%	590.1	2.7%	74.6	5.7	0.7	76.6	4.2	94.9%	79.0
15-20	23,885	5.2%	838.7	3.8%	96.2	7.7	0.9	98.8	5.1	95.1%	101.0
20-25	16,455	3.6%	741.2	3.4%	123.0	7.4	1.2	127.0	7.0	94.6%	130.0
25-30	11,561	2.5%	641.8	2.9%	152.0	5.0	1.2	156.0	7.0	95.8%	159.0
30-40	15,957	3.5%	1,114.8	5.1%	191.0	9.4	1.6	197.0	9.0	95.5%	201.0
40-50	9,851	2.1%	887.8	4.0%	247.0	6.9	1.9	254.0	11.0	95.8%	258.0
50-100	22,195	4.8%	3,113.7	14.1%	384.0	21.7	2.7	395.0	16.0	96.2%	399.0
100-200	13,056	2.8%	3,420.6	15.5%	718.0	29.5	6.2	737.0	36.0	95.4%	753.0
200-400	5,171	1.1%	2,400.6	10.9%	1,272.0	20.2	10.7	1,306.0	62.0	95.5%	1,332.0
400-800	1,757	0.4%	1,440.6	6.5%	2,246.0	18.9	29.4	2,307.0	170.0	93.1%	2,412.0
800-1,600	661	0.1%	1,044.6	4.7%	4,330.0	19.8	82.0	4,446.0	476.0	90.3%	4,793.0
1,600-3,200	388	0.1%	1,351.4	6.1%	9,542.0	30.6	216.0	9,800.0	1,254.0	88.7%	10,763.0
3,200-6,400	213	0.0%	1,653.7	7.5%	21,271.0	41.2	529.0	21,845.0	3,071.0	87.7%	24,261.0
6,400-12,800	35	0.0%	491.2	2.2%	38,452.0	9.0	704.0	39,490.0	4,082.0	90.6%	42,427.0
> 12,800	1	0.0%	26.7	0.1%	73,163.0	1.0	2,673.0	75,138.0	15,501.0	82.9%	88,256.0
Total	**458,747**	**100.0%**	**22,075.4**	**100.0%**	**132.0**	**256.8**	**1.5**	**135.0**	**8.9**	**93.8%**	**140.0**

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[1] Adjusted by energy-based co-product allocation

Co-product Allocation of Oil

The EIA data also shows that gas wells produce a small share of oil. On an energy basis, oil comprises approximately 3.8 to 17 percent of gas well production, depending on the production rate bracket. Using energy-based, co-product allocation, it is necessary to scale the production rates of the gas wells so they are representative of 100 percent gas production.

For example, a gas well that has daily production rates of 718 Mcf of natural gas and 6.2 barrels of oil has a total daily production of 773 MMBtu of energy. This energy equivalency is calculated using heating values of 1,027 Btu/cf for natural gas and 5.8 MMBtu/bbl for oil. If expressed solely on and energy-equivalent basis of natural gas, 773 MMBtu of energy is equal to 753 Mcf of natural gas. Thus, in this instance, accounting for the co-production of oil increases the nominal production rate of the gas well from 718 Mcf/day to 752 Mcf/day. Note that this nominal rate of 752 Mcf/day does not represent the actual gas produced by the well, but is an LCA accounting method that uses the relative energies of produced oil and natural gas to scale the gas production rate so it is representative of a well that produces only natural gas.

Selection of Representative Production Brackets

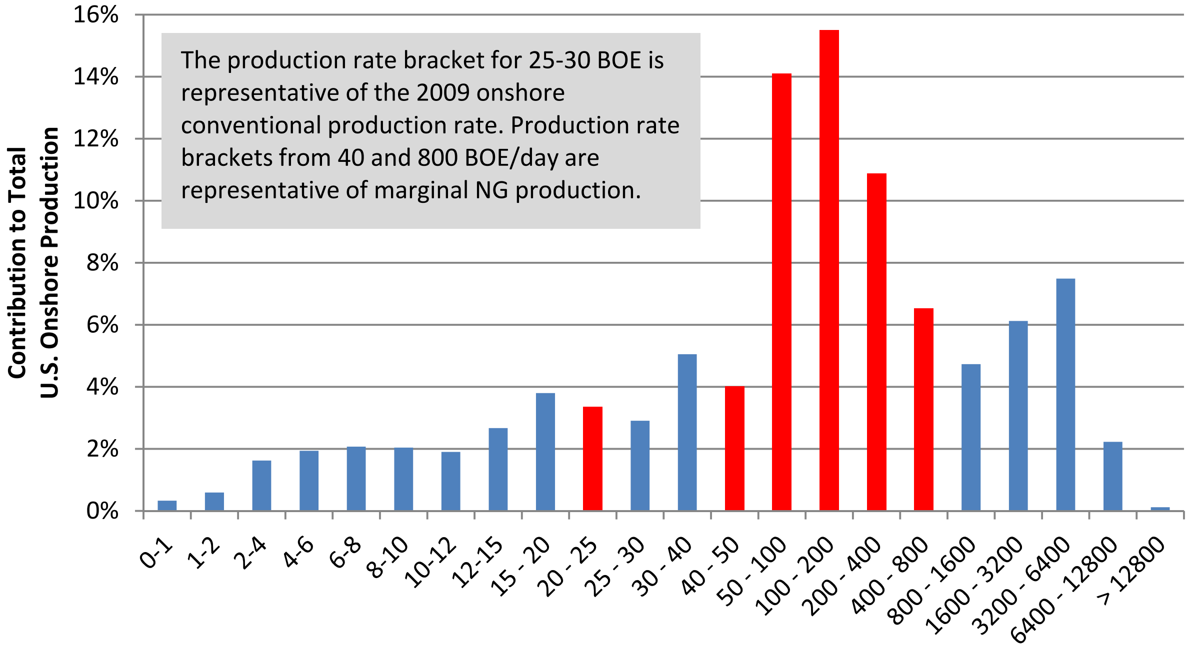
The production rates of onshore conventional natural gas wells vary widely and are a function of reservoir properties, extraction technology, and age. As shown by the EIA data, the production rates of onshore gas wells range from less than 1 BOE/day to more than 12,800 BOE/day. There are not enough data to determine the split between conventional and unconventional wells within each production rate bracket; however, the total production of each bracket and the production rates of unconventional wells can be used to determine the most likely production rates for onshore conventional natural gas. The distribution of gas wells by total gas produced is shown in **Figure A-2**

The production categories in **Table A-15** include a large population of wells in the lowest production rate bracket; 19.8 percent of U.S. onshore natural gas wells produce less than one BOE per day. Similarly, the production rate bracket for 1 - 2 BOE/day includes 9.8 percent of natural gas wells, the production rate bracket for 2 - 4 BOE/day includes 13.3 percent of natural gas wells, and the production rate bracket for 4 - 6 BOE/day includes 9.4 percent of natural gas wells. While these four production rate brackets account for 52 percent of the total count of natural gas wells, they account for only 4.5 percent of total natural gas production.

The average production rate for conventional onshore natural gas wells in 2009 was 66 Mcf per day. This production rate was calculated by dividing the amount of onshore conventional natural gas that was produced in 2009 by the total number of onshore conventional natural gas wells in 2009.

The marginal production rate for conventional onshore natural gas was calculated by selecting the most productive region of the production rate brackets. The production rate brackets that include 40 to 800 BOE/day represent 51 percent of total onshore natural gas production. The average production rate of this range of wells is 592 Mcf/day.

Figure A-2: Distribution of Onshore Natural Gas Wells



A.2 Raw Material Acquisition: Coal

Raw material extraction for coal incorporates extraction profiles for coal derived from the PRB, where sub-bituminous, low-rank coal extracted from thick coal seams (up to approximately 180 feet) via surface mines located in Montana and Wyoming, and coal derived from the Illinois No. 6 coal seam, where bituminous coal is extracted from approximately 2 to 15 foot seams via underground longwall and continuous mining. Each modeling approach is described below.

Powder River Basin Coal

The PRB coal-producing region consists of counties in two states – Big Horn, Custer, Powder River, Rosebud, and Treasure in Montana, and Campbell, Converse, Crook, Johnson, Natrona, Niobrara, Sheridan, and Weston in Wyoming (EIA, 2009). PRB coal is advantageous in comparison to bituminous coals in that it has lower ash and sulfur content. However, PRB coal also has a lower heating value than higher rank coals (Clyde Bergemann, 2005). In 2007, there were 17 surface mines extracting PRB coal, which produced over 479 million short tons (EIA, 2009).

PRB coal is modeled using modern mining methods in practice at the following mines: Peabody Energy's North Antelope-Rochelle mine (97.5 million short tons produced in 2008), Arch Coal, Inc.'s Black Thunder Mine (88.5 million short tons produced in 2008), Rio Tinto Energy America's Jacobs Ranch (42.1 million short tons produced in 2008), and Cordero Rojo Operation (40.0 million short tons produced in 2008). These four mines were the largest surface mines in the United States in 2008 according to the National Mining Association's 2008 Coal Producer Survey (National Mining Association, 2009).

Equipment and Mine Site

Much of the equipment utilized for surface coal mining in the PRB is very large. GHG emissions that result from the production of construction materials required for coal extraction were quantified for the following equipment, within the model: track loader (10 pieces at 26,373 kg each); rotary drill (3 pieces at 113,400 kg each); walking dragline (3 pieces at 7,146,468 kg each); electric mining shovel (10 pieces at 1,256,728 kg each); mining truck (11 pieces at 278,690 kg each); coal crusher (1 piece at 115,212 kg); conveyor (1 piece at 1,064,000 kg); and loading silo (6 pieces at 10,909,569 kg each).

Coal seams are located relatively close to the ground surface in the PRB such that large-scale surface mining is common. The coal seam ranges in thickness from 42 to 184 feet thick (EPA, 2004a). Before overburden drilling and cast blasting can be carried out, topsoil and unconsolidated overburden must be removed from the consolidated overburden that is to be blasted. These operations use both truck and shovel operations and bulldozing to move these materials to a nearby stockpile location so that they can be used in post-mining site reclamation. Estimates are made for topsoil/overburden operations based on requirements reported in the Energy and Environmental Profile of the U.S. Mining Industry (DOE, 2002) for a hypothetical western surface coal mine.

Overburden Blasting and Removal

Blast holes are drilled into overburden for subsequent ammonium nitrate and fuel oil packing and detonation using large rotary drills. Drills use electricity to drill 220-270 millimeter diameter holes through sandstone, siltstone, mudstone and carbonaceous shale that make up the overburden. Typically this overburden contains water, which controls particulate emission associated with drilling activities. For the purposes of this assessment it is assumed that drilling operations produce no direct emissions. Electricity requirements for drilling are taken from the U.S. DOE report Mining Industry for the Future: Energy and Environmental Profile of the U.S. Mining Industry (DOE, 2002).

Cast blasting is a blasting technique that was developed relatively recently, and has found broad application in large surface mines. Cast blasting comminutes (breaks into fragments/particles) overburden, and also moves an estimated 25-35 percent (modeled at 30 percent) of the blasted overburden to the target fill location (Mining Technology, 2007). The model assumes that blasting uses ammonium nitrate and fuel oil explosives with a powder factor[1] of 300 g per m^3 of overburden blasted (SME, 1990), and GHG emissions associated with explosive production and the blasting process are included in the model, based on EPA's AP-42 report (EPA, 1995).

Overburden removal is achieved primarily through dragline operations, with the remainder moved using large electric shovels. Dragline excavation systems are among the largest on-land machines, and utilize a large bucket suspended from a boom, where the bucket is scraped along the ground to fill the bucket. The bucket is then emptied at a nearby fill location. Electricity requirements for dragline operation combined with other on site operations, were estimated based on electricity usage at the North Antelope Rochelle Mine, to be approximately 971 kWh per 1000 tons of coal (Peabody, 2006). During this time dragline operation accounted for approximately 50% of the overburden energy.

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[1] Powder factor refers to the mass of explosive needed to blast a given mass of material.

Coal Recovery

Following overburden removal, coal is extracted using truck and shovel-type operations. Because of the large scale of operations, large electric mining shovels (Bucyrus 495 High Performance Series) are assumed to be employed, with a bucket capacity of 120 tons, alongside 320-400 ton capacity mining trucks (Bucyrus International Inc., 2008).

The amount of coal that could be moved by a single shovel per year was determined by using data for the Black Thunder and Cordero Rojo coal mines (Mining Technology, 2007). A coal hauling distance of two miles is assumed, with a round-trip distance of four miles, based on evaluation of satellite imagery of mining operations. The extracted coal is ground and crushed to the necessary size for transportation. It is assumed that the coal does not require cleaning before leaving the mine site. The crushed coal is carried from the preparation facility to a loading silo by an overland conveyor belt. From the loading silo, the coal is loaded into railcars for transportation.

Coal Bed Methane Emissions

During coal acquisition, methane is released during both the coal extraction and post-mining coal preparation activities. While the PRB has relatively low specific methane content, the large thickness of the coal deposit (80 feet thick or more in many areas) has a large methane content per square foot of surface area. As a result the PRB has recently begun to be exploited on a large scale. Extraction of coal bed methane, prior to mining of the coal seam, results in a net reduction of the total amount of coal bed methane that is emitted to the atmosphere, since extracted methane is typically sold into the natural gas market, and eventually combusted.

For the purposes of this assessment, it is assumed that the coal seam in the area of active mining was previously drilled to extract methane. Based on recent data available from the EPA, coal bed methane emissions for surface mining, including the PRB, are expected to range from 8 to 98 standard cubic feet per ton (cf/ton) of produced coal, with a typical value of 51 cf/ton (EPA, 2011b).

Illinois No. 6 Coal

Illinois No. 6 coal is part of the Herrin Coal, and is a bituminous coal that is found in seams that typically range from about 2 to 15 feet in thickness, and is found in the southern and eastern regions of Illinois and surrounding areas. Illinois No. 6 coal is commonly extracted via underground mining techniques, including continuous mining and longwall mining. Illinois No. 6 coal seams may contain relatively high levels of mineral sediments or other materials, and therefore require coal cleaning (beneficiation) at the mine site. The following sections describe the unit processes modeled for Illinois No. 6 coal mining.

Equipment and Mine Site

Extraction of Illinois No. 6 coal requires several types of major equipment and mining components, in order to operate the coal mine. The following components were modeled for use during underground mining operations: site paving and concrete, conveyor belt, stacker/reclaimer, crusher, coal cleaning, silo, wastewater treatment, continuous miner, longwall mining systems (including shear head, roof supports, armored force conveyor, stage loader, and mobile belt tailpiece), and shuttle car systems with replacement. Overall, when considering materials requirements for the construction of these systems, the material inputs values shown in **Table A-16** were required for mine and mining system construction, on a per lb of coal output basis. GHG emissions associated with the production of these materials were incorporated into the model and accounted for as construction related emissions.

Table A-16: Construction Materials Required for Illinois No. 6 Coal Mining

Construction Material	Amount	Units
Cold-Rolled Steel	1.47E-05	lb/lb coal produced
Hot-dip Galvanized Steel	1.52E-06	lb/lb coal produced
Rubber	4.45E-07	lb/lb coal produced
Steel Plate	1.80E-04	lb/lb coal produced
Concrete	6.06E-05	lb/lb coal produced
Rebar	1.41E-06	lb/lb coal produced
Polyvinylchloride Pipe	1.30E-07	lb/lb coal produced
Steel, Stainless, 316	6.77E-08	lb/lb coal produced
Stainless Steel Cold Roll 431	6.77E-08	lb/lb coal produced
Cast Iron	3.38E-07	lb/lb coal produced
Copper Mix	8.11E-09	lb/lb coal produced
Asphalt	1.11E-03	lb/lb coal produced

Coal Mine Operations

Operations of the coal mine were based on operation of the Galatia Mine, which is operated by the American Coal Company and located in Saline County, Illinois. Sources reviewed in support of coal mine operations include Galatia Mine production rates, electricity usage, particulate emissions, methane emissions, wastewater discharge permit monitoring reports, and communications with Galatia Mine staff. When data from the Galatia Mine were not available, surrogate data were taken from other underground mines, as relevant.

Electricity is the main source of energy for coal mine operations. Electricity use for this model was estimated based on previous estimates made by EPA for electricity use for underground mining and coal cleaning at the Galatia Mine (EPA, 2008). The life cycle profile for electricity use is based on eGRID2007. The Emissions and Generation Resource Integrated Database (eGRID) is a comprehensive inventory of environmental attributes for electric power systems (EPA, 2010).

Although no Galatia Mine data were found that estimated the diesel fuel used during mining operations, it was assumed that some diesel would be used to operate trucks for moving materials, workers, and other secondary on-site operations. Therefore, diesel use was estimated for the Galatia Mine from 2002 U.S. Census data for bituminous coal underground mining operations and associated cleaning operations (U.S. Census Bureau, 2004). Emissions of GHGs were based on emissions associated with the use of diesel. EPA Tier 4 diesel standards for non-road diesel engines were used, since these standards would go into effect within a couple years of commissioning of the mine for this study (EPA, 2004b).

Coal Bed Methane

During the acquisition of Illinois No. 6 coal, methane is released during both the underground coal extraction and the post-mining coal preparation activities. Illinois No. 6 coal seams are not nearly as thick as PRB coals, and as a result are less commonly utilized as a resource for coal bed methane extraction. Instead, methane capture may be applied during the coal extraction process. Based on recent data available from the EPA, coal bed methane emissions for underground mining, including mining within the Illinois No. 6 coal seam, are expected to range from 360 to 500 cf/ton of produced coal, with a nominal value of 422 cf/ton (EPA, 2011b). It is assumed that no methane capture is applied for Illinois No. 6 coal.

A.3 Raw Material Transport: Natural Gas

The boundary of raw material transport begins with receipt of processed natural gas at the extraction site and ends with the delivery of natural gas to an energy conversion facility. Methane emissions from pipeline operations are a function of pipeline distance. This analysis uses a pipeline transport distance of 604 miles (971.4 km), which is the average distance for natural gas pipeline transmission in the U.S. The data sources and assumptions for calculating the greenhouse gas emissions from construction and operation of natural gas transmission pipelines are discussed below.

Pipeline Construction and Decommissioning

Carbon steel is the primary material used in the construction of natural gas pipelines. The mass of pipeline per unit length was determined using an online calculator (Steel Pipes & Tubes, 2009). The weight of valves and fittings were estimated at an additional 10 percent of the total pipeline weight. The pipeline was assumed to have a life of 30 years. The mass of pipeline construction per kilogram of natural gas was determined by dividing the total pipeline weight by the total natural gas flow through the pipeline for a 30-year period.

The decommissioning of a natural gas pipeline involves cleaning and capping activities. This analysis assumes that the decommissioning of a natural gas pipeline incurs 10 percent of the energy requirements and emissions as the original installation of the pipeline.

Pipeline Operations

The U.S. has an extensive natural gas pipeline network that connects natural gas supplies and markets. Compressor stations are necessary every 50 to 100 miles along the natural gas transmission pipelines in order to boost the pressure of the natural gas. Compressor stations consist of centrifugal and reciprocating compressors. Most natural gas compressors are powered by natural gas, but, when electricity is available, electrically-powered compressors are used.

A 2008 paper published by the Interstate Natural Gas Association of America provides data from its 2004 database, which shows that the U.S. pipeline transmission network has 5,400 reciprocating compressors and over 1,000 gas turbine compressors (Hedman, 2008). Further, based on written communication from El Paso Pipeline Group, approximately three percent of transmission compressors are electrically driven (El Paso Pipeline Group, 2011). El Paso Pipeline Group has the highest transmission capacity of all natural gas pipeline companies in the U.S., and it is thus assumed that the share of electrically-powered compressors in their fleet is representative of the entire natural gas transmission network. Based on written communication with El Paso Pipeline Group (El Paso Pipeline Group, 2011), the share of compressors on the U.S. natural gas pipeline transmission network is approximately 78 percent reciprocating compressors, 19 percent turbine-powered centrifugal compressors, and 3 percent electrically-powered compressors.

The use rate of natural gas for fuel in transmission compressors was calculated from the Federal Energy Regulatory Commission (FERC) Form 2 database, which is based on an annual survey of gas producers and pipeline companies (FERC, 2010). The 28 largest pipeline companies were pulled from the FERC Form 2 database. These 28 companies represent 81 percent of NG transmission in 2008. The FERC data for 81 percent of U.S. natural gas transmission is assumed to be a representative sample of the fuel use rate of the entire transmission network. This data shows that

0.96 percent of natural gas product is consumed as compressor fuel. This fuel use rate was converted to a basis of kg of natural gas consumed per kg of natural gas transported by multiplying it by the total natural gas delivered by the transmission network in 2008 (EIA, 2011) and dividing it by the annual tonne-km of pipeline transmission in the U.S. (Dennis, 2005). The total delivery of natural gas in 2008 was 21 Tcf, which is approximately 400 billion kg of natural gas. The annual transport rate for natural gas transmission was steady from 1995 through 2003, at approximately 380 billion tonne-km per year. More recent transportation data are not available, and thus this analysis assumes the same tonne-km rate for 2008 as shown from 1995 through 2003.

The air emissions from the combustion of natural gas by compressors are estimated by applying EPA emission factors to the natural gas consumption rate of the compressors (EPA, 1995). Specifically, the emission profile of gas-powered, centrifugal compressors is based on emission factors for gas turbines; the emission profile of gas-powered, reciprocating compressors is based on emission factors for 4-stroke, lean burn engines. For electrically-powered compressors, this analysis assumes that the indirect emissions are representative of the U.S. average fuel mix for electricity generation.

The average power of electrically-driven compressors for U.S. NG transmission is assumed to be the same as the average power of all compressors on the transmission network. An average compressor on the U.S. natural gas transmission network has a power rating of 14,055 horsepower (10.5 MW) and a throughput of 734 million cubic feet of natural gas per day (583,000 kg NG/hour) (EIA, 2007). Electrically-driven compressors have efficiencies of 95 percent (DOE, 1996; Hedman, 2008). This efficiency is the ratio of mechanical power output to electrical power input. Thus, approximately 1.05 MWh of electricity is required per MWh of compressor energy output.

In addition to air emissions from combustion processes, fugitive venting from pipeline equipment results in the methane emissions to air. The fugitive emission rate for natural gas pipeline operations is based on data published by the Bureau of Transportation Statistics (BTS) and EPA. The transport data for natural gas transmission is based on ton-mileage estimates by BTS, which calculates 253 billion ton-miles of natural gas transmission in 2003 (Dennis, 2005). The 2003 data are the most recent data point in the BTS reference, and thus EPA's inventory data for the years 2000 and 2005 were interpolated to arrive at a year 2003 value of 1,985 million kg of fugitive methane emissions per year (EPA, 2011b). Dividing the EPA emission by the transport requirements and converting to metric units gives 5.37E-06 kg/kg-km.

Calculation of Average Natural Gas Transmission Distance

The average pipeline distance for natural gas transport is determined by balancing national emission inventory (EPA, 2011b) and natural gas consumption data (EIA, 2011) with NETL’s unit process emission factor for fugitive methane emissions from pipeline operations. **Equation 5** shows the national inventory and consumption data on the left-hand side and NETL’s emission factor for fugitive methane on the right-hand side.

$$\frac{E_{methane}}{NG_{consumption}} = d * EF_{methane} \qquad \textbf{(Equation 5)}$$

Where,

$E_{methane}$ = Total pipeline fugitive methane emissions (default = 2,115E+06 kg CH_4/yr)
$NG_{consumption}$ = consumption of natural gas (default = 21.84 MMBtu/yr)
$EF_{methane}$ = Emission factor for fugitive methane (default =9.97E-05 kg CH_4/MMBtu-km)

The default value for total fugitive emissions of methane from pipeline transmission are based on the 2009 national inventory emissions for natural gas transmission and storage reported by EPA (EPA, 2011b). The value reported by EPA is 2,115 Gg CH_4/yr, which is equal to 2,115 million kg CH_4/yr.

The default value for annual natural gas consumption is based on annual EIA statistics for natural gas production and consumption (EIA, 2011). The volume of natural gas transported by pipeline is 21.26 Tcf/year. This value is the midpoint of the volume of processed natural gas injected to the pipeline transmission network and the volume of natural gas delivered to consumers. In 2009 the volume of natural gas injected to the natural gas transmission network by NG processing plants was 21.56 Tcf; this volume was calculated by subtracting the natural gas consumption at the extraction and processing sites (1.28 Tcf) from total annual consumption (22.84 Tcf) (EIA, 2011). In 2009 the volume of natural gas delivered to consumers was 20.97 Tcf (EIA, 2011). The average volume of natural gas transmission was converted to an energy basis using an energy density of 1,027 Btu/cf; 21.26 Tcf/year is equivalent to 21.84 E+09 MMBtu. Converting to an energy basis (using a density of 0.042 lbs/cf and energy content of 1,027 Btu/cf) gives 21.84 billion MMBtu.

For **Equation 5** it is necessary to convert the emission factor for fugitive emissions from pipeline operations (calculated above) to an energy basis so that it can be factored with the annual consumption data for natural gas. The emission factor used by the pipeline unit process is 5.37E-06 kg/kg-km. Converting to an energy basis (using the conversion factors of 0.042 lb/cf NG and 1,027 Btu/cf) results in an emission factor of 9.97E-05 kg CH_4/MMBtu-km.

The unknown *d* in **Equation 5** is the distance (km) that reconciles NETL's unit process with the national level data. Solving for *d* gives the following equation:

$$d = \frac{E_{methane}}{NG_{consumption} * EF_{methane}}$$ **(Equation 6)**

Applying the default values to **Equation 6** gives a distance of 971 km (604 miles), as shown in **Equation 7**.

$$d = \frac{2{,}115\times10^6 kg\ CH_4/yr}{(21.84\times10^9 MMBtu/yr)(9.97\times10^{-5} kgCH_4/MMBtu\ km)} = 971\ km$$ **(Equation 7)**

The pipeline transport of natural gas results in losses of natural gas product to two activities: (1) fugitive emissions and (2) natural gas used as fuel in pipeline compressors. Based on the data and assumptions of this unit process, the transmission of natural gas a distance of 971 km results in a 1.45 percent loss of natural gas product (1.0148 kg of natural gas are injected into the pipeline to deliver 1.0 kg of natural gas to the consumer). The annual data for natural gas production and consumption (EIA, 2011) show a 2.81 percent loss of natural gas for transmission and distribution (natural gas processing plants produce 21.56 Tcf of natural gas and 20.97 Tcf of natural gas are delivered to consumers). The 2.81 percentage loss factor includes pipeline *distribution* in addition to pipeline transmission, and thus it is expected for the transmission losses (1.45 percent) to be lower than the transmission and distribution loss (2.81 percent).

The default values for key variables for NETL's model of natural gas pipeline transmission are shown in the **Table A-17**.

Table A-17: Natural Gas Transport to Large End User

Natural Gas Emissions and Transmission Infrastructure	Units	Value
Pipeline Transport Distance (national average)	Miles	604
Distance Between Compressor Stations	Miles	75
Compression, Gas-powered, Reciprocating Engine	Percent	78%
Compression, Gas-powered, Centrifugal Engine	Percent	19%
Compression, Electrical, Centrifugal Engine	Percent	3%

A.4 Raw Material Transport: Coal

Train transport was modeled for the transport of both PRB and Illinois No. 6 coal from mining sites to energy conversion facilities. Mined coal is presumed to be transported by rail from PRB and Illinois No. 6 coal mine sources, in support of electricity production. Coal is assumed to be transported via unit train, where a unit train is defined as one locomotive pulling 100 railcars loaded with coal. The locomotive is powered by a 4,400 horsepower diesel engine (General Electric, 2008) and each car has a 100-ton coal capacity (NETL, 2007).

GHG emissions for train transport are evaluated based on typical diesel combustion emissions for a locomotive engine. Loss of coal during transport is assumed to be equal to the fugitive dust emissions; loss during loading at the mine is assumed to be included in the coal reject rate and no loss is assumed during unloading. It is assumed that the majority of the railway connecting the coal mine and the energy conversion facility is existing infrastructure. An assumed 25-mile rail spur was constructed between the energy conversion facility and the primary railway.

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Appendix B:
Inventory Results in Alternate Units

Table B-1: Upstream Greenhouse Gas Inventory Results for Natural Gas

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Avg. Gas	CO_2	5.93E+00	1.05E+00	6.98E+00	2.69E+00	4.76E-01	3.16E+00	2.55E+00	4.51E-04	3.00E-03	1.22E+01	2.16E+00	1.43E+01
	N_2O	1.85E-04	2.02E-05	2.05E-04	8.39E-05	9.17E-06	9.31E-05	7.95E-05	8.69E-06	8.82E-05	3.80E-04	4.15E-05	4.22E-04
	CH_4	6.42E-01	2.14E-01	8.56E-01	2.91E-01	9.69E-02	3.88E-01	2.76E-01	9.18E-02	3.68E-01	1.32E+00	4.39E-01	1.76E+00
	CO_2e (20-year)	52.2	16.4	68.6	23.7	7.5	31.1	22.4	7.1	29.5	107.2	33.8	141.0
	CO_2e (100-year)	22.0	6.4	28.4	10.0	2.9	12.9	9.5	2.7	12.2	45.3	13.1	58.4
	CO_2e (500-year)	10.8	2.7	13.5	4.9	1.2	6.1	4.7	1.2	5.8	22.3	5.5	27.8
Conv. Gas	CO_2	6.34E+00	1.05E+00	7.38E+00	2.87E+00	4.76E-01	3.35E+00	2.72E+00	4.51E-01	3.17E+00	1.30E+01	2.16E+00	1.52E+01
	N_2O	2.14E-04	2.02E-05	2.35E-04	9.72E-05	9.17E-06	1.06E-04	9.22E-05	8.69E-06	1.01E-04	4.40E-04	4.15E-05	4.82E-04
	CH_4	5.29E-01	2.14E-01	7.43E-01	2.40E-01	9.69E-02	3.37E-01	2.28E-01	9.18E-02	3.19E-01	1.09E+00	4.39E-01	1.53E+00
	CO_2e (20-year)	44.5	16.4	60.9	20.2	7.5	27.6	19.1	7.1	26.2	91.4	33.8	125.2
	CO_2e (100-year)	19.6	6.4	26.0	8.9	2.9	11.8	8.4	2.7	11.2	40.3	13.1	53.5
	CO_2e (500-year)	10.4	2.7	13.1	4.7	1.2	5.9	4.5	1.2	5.6	21.3	5.5	26.8
UnConv. Gas	CO_2	5.60E+00	1.05E+00	6.65E+00	2.54E+00	4.76E-01	3.02E+00	2.41E+00	4.51E-01	2.86E+00	1.15E+01	2.16E+00	1.37E+01
	N_2O	1.62E-04	2.02E-05	1.82E-04	7.33E-05	9.17E-06	8.25E-05	6.95E-05	8.69E-06	7.82E-05	3.32E-04	4.15E-05	3.74E-04
	CH_4	7.32E-01	2.14E-01	9.45E-01	3.32E-01	9.69E-02	4.29E-01	3.15E-01	9.18E-02	4.06E-01	1.50E+00	4.39E-01	1.94E+00
	CO_2e (20-year)	58.3	16.4	74.8	26.5	7.5	33.9	25.1	7.1	32.1	119.8	33.8	153.6
	CO_2e (100-year)	23.9	6.4	30.3	10.9	2.9	13.8	10.3	2.7	13.0	49.2	13.1	62.3
	CO_2e (500-year)	11.2	2.7	13.9	5.1	1.2	6.3	4.8	1.2	6.0	23.0	5.5	28.5
Onshore Gas	CO_2	7.18E+00	1.05E+00	8.23E+00	3.26E+00	4.76E-01	3.74E+00	3.09E+00	4.51E-01	3.54E+00	1.48E+01	2.16E+00	1.69E+01
	N_2O	2.13E-04	2.02E-05	2.33E-04	9.66E-05	9.17E-06	1.06E-04	9.16E-05	8.69E-06	1.00E-04	4.38E-04	4.15E-05	4.79E-04
	CH_4	8.21E-01	2.14E-01	1.03E+00	3.72E-01	9.69E-02	4.69E-01	3.53E-01	9.18E-02	4.45E-01	1.69E+00	4.39E-01	2.12E+00
	CO_2e (20-year)	66.3	16.4	82.8	30.1	7.5	37.5	28.5	7.1	35.6	136.3	33.8	170.0
	CO_2e (100-year)	27.8	6.4	34.2	12.6	2.9	15.5	11.9	2.7	14.7	57.0	13.1	70.2
	CO_2e (500-year)	13.5	2.7	16.1	6.1	1.2	7.3	5.8	1.2	6.9	27.6	5.5	33.1
Offshore Gas	CO_2	5.37E+00	1.05E+00	6.42E+00	2.44E+00	4.76E-01	2.91E+00	2.31E+00	4.51E-01	2.76E+00	1.10E+01	2.16E+00	1.32E+01
	N_2O	2.55E-04	2.02E-05	2.75E-04	1.15E-04	9.17E-06	1.25E-04	1.09E-04	8.69E-06	1.18E-04	5.23E-04	4.15E-05	5.64E-04
	CH_4	9.71E-02	2.14E-01	3.11E-01	4.40E-02	9.69E-02	1.41E-01	4.17E-02	9.18E-02	1.34E-01	1.99E-01	4.39E-01	6.38E-01
	CO_2e (20-year)	12.4	16.4	28.9	5.6	7.5	13.1	5.3	7.1	12.4	25.5	33.8	59.3
	CO_2e (100-year)	7.9	6.4	14.3	3.6	2.9	6.5	3.4	2.7	6.1	16.2	13.1	29.3
	CO_2e (500-year)	6.1	2.7	8.8	2.8	1.2	4.0	2.6	1.2	3.8	12.6	5.5	18.1
Assoc. Gas	CO_2	5.04E+00	1.05E+00	6.09E+00	2.29E+00	4.76E-01	2.76E+00	2.17E+00	4.51E-01	2.62E+00	1.04E+01	2.16E+00	1.25E+01
	N_2O	1.42E-04	2.02E-05	1.62E-04	6.42E-05	9.17E-06	7.34E-05	6.09E-05	8.69E-06	6.96E-05	2.91E-04	4.15E-05	3.32E-04
	CH_4	2.82E-01	2.14E-01	4.96E-01	1.28E-01	9.69E-02	2.25E-01	1.21E-01	9.18E-02	2.13E-01	5.80E-01	4.39E-01	1.02E+00
	CO_2e (20-year)	25.4	16.4	41.8	11.5	7.5	19.0	10.9	7.1	18.0	52.2	33.8	85.9
	CO_2e (100-year)	12.1	6.4	18.5	5.5	2.9	8.4	5.2	2.7	8.0	24.9	13.1	38.1
	CO_2e (500-year)	7.2	2.7	9.9	3.3	1.2	4.5	3.1	1.2	4.2	14.8	5.5	20.3

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Tight Gas	CO_2	5.53E+00	1.05E+00	6.57E+00	2.51E+00	4.76E-01	2.98E+00	2.38E+00	4.51E-01	2.83E+00	1.13E+01	2.16E+00	1.35E+01
	N_2O	1.57E-04	2.02E-05	1.78E-04	7.14E-05	9.17E-06	8.06E-05	6.77E-05	8.69E-06	7.64E-05	3.23E-04	4.15E-05	3.65E-04
	CH_4	8.16E-01	2.14E-01	1.03E+00	3.70E-01	9.69E-02	4.67E-01	3.51E-01	9.18E-02	4.43E-01	1.68E+00	4.39E-01	2.11E+00
	CO_2e (20-year)	64.3	16.4	80.7	29.2	7.5	36.6	27.6	7.1	34.7	132.1	33.8	165.8
	CO_2e (100-year)	26.0	6.4	32.4	11.8	2.9	14.7	11.2	2.7	13.9	53.3	13.1	66.5
	CO_2e (500-year)	11.7	2.7	14.4	5.3	1.2	6.5	5.1	1.2	6.2	24.1	5.5	29.6
CBM Gas	CO_2	5.45E+00	1.05E+00	6.50E+00	2.47E+00	4.76E-01	2.95E+00	2.34E+00	4.51E-01	2.79E+00	1.12E+01	2.16E+00	1.33E+01
	N_2O	1.55E-04	2.02E-05	1.75E-04	7.03E-05	9.17E-06	7.95E-05	6.67E-05	8.69E-06	7.53E-05	3.18E-04	4.15E-05	3.60E-04
	CH_4	2.86E-01	2.14E-01	5.00E-01	1.30E-01	9.69E-02	2.27E-01	1.23E-01	9.18E-02	2.15E-01	5.88E-01	4.39E-01	1.03E+00
	CO_2e (20-year)	26.1	16.4	42.5	11.8	7.5	19.3	11.2	7.1	18.3	53.6	33.8	87.4
	CO_2e (100-year)	12.7	6.4	19.1	5.7	2.9	8.6	5.4	2.7	8.2	26.0	13.1	39.1
	CO_2e (500-year)	7.7	2.7	10.3	3.5	1.2	4.7	3.3	1.2	4.4	15.7	5.5	21.2
Shale Gas	CO_2	5.84E+00	1.05E+00	6.89E+00	2.65E+00	4.76E-01	3.13E+00	2.51E+00	4.51E-01	2.96E+00	1.20E+01	2.16E+00	1.42E+01
	N_2O	1.74E-04	2.02E-05	1.94E-04	7.89E-05	9.17E-06	8.81E-05	7.48E-05	8.69E-06	8.35E-05	3.57E-04	4.15E-05	3.99E-04
	CH_4	8.07E-01	2.14E-01	1.02E+00	3.66E-01	9.69E-02	4.63E-01	3.47E-01	9.18E-02	4.39E-01	1.66E+00	4.39E-01	2.10E+00
	CO_2e (20-year)	64.0	16.4	80.5	29.0	7.5	36.5	27.5	7.1	34.6	131.5	33.8	165.3
	CO_2e (100-year)	26.1	6.4	32.5	11.8	2.9	14.7	11.2	2.7	14.0	53.6	13.1	66.7
	CO_2e (500-year)	12.0	2.7	14.7	5.5	1.2	6.7	5.2	1.2	6.3	24.7	5.5	30.2
LNG Gas	CO_2	2.93E+01	1.05E+00	3.04E+01	1.33E+01	4.76E-01	1.38E+01	1.26E+01	4.51E-01	1.31E+01	6.02E+01	2.16E+00	6.24E+01
	N_2O	3.42E-04	2.02E-05	3.62E-04	1.55E-04	9.17E-06	1.64E-04	1.47E-04	8.69E-06	1.56E-04	7.02E-04	4.15E-05	7.44E-04
	CH_4	2.78E-01	2.14E-01	4.91E-01	1.26E-01	9.69E-02	2.23E-01	1.19E-01	9.18E-02	2.11E-01	5.70E-01	4.39E-01	1.01E+00
	CO_2e (20-year)	49.4	16.4	65.8	22.4	7.5	29.9	21.2	7.1	28.3	101.5	33.8	135.2
	CO_2e (100-year)	36.4	6.4	42.8	16.5	2.9	19.4	15.6	2.7	18.4	74.7	13.1	87.8
	CO_2e (500-year)	31.5	2.7	34.2	14.3	1.2	15.5	13.5	1.2	14.7	64.7	5.5	70.1

Table B-2: Upstream Greenhouse Gas Inventory Results for Marginal Natural Gas

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Marg. Onshore Gas	CO_2	5.11E+00	1.05E+00	6.16E+00	2.32E+00	4.76E-01	2.79E+00	2.20E+00	4.51E-01	2.65E+00	1.05E+01	2.16E+00	1.26E+01
	N_2O	1.44E-04	2.02E-05	1.64E-04	6.53E-05	9.17E-06	7.44E-05	6.19E-05	8.69E-06	7.06E-05	2.96E-04	4.15E-05	3.37E-04
	CH_4	3.41E-01	2.14E-01	5.55E-01	1.55E-01	9.69E-02	2.52E-01	1.47E-01	9.18E-02	2.38E-01	7.01E-01	4.39E-01	1.14E+00
	CO_2e (20-year)	29.7	16.4	46.1	13.5	7.5	20.9	12.8	7.1	19.8	61.0	33.8	94.8
	CO_2e (100-year)	13.7	6.4	20.1	6.2	2.9	9.1	5.9	2.7	8.6	28.1	13.1	41.2
	CO_2e (500-year)	7.7	2.7	10.4	3.5	1.2	4.7	3.3	1.2	4.5	15.9	5.5	21.4
Marg. Offshore Gas	CO_2	5.34E+00	1.05E+00	6.39E+00	2.42E+00	4.76E-01	2.90E+00	2.30E+00	4.51E-01	2.75E+00	1.10E+01	2.16E+00	1.31E+01
	N_2O	2.54E-04	2.02E-05	2.74E-04	1.15E-04	9.17E-06	1.24E-04	1.09E-04	8.69E-06	1.18E-04	5.21E-04	4.15E-05	5.62E-04
	CH_4	9.01E-02	2.14E-01	3.04E-01	4.09E-02	9.69E-02	1.38E-01	3.87E-02	9.18E-02	1.31E-01	1.85E-01	4.39E-01	6.24E-01
	CO_2e (20-year)	11.9	16.4	28.3	5.4	7.5	12.9	5.1	7.1	12.2	24.4	33.8	58.2
	CO_2e (100-year)	7.7	6.4	14.1	3.5	2.9	6.4	3.3	2.7	6.0	15.8	13.1	28.9
	CO_2e (500-year)	6.1	2.7	8.7	2.8	1.2	4.0	2.6	1.2	3.8	12.5	5.5	18.0

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Marg. Assoc. Gas	CO_2	4.91E+00	1.05E+00	5.96E+00	2.23E+00	4.76E-01	2.70E+00	2.11E+00	4.51E-01	2.56E+00	1.01E+01	2.16E+00	1.22E+01
	N_2O	1.37E-04	2.02E-05	1.57E-04	6.22E-05	9.17E-06	7.14E-05	5.90E-05	8.69E-06	6.77E-05	2.82E-04	4.15E-05	3.23E-04
	CH_4	2.82E-01	2.14E-01	4.95E-01	1.28E-01	9.69E-02	2.25E-01	1.21E-01	9.18E-02	2.13E-01	5.78E-01	4.39E-01	1.02E+00
	CO_2e (20-year)	25.2	16.4	41.7	11.4	7.5	18.9	10.8	7.1	17.9	51.8	33.8	85.6
	CO_2e (100-year)	12.0	6.4	18.4	5.4	2.9	8.3	5.2	2.7	7.9	24.6	13.1	37.8
	CO_2e (500-year)	7.1	2.7	9.7	3.2	1.2	4.4	3.0	1.2	4.2	14.5	5.5	20.0
Marg. Tight Gas	CO_2	5.53E+00	1.05E+00	6.57E+00	2.51E+00	4.76E-01	2.98E+00	2.38E+00	4.51E-01	2.83E+00	1.13E+01	2.16E+00	1.35E+01
	N_2O	1.57E-04	2.02E-05	1.78E-04	7.14E-05	9.17E-06	8.06E-05	6.77E-05	8.69E-06	7.64E-05	3.23E-04	4.15E-05	3.65E-04
	CH_4	8.16E-01	2.14E-01	1.03E+00	3.70E-01	9.69E-02	4.67E-01	3.51E-01	9.18E-02	4.43E-01	1.68E+00	4.39E-01	2.11E+00
	SF_6	6.49E-09	2.50E-09	8.99E-09	2.94E-09	1.13E-09	4.08E-09	2.79E-09	1.07E-09	3.86E-09	1.33E-08	5.13E-09	1.85E-08
	CO_2e (20-year)	64.3	16.4	80.7	29.2	7.5	36.6	27.6	7.1	34.7	132.1	33.8	165.8
	CO_2e (100-year)	26.0	6.4	32.4	11.8	2.9	14.7	11.2	2.7	13.9	53.3	13.1	66.5
	CO_2e (500-year)	11.7	2.7	14.4	5.3	1.2	6.5	5.1	1.2	6.2	24.1	5.5	29.6
Marg. Shale Gas	CO_2	5.84E+00	1.05E+00	6.89E+00	2.65E+00	4.76E-01	3.13E+00	2.51E+00	4.51E-01	2.96E+00	1.20E+01	2.16E+00	1.42E+01
	N_2O	1.74E-04	2.02E-05	1.94E-04	7.89E-05	9.17E-06	8.81E-05	7.48E-05	8.69E-06	8.35E-05	3.57E-04	4.15E-05	3.99E-04
	CH_4	8.07E-01	2.14E-01	1.02E+00	3.66E-01	9.69E-02	4.63E-01	3.47E-01	9.18E-02	4.39E-01	1.66E+00	4.39E-01	2.10E+00
	CO_2e (20-year)	64.0	16.4	80.5	29.0	7.5	36.5	27.5	7.1	34.6	131.5	33.8	165.3
	CO_2e (100-year)	26.1	6.4	32.5	11.8	2.9	14.7	11.2	2.7	14.0	53.6	13.1	66.7
	CO_2e (500-year)	12.0	2.7	14.7	5.5	1.2	6.7	5.2	1.2	6.3	24.7	5.5	30.2
Marg. CBM Gas	CO_2	5.67E+00	1.05E+00	6.72E+00	2.57E+00	4.76E-01	3.05E+00	2.44E+00	4.51E-01	2.89E+00	1.16E+01	2.16E+00	1.38E+01
	N_2O	1.62E-04	2.02E-05	1.83E-04	7.36E-05	9.17E-06	8.28E-05	6.98E-05	8.69E-06	7.85E-05	3.33E-04	4.15E-05	3.75E-04
	CH_4	2.88E-01	2.14E-01	5.02E-01	1.31E-01	9.69E-02	2.28E-01	1.24E-01	9.18E-02	2.16E-01	5.92E-01	4.39E-01	1.03E+00
	CO_2e (20-year)	26.5	16.4	42.9	12.0	7.5	19.5	11.4	7.1	18.4	54.4	33.8	88.1
	CO_2e (100-year)	12.9	6.4	19.3	5.9	2.9	8.8	5.6	2.7	8.3	26.6	13.1	39.7
	CO_2e (500-year)	7.9	2.7	10.6	3.6	1.2	4.8	3.4	1.2	4.5	16.2	5.5	21.7
Marg. LNG Gas	CO_2	2.93E+01	1.05E+00	3.03E+01	1.33E+01	4.76E-01	1.38E+01	1.26E+01	4.51E-01	1.30E+01	6.01E+01	2.16E+00	6.23E+01
	N_2O	3.41E-04	2.02E-05	3.61E-04	1.54E-04	9.17E-06	1.64E-04	1.46E-04	8.69E-06	1.55E-04	7.00E-04	4.15E-05	7.41E-04
	CH_4	2.70E-01	2.14E-01	4.83E-01	1.22E-01	9.69E-02	2.19E-01	1.16E-01	9.18E-02	2.08E-01	5.54E-01	4.39E-01	9.92E-01
	CO_2e (20-year)	48.8	16.4	65.2	22.1	7.5	29.6	21.0	7.1	28.0	100.2	33.8	133.9
	CO_2e (100-year)	36.1	6.4	42.5	16.4	2.9	19.3	15.5	2.7	18.3	74.2	13.1	87.3
	CO_2e (500-year)	31.4	2.7	34.1	14.2	1.2	15.4	13.5	1.2	14.6	64.5	5.5	69.9

Table B-3: Upstream Greenhouse Gas Inventory Results for Coal

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Avg. Coal	CO_2	1.32E+00	1.33E+00	2.64E+00	5.97E-01	6.02E-01	1.20E+00	5.66E-01	5.71E-01	1.14E+00
	N_2O	5.29E-04	3.21E-05	5.61E-04	2.40E-04	1.46E-05	2.54E-04	2.27E-04	1.38E-05	2.41E-04
	CH_4	3.78E-01	7.23E-04	3.79E-01	1.72E-01	3.28E-04	1.72E-01	1.63E-01	3.11E-04	1.63E-01
	CO_2e (20-year)	28.7	1.4	30.1	13.0	0.6	13.7	12.3	0.6	12.9
	CO_2e (100-year)	10.9	1.4	12.3	5.0	0.6	5.6	4.7	0.6	5.3
	CO_2e (500-year)	4.3	1.3	5.6	1.9	0.6	2.5	1.8	0.6	2.4
Illinois No. 6 Coal	CO_2	2.53E+00	1.33E+00	3.86E+00	1.15E+00	6.02E-01	1.75E+00	1.09E+00	5.71E-01	1.66E+00
	N_2O	3.97E-05	3.21E-05	7.18E-05	1.80E-05	1.46E-05	3.26E-05	1.71E-05	1.38E-05	3.09E-05
	CH_4	9.40E-01	7.23E-04	9.41E-01	4.27E-01	3.28E-04	4.27E-01	4.04E-01	3.11E-04	4.05E-01
	SF_6	4.98E-07	5.47E-12	4.98E-07	2.26E-07	2.48E-12	2.26E-07	2.14E-07	2.35E-12	2.14E-07
	CO_2e (20-year)	70.3	1.4	71.7	31.9	0.6	32.5	30.2	0.6	30.8
	CO_2e (100-year)	26.1	1.4	27.4	11.8	0.6	12.4	11.2	0.6	11.8
	CO_2e (500-year)	9.7	1.3	11.0	4.4	0.6	5.0	4.2	0.6	4.7
PRB Coal	CO_2	7.73E-01	1.33E+00	2.10E+00	3.51E-01	6.02E-01	9.53E-01	3.32E-01	5.71E-01	9.03E-01
	N_2O	7.48E-04	3.21E-05	7.80E-04	3.39E-04	1.46E-05	3.54E-04	3.22E-04	1.38E-05	3.35E-04
	CH_4	1.26E-01	7.23E-04	1.26E-01	5.70E-02	3.28E-04	5.74E-02	5.41E-02	3.11E-04	5.44E-02
	CO_2e (20-year)	10.0	1.4	11.4	4.6	0.6	5.2	4.3	0.6	4.9
	CO_2e (100-year)	4.1	1.4	5.5	1.9	0.6	2.5	1.8	0.6	2.4
	CO_2e (500-year)	1.8	1.3	3.2	0.8	0.6	1.4	0.8	0.6	1.4

Table B-4: Upstream Greenhouse Gas Inventory Results for Natural Gas-fired Power Generation

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (Avg. Gas)	CO_2	5.81E+01	1.01E+01	8.75E+02	0.00E+00	9.43E+02	2.63E+01	4.60E+00	3.97E+02	0.00E+00	4.28E+02	7.31E+00	1.28E+00	1.10E+02	0.00E+00	1.19E+02
	N_2O	1.81E-03	1.96E-04	2.45E-03	0.00E+00	4.45E-03	8.22E-04	8.88E-05	1.11E-03	0.00E+00	2.02E-03	2.28E-04	2.47E-05	3.08E-04	0.00E+00	5.61E-04
	CH_4	6.31E+00	2.09E+00	2.44E-02	0.00E+00	8.42E+00	2.86E+00	9.46E-01	1.11E-02	0.00E+00	3.82E+00	7.95E-01	2.63E-01	3.07E-03	0.00E+00	1.06E+00
	SF_6	4.80E-07	4.38E-12	0.00E+00	3.16E-04	3.16E-04	2.18E-07	1.99E-12	0.00E+00	1.43E-04	1.44E-04	6.04E-08	5.51E-13	0.00E+00	3.98E-05	3.99E-05
	CO_2e (20-year)	513.0	160.4	877.0	5.2	1,555.6	232.7	72.8	397.8	2.3	705.6	64.6	20.2	110.5	0.6	196.0
	CO_2e (100-year)	216.4	62.4	875.9	7.2	1,161.8	98.2	28.3	397.3	3.3	527.0	27.3	7.9	110.4	0.9	146.4
	CO_2e (500-year)	106.3	26.0	875.1	10.3	1,017.7	48.2	11.8	396.9	4.7	461.6	13.4	3.3	110.3	1.3	128.2
Fleet Baseload (Conv. Gas)	CO_2	6.22E+01	1.01E+01	8.75E+02	0.00E+00	9.47E+02	2.82E+01	4.60E+00	3.97E+02	0.00E+00	4.30E+02	7.84E+00	1.28E+00	1.10E+02	0.00E+00	1.19E+02
	N_2O	2.10E-03	1.96E-04	2.45E-03	0.00E+00	4.75E-03	9.55E-04	8.88E-05	1.11E-03	0.00E+00	2.15E-03	2.65E-04	2.47E-05	3.08E-04	0.00E+00	5.98E-04
	CH_4	5.26E+00	2.09E+00	2.44E-02	0.00E+00	7.37E+00	2.38E+00	9.46E-01	1.11E-02	0.00E+00	3.34E+00	6.62E-01	2.63E-01	3.07E-03	0.00E+00	9.28E-01
	SF_6	5.26E-08	4.38E-12	0.00E+00	3.16E-04	3.16E-04	2.39E-08	1.99E-12	0.00E+00	1.43E-04	1.43E-04	6.63E-09	5.51E-13	0.00E+00	3.98E-05	3.98E-05
	CO_2e (20-year)	441.3	160.4	877.0	5.2	1,483.9	200.2	72.8	397.8	2.3	673.1	55.6	20.2	110.5	0.6	187.0
	CO_2e (100-year)	194.3	62.4	875.9	7.2	1,139.7	88.1	28.3	397.3	3.3	517.0	24.5	7.9	110.4	0.9	143.6
	CO_2e (500-year)	102.5	26.0	875.1	10.3	1,013.9	46.5	11.8	396.9	4.7	459.9	12.9	3.3	110.3	1.3	127.8

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (UnConv. Gas)	CO_2	5.47E+01	1.01E+01	8.75E+02	0.00E+00	9.39E+02	2.48E+01	4.60E+00	3.97E+02	0.00E+00	4.26E+02	6.90E+00	1.28E+00	1.10E+02	0.00E+00	1.18E+02
	N_2O	1.58E-03	1.96E-04	2.45E-03	0.00E+00	4.22E-03	7.17E-04	8.88E-05	1.11E-03	0.00E+00	1.91E-03	1.99E-04	2.47E-05	3.08E-04	0.00E+00	5.32E-04
	CH_4	7.15E+00	2.09E+00	2.44E-02	0.00E+00	9.26E+00	3.24E+00	9.46E-01	1.11E-02	0.00E+00	4.20E+00	9.01E-01	2.63E-01	3.07E-03	0.00E+00	1.17E+00
	SF_6	8.20E-07	4.38E-12	0.00E+00	3.16E-04	3.17E-04	3.72E-07	1.99E-12	0.00E+00	1.43E-04	1.44E-04	1.03E-07	5.51E-13	0.00E+00	3.98E-05	3.99E-05
	CO_2e (20-year)	570.1	160.4	877.0	5.2	1,612.7	258.6	72.8	397.8	2.3	731.5	71.8	20.2	110.5	0.6	203.2
	CO_2e (100-year)	234.0	62.4	875.9	7.2	1,179.5	106.1	28.3	397.3	3.3	535.0	29.5	7.9	110.4	0.9	148.6
	CO_2e (500-year)	109.4	26.0	875.1	10.3	1,020.8	49.6	11.8	396.9	4.7	463.0	13.8	3.3	110.3	1.3	128.6
Fleet Baseload (Marg. Onshore Gas)	CO_2	4.99E+01	1.01E+01	8.75E+02	0.00E+00	9.35E+02	2.26E+01	4.60E+00	3.97E+02	0.00E+00	4.24E+02	6.29E+00	1.28E+00	1.10E+02	0.00E+00	1.18E+02
	N_2O	1.41E-03	1.96E-04	2.45E-03	0.00E+00	4.05E-03	6.38E-04	8.88E-05	1.11E-03	0.00E+00	1.84E-03	1.77E-04	2.47E-05	3.08E-04	0.00E+00	5.10E-04
	CH_4	3.33E+00	2.09E+00	2.44E-02	0.00E+00	5.44E+00	1.51E+00	9.46E-01	1.11E-02	0.00E+00	2.47E+00	4.20E-01	2.63E-01	3.07E-03	0.00E+00	6.86E-01
	SF_6	9.27E-09	4.38E-12	0.00E+00	3.16E-04	3.16E-04	4.20E-09	1.99E-12	0.00E+00	1.43E-04	1.43E-04	1.17E-09	5.51E-13	0.00E+00	3.98E-05	3.98E-05
	CO_2e (20-year)	290.4	160.4	877.0	5.2	1,332.9	131.7	72.8	397.8	2.3	604.6	36.6	20.2	110.5	0.6	167.9
	CO_2e (100-year)	133.7	62.4	875.9	7.2	1,079.1	60.6	28.3	397.3	3.3	489.5	16.8	7.9	110.4	0.9	136.0
	CO_2e (500-year)	75.5	26.0	875.1	10.3	986.9	34.2	11.8	396.9	4.7	447.6	9.5	3.3	110.3	1.3	124.3
GTSC (Avg. Gas)	CO_2	7.26E+01	1.27E+01	1.33E+03	0.00E+00	1.42E+03	3.29E+01	5.75E+00	6.04E+02	0.00E+00	6.42E+02	9.15E+00	1.60E+00	1.68E+02	0.00E+00	1.78E+02
	N_2O	2.27E-03	2.45E-04	2.86E-05	0.00E+00	2.54E-03	1.03E-03	1.11E-04	1.30E-05	0.00E+00	1.15E-03	2.86E-04	3.08E-05	3.61E-06	0.00E+00	3.20E-04
	CH_4	7.90E+00	2.61E+00	2.64E-03	0.00E+00	1.05E+01	3.58E+00	1.18E+00	1.20E-03	0.00E+00	4.77E+00	9.95E-01	3.29E-01	3.32E-04	0.00E+00	1.32E+00
	SF_6	6.00E-07	5.48E-12	4.34E-08	3.16E-04	3.17E-04	2.72E-07	2.48E-12	1.97E-08	1.43E-04	1.44E-04	7.56E-08	6.90E-13	5.47E-09	3.98E-05	3.99E-05
	CO_2e (20-year)	641.8	200.7	1,330.7	5.2	2,178.4	291.1	91.0	603.6	2.3	988.1	80.9	25.3	167.7	0.6	274.5
	CO_2e (100-year)	270.7	78.0	1,330.6	7.2	1,686.6	122.8	35.4	603.6	3.3	765.0	34.1	9.8	167.7	0.9	212.5
	CO_2e (500-year)	133.0	32.6	1,330.6	10.3	1,506.4	60.3	14.8	603.5	4.7	683.3	16.8	4.1	167.6	1.3	189.8
NGCC (Avg. Gas)	CO_2	4.71E+01	8.23E+00	8.66E+02	0.00E+00	9.22E+02	2.14E+01	3.73E+00	3.93E+02	0.00E+00	4.18E+02	5.94E+00	1.04E+00	1.09E+02	0.00E+00	1.16E+02
	N_2O	1.47E-03	1.59E-04	3.33E-05	0.00E+00	1.66E-03	6.67E-04	7.21E-05	1.51E-05	0.00E+00	7.55E-04	1.85E-04	2.00E-05	4.20E-06	0.00E+00	2.10E-04
	CH_4	5.12E+00	1.69E+00	1.31E-03	0.00E+00	6.82E+00	2.32E+00	7.68E-01	5.94E-04	0.00E+00	3.09E+00	6.46E-01	2.13E-01	1.65E-04	0.00E+00	8.59E-01
	SF_6	3.89E-07	3.55E-12	7.55E-07	3.16E-04	3.17E-04	1.77E-07	1.61E-12	3.42E-07	1.43E-04	1.44E-04	4.91E-08	4.48E-13	9.51E-08	3.98E-05	4.00E-05
	CO_2e (20-year)	416.5	130.2	866.5	5.2	1,418.5	188.9	59.1	393.1	2.3	643.4	52.5	16.4	109.2	0.6	178.7
	CO_2e (100-year)	175.7	50.6	866.5	7.2	1,100.0	79.7	23.0	393.0	3.3	499.0	22.1	6.4	109.2	0.9	138.6
	CO_2e (500-year)	86.3	21.1	866.5	10.3	984.2	39.2	9.6	393.0	4.7	446.4	10.9	2.7	109.2	1.3	124.0
NGCC/ccs (Avg. Gas)	CO_2	5.52E+01	9.65E+00	1.13E+02	0.00E+00	1.78E+02	2.51E+01	4.38E+00	5.13E+01	0.00E+00	8.07E+01	6.96E+00	1.22E+00	1.42E+01	0.00E+00	2.24E+01
	N_2O	1.72E-03	1.86E-04	5.18E-05	0.00E+00	1.96E-03	7.82E-04	8.45E-05	2.35E-05	0.00E+00	8.90E-04	2.17E-04	2.35E-05	6.53E-06	0.00E+00	2.47E-04
	CH_4	6.01E+00	1.99E+00	1.71E-03	0.00E+00	7.99E+00	2.72E+00	9.01E-01	7.78E-04	0.00E+00	3.63E+00	7.57E-01	2.50E-01	2.16E-04	0.00E+00	1.01E+00
	SF_6	4.57E-07	4.16E-12	8.81E-07	3.16E-04	3.17E-04	2.07E-07	1.89E-12	4.00E-07	1.43E-04	1.44E-04	5.75E-08	5.25E-13	1.11E-07	3.98E-05	4.00E-05
	CO_2e (20-year)	488.2	152.7	113.2	5.2	759.2	221.5	69.2	51.3	2.3	344.4	61.5	19.2	14.3	0.6	95.7
	CO_2e (100-year)	205.9	59.3	113.1	7.2	385.6	93.4	26.9	51.3	3.3	174.9	25.9	7.5	14.3	0.9	48.6
	CO_2e (500-year)	101.2	24.8	113.1	10.3	249.3	45.9	11.2	51.3	4.7	113.1	12.7	3.1	14.2	1.3	31.4

Table B-5: Upstream Greenhouse Gas Inventory Results for Coal-fired Power Generation

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (Avg. Coal)	CO_2	1.38E+01	1.39E+01	2.33E+03	0.00E+00	2.35E+03	6.26E+00	6.31E+00	1.06E+03	0.00E+00	1.07E+03	1.74E+00	1.75E+00	2.93E+02	0.00E+00	2.97E+02
	N_2O	5.54E-03	3.36E-04	3.99E-02	0.00E+00	4.58E-02	2.51E-03	1.53E-04	1.81E-02	0.00E+00	2.08E-02	6.98E-04	4.24E-05	5.03E-03	0.00E+00	5.77E-03
	CH_4	3.96E+00	7.57E-03	2.67E-02	0.00E+00	4.00E+00	1.80E+00	3.43E-03	1.21E-02	0.00E+00	1.81E+00	4.99E-01	9.54E-04	3.37E-03	0.00E+00	5.04E-01
	SF_6	1.77E-06	5.73E-11	0.00E+00	3.16E-04	3.18E-04	8.03E-07	2.60E-11	0.00E+00	1.43E-04	1.44E-04	2.23E-07	7.22E-12	0.00E+00	3.98E-05	4.00E-05
	CO_2e (20-year)	300.8	14.5	2,340.1	5.2	2,660.6	136.4	6.6	1,061.5	2.3	1,206.8	37.9	1.8	294.9	0.6	335.2
	CO_2e (100-year)	114.6	14.2	2,339.2	7.2	2,475.2	52.0	6.4	1,061.1	3.3	1,122.7	14.4	1.8	294.7	0.9	311.9
	CO_2e (500-year)	44.8	14.0	2,333.0	10.3	2,402.1	20.3	6.4	1,058.2	4.7	1,089.6	5.6	1.8	294.0	1.3	302.7
EXPC (Illinois No. 6 Coal)	CO_2	2.24E+01	1.18E+01	2.23E+03	0.00E+00	2.27E+03	1.02E+01	5.34E+00	1.01E+03	0.00E+00	1.03E+03	2.83E+00	1.48E+00	2.81E+02	0.00E+00	2.85E+02
	N_2O	3.52E-04	2.85E-04	3.77E-02	0.00E+00	3.83E-02	1.60E-04	1.29E-04	1.71E-02	0.00E+00	1.74E-02	4.44E-05	3.59E-05	4.75E-03	0.00E+00	4.83E-03
	CH_4	8.35E+00	6.42E-03	2.51E-02	0.00E+00	8.38E+00	3.79E+00	2.91E-03	1.14E-02	0.00E+00	3.80E+00	1.05E+00	8.08E-04	3.17E-03	0.00E+00	1.06E+00
	SF_6	4.42E-06	4.85E-11	6.11E-07	3.16E-04	3.21E-04	2.00E-06	2.20E-11	2.77E-07	1.43E-04	1.46E-04	5.57E-07	6.11E-12	7.70E-08	3.98E-05	4.04E-05
	CO_2e (20-year)	623.7	12.3	2,243.5	5.2	2,884.7	282.9	5.6	1,017.6	2.3	1,308.5	78.6	1.6	282.7	0.6	363.5
	CO_2e (100-year)	231.4	12.0	2,242.7	7.2	2,493.3	104.9	5.5	1,017.3	3.3	1,130.9	29.2	1.5	282.6	0.9	314.1
	CO_2e (500-year)	86.1	11.9	2,236.8	10.3	2,345.0	39.0	5.4	1,014.6	4.7	1,063.7	10.8	1.5	281.8	1.3	295.5
IGCC (Illinois No. 6 Coal)	CO_2	1.98E+01	1.04E+01	1.89E+03	0.00E+00	1.92E+03	8.98E+00	4.72E+00	8.57E+02	0.00E+00	8.71E+02	2.49E+00	1.31E+00	2.38E+02	0.00E+00	2.42E+02
	N_2O	3.11E-04	2.52E-04	4.67E-05	0.00E+00	6.09E-04	1.41E-04	1.14E-04	2.12E-05	0.00E+00	2.76E-04	3.92E-05	3.17E-05	5.89E-06	0.00E+00	7.68E-05
	CH_4	7.37E+00	5.66E-03	9.58E-03	0.00E+00	7.38E+00	3.34E+00	2.57E-03	4.35E-03	0.00E+00	3.35E+00	9.28E-01	7.13E-04	1.21E-03	0.00E+00	9.30E-01
	SF_6	3.90E-06	4.28E-11	7.69E-07	3.16E-04	3.21E-04	1.77E-06	1.94E-11	3.49E-07	1.43E-04	1.45E-04	4.91E-07	5.40E-12	9.69E-08	3.98E-05	4.04E-05
	CO_2e (20-year)	550.4	10.9	1,890.8	5.2	2,457.2	249.7	4.9	857.7	2.3	1,114.6	69.3	1.4	238.2	0.6	309.6
	CO_2e (100-year)	204.2	10.6	1,890.4	7.2	2,112.4	92.6	4.8	857.5	3.3	958.2	25.7	1.3	238.2	0.9	266.2
	CO_2e (500-year)	76.0	10.5	1,890.2	10.3	1,987.0	34.5	4.8	857.4	4.7	901.3	9.6	1.3	238.2	1.3	250.4
IGCC/ccs (Illinois No. 6 Coal)	CO_2	2.33E+01	1.22E+01	2.46E+02	0.00E+00	2.81E+02	1.06E+01	5.55E+00	1.11E+02	0.00E+00	1.28E+02	2.94E+00	1.54E+00	3.10E+01	0.00E+00	3.54E+01
	N_2O	3.66E-04	2.96E-04	9.13E-05	0.00E+00	7.54E-04	1.66E-04	1.34E-04	4.14E-05	0.00E+00	3.42E-04	4.61E-05	3.73E-05	1.15E-05	0.00E+00	9.50E-05
	CH_4	8.67E+00	6.67E-03	1.15E-02	0.00E+00	8.69E+00	3.93E+00	3.02E-03	5.20E-03	0.00E+00	3.94E+00	1.09E+00	8.40E-04	1.45E-03	0.00E+00	1.10E+00
	SF_6	4.59E-06	5.04E-11	8.72E-07	3.16E-04	3.21E-04	2.08E-06	2.29E-11	3.96E-07	1.43E-04	1.46E-04	5.78E-07	6.35E-12	1.10E-07	3.98E-05	4.05E-05
	CO_2e (20-year)	648.1	12.8	246.6	5.2	912.7	294.0	5.8	111.9	2.3	414.0	81.7	1.6	31.1	0.6	115.0
	CO_2e (100-year)	240.4	12.5	246.1	7.2	506.2	109.0	5.7	111.6	3.3	229.6	30.3	1.6	31.0	0.9	63.8
	CO_2e (500-year)	89.5	12.3	245.9	10.3	358.0	40.6	5.6	111.5	4.7	162.4	11.3	1.6	31.0	1.3	45.1

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
SCPC (Illinois No. 6 Coal)	CO_2	1.94E+01	1.02E+01	1.91E+03	0.00E+00	1.94E+03	8.78E+00	4.61E+00	8.66E+02	0.00E+00	8.79E+02	2.44E+00	1.28E+00	2.41E+02	0.00E+00	2.44E+02
	N_2O	3.04E-04	2.46E-04	6.99E-05	0.00E+00	6.20E-04	1.38E-04	1.12E-04	3.17E-05	0.00E+00	2.81E-04	3.83E-05	3.10E-05	8.81E-06	0.00E+00	7.81E-05
	CH_4	7.20E+00	5.53E-03	8.98E-03	0.00E+00	7.22E+00	3.27E+00	2.51E-03	4.07E-03	0.00E+00	3.27E+00	9.07E-01	6.97E-04	1.13E-03	0.00E+00	9.09E-01
	SF_6	3.81E-06	4.19E-11	8.26E-07	3.16E-04	3.21E-04	1.73E-06	1.90E-11	3.74E-07	1.43E-04	1.45E-04	4.80E-07	5.27E-12	1.04E-07	3.98E-05	4.04E-05
	CO_2e (20-year)	538.0	10.6	1,910.1	5.2	2,463.9	244.0	4.8	866.4	2.3	1,117.6	67.8	1.3	240.7	0.6	310.5
	CO_2e (100-year)	199.6	10.4	1,909.7	7.2	2,126.9	90.5	4.7	866.2	3.3	964.7	25.1	1.3	240.6	0.9	268.0
	CO_2e (500-year)	74.3	10.2	1,909.5	10.3	2,004.3	33.7	4.6	866.2	4.7	909.2	9.4	1.3	240.6	1.3	252.5
SCPC/ccs (Illinois No. 6 Coal)	CO_2	2.78E+01	1.46E+01	3.02E+02	0.00E+00	3.45E+02	1.26E+01	6.63E+00	1.37E+02	0.00E+00	1.56E+02	3.51E+00	1.84E+00	3.81E+01	0.00E+00	4.34E+01
	N_2O	4.37E-04	3.53E-04	1.07E-04	0.00E+00	8.97E-04	1.98E-04	1.60E-04	4.85E-05	0.00E+00	4.07E-04	5.50E-05	4.45E-05	1.35E-05	0.00E+00	1.13E-04
	CH_4	1.04E+01	7.95E-03	9.79E-03	0.00E+00	1.04E+01	4.69E+00	3.61E-03	4.44E-03	0.00E+00	4.70E+00	1.30E+00	1.00E-03	1.23E-03	0.00E+00	1.31E+00
	SF_6	5.48E-06	6.02E-11	8.34E-07	3.16E-04	3.22E-04	2.48E-06	2.73E-11	3.78E-07	1.43E-04	1.46E-04	6.90E-07	7.58E-12	1.05E-07	3.98E-05	4.06E-05
	CO_2e (20-year)	773.3	15.3	302.8	5.2	1,096.5	350.7	6.9	137.4	2.3	497.4	97.4	1.9	38.2	0.6	138.2
	CO_2e (100-year)	286.8	14.9	302.4	7.2	611.3	130.1	6.8	137.2	3.3	277.3	36.1	1.9	38.1	0.9	77.0
	CO_2e (500-year)	106.7	14.7	302.2	10.3	434.0	48.4	6.7	137.1	4.7	196.8	13.4	1.9	38.1	1.3	54.7

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American Petroleum Institute

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Please note: We are currently revising the Liquids Unloading section of this report to incorporate public comments and data revisions. An updated report will be available in the 3rd quarter of 2012.

Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production

Summary and Analysis of API and ANGA Survey Responses

Terri Shires and Miriam Lev-On
URS Corporation and The LEVON Group

FINAL REPORT
June 1, 2012

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Executive Summary

This document presents the results from a collaborative effort among members of the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) to gather data on key natural gas production activities and equipment emission sources - including unconventional natural gas production - that are essential to developing estimates of methane emissions from upstream natural gas production.

API and ANGA members undertook this effort as part of an overall priority to develop new and better data about natural gas production and make this information available to the public. This information acquired added importance in 2011, when the EPA released an inventory of U.S. greenhouse gases (GHG) emissions that substantially increased estimates of methane emissions from Petroleum and Natural Gas Systems. Public comments submitted by both trade associations reflected a number of concerns – most notably that EPA's estimates were based on a small set of data submitted by a limited number of companies in a different context (i.e., data not developed for the purpose of estimating nationwide emissions).

The API/ANGA data set (also referred to as ANGA/API) provides data on 91,000 wells distributed over a broad geographic area and operated by over 20 companies. This represents nearly one-fifth (18.8%) of the estimated number of total wells used in EPA's 2010 emissions inventory.[1] The ANGA/API data set is also more than 10 times larger than the set of wells in one of EPA's key data sources taken from an older Natural Gas Star sample that was never intended for developing nationwide emissions estimates. ***Although more and better data efforts will still be needed, API/ANGA members believe this current collaborative effort is the most comprehensive data set compiled for natural gas operations.***

As Table ES-1 demonstrates, survey results in two source categories – liquids unloading and unconventional gas well re-fracture rates - substantially lower EPA's estimated emissions from natural gas production and shift Natural Gas Systems from the largest contributor of methane emissions to the second largest (behind Enteric Fermentation, which is a consequence of bovine digestion).[2] The right-hand column of this table shows the impact of ANGA/API data on the estimated emissions for each source category. Gas well liquids unloading and the rate at which unconventional gas wells are re-fractured are key contributors to the overall GHG emissions estimated by EPA in the national emissions inventory. For example, methane emissions from liquids unloading and unconventional well re-fracturing accounted for 59% of EPA's estimate for overall natural gas production sector methane emissions. Overall, API/ANGA activity data for these two source categories indicate that EPA estimates of potential emissions from the production sector of "Natural Gas Systems" would be 50% lower if EPA were to use ANGA/API's larger and more recent survey results.

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[1] EPA's 2010 national inventory indicates a total of 484,795 gas wells (EPA, 2012).

[2] Table ES-2 of the 2010 national inventory (EPA, 2012).

TABLE ES-1. EMISSION COMPARISON BETWEEN EPA AND INDUSTRY DATA

Source Category	EPA		API/ANGA		Impact on Source Category Emissions
	Metric tons of CH4	% of EPA Emissions Total	Metric tons of CH4	% of Revised Emissions Total	API & ANGA - EPA EPA % Difference
Gas Wells Liquids Unloading	4,501,465 *	51%	637,766	14%	-86%
Unconventional Well Re-fracture Rates	712,605 *	8%	197,311	4%	-72%
Other Production Sector Emissions**	3,585,600	41%	3,585,600	81%	
Total Production Sector Emissions	8,799,670		4,420,677		-50%

* EPA's estimates are adjusted to industry standard conditions of 60 degrees F and 14.7 psia for comparison to the ANGA/API emission estimates.

**The "Other Production Sector Emissions" are comprised of over 30 different source categories detailed in Table A-129 in the Annex of the EPA's 2012 national inventory. The "Other Production Sector Emissions" are the same values for this comparison between the EPA national inventory and the API/ANGA survey to focus the comparison on quantified differences in emission estimates for gas well liquids unloading and unconventional well re-fracture rates.

As mentioned above, the differences between EPA and ANGA/API estimates hinge on the following key differences in activity data and thus considerably impact overall emissions from Natural Gas Systems:

- ***Liquids unloading and venting.*** API/ANGA data showed lower average vent times as well as a lower percentage of wells with plunger lifts and wells venting to the atmosphere than EPA assumed. This is particularly significant because liquids unloading accounted for 51% of EPA's total "Natural Gas Systems" methane emissions in the 2010 inventory. Applying emission factors based on ANGA/API data reduces the calculated emissions for this source by 86% (from 4,501,465 metric tons of CH_4 to 637,766 metric tons of CH_4 when compared on an equivalent basis) from EPA's 2010 national GHG inventory.
- ***Re-fracture rates for unconventional wells***. API/ANGA members collected data on re-fracture rates for unconventional wells in two phases. The first phase collected data for all well types (conventional and unconventional), while the second phase targeted unconventional gas wells. Both phases of the survey data show significantly lower rates of well re-fracturing than the 10% assumption used by EPA. As discussed in detail in this report, the re-fracture rate varied from 0.7% to 2.3%. The second phase of the survey gathered data from only unconventional well activity and using the re-fracture rate data from this second phase of the ANGA/API survey reduces the national emission estimate

for this source category by 72%, - from 712,605 metric tons of CH_4 to 197,311 metric tons of CH_4 when compared on an equivalent basis.

This report also discusses an important related concern that the government lacks a single coordinated and cohesive estimate of well completions and well counts. Although the 2010 national GHG inventory appears to under-represent the number of well completions according to the numbers reported through both the API/ANGA data and IHS CERA, differences in national well data reporting systems make it difficult to accurately investigate well completion differences with any certainty. The EPA inventory, which uses data from HPDI, and the Energy Information Administration (in addition to privately sourced data) all report different well counts that do not consistently distinguish between conventional and unconventional wells. Without a consistent measure for the quantity and type of wells, it is difficult to be confident of the accuracy of the number of wells that are completed annually, let alone the amount of emissions from them. Natural gas producers strongly believe that the effects of any possible under-representation of well completions will be offset by a more realistic emission factor for the rate of emissions per well.

This survey also collected data on centrifugal compressors and pneumatic controllers. While the sample sizes are too small to make strong conclusions, the results discussed in the body of the report indicate that further research is necessary to accurately account for the different types of equipment in this area (e.g., wet vs. dry seal centrifugal compressors and “high bleed,” “low bleed,” and “intermittent bleed” pneumatic controllers).

As government and industry move forward in addressing emissions from unconventional gas operations, three key points are worth noting:

- ***In addition to the voluntary measures undertaken by industry, more data will become available in the future.*** Emission reporting requirements under Subpart W of the national Greenhouse Gas Reporting Program (GHGRP) went into effect January 1, 2011 with the first reporting due in the fall of 2012. As implementation of the GHGRP progresses from year to year, the natural gas industry will report more complete and more accurate data. If EPA makes use of the data submitted and transparently communicates their analyses, ANGA/API members believe this will increase public confidence in the emissions estimated for key emission source categories of the Natural Gas Systems sector.
- ***Industry has a continuous commitment to improvement.*** It is clear that companies are not waiting for regulatory mandates or incentives to upgrade equipment, or to alter practices like venting and flaring in favor of capturing methane where practical. Instead, operators are seizing opportunities to reduce the potential environmental impacts of their operations. Industry is therefore confident that additional, systematic collection of production sector activity data will not only help target areas for future reductions but also demonstrate significant voluntary progress toward continually ‘greener’ operations.
- ***Members of industry participating in this survey are committed to providing information about the new and fast-changing area of unconventional oil and gas operations. API and ANGA members look forward to working with the EPA to revise current assessment methodologies as well as promote the accurate and defensible uses of existing data sources.***

1. *Overview*

The accuracy of GHG emission estimates from unconventional natural gas production has become a matter of increasing public debate due in part to limited data, variability in the complex calculation methodologies, and assumptions used to approximate emissions where measurements in large part are sparse to date. Virtually all operators have comprehensive methane mitigation strategies; however, beyond the requirements of the Environmental Protection Agency's (EPA) Mandatory Reporting Rule or incentives of programs like the EPA's Natural Gas Star program, data is often not gathered in a unified way that facilitates comparison among companies.

In an attempt to provide additional data and identify uncertainty in existing data sets, the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) began a joint study on methane (CH_4) emissions from unconventional gas operations in July 2011. The first part of this section offers context to the decision to conduct this survey, while the second offers a brief introduction to the survey itself.

1.1 Context

Shale gas will undoubtedly play a key role in America's energy future and therefore additional information must be collected to quantify the methane emissions from both conventional and unconventional natural gas production. Meaningful, publicly available data is a priority, especially in light of EPA's 2011 revision of its calculation methodology for Natural Gas Systems in the 2009 national inventory (EPA, 2011b). (EPA added two new sources for unconventional gas well completions and workovers, and also significantly revised its estimates for liquids unloading and made adjustments to other source categories.) These changes substantially increased EPA's estimated GHG emissions for the production sector of the Natural Gas Systems by 204%.

Industry was alarmed by the upward adjustment, especially since previous EPA estimates had been based on a 1996 report prepared by the EPA and GRI – and did not take into account the considerable improvements in equipment and industry practice that have occurred in the fifteen years between 1996 and 2011 (GRI, 1996).

An EPA technical note to the 2009 inventory attributed the changes to adjustments in calculation methods for existing sources, including gas well liquids unloading, condensate storage tanks, and centrifugal compressor seals. EPA also added two new sources not previously included in its inventories, namely unconventional gas well completions and workovers (re-completions) (EPA, 2011e).

Industry did not have an adequate opportunity to examine EPA's rationale for the new emissions factor prior to its initial release. Unlike changes in regulatory requirements, EPA is not required to initiate a formal comment process for changes in methodologies like emission factors and calculations methods in the national GHG inventory. As such, EPA is not compelled to incorporate or consider input provided by stakeholders and experts. Indeed, changes to methodologies are often made without the benefit of dialogue or expert review. Although EPA further acknowledged in the 2010 inventory (released in 2012), that their natural gas calculations needed work, their practice is to continue using the same numbers until adjusted estimates have been made. It is important to note that EPA has indicated a willingness to engage and discuss this matter with some members of industry; however, no time frame has yet been determined for this discussion.

Under the best of circumstances, EPA had remarkably little information to draw on in determining their new emission factor. Input from industry on this topic was not directly solicited. Specific guidance also did not exist on the international level, nor was it available from other national regulators. A review of the Intergovernmental Panel on Climate Change (IPCC) and other inventories submitted to the United Nations Framework Convention on Climate Change (UNFCCC) indicate that the U.S. is currently the only country to date to differentiate between conventional and unconventional natural gas production. Regulators, academics, and environmentalists around the world therefore considered the new estimated emission factor as an unprecedented development in a controversial issue.

Widespread criticism of the figures revealed problematic methodology and less justification for the underlying numbers than originally anticipated. In a paper entitled *Mismeasuring Methane*, the well-respected energy consultancy IHS CERA succinctly detailed several concerns about the revisions – most notably that EPA's new estimate was based on only four (4) data points that natural gas well operators had submitted voluntarily under the Natural Gas Star Program, which highlights emissions reductions. Together, the four data points cover approximately 8,880 wells – or roughly 2% of those wells covered in the EPA's national greenhouse gas inventory. Those numbers, which were submitted in the context of showcasing achieved emissions reductions and not to estimate emissions, were then extrapolated to over 488,000 wells in the 2009 emissions inventory (IHS CERA, 2011).

With an emerging topic like shale energy development, however, the impact of EPA's revised estimates was enormous. Emission estimates from production using EPA's figures were used to question the overall environmental benefits of natural gas. They were cited widely by unconventional gas opponents - many of whom used the new figures selectively and without caveats like "estimated" to argue against further development of shale energy resources. For example, an article published by ProPublica cited the revised EPA emission factors as "new research" which "casts doubt" on whether natural gas contributes lower GHG emissions than other fossil fuels (Lustgarten, 2011). Many of these studies – e.g., the work of Howarth *et al.* were widely reported in the popular press (Zellers, 2011) with little attention to the quality of analysis behind their conclusions.

Notably, other authors using more robust and defensible scientific methodologies argued that - even with undoubtedly high emissions estimates - natural gas still possessed a lifecycle advantage when its comparative efficiency in electricity generation was taken into account. For example, a study by Argonne National Laboratory utilizing the same EPA data sources concluded that taking into account power plant efficiencies, electricity from natural gas shows significant life-cycle GHG benefits over coal power plants (Burnham, 2011). Unfortunately, the complex technical arguments in these studies generated considerably less media and public attention.

It is important to understand that the ongoing debate about the accuracy of EPA's adjusted emission factor as contained in the 2009 inventory did not keep these numbers from being used in a series of rules that have wide ranging ramifications on national natural gas policies both in the United States and globally. Many countries considering shale energy development remain bound by the emissions reduction targets in the Kyoto Protocol and their regulatory discussions reflect greenhouse gas concerns. In addition to the very real risk that other countries could adopt the emission factor before the EPA can refine its calculations, the possibility of higher emissions (even if only on paper) might deter other nations from developing their own unconventional energy resources.

By the summer of 2011, it was clear to ANGA/API members (also referred to as API/ANGA members) that gathering additional data about actual emissions and points of uncertainty during unconventional gas production was essential to improve GHG life cycle analysis (LCA) of natural gas for the following reasons: 1) to focus the discussion of emissions from natural gas production around real data; 2) to promote future measurement and mitigation of emissions from natural gas production; and 3) to contribute to improving the emission estimation methods used by EPA for the natural gas sector in their annual national GHG inventory.

1.2 Introduction to the API/ANGA Survey

API and ANGA members uniformly believed that EPA's current GHG emissions estimates for the natural gas production sector were overstated due to erroneous activity data in several key areas - including liquids unloading, well re-fracturing, centrifugal compressors, and pneumatic controllers. Members therefore worked cooperatively to gather information through two data requests tailored to focus on these areas and reasonably accessible information about industry activities and practices. Specifically, information was requested on gas well types, gas well venting/flaring from completions, workovers, and liquids unloading, and the use of centrifugal compressor and pneumatic controllers.

The actual data requests sent to members can be found in Appendix A, and Appendix B provides more detailed data from the ANGA/API well survey information**.**

Survey results and summaries of observations, including comparisons to EPA's emission estimation methods, are provided in the following sections.

2. Well Data

This section examines well data gathered by API and ANGA members. Overall, ANGA/API's survey effort gathered activity data from over 20 companies covering nearly 91,000 wells and 19 of the 21 American Association of Petroleum Geologists (AAPG) basins[3] containing over 1% of the total well count in EPA's database of gas wells. Members believe that the API/ANGA survey represents the most comprehensive data set ever compiled for natural gas operations and, as such, provides a much more accurate picture of operations and emissions.

Information to characterize natural gas producing wells was collected by survey in two parts:

- The first part of the survey requested high-level information on the total number of operating gas wells, the number of gas well completions, and the number of gas well workovers with hydraulic fracturing. Data on over 91,000 wells was collected primarily for 2010, with some information provided for the first half of 2011.
- The second part of the survey requested more detailed well information about key activities. The well information collected through the two surveys is provided in Appendix B.

Section 2.1 looks at overall natural gas well counts, Section 2.2 examines completion data from ANGA/API members, and Section 2.3 briefly identifies several unresolved issues concerning well counts and classifications that could benefit from future analysis for examination. For the purposes of this report, unconventional wells are considered to be shale gas wells, coal bed wells, and tight sand wells which must be fractured to produce economically.

2.1 National Gas Well Counts

To provide context for the information collected by API and ANGA, comparisons were made to information about national gas wells from EPA and the U.S. Energy Information Administration (EIA). Unfortunately, the government lacks a single coordinated and cohesive set of estimates for gas wells.

Industry grew concerned when it became apparent that significant discrepancies existed among different sources of national gas well data. The EPA inventory, the EIA, and IHS all reported different well counts that do not consistently distinguish between key areas like conventional and unconventional wells. Furthermore, there does not appear to be a single technical description for classifying wells that is widely accepted. Without consistent measures and definitions for the quantity and type of wells, it is difficult to reach agreement on the number of unconventional wells completed annually - let alone their emissions.

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[3] Basins are defined by the American Association of Petroleum Geologists (AAPG) AAPG–CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978.

Both the EIA data and the EPA data accompanying the national GHG inventory lack sufficient detail for well classifications to provide a basis for helpful comparison with the survey data reported here. Instead, national well data developed as part of mandatory emissions reporting is used for comparison because it has the most appropriate level of detail in well categories (EPA, 2011d).

In EPA's database gas well count (EPA, 2011d), 21 of the AAPG basins each have more than 1% of the total well count. The API/ANGA survey has wells from 19 of those 21 basins. In terms of wells represented by these basins, 92% of the total EPA database well count is accounted for by wells in those 21 basins, while 95% of the ANGA/API surveyed gas wells are accounted for by those 21 basins. These results are summarized in Table 1 and illustrated in Figure 1. This indicates that the API/ANGA survey results have good representation for the basins with the largest numbers of wells nationally.

TABLE 1. COMPARISON OF GAS WELL COUNT DATA BY AAPG BASIN: SUMMARY STATISTICS

	EPA Database Gas Well Count*	API/ANGA Survey Data	ANGA/API as a % of EPA
Total number of U.S. gas wells	355,082 gas wells	91,028 gas wells	26%
Number of significant AAPG basins**	21 basins	Data on wells in 19 of those 21 basins	90%
Number of wells in significant AAPG basins	325,338 wells	86,759 wells	27%
% of total wells in significant AAPG basins	92%	95%	

[*] EPA's database gas well count (EPA, 2011d) differs from the well count provided in EPA's 2010 national inventory, but provides more detail on the types of wells. Additional details are provided in Appendix B.

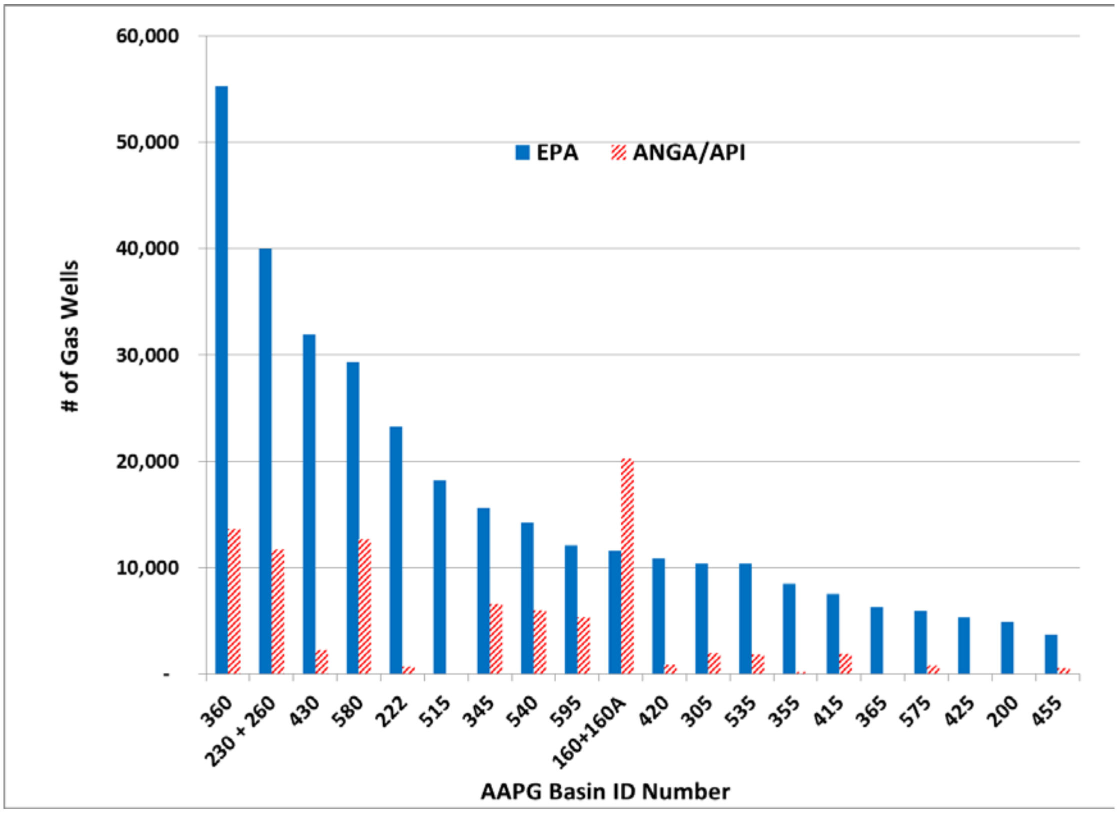
[**] Significant basins are defined as basins with more than 1% of the total national gas wells.

As shown in Figure 1, the API/ANGA survey results more heavily represent gas wells in specific AAPG basins when compared to EPA's basin-level well counts (EPA, 2011c). Unlike the EPA data, the ANGA/API data is more heavily influenced by AAPG 160 and 160A. AAPG basins 360, 230, and 580 are important for both data sets.

The smaller data set provided by EPA (2011d) may not include all of the Marcellus shale wells (particularly in Pennsylvania), and the well classification system used in this smaller data set could probably be made more rigorous. Although this comparison may not show a perfect distributional match for the basin by basin distribution of the API/ANGA survey data presented here, it does not change the fundamental conclusion of the ANGA/API survey since this data set does cover 90% of the basins and 27% of the national gas well count for the significant basins as reported by EPA (EPA, 2011d). The data discussed in this report provides substantial new information for understanding the emissions from Natural Gas Systems and offers a compelling justification for re-examining the current emission estimates for unconventional gas wells.

Appendix B contains more detail about the industry well data sample compared to the overall data maintained by the government. Unless otherwise noted, further statistical comparisons of well data throughout this paper are done with reference to the EPA data because it was the only one which effectively parsed the data by well type (EPA, 2011d).

FIGURE 1. COMPARISON OF EPA TO API/ANGA GAS WELL COUNT DATA BY AAPG BASIN



2.2 Gas Well Completions

Acknowledging the somewhat different time periods covered, the API/ANGA survey data represents 57.5% of the national data for tight gas well completions and 44.5% of shale gas well completions, but only 7.5% of the national conventional well completions and 1.5% of coal-bed methane well completions. About one-third of the surveyed well completions (2,205) could not be classified into the well types requested (i.e., tight, shale, or coal-bed methane). The survey results for well completions are provided in Table 2 and compared to national data provided to ANGA by IHS.[4]

EPA's 2010 inventory showed 4,169 gas well completions with hydraulic fracturing (EPA, 2012, Table A-122); however, EPA does not provide a breakout of completions by well type (shale gas, tight gas or coal-bed methane). In comparing the EPA 2010 count of gas well completions with hydraulic fracturing (4,169 completions) to both the survey results and data

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[4] Data provided in e-mail from Mary Barcella (IHS) to Sara Banaszak (ANGA) on August 29,2011. Data were pulled from current IHS well database and represent calendar year 2009 (2010 data are not yet available).

provided by IHS, it seems that EPA's national GHG inventory underestimates the number of well completions. Even accounting for the difference in time periods (2010 for EPA compared to 2010/2011 data from the ANGA/API survey), the national inventory appears to under-represent the number of well completions.

TABLE 2. API/ANGA SURVEY – SUMMARY OF GAS WELL COMPLETIONS BY NEMS REGION AND WELL TYPE* (FIRST SURVEY DATA REQUEST PHASE)

NEMS Region	Conventional Wells	Shale	Coal-bed Methane	Tight	Unspecified	Regional Total
API/ANGA Survey Data Gas Well Completions						
Northeast	2	291	3	67	126	489
Gulf Coast	81	588	-	763	374	1,806
Mid-Continent	22	734	-	375	270	1,401
Southwest	425	442	-	346	310	1,523
Rocky Mountain	10		30	977		1,017
Unspecified	-	-	-	-	1,125	1,125
Survey TOTAL	540	2,055	33	2,528	2,205	7,361
% of Survey Total	7.3%	27.9%	0.4%	34.3%	30.0%	
2010 IHS Gas Well Completions						IHS Total
2010 National Well Completions (from IHS)[1]	7,178	4,620	2,254	4,400		18,452
	38.9%	25.0%	12.2%	23.8%		
API/ANGA as % of IHS National Well Counts	7.5%	44.5%	1.5%	57.5%		

* ANGA/API survey data represents well counts current for calendar year 2010 or the first half of 2011.

** EPA's national GHG inventory does not designate gas wells by classifications of "shale", "coal bed methane" or "tight".

As shown in Table 3, the ANGA/API survey noted 7,361 gas well completions for 2010 and the first half of 2011. This is equivalent to approximately 40% of the gas well completions reported by IHS for 2010. Although EPA's 2010 national GHG inventory appears to under-represent the number of gas well completions according to the numbers reported through both the API/ANGA data and the IHS, differences in national well data reporting systems make it difficult to accurately investigate well completion differences with certainty. The EPA inventory, which uses data from HPDI, and the Energy Information Administration (in addition to privately sourced data) - all of which report different well counts that do not consistently distinguish between conventional and unconventional wells. Without a consistent measure for the quantity and type of wells, it is difficult to be confident of the accuracy of how many wells are completed annually, let alone to estimate their emissions. Industry strongly believes that the effects of any current under-representation of well completions will be offset by a more realistic emission factor for the rate of emissions per well.

Table 3. Summary of Gas Well Completions Data
(First Survey Data Request Phase)

	# Completions for Gas Wells without hydraulic fracturing	# Completions for Gas Wells with hydraulic fracturing	Total Completions
2010 National Well Completions (from EPA; EPA 2012)	702	4,169	4,871
% of National Total	14%	86%	
API/ANGA Survey Well Completions	540	6,821	7,361
% of National Total	7%	93%	
Well Completions from IHS	7,178	11,274	18,452
% of National Total	39%	61%	

Table 4 provides detailed data for well completions from the ANGA/API survey. From the survey, 94% of gas well completions in 2010 and the first half of 2011, were conducted on wells with hydraulic fracturing. About one-half of all gas well completions for this time period were for tight wells, and about one-half of all gas well completions were for vertical wells with hydraulic fracturing. Any differences in totals between Tables 2, 3 and 4 are because these tables were derived from the two different data requests sent to member companies as described previously in the introduction to Section 2.

Table 4. API/ANGA Survey – Additional Details on Gas Well Completions
(Second Survey Data Request Phase)

	# Completions for Gas Wells with hydraulic fracturing (HF)				Gas Wells without hydraulic fracturing		Total Completions
	# Vertical wells completions	# Horizontal well completions	Total Wells with HF	% of Wells with HF	# Completions	% of Wells without HF	
TOTAL Conventional	315	57	372	69%	164	31%	536
TOTAL Shale	317	1,863	2,180	99%	30	1%	2,210
TOTAL Tight	2,054	368	2,422	96%	106	4%	2,528
TOTAL Coal Bed Methane	27	3	30	91%	3	9%	33
TOTAL OVERALL	**2,713**	**2,291**	**5,004**	**94%**	**303**	**6%**	**5,307**

The following points summarize survey information provided in Tables 2, 3 and 4. These tables represent a snapshot of well activity data during this time.

- Overall, the survey showed 94% of the 5,307 wells reported in the API/ANGA data set as completed in 2010 and the first half of 2011 used hydraulic fracturing.
- *536 conventional gas wells were completed in 2010 and the first half 2011.*
    - 59% were vertical wells with hydraulic fracturing,
    - 11% were horizontal wells with hydraulic fracturing, and
    - 31% were wells without hydraulic fracturing.
- *2,210 shale gas wells were completed in 2010 and the first half 2011.*
    - 14% were vertical wells with hydraulic fracturing,
    - 84% were horizontal wells with hydraulic fracturing, and
    - 1% were wells without hydraulic fracturing.
- *2,528 tight gas wells were completed in 2010 and the first half 2011.*
    - 81% were vertical wells with hydraulic fracturing,
    - 15% were horizontal wells with hydraulic fracturing, and
    - 4% were wells without hydraulic fracturing.
- *33 coal-bed methane wells were completed in 2010 and the first half 2011.*
    - 82% were vertical wells with hydraulic fracturing,
    - 9% were horizontal wells with hydraulic fracturing, and
    - 9% were wells without hydraulic fracturing.

2.3 Data Limitations Concerning Wells

In response to follow-up questions on well data, EPA indicated that they classified gas well formations into four types (conventional, tight, shale, and coal-bed) (EPA, 2011d). When developing the gas well classifications, EPA applied their judgment where data were not available in the database. ANGA and API are interested in using the well database compiled by IHS or a similar database, to more completely classify gas wells at some point in the future. The API/ANGA survey did not specifically define conventional wells for collecting the well data presented in this section, leaving the respondents to determine the classification of wells based on their knowledge of the well characteristics or state classifications. As such, this well classification may vary somewhat according to the respondent's classification of wells.

It should be noted that there is not a generally accepted definition for "gas wells." Producers might be producing from several zones in the same formation, and different states define "gas" or "oil" wells differently due to the historical structure of royalties and revenues. There is also no commonly used definition of "conventional" gas wells. Thus, different definitions of these terms may have produced inconsistency in the classification of wells between gas and oil, and conventional and unconventional for the surveyed results, as well as for the EPA and EIA national data. For the purposes of this report, unconventional wells are considered to be shale gas wells, coal bed wells, and tight sand wells which must be fractured to produce economically.

3. Gas Well Liquids Unloading

Gas well clean ups also known as liquids unloading accounts for 51% of total CH_4 emissions from the natural gas production sector in EPA's national GHG inventory (EPA, 2012).[5] This was a considerable increase from the 6% of CH_4 emissions that liquids unloading represented in the 2008 inventory. The accuracy of assumptions regarding this activity was therefore a major concern to API/ANGA members.

As the name indicates, liquids unloading is a technique to remove water and other liquids from the wellbore so as to improve the flow of natural gas in conventional wells and unconventional wells.

In EPA's national inventory, emissions from gas well liquids unloading are based on the following assumptions:

- 41.3% of conventional wells require liquids unloading.
- 150,000 plunger lifts are in service, which equates to 42% of gas wells.
- The average gas well is blown down to the atmosphere 38.73 times per year.
- The average casing diameter is 5 inches.
- A gas well is vented to the atmosphere for 3 hours once the liquids are cleared from the well.

The ANGA/API survey gathered activity and emissions related information for gas well liquids unloading. Information was received covering eight conventional well data sets and 26 unconventional well data sets. The following information was requested:

- Geographic area represented by the information provided;
- Time period – data were annualized to 12 months if the information was provided for a partial year;
- Number of operated gas wells represented by the information provided;
- Number of gas wells with plunger lift installed;
- Number of gas wells with other artificial lift (beam pump; ESP; etc.);
- Total number of gas well vents;
- Number of wells with and without plunger lifts that vent to the atmosphere;
- Total count of gas well vents for time period with and without plunger lifts;
- Average venting time for wells with and without plunger lifts;
- Average daily production of venting gas wells (Mcf/day);
- Average depth of venting wells (feet);

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[5] See EPA Table A-129, of Annex 3 of the 2010 inventory report.

- Average casing diameter of venting gas wells (inches);
- Average tubing diameter of venting gas wells with plunger lift (inches); and
- Average surface pressure - venting gas wells (psig).

Table 5 summarizes the results from the API/ANGA survey and compares the results to the assumptions EPA uses to estimate emissions for this source in the national GHG inventory.

The ANGA/API data differed from EPA's assumptions in several ways:

1) API/ANGA showed lower percentages of wells with plunger lifts;
2) API/ANGA data indicated lower percentages of wells venting to the atmosphere;
3) API/ANGA data showed lower average vent times than EPA's numbers; and
4) Casing diameters from the API/ANGA survey were comparable to EPA's assumption of 5 inches.

Table 5. ANGA/API Survey – Summary of Liquids Unloading Data

	API/ANGA Survey		
Parameter	**Conventional Wells**	**Unconventional Wells**	**EPA Assumptions**
Number of gas wells with plunger lifts	10%	45%	42%
Number of gas wells with other artificial lift (beam pump, ESP, etc.)	25%	7%	
Number of gas wells vented to the atmosphere for liquids unloading	11%	16%	41.3%
# vents per well (weighted average)	303.9 (all data)*	33.6	38.7
	32.4 (w/o outliers) **		
Average venting time per vent (weighted average)			3 hours
With plunger lifts	0.25 hours	0.77 hours	
Without plunger lifts	1.78 hours	1.48 hours	
Weighted Average casing diameter	4.64 inches	5.17 inches	5 inches
Weighted Average tubing diameter	2.27 inches	2.43 inches	
Average Emission factor, Mscf/well			
With plunger lifts	823 (all data)*	196	
	14.7 (w/o outliers)**		
Without plunger lifts	56.4	318	
Weighted average Methane emission factor, Mscf CH4/well	175*		1,316

* Includes all liquids unloading data from the ANGA/API survey

** Excluding two high data points

When examining Table 5, it is important to note the presence of several outliers. Two data responses for operations with conventional wells reported very high frequencies of vents to the atmosphere. These data sets represent 174 gas wells with plunger lifts (out of a total 788 gas wells with plunger lifts represented by the total data set) located in the Mid-Continent region. The wells represented by these data points have plunger lifts that vent to the atmosphere for each plunger cycle. The information was confirmed by the two data respondents and is an artifact of the plunger control for these wells which results in very short venting durations (between 4 and 5 minutes) for each plunger cycle. As a result, accounting for the high frequency of plunger lift cycles for these wells results in a high average vent frequency, but still produces a lower emission factor than the EPA assumptions.

Excluding these two data points, the API/ANGA survey data for the number of vents per well was comparable to EPA's assumed frequency. Moreover, even with the high frequency of vents from these wells, the emissions are much lower than EPA's estimates (see Table 6).

TABLE 6. ANGA/API SURVEY –LIQUIDS UNLOADING EMISSIONS COMPARISON

NEMS Region	API/ANGA Survey		EPA Inventory			API & ANGA - EPA EPA % Difference in Emissions
	Emission Factor, Mscf CH4/well	Estimated Emissions, tonnes CH_4	# wells	Emission Factor, Mscf CH_4/well	Estimated Emissions, tonnes CH_4 *	
Northeast	136	202,503	77,931	1,360	2,027,265	-90%
Mid Continent	392	235,813	31,427	703	422,893	-44%
Rocky Mountain	177	90,387	26,620	690	351,672	-74%
Southwest	36	7,913	11,444	865	189,407	-96%
Gulf Coast	169	101,150	31,331	2,519	1,510,259	-93%
West Coast	No data for this region		638	1,492	Excluded for consistent comparison	
TOTAL	175 (weighted average)	637,766	179,391		4,501,465	-86%

*EPA estimated emissions = # wells × EPA emission factor, converted to mass emissions based on 60 degrees F and 14.7 psia

These variances among operators in ANGA/API data demonstrate the challenge of applying national emissions estimates to conditions in which there can be considerable variation in wells and operating techniques, among and even within various regions. As member companies have noted in various comments to regulators, oil and natural gas production operations vary considerably according to factors such as local geology, hydrology, and state law.

EPA noted that wells equipped with plunger lifts have approximately 60% lower emissions from liquids unloading than wells without plunger lifts (EPA, 2011b). From the API/ANGA survey, an emission reduction of about 38% was observed for the unconventional wells equipped with plunger lifts compared to those without plunger lifts. However, Table 5 indicates that for conventional gas wells, the average emission factor is higher for wells with plunger lifts compared to those without when the two high data points are included. Excluding the two high data points, the emission factor for conventional wells with plunger lifts is 74% lower than the emission factor for conventional wells without plunger lifts.

One reason for this discrepancy in the data may be that EPA has acknowledged that their current estimation method for liquids unloading does not account for activities used to reduce CH_4 emissions by many different artificial lift methods used in industry. According to Natural Gas Star Reports, the applicable emission reductions range from 4,700 to 18,250 Mscf/yr for plunger lift systems (EPA, 2006); however, since the emission reductions are reported separate from the emission estimate in the national inventory, they cannot be linked back to EPA emission source categories.

Emissions were calculated by applying Equation W-8 or W-9 from the EPA GHG reporting rule in 40 CFR 98 Subpart W, where Equation W-8 applies to gas wells without plunger lifts, and Equation W-9 applies to gas wells with plunger lifts. Appendix C summarizes the data collected and estimated emissions. The emission results are shown in Table 6 by NEMS region for comparison to EPA's emission estimates. The ANGA/API survey averaged the emission factors data within each NEMS region for conventional and unconventional wells combined. The emission results shown in Table 6 were determined by applying the API/ANGA emission factors and EPA emission factors, respectively, to the total number of wells requiring liquids unloading from the 2010 national GHG inventory.

As production companies continue to collect information for EPA's mandatory GHG reporting program, better information on liquids unloading frequency and emissions will be available. One area that would benefit from additional information is an investigation of regional differences, or plunger lift control practices, in view of the high frequency of vents observed for two data sets containing conventional gas wells with plunger lifts in the Mid-Continent region.

Key findings of the ANGA/API survey on liquids unloading are:

- ***For all of the NEMS regions, the API/ANGA survey data resulted in lower emission estimates than EPA estimated for the 2010 national GHG inventory when compared on a consistent basis.***
- ***Overall, the change in emission factors based on data collected from the ANGA/API survey reduces estimated emissions for this source by 86% from the emissions reported in EPA's 2010 national GHG inventory.***

4. Hydraulic Fracturing and Re-fracturing (Workovers)

A well workover refers to remedial operations on producing natural gas wells to try to increase production. Starting with the 2009 inventory, EPA split the estimation of emissions from producing gas wells into conventional (i.e., without hydraulic fracturing) and unconventional (i.e., with hydraulic fracturing). For workovers of wells without hydraulic fracturing, the 2009 and 2010 national inventories used emission factors of the same order of magnitude as the 2008 inventory (2,454 scf of CH_4/workover). In contrast, the unconventional (with hydraulic fracturing) well workover emission factor increased by a factor of three thousand (3,000).

EPA did acknowledge that the new emission factor for well workovers was based on limited information (EPA, 2011a). Moreover, several publications including *Mismeasuring Methane* by IHS CERA underscored the perils of extrapolating estimates using only four (4) data points representing approximately two percent (2%) of wells – particularly when the data was submitted in the context of the Natural Gas Star program, which was designed to highlight emissions reduction options (IHS CERA, 2011). Unfortunately, even if the EPA's workover factor is high, it must be used in estimated emissions calculations until it is officially changed.

EPA's new emission factor is 9.175 MMscf of natural gas per re-fracture (equivalent to 7.623 MMscf CH_4/re-fracture). Additionally, EPA used this new emission factor in conjunction with an assumed re-fracture rate of 10% for unconventional gas well workovers each year to arrive at their GHG emission estimate for this particular category.

4.1 API/ANGA Survey

The ANGA/API survey requested counts for gas well workovers or re-fractures in two separate phases of the survey, covering 91,028 total gas wells (Table 7 covering 2010 and first half of 2011 data) and 69,034 unconventional gas wells (Table 8, 2010 data only), respectively.

The first phase of the survey was part of the general well data request. Counts of workovers by well type (conventional, tight, shale, and coal bed methane) and by AAPG basin were requested. The frequency of workovers was calculated by dividing the reported workover rates by the reported total number of each type of gas well. These results are summarized in Table 7, which includes a comparison to national workover data from EPA's annual GHG inventory. The high number of workovers in the Rocky Mountain region is discussed further below.

Table 7 indicates that even for the high workover rates associated with unconventional tight gas wells, the workover rate is much less than EPA's assumed 10% of gas wells re-fractured each year. Based on this first phase of the survey,

- The overall workover rate involving hydraulic fracturing was 1.6%.
- However, many of these workovers were in a single area, AAPG-540, where workovers are known to be conducted more routinely than in the rest of the country (as described in more detail below Table 8). Excluding AAPG 540, the overall workover rate involving hydraulic fracturing was 0.7%

- For all unconventional wells in Table 7, the overall workover rate involving hydraulic fracturing was 2.2%. Excluding AAPG 540, the overall workover rate involving hydraulic fracturing was 0.9%.

Table 7. API/ANGA Survey – Summary of Gas Well Workovers with Hydraulic Fracturing in 2010 and first half of 2011 by NEMS Region and Well Type (First Phase Data Survey)

NEMS Region	Conventional Wells	Unconventional Wells			
		Shale	Coal-bed Methane	Tight	Unspecified
Northeast	-	-	-	-	-
Gulf Coast	-	5	-	38	73
Mid-Continent	8	1	-	73	33
Southwest	60	25	-	8	7
Rocky Mountain	4	-	25	901	-
West Coast	-	-	-	-	-
Unspecified	-	-	-	-	200
Survey TOTAL	72	31	25	1,020	313
		1,076			
% of national	0.3%	21.3%			
Overall Survey Total	1,461				
% of national	5.6%				

National Workover Counts (from EPA's 2010 national inventory)	Conventional Wells	Unconventional Wells
	21,088	5,044
	80.7%	19.3%
	26,132	

	Conventional Wells	Unconventional Wells			
		Shale	Coal-bed Methane	Tight	Unspecified
% Workover Rate with Hydraulic Fracturing (from ANGA/API Survey)	0.3%	0.3%	0.5%	3.0%	2.4%
Tight w/out AAPG 540				0.5%	
Unconventional Wells		2.2%			
W/out AAPG 540		0.9%			
All Wells	1.6%				
All Wells w/out AAPG 540	0.7%				

Also, the ANGA/API survey collected information on the number of workovers for vertical and horizontal unconventional gas wells. Nearly 99% of the unconventional gas well workovers were on vertical wells. Additionally, 18% of the gas well workovers from the API/ANGA survey were conducted on gas wells without hydraulic fracturing.

A second phase of the survey was conducted which targeted collecting gas well re-fracture information for 2010 to provide a better estimate than EPA's assumption that 10% of wells are re-fractured each year. This portion of the ANGA/API survey requested information just for “unconventional” gas wells (i.e., those located on shale, coal-bed methane, and tight formation reservoirs), where the formations require fracture stimulation to economically produce gas. A re-fracture or workover was defined for this second phase of the survey as a re-completion to a different zone in an existing well or a re-stimulation of the same zone in an existing well. These results are summarized in Table 8.

While there likely is significant overlap of unconventional well data reported in the first and second phases of the survey (which covered over 62,500 unconventional wells and 69,000 unconventional wells respectively), combined these data indicate an unconventional well re-fracture rate of 1.6% to 2.3% including AAPG 540 and 0.7% to 1.15% excluding AAPG 540.

AAPG Basin 540 (i.e. DJ Basin) which is part of the Rocky Mountain Region stands out in Tables 7 and 8. After four (4) to eight (8) years of normal production decline, the gas wells in this basin can be re-fractured in the same formation and returned to near original production. Success of the re-fracture program in the DJ Basin is uniquely related to the geology of the formation, fracture reorientation, fracture extension and the ability to increase fracture complexity. Also, most DJ Basin gas wells are vertical or directional, which facilitates the ability to execute re-fracture operations successfully and economically. These characteristics result in a high re-fracture or workover rate specific to this formation.

ANGA and API believe the high re-fracture rate observed in the DJ Basin is unique and not replicated in other parts of the country. There may be a few other formations in the world that have similar performance, but the successful re-fracture rate in the DJ Basin is not going to be applicable to every asset/formation and there is no evidence of the high re-fracture rate in any of the other 22 AAPGs covered in the API/ANGA survey. It is highly dependent on the type of rock, depositional systems, permeability, etc. For these reasons, re-fracture rates for tight gas wells and all gas wells with and without AAPG Basin 540 are summarized in Tables 7 and 8.

Table 8. API/ANGA Survey – Summary of 2010 Gas Well Workovers on Unconventional Wells by AAPG Basin and NEMS Region (Second Phase Survey Data)

NEMS Region	AAPG	Number of Unconventional Operating Gas Wells	Number of Hydraulic Fracture Workovers on Previously Fracture Stimulated Wells	% Wells re-fractured per year	Regional % Wells re-fractured per year
Northeast	160	1,976	0	0.00%	0%
	160A	760	0	0.00%	
Gulf Coast	200	2	0	0.00%	0.91%
	220	649	2	0.31%	
	222	629	3	0.48%	
	230	820	4	0.49%	
	250	13	0	0.00%	
	260	2,830	36	1.27%	
Mid-Continent	345	3,296	11	0.33%	0.95%
	350	213	3	1.41%	
	355	282	8	2.84%	
	360	7,870	89	1.13%	
	375	12	0	0.00%	
	385	1	0	0.00%	
	400	64	0	0.00%	
Southwest	415	1,834	0	0.00%	1.04%
	420	838	8	0.95%	
	430	1,548	36	2.33%	
	435	2	0	0.00%	
Rocky Mountain	515	1	0	0.00%	4.7%
	540	5,950	866	14.55%	
	580	8,197	8	0.10%	
	595	5,222	32	0.61%	
Not specified		26,025	487	1.87%	1.87%
Unconventional TOTAL (all wells)		**69,034**	**1,593**	**2.31%**	
Unconventional Median		790	3		
Rocky Mountain Region Unconventional Total		19,370	906	4.68%	
Unconventional TOTAL (Without AAPG 540)		63,084	727	1.15%	

4.2 WRAP Survey

Other information on re-fracture rates is available in a survey conducted by the Western Regional Air Partnership (WRAP). WRAP conducted a survey of production operators in the Rocky Mountain Region (Henderer, 2011) as part of the initiative to develop GHG reporting guidelines for a regional GHG cap and trade program.

Within each basin in this region, the top oil and gas producers were identified and invited to participate in the survey. The goal was to have operator participation that represented 80% of the production for the region. The spreadsheet survey requested information on the completions, workovers, and emissions associated with these activities. An emission factor and frequency of re-fracturing was developed for each basin as a weighted average of the operator responses.

The re-fracture rates from the WRAP survey are shown in Table 9 (Henderer, 2011).

TABLE 9. WRAP SURVEY – SUMMARY OF GAS WELL WORKOVERS BY AAPG BASIN FOR THE ROCKY MOUNTAIN REGION, 2006 DATA

AAPG Basin	# Wells represented by survey	# Wells Recompleted	% Recompleted
515	4,484	121	2.70%
530	731	5	0.68%
535	4,982	201	4.03%
540	8,247	636	7.71%
580	3,475	14	0.40%
595	4,733	275	5.81%
Total	26,652	1,252	
Weighted average			4.70%

AAPG Basin 540 results in the highest re-fracture rate for this data set, consistent with the ANGA/API survey as noted above. It is noteworthy that, while there are differences among individual AAPG Basin results, the weighted average re-fracture rate from the WRAP survey in 2006 is the same as the Rocky Mountain regional 4.7% re-fracture rate from the API/ANGA survey shown in Table 8.

4.3 Impact of Completions and Re-fracture Rate Assumptions

Table 10 compares the considerable reduction in the national GHG inventory that would result from applying a lower re-fracture rate.

EPA indicated that the national inventory assumes 10% of unconventional gas wells are re-fractured each year. Table 10 replaces this value with results from the ANGA/API survey. A re-fracture rate of 1.15% is applied to unconventional gas wells in the Mid-Continent and Southwest regions (No unconventional gas wells were assigned to the Northeast and Gulf Coast regions. The West Coast region is not shown since the API/ANGA survey did not include any responses for gas well operations in this region.) A re-fracture rate of 4.7% is applied to unconventional gas wells in the Rocky Mountain region.

With these adjustments to the re-fracture rate for unconventional gas wells, the national emission estimate is reduced by 72% for this emission source category, from 712,605 metric tons of CH_4 to 197,311 metric tons of CH_4 when compared on a consistent basis.

4.4 Completion and Re-fracture Emission Factor

In the 2009 GHG national inventory, EPA applies an emission factor of 2,454 scf CH_4/event for conventional gas well workovers, while the emission factor for unconventional gas well completions and workovers was increased to 7,623,000 scf CH_4/event (EPA, 2011b). Similarly, for the 2010 national GHG inventory, EPA maintained the emission factor of 2,454 scf CH_4/event for gas well workovers without hydraulic fracturing, but applied an average emission factor of 7,372,914 to gas well workovers with hydraulic fracturing (EPA, 2012). (EPA applies slightly different emission factors for each NEMS region based on differing gas compositions.)

The ANGA/API survey focused on activity data and did not collect data to revise the emission factor for unconventional gas well completions and workovers.

Table 10. API/ANGA Survey –Gas Well Workover Emissions Comparison

NEMS Region	Well type	2010 EPA National Inventory # workover	Adjusted # workovers (based on API/ANGA survey)	2010 EPA National Inventory		Revised Emissions, tonnes CH_4 (based on ANGA/API survey)	API & ANGA - EPA EPA % Difference
				Emission Factor, scf CH_4/workover	Estimated Emissions, tonnes CH_4*		
Northeast	Wells without Hydraulic Fracturing	8,208	8,208	2,607	409	409	
	Wells with Hydraulic Fracturing	0	0	7,694,435	0	0	
Mid Continent	Wells without Hydraulic Fracturing	3,888	3,888	2,574	191	191	
	Wells with Hydraulic Fracturing	1,328	153	7,672,247	194,950	22,462**	-89%
Rocky Mountain	Wells without Hydraulic Fracturing	3,822	3,822	2,373	174	174	
	Wells with Hydraulic Fracturing	2,342	1,100	7,194,624	322,402	151,432**	-53%
Southwest	Wells without Hydraulic Fracturing	1,803	1,803	2,508	87	87	
	Wells with Hydraulic Fracturing	1,374	158	7,387,499	194,217	22,382**	-89%
Gulf Coast	Wells without Hydraulic Fracturing	3,300	3,300	2,755	174	174	
	Wells with Hydraulic Fracturing	0	0	8,127,942	0	0	
TOTAL					712,605	197,311	-72%

* EPA Estimated emissions = 2010 # Workovers x EPA 2010 Emission Factor, converted to mass emissions based on 60°F and 14.7 psia.

** Revised emissions = Adjusted # Workovers x Emission Factor, converted to mass emissions based on 60°F and 14.7 psia.

Emissions Data from WRAP Study

The WRAP study discussed in Section 4.2 also gathered data on emissions from completions. This information supports a revised emission factor but was reported by sources outside the ANGA/API data survey. The results are summarized in Table 11. The WRAP emission factor is 78% lower than EPA's emission factor (9.175 MMscf gas/event). The WRAP survey did not provide a methodology for determining emissions data.

TABLE 11. WRAP SURVEY – SUMMARY OF COMPLETION EMISSIONS FOR THE ROCKY MOUNTAIN REGION, 2006 DATA

AAPG Basin	Weighted average gas emissions from completion, Mcf gas/well	# completions represented
515	167	207
530	268	54
535	76	642
540	59	608
580	6,559	283
595	4,053	819
Total		2,613
Weighted average	2,032 Mcf/well	

4.5 Data Limitations for Completion and Re-fracture Emissions

Although the data sets are limited, it appears that EPA's assumed re-fracture rate of 10% is a significant overestimate. Information from the API/ANGA survey indicates that even including what appears to be unique activity in AAPG-540, the re-fracture rate is much less frequent, ranging from 1.6% to 2.3% based on two sets of survey information (Tables 7 and 8, respectively). The re-fracture rate for AAPG Basin 540 appears to be higher than other areas in the U.S. due to unique geologic characteristics in that region (4.7% based on a weighted average of data reported for that region). Without AAPG Basin 540, the national rate of re-fracturing is between 0.7% and 1.15% of all gas wells annually.

Additionally, limited information on the emissions from completions and workovers with hydraulic fracturing indicate that EPA's GHG emission factor for these activities is significantly overestimated. It is expected that better emissions data will develop as companies begin to collect information for EPA's mandatory GHG reporting program (EPA, 2011c).

5. Other Surveyed Information

EPA had indicated that activity data for centrifugal compressor wet seals and pneumatic devices used in the national inventory is lacking. Note that the need for better equipment data persists throughout the majority of the U.S. inventory and is not unique to the oil and natural gas industry. The ANGA/API survey requested the following information related to centrifugal compressors and pneumatic devices:

- The number of centrifugal compressors, reported separately for production/gathering versus processing;
- The number of centrifugal compressors with wet versus dry seals, reported separately for production/gathering versus processing;
- The number of pneumatic controllers, classified as “high-bleed,” “low-bleed,” and “intermittent,” reported separately for well sites, gathering/compressor sites, and gas processing plants; and
- The corresponding number of well sites, gathering/compressor sites, and gas processing plants, associated with the pneumatic controller count.

5.1 Centrifugal Compressors

Processing Facilities

The API/ANGA survey collected the equivalent of 5% of the national centrifugal compressor count for gas processing operations (38 centrifugal compressors from the survey, compared to 811 from EPA’s 2010 national GHG inventory). For the gas processing centrifugal compressors reported through the survey, 79% were dry seal compressors and 21% were wet seals. EPA’s 2010 national inventory reported 20% of centrifugal compressors at gas processing plants were dry seal, and 80% were wet seal. EPA’s emission factor for wet seals (51,370 scfd CH_4/compressor) is higher than the emission factor for dry seals (25,189 scfd CH_4/compressor).[6]

Based on the ANGA/API survey, EPA appears to be overestimating emissions from centrifugal compressors. If the small sample size from the API/ANGA survey is representative, non-combustion emissions from centrifugal compressors would be 173,887 metric tons of methane compared to 261,334 metric tons of methane from the 2010 national inventory (when applying industry standard conditions of 60 °F and 14.7 psia to convert volumetric emissions to mass emissions). Although based on very limited data, if the ANGA/API survey results reflect the population of wet seal versus dry seal centrifugal compressors, the emissions from this source would be reduced by 34% from EPA’s emission estimate in the national inventory. Better data on the number of centrifugal compressors and seal types will be available from companies reporting to EPA under the mandatory GHG reporting program.

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[6] EPA Table A-123, of Annex 3 of the 2010 inventory report.

Production and Gathering Facilities

Very few of the data sets reported through the API/ANGA survey indicate counts of centrifugal compressors associated with production/gathering operations - only 550 centrifugal compressors from 21 participating companies. EPA's 2010 GHG inventory did not include centrifugal compressors in production/gathering operations. On a well basis, the survey responses equate to 0.07 centrifugal compressors per gas well, with 81% dry seal centrifugal compressors and the remaining wet seal compressors. Information reported through EPA's mandatory GHG reporting program will provide additional information to account for GHG emissions from centrifugal compressors in production operations.

5.2 Pneumatic Controllers

Table 12 summarizes the survey responses for pneumatic controllers. For each type of location – gas well sites, gathering compressor sites, and gas processing plants – the count of the number of sites represented by the survey data is shown. Table 12 also shows the percent of each pneumatic controller type for each type of location.

TABLE 12. ANGA/API SURVEY –PNEUMATIC CONTROLLER COUNTS

	Gas Well Sites		Gathering/ Compressor Sites		Gas Processing Plants	
# wells, sites or plants	48,046 wells		1,988 sites		21 plants	
# controllers/well, site or plant	0.99 per well		8.6 per site		7.8 per plant	
# Low Bleed Controllers	12,850	27%	5,596	33%	117	71%
# High Bleed Controllers	11,188	24%	1,183	7%	47	29%
# Intermittent Controllers	23,501	49%	10,368	60%	0	0%

The survey requested that the responses designate pneumatic controllers as either "high bleed", "low bleed", or "intermittent" following the approach each company is using for Subpart W reporting. For example, Subpart W defines high-bleed pneumatic devices as automated, continuous bleed flow control devices powered by pressurized natural gas where part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate in excess of 6 standard cubic feet per hour (EPA, 2011c).

EPA does not currently track pneumatic controllers by controller type in the national inventory. This information will be collected under 40 CFR 98 Subpart W starting in September 2012. From the API/ANGA survey, intermittent bleed controllers are the more prevalent type at gas well sites and gathering/compressor sites, while gas plants predominately use low-bleed controllers. No intermittent controllers were reported for gas plants by the survey respondents.

Table 13 compares emission results based on applying the emission factors from the EPA's GHG reporting rule to emissions presented in the 2010 national GHG inventory, using the counts of pneumatic controller from the ANGA/API survey for production operations.

For production, the EPA national inventory combines pneumatic controller counts associated with large compressor stations with pneumatic controllers in production. An emission factor for each NEMS region is applied to the count of total controllers in each NEMS region. For this comparison, a weighted average emission factor of 359 scfd CH_4/device was applied to the count of pneumatic controllers located at well sites and gathering/compressor sites.

Under the EPA mandatory reporting rule (40 CFR 98 Subpart W), separate emission factors are applied to pneumatic controllers based on the controller type and whether the controller is located in the Eastern or Western region of the United States, as specified in the rule (EPA, 2011c). For this comparison, an average of the eastern and western emission factors is applied to each device type in computing the emission estimates resulting from the EPA GHG reporting rule.

TABLE 13. PNEUMATIC CONTROLLER EMISSION COMPARISON – PRODUCTION OPERATIONS

	API/ANGA Survey Count of Controllers			EPA GHG Reporting Rule (Subpart W)		2010 National GHG Inventory	
	Gas Well Sites	Gathering/ Compressor Sites	Total	Emission Factor,* scfh CH_4/device	Emissions, tonnes CH_4/yr	Emission Factor, scfd CH_4/device	Emissions, tonnes CH_4/yr
# Low Bleed Controllers	12,850	5,596	18,446	1.58	4,885	359	46,286
# High Bleed Controllers	11,188	1,183	12,371	42.35	87,814		31,042
# Intermittent Controllers	23,501	10,368	33,869	15.3	86,856		84,987
Total			64,686		179,556		162,315

* Emission factors shown are the average of the eastern and western emission factors from Table W-1A (EPA, 2011c).

Based on the types of pneumatic controllers reported in the ANGA/API survey, EPA's mandatory GHG reporting rule could increase CH_4 emissions 11% over the pneumatic controller portion of the 2010 national GHG inventory. To put this in context, in EPA's inventory report for 2010, emissions from pneumatic controllers accounted for approximately 13% of CH_4 emissions from the natural gas field production stage. Any increase from that initially reported data, however, will likely represent a worst case scenario. It is important to remember that pneumatic controllers operate only intermittently, so variability such as the frequency and duration of the activations will be important information to consider when defining an accurate and effective reporting regime for these sources.

EPA's mandatory GHG reporting rule does not require reporting emissions from pneumatic controllers at gas processing plants, so no emission factors are specified. The GHG national inventory applies an emission factor of 164,721 scfy CH_4 per gas plant for pneumatic controllers. For the national inventory, this results in 1,856 tonnes CH_4 emissions - a very small contribution to CH_4 emissions from onshore oil and gas operations.

6. Conclusions

API and ANGA members believe this to be the most comprehensive set of natural gas data to date and are pleased to share these results with both regulators and the public.

Based on the information gathered from member companies during this project, it appears that EPA has overstated several aspects of GHG emissions from unconventional natural gas production. As summarized in Table 14, the ANGA/API survey data results in significantly lower emission estimates for liquids unloading and unconventional gas well refracturing when compared to EPA's emission estimates in the national inventory. Using the combined emission estimates from the survey for these two key emission sources would indicate a 50% reduction in calculated natural gas production sector emissions compared to EPA's estimates. This reduction would shift Natural Gas Systems from the largest to the second largest producer of methane emissions (approximately 123.4 MMT CO_2e in lieu of 215.4 MMT CO_2e), behind Enteric Fermentation (which is a consequence of bovine digestion, at 141.3 MMT CO_2e).

TABLE 14. EMISSION COMPARISON BETWEEN EPA AND INDUSTRY DATA

Source Category	EPA National Inventory		API/ANGA Survey		Impact on Source Category Emissions
	Metric tons of CH4	% of EPA Production Total	Metric tons of CH4	% of Revised Production Total	API & ANGA - EPA EPA % Difference in Emissions
Liquids Unloading	4,501,465 *	51%	637,766	14%	-86%
Unconventional Well Re-fracture Rates	712,605 *	8%	197,311	4%	-72%
Other Production Sector Emissions**	3,585,600	41%	3,585,600	81%	
Total Production Sector Emissions	8,799,670		4,420,677		-50%

* EPA's estimates are adjusted to industry standard conditions of 60 degrees F and 14.7 psia for comparison to the ANGA/API emission estimates.

**The "Other Production Sector Emissions" are comprised of over 30 different source categories detailed in Table A-129 in the Annex of the EPA's 2012 national inventory. The "Other Production Sector Emissions" are the same values for this comparison between the EPA national inventory and the API/ANGA survey to focus the comparison on quantified differences in emission estimates for gas well liquids unloading and unconventional well re-fracture rates.

This project was directed toward gathering more robust information on workovers, completions, liquids unloading, centrifugal compressors, and pneumatic controllers with the intent of supporting revisions to the activity factors used in EPA's national inventory and cited by many media publications. Although limited information was collected on centrifugal compressors and pneumatic controllers, the survey results indicated potential additional differences, which are not included in the Table 14 comparison, when comparing total emissions from all sources to the national inventory. Additional future data collection efforts, including more detailed reporting under Subpart W of the GHGRP will likely resolve these differences and continue to inform the overall natural gas emissions data.

In the meantime, however, while API and ANGA recognize that the data collected for this report represents a sample of the universe of natural gas wells operating in the U.S., we believe that the conclusions drawn from the data analysis are relevant and representative of natural gas production as whole. In EPA's gas well count, 21 of the AAPG basins each have more that 1% of the total well count. The ANGA/API survey has wells from 19 of those 21 basins. In terms of wells represented by these basins, 92% of the total EPA well count is accounted for by wells in those 21 basins, while 95% of the API/ANGA surveyed gas wells are accounted for by those 21 basins. This indicates that the ANGA/API survey results have good representation for the basins with the largest numbers of wells nationally.

Industry also believes that the systematic approach in which the API/ANGA data were collected and vetted by natural gas experts is an improvement over the *ad hoc* way in which EPA collected some of their data. This study indicates that EPA should reconsider their inventory methodologies for unconventional natural gas production particularly in light of more comprehensive and emerging data from the industry. ANGA and API members look forward to working with the agency to continue to educate and evaluate the latest data as it develops about the new and fast-changing area of unconventional well operations.

7. References

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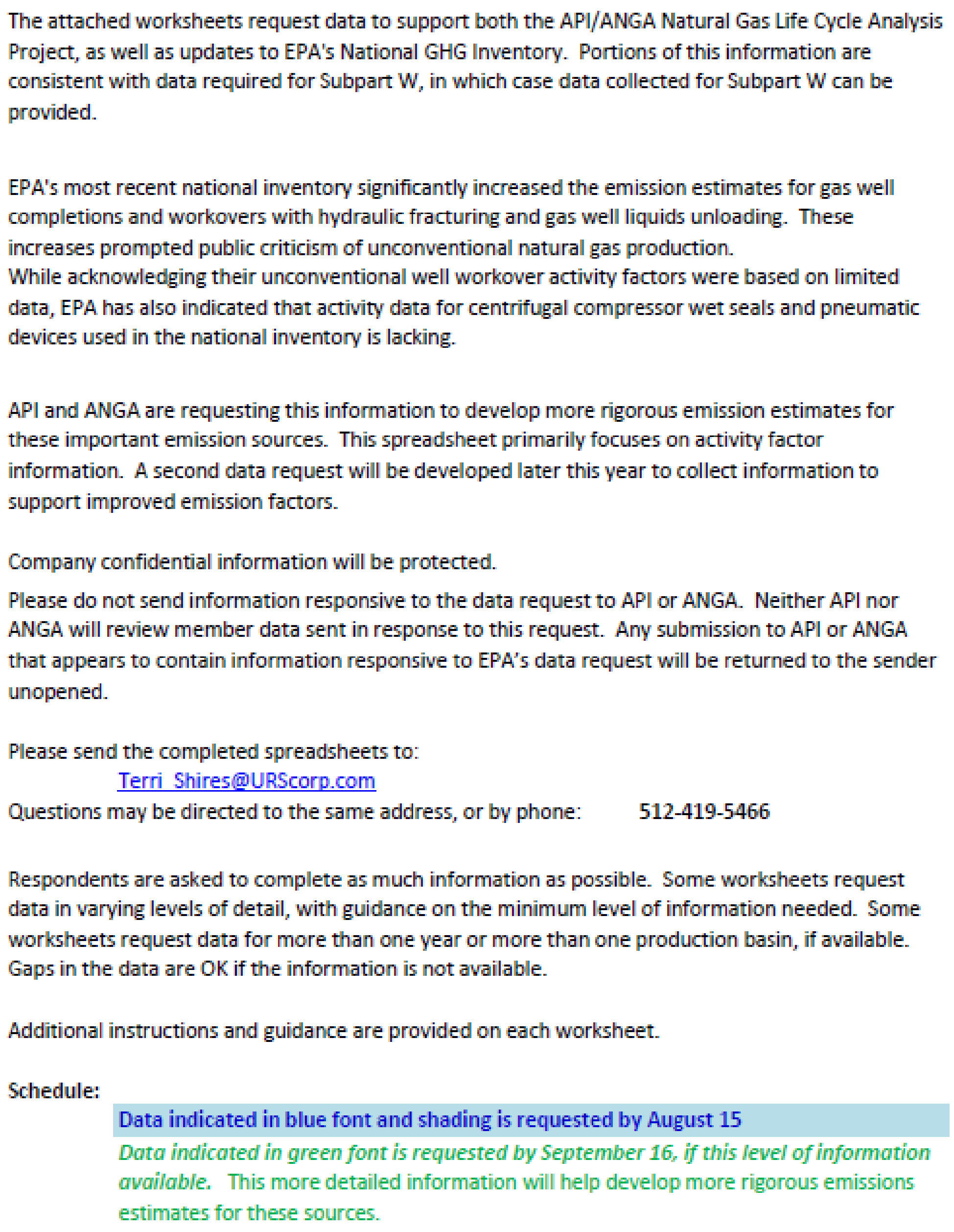
Appendix A. API/ANGA Survey Forms

The following provides the survey forms used to gather data presented in this report.

Figure A-1. Survey Instructions



The attached worksheets request data to support both the API/ANGA Natural Gas Life Cycle Analysis Project, as well as updates to EPA's National GHG Inventory. Portions of this information are consistent with data required for Subpart W, in which case data collected for Subpart W can be provided.

EPA's most recent national inventory significantly increased the emission estimates for gas well completions and workovers with hydraulic fracturing and gas well liquids unloading. These increases prompted public criticism of unconventional natural gas production.
While acknowledging their unconventional well workover activity factors were based on limited data, EPA has also indicated that activity data for centrifugal compressor wet seals and pneumatic devices used in the national inventory is lacking.

API and ANGA are requesting this information to develop more rigorous emission estimates for these important emission sources. This spreadsheet primarily focuses on activity factor information. A second data request will be developed later this year to collect information to support improved emission factors.

Company confidential information will be protected.

Please do not send information responsive to the data request to API or ANGA. Neither API nor ANGA will review member data sent in response to this request. Any submission to API or ANGA that appears to contain information responsive to EPA's data request will be returned to the sender unopened.

Please send the completed spreadsheets to:
Terri_Shires@URScorp.com
Questions may be directed to the same address, or by phone: 512-419-5466

Respondents are asked to complete as much information as possible. Some worksheets request data in varying levels of detail, with guidance on the minimum level of information needed. Some worksheets request data for more than one year or more than one production basin, if available. Gaps in the data are OK if the information is not available.

Additional instructions and guidance are provided on each worksheet.

Schedule:

Data indicated in blue font and shading is requested by August 15

Data indicated in green font is requested by September 16, if this level of information available. This more detailed information will help develop more rigorous emissions estimates for these sources.

FIGURE A-2. GAS WELL SURVEY DATA

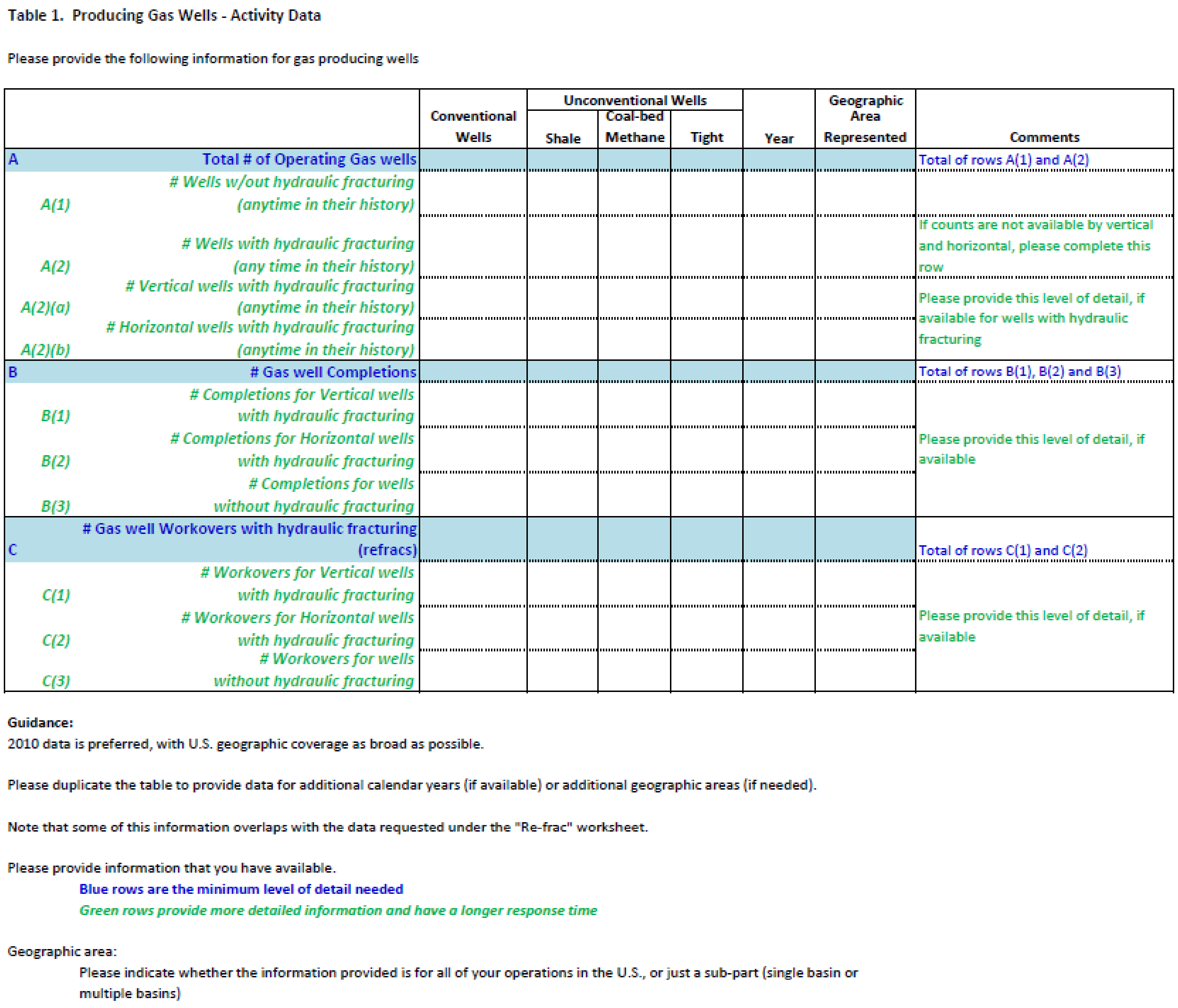


Table 1. Producing Gas Wells - Activity Data

Please provide the following information for gas producing wells

		Conventional Wells	Unconventional Wells			Year	Geographic Area Represented	Comments
			Shale	Coal-bed Methane	Tight			
A	Total # of Operating Gas wells							Total of rows A(1) and A(2)
A(1)	*# Wells w/out hydraulic fracturing (anytime in their history)*							
A(2)	*# Wells with hydraulic fracturing (any time in their history)*							If counts are not available by vertical and horizontal, please complete this row
A(2)(a)	*# Vertical wells with hydraulic fracturing (anytime in their history)*							Please provide this level of detail, if available for wells with hydraulic fracturing
A(2)(b)	*# Horizontal wells with hydraulic fracturing (anytime in their history)*							
B	# Gas well Completions							Total of rows B(1), B(2) and B(3)
B(1)	*# Completions for Vertical wells with hydraulic fracturing*							Please provide this level of detail, if available
B(2)	*# Completions for Horizontal wells with hydraulic fracturing*							
B(3)	*# Completions for wells without hydraulic fracturing*							
C	# Gas well Workovers with hydraulic fracturing (refracs)							Total of rows C(1) and C(2)
C(1)	*# Workovers for Vertical wells with hydraulic fracturing*							Please provide this level of detail, if available
C(2)	*# Workovers for Horizontal wells with hydraulic fracturing*							
C(3)	*# Workovers for wells without hydraulic fracturing*							

Guidance:
2010 data is preferred, with U.S. geographic coverage as broad as possible.

Please duplicate the table to provide data for additional calendar years (if available) or additional geographic areas (if needed).

Note that some of this information overlaps with the data requested under the "Re-frac" worksheet.

Please provide information that you have available.

Blue rows are the minimum level of detail needed

Green rows provide more detailed information and have a longer response time

Geographic area:

Please indicate whether the information provided is for all of your operations in the U.S., or just a sub-part (single basin or multiple basins)

FIGURE A-3. GAS WELL WORKOVER SURVEY DATA

Table 2. Gas Well Workover Activity Data: Frequency of Re-fractures

	Year	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001
A	*Geographic area*										
B	*Number of Unconventional Operating Gas Wells*										
C	*Number of Fracture Stimulation Wells Completed each year (New Completions)*										
D	*Number of Fracture Stimulation Jobs conducted each year on Previously Fracture Stimulated Wells (i.e., # of Workovers or re-fracs)*										

Guidance

Please provide information that you have available.

Please provide data that are available for any or all of the years listed. Gaps in the data are OK.

Copy the table to provide data for additional geographic areas

A Geographic Area: Please indicate whether the information provided is for all of your operations in the U.S., or just a sub-part (single basin or multiple basins)

B Provide the number of Unconventional Operating Wells. This refers to wells located on shale, coal-bed Methane, and Tight Formations reservoirs. Unconventional reservoirs are reservoirs that require fracture stimulation to economically produce.

C Provide the number of new completions conducted in the year. This may be the same value provided in the "Well data" worksheet, Item B.

D Provide the number of re-fractures (workovers). A re-frac or workover is defined as a re-completion to a different zone in an existing well or re-stimulation of the same zone in an existing well. This may be the same value provided in the "Well data" worksheet, Item C. Hydraulic Fracture jobs conducted more than 30 days from the end of one stimulation job to the beginning of another stimulation job in the same well-bore is a new re-frac.

Notes

The EPA uses an assumption that 10% of wells are refractured each year to determine the number of re-frac's per year and then multiplies this by 9.175 MMSCF methane per re-frac to arrive at their inventory for this particular category.

For the year reported in Table 1, this table requests redundant information. The purpose of this table is to collect refracture information over a ten-year time period to provide a better estimate to EPA's assumption that 10% of wells are refractured each year.

FIGURE A-4. GAS WELL LIQUIDS UNLOADING SURVEY DATA

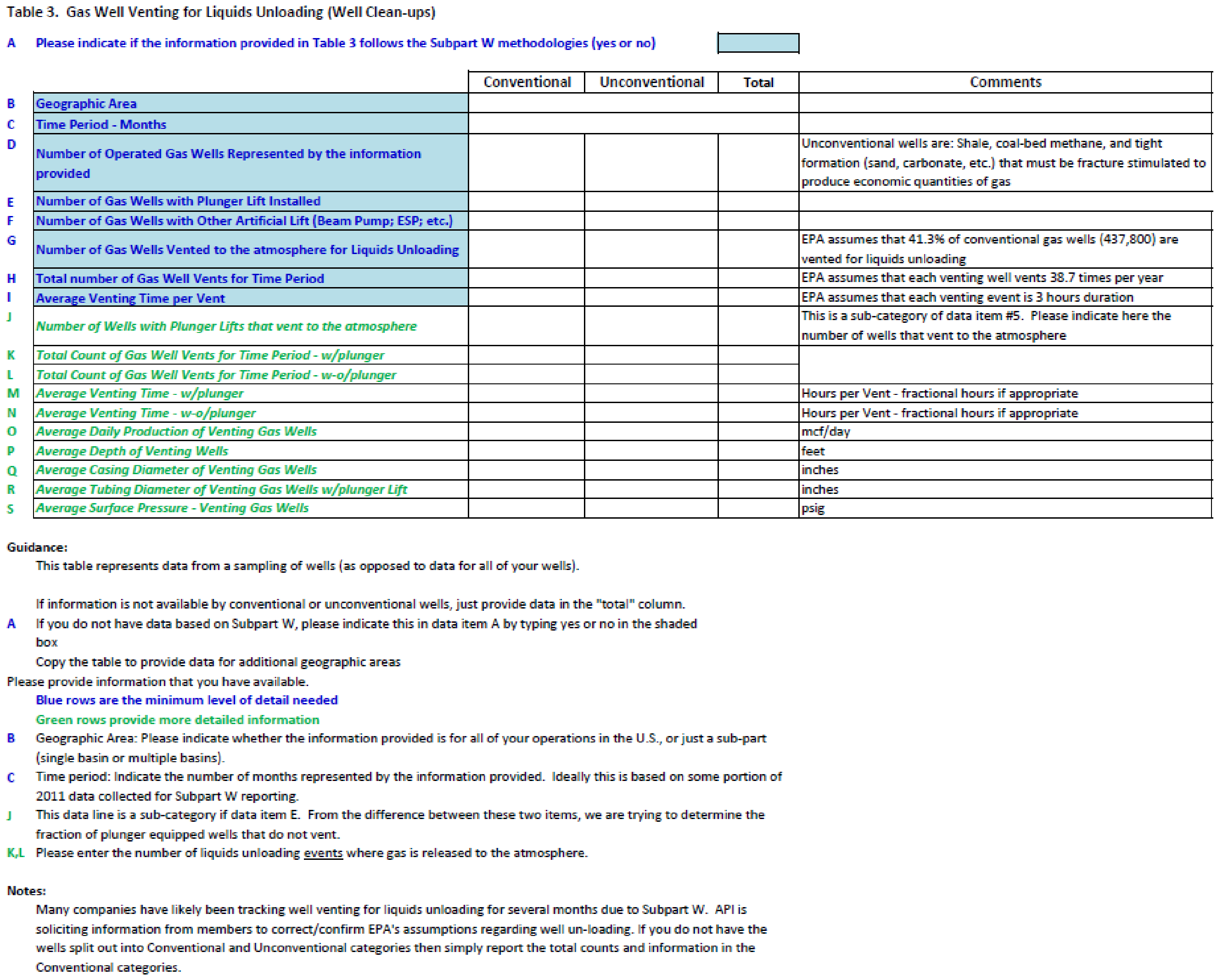


Table 3. Gas Well Venting for Liquids Unloading (Well Clean-ups)

A Please indicate if the information provided in Table 3 follows the Subpart W methodologies (yes or no)

		Conventional	Unconventional	Total	Comments
B	Geographic Area				
C	Time Period - Months				
D	Number of Operated Gas Wells Represented by the information provided				Unconventional wells are: Shale, coal-bed methane, and tight formation (sand, carbonate, etc.) that must be fracture stimulated to produce economic quantities of gas
E	Number of Gas Wells with Plunger Lift Installed				
F	Number of Gas Wells with Other Artificial Lift (Beam Pump; ESP; etc.)				
G	Number of Gas Wells Vented to the atmosphere for Liquids Unloading				EPA assumes that 41.3% of conventional gas wells (437,800) are vented for liquids unloading
H	Total number of Gas Well Vents for Time Period				EPA assumes that each venting well vents 38.7 times per year
I	Average Venting Time per Vent				EPA assumes that each venting event is 3 hours duration
J	*Number of Wells with Plunger Lifts that vent to the atmosphere*				This is a sub-category of data item #5. Please indicate here the number of wells that vent to the atmosphere
K	*Total Count of Gas Well Vents for Time Period - w/plunger*				
L	*Total Count of Gas Well Vents for Time Period - w-o/plunger*				
M	*Average Venting Time - w/plunger*				Hours per Vent - fractional hours if appropriate
N	*Average Venting Time - w-o/plunger*				Hours per Vent - fractional hours if appropriate
O	*Average Daily Production of Venting Gas Wells*				mcf/day
P	*Average Depth of Venting Wells*				feet
Q	*Average Casing Diameter of Venting Gas Wells*				inches
R	*Average Tubing Diameter of Venting Gas Wells w/plunger Lift*				inches
S	*Average Surface Pressure - Venting Gas Wells*				psig

Guidance:

This table represents data from a sampling of wells (as opposed to data for all of your wells).

If information is not available by conventional or unconventional wells, just provide data in the "total" column.

A If you do not have data based on Subpart W, please indicate this in data item A by typing yes or no in the shaded box

Copy the table to provide data for additional geographic areas

Please provide information that you have available.

Blue rows are the minimum level of detail needed

Green rows provide more detailed information

B Geographic Area: Please indicate whether the information provided is for all of your operations in the U.S., or just a sub-part (single basin or multiple basins).

C Time period: Indicate the number of months represented by the information provided. Ideally this is based on some portion of 2011 data collected for Subpart W reporting.

J This data line is a sub-category if data item E. From the difference between these two items, we are trying to determine the fraction of plunger equipped wells that do not vent.

K,L Please enter the number of liquids unloading events where gas is released to the atmosphere.

Notes:

Many companies have likely been tracking well venting for liquids unloading for several months due to Subpart W. API is soliciting information from members to correct/confirm EPA's assumptions regarding well un-loading. If you do not have the wells split out into Conventional and Unconventional categories then simply report the total counts and information in the Conventional categories.

FIGURE A-5. OTHER SURVEY DATA

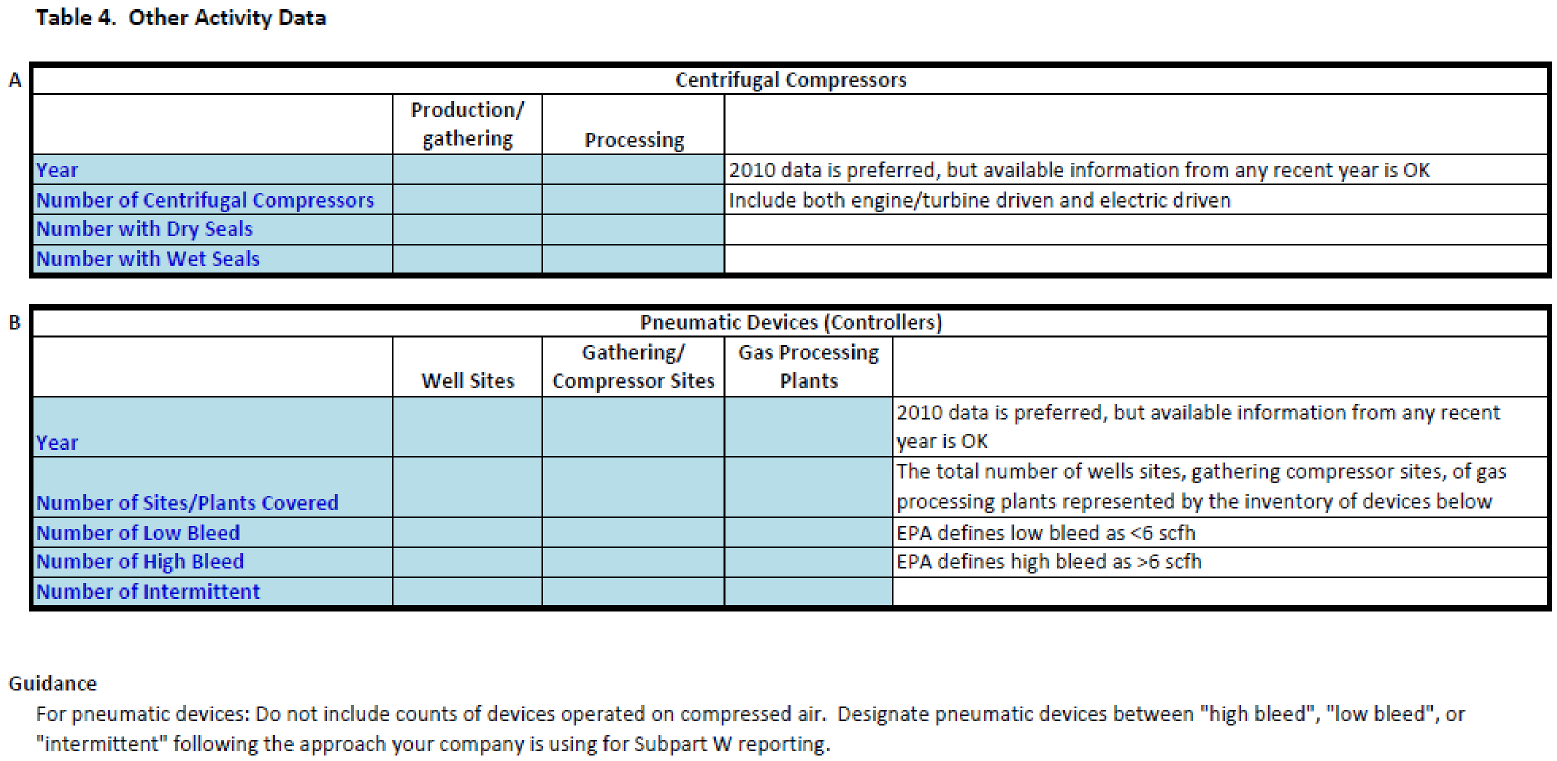


Table 4. Other Activity Data

A

Centrifugal Compressors			
	Production/ gathering	Processing	
Year			2010 data is preferred, but available information from any recent year is OK
Number of Centrifugal Compressors			Include both engine/turbine driven and electric driven
Number with Dry Seals			
Number with Wet Seals			

B

Pneumatic Devices (Controllers)				
	Well Sites	Gathering/ Compressor Sites	Gas Processing Plants	
Year				2010 data is preferred, but available information from any recent year is OK
Number of Sites/Plants Covered				The total number of wells sites, gathering compressor sites, of gas processing plants represented by the inventory of devices below
Number of Low Bleed				EPA defines low bleed as <6 scfh
Number of High Bleed				EPA defines high bleed as >6 scfh
Number of Intermittent				

Guidance

For pneumatic devices: Do not include counts of devices operated on compressed air. Designate pneumatic devices between "high bleed", "low bleed", or "intermittent" following the approach your company is using for Subpart W reporting.

Appendix B. ANGA/API Well Survey Information

Responses from the API/ANGA survey covered more than 60,000 wells and provided data on:

- # of gas wells without hydraulic fracturing (anytime in their history)
- # of gas wells with hydraulic fracturing (any time in their history);
  - # of vertical gas wells with hydraulic fracturing (anytime in their history);
  - # of horizontal gas wells with hydraulic fracturing (anytime in their history);
- # of completions for vertical gas wells with hydraulic fracturing;
- # of completions for horizontal gas wells with hydraulic fracturing;
- # of completions for gas wells without hydraulic fracturing;
- # of workovers for vertical wells with hydraulic fracturing;
- # of workovers for horizontal wells with hydraulic fracturing; and
- # of workovers for wells without hydraulic fracturing.

Table B-1 summarizes the well data collected by the ANGA/API survey and presents its distribution by formation type and region. The regional distribution follows the National Energy Modeling System (NEMS) regions defined by the EIA. The data are compared to EPA's national well counts classified by type as provided in the August 2011 database file (EPA, 2011d).

Table B-1. API/ANGA Survey – Summary of Gas Well Counts by Type and NEMS Region*

NEMS Region	Conventional Wells	Shale	Coal-bed Methane	Tight	Unspecified
Northeast	12,144	3,541	9	3,874	2,563
Gulf Coast	2,870	1,990	-	7,968	1,521
Mid-Continent	9,081	2,333	-	3,747	5,579
Southwest	646	1,208	-	726	2,326
Rocky Mountain	3,707	366	5,458	18,053	11
West Coast	-	-	-	-	-
Unspecified					1,307
Survey TOTAL	28,448	9,438	5,467	34,368	13,307
% of EPA 2010 Well Counts (from database file)	14.2%	30.1%	11.5%	45.6%	
Overall Survey Total	91,028				
EPA Well Counts (2010, from database file)	200,921	31,381	47,371	75,409	
	56.6%	8.8%	13.3%	21.2%	
	355,082				
EPA National Inventory (2010)	484,795				
EIA National Well Count (2010)	487,627				

* ANGA/API survey data represents well counts current for calendar year 2010 or the first half of 2011.

As shown in Table B-1, data from the API/ANGA survey represent approximately 26% of the national gas wells reported by EPA's database (or 18.7% of the EIA well count data). This includes almost 46% of all tight gas wells and 30% of shale gas wells. This may indicate that the ANGA/API information has an uneven representation of unconventional gas wells, and in particular shale and tight gas wells, but it also appears that EPA's data may mis-categorize these types of wells. For example, the EPA/HPDI data set contains few wells from Pennsylvania and West Virginia while the API/ANGA survey includes 9,422 wells from that area (AAPG 160A).

Table B-2 summarizes additional details on the natural gas wells information collected through the second data collection effort by the ANGA/API survey which covered 60,710 wells.

TABLE B-2. ANGA/API SURVEY – ADDITIONAL DETAILS ON GAS WELL COUNTS*

	# Wells w/out hydraulic fracturing (anytime in their history)	# Wells with hydraulic fracturing (any time in their history)		
		Total	# Vertical wells	# Horizontal wells
TOTAL Conventional	1,498	16,678	14,844	1,834
TOTAL Coal Bed Methane	42	3,475	3,424	42
TOTAL Shale	1,931	9,084	2,012	7,072
TOTAL Tight	122	27,880	24,048	3,835
TOTAL OVERALL	**3,593**	**57,117**	**44,325**	**12,783**

* API/ANGA survey data represents well counts current for calendar year 2010 or the first half of 2011.

Additional information on natural gas wells with and without hydraulic fracturing was provided for approximately two-thirds (60,710 natural gas wells) of the total well data collected by the ANGA/API survey. For this subset of the well data, 94% of the gas wells have been hydraulically fractured at some point in their operating history, including almost 92% of the conventional wells. EPA's 2010 national inventory reported 50,434 gas wells with hydraulic fracturing. This is very similar to the number of unconventional gas wells that EPA reported in the 2009 national inventory. ***Based on the API/ANGA survey results, it appears that EPA has underestimated the number of gas wells with hydraulic fracturing.***

Of the ANGA/API survey responses for wells that have been hydraulically fractured, most (77.6%) are vertical wells. Vertical wells are predominately conventional gas wells, coal-bed methane and tight gas wells; while the majority of shale gas wells are horizontal. EPA does not currently distinguish between vertical and horizontal gas wells.

A Short Note About EPA and EIA's Well Counts

There is a discrepancy of over 132,000 natural gas wells between the EPA database information (EPA, 2011d) and the EIA national gas well counts (EIA, 2012), and a difference of almost 130,000 gas wells between the two EPA data sources (EPA, 2011d and EPA, 2012). This difference needs to be understood since ultimately both the IHS (EIA) and HPDI (EPA) data originate from the same state-level sources of information.

The EIA provides a gas well count of 487,627 for 2010 based on Form EIA-895A[7], the Bureau of Ocean Energy Management, Regulation and Enforcement (formerly the Minerals

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[7] Form EIA-895, Annual Quantity And Value Of Natural Gas Production Report; http://www.eia.gov/survey/form/eia_895/form.pdf

Management Service) data, and World Oil Magazine (EIA, 2010). However, the EIA does not classify gas wells by conventional and unconventional, or by formation types, precluding more detailed comparison against the EIA data. For some parameters the classifications were based on qualitative descriptions of the formations' physical properties (e.g. permeability) rather than on actual measurements (i.e. permeability data in millidarcy readings).[8]

EPA provides a similar well count in the 2010 national inventory: 434,361 non-associated gas wells + 50,434 gas wells with hydraulic fracturing, resulting in a total of 484,795 gas wells (EPA, 2012). Further classification of gas wells or description on what constitutes a "non-associated" gas well versus a "gas well with hydraulic fracturing" is not provided in EPA's national inventory.

Small differences in the HPDI and IHS original data may arise from definitional differences as HPDI and IHS compile the raw data. In addition, each state may have a different interpretation of well definitions of gas versus oil wells that introduces differences among states for the wells reported. EPA had indicated in discussions with the API/ANGA group that their database well count information may not include all of the wells in the Marcellus basin. EIA indicates 44,500 gas wells in Pennsylvania in 2010. However, even in accounting for these wells, there is still a large difference (almost 88,000 wells) between EPA's total gas well number from their database source and EIA's well data.

Nevertheless, these discrepancies among the well counts need to be understood since these data all originate from the same state-level sources of information. Differences could arise, for example, from different interpretations of well definitions.

Since the EIA data is the *de facto* benchmark in the energy industry, the difference between the EIA and EPA well count data needs to be understood before any meaningful conclusions can be made from the EPA data.

Since EPA's well count from HPDI was much lower than the EIA, this report does not attempt to come up with a national gas well count but chose to use the 355,082 number from the EPA HPDI database because it was the only available database which parsed the wells into conventional and unconventional categories (EPA, 2011d).

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[8] Information provided by Don Robinson of ICF (EPA's contractor).

Appendix C. Emission Estimates for Gas Well Liquids Unloading

Tables C-1 through C-4 summarize the liquids unloading emissions data collected through the API/ANGA survey and the resulting emission estimates. The emission factors reported in Table 4 are based on a regional weighted average of the conventional and unconventional gas wells, with and without plunger lifts. This provided a consistent comparison against the EPA emission factors which are reported only on a regional basis and do not differentiate between conventional and unconventional wells or wells with and without plunger lifts.

TABLE C-1. LIQUIDS UNLOADING FOR CONVENTIONAL GAS WELLS WITHOUT PLUNGER LIFTS

NEMS Region	Northeast		Gulf Coast		Mid-Continent		Southwest
# venting gas wells	190	916	12	6	1	38	220
# gas well vents	4,335	39,668	144	60	1	2,444	880
Average casing diameter, inches	5	4.5	5.5	3.65	4.83	4	5.5
Average well depth, feet	3,375	3,448	10,000	19,334	7,033	4,269	8,000
Average surface pressure, psig (for venting wells)	85	50	Applied average 122	224	25.5	60.8	100
Average venting time, hours	1	2	1	2.5	.25	4.95	1
Average gas flow rate, Mscfd	2,861	7,388.5	300	664	58.43	84	100
Total emissions, scf gas/yr	11,503,329	51,547,287	1,961,463	1,322,380	1,548	3,769,194	7,879,520
Emissions per well, scfy gas/well	60,544	56,274	163,455	220,397	1,548	99,189	35,816

TABLE C-2. LIQUIDS UNLOADING FOR CONVENTIONAL GAS WELLS WITH PLUNGER LIFTS

NEMS Region	Northeast		Mid-Continent		
# venting gas wells	33	109	164	2	10
# gas well vents	1,272	4,217	489,912	23	7,300
Average tubing diameter, inches	2	2.375	1.995	2	2.375
Average well depth, feet	3,375	3,448	4,269	7,033	9,500
Average surface pressure, psig (for venting wells)	85	50	60.8	25.5	500
Average venting time, hours	1	0.3	0.067	0.75	0.08
Average gas flow rate, Mscfd	2,861	7,388.5	84	58.43	30
Total emissions, scf gas/yr	599,664	1,517,294	187,255,825	6,713	72,367,809
Emissions per well, scfy gas/well	18,172	13,920	1,141,804	3,357	7,236,781

TABLE C-3. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITHOUT PLUNGER LIFTS

NEMS Region	Northeast	Gulf Coast					
# venting gas wells	337	6	14	8	27	11	15
# gas well vents	27,720	6	14	104	207	572	15
Average casing diameter, inches	4.5	5.5	5.5	5.5	4.5	5.5	10.75
Average well depth, feet	4,845	6,000	8,500	11,000	9,000	13,752	16,000
Average surface pressure, psig (for venting wells)	121.6	400	3,200	200	50	450	1,671
Average venting time, hours	1.3638	3	4	1	5.3	2	2
Average gas flow rate, Mscfd	26	200	13,000	25	130	353	8,500
Total emissions, scf gas/yr	122,362,610	177,839	5,887,104	2,560,844	722,663	39,633,526	17,501,885
Emissions per well, scfy gas/well	363,094	29,640	420,507	320,106	26,765	3,603,048	1,166,792

TABLE C-3. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITHOUT PLUNGER LIFTS, CONTINUED

NEMS Region	Gulf Coast				Mid-Continent			
# venting gas wells	146	2	10	40	177	3	136	215
# gas well vents	146	12	120	40	400	7.2	391.2	2,580
Average casing diameter, inches	4.5	5.5	5.5	8.625	5.5	4.92	5.02	5.5
Average well depth, feet	8,500	11,647	11,000	12,500	3,911	10,293	7,888	11,000
Average surface pressure, psig (for venting wells)	15	25	94	661	80	90.04	98.75	200
Average venting time, hours	0.6875	1.5	4	1	2.5	1.58	1.925	0.5
Average gas flow rate, Mscfd	99	83	92	6,500	250	727	875	100
Total emissions, scf gas/yr	139,473	40,837	1,400,265	9,096,858	1,416,389	77,333	2,874,991	63,528,630
Emissions per well, scfy gas/well	955	20,418	140,027	227,421	8,002	25,778	21,140	295,482

TABLE C-3. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITHOUT PLUNGER LIFTS, CONTINUED

NEMS Region	Southwest			Rocky Mountain		
# venting gas wells	228	6	3	113	2	28
# gas well vents	221	6	1	2,004	4	10,584
Average casing diameter, inches	9.625	5.5	5	4.038	4.7	4.5
Average well depth, feet	8,725	8,000	15,000	11,149	11,056	10,844
Average surface pressure, psig (for venting wells)	208	50	200	250	250	198
Average venting time, hours	1	0.5	6.67	1.616	0.75	3.18
Average gas flow rate, Mscfd	1,500	12	150	127	433	83
Total emissions, scf gas/yr	13,747,516	26,862	63,188	33,701,560	90,364	170,274,852
Emissions per well, scfy gas/well	60,296	4,477	21,063	298,244	45,182	6,081,245

Table C-4. Liquids unloading for Unconventional gas wells with plunger lifts

NEMS Region	Northeast			Gulf Coast				
# venting gas wells	308	103	5	3	2	22	59	5
# gas well vents	63,840	75,190	194	156	2	22	354	5
Average tubing diameter, inches	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Average well depth, feet	4,845	2,500	7,000	13,752	16,000	8,500	11,647	12,500
Average surface pressure, psig (for venting wells)	121.6	200	130	450	1,671	15	25	661
Average venting time, hours	0.2209	0.05	0.1	2	1	0.875	0.3	0.5
Average gas flow rate, Mscfd	26	15	628	353	8,500	99	83	6,500
Total emissions, scf gas/yr	78,496,300	78,461,940	368,444	2,036,862	288,681	7,401	215,123	86,220
Emissions per well, scfy gas/well	254,858	761,766	73,689	678,954	144,341	336	3,646	17,244

TABLE C-4. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITH PLUNGER LIFTS, CONTINUED

NEMS Region	Mid-Continent				Southwest
# venting gas wells	48	4	64	29	18
# gas well vents	155,742	9.6	170.4	348	25
Average tubing diameter, inches	2.375	3.88	4.11	2.4	1.995
Average well depth, feet	3,911	10,293	7,888	Applied average 9,521	8,725
Average surface pressure, psig (for venting wells)	80	90.04	98.75	74.69	208
Average venting time, hours	0.0833	2.99	2.6	0.5425	0.5
Average gas flow rate, Mscfd	250	727	875	Average applied 1,276.8	1500
Total emissions, scf gas/yr	101,698,021	124,984	906,144	529,679	66,812
Emissions per well, scfy gas/well	2,118,709	31,246	14,158	18,265	3,712

TABLE C-4. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITH PLUNGER LIFTS, CONTINUED

NEMS Region	Rocky Mountain				
# venting gas wells	247	23	296	19	793
# gas well vents	1,476	51.43	2,080	21,888	9,516
Average tubing diameter, inches	1.997	1.92	2.375	2.375	2.375
Average well depth, feet	11,149	11,164	11,056	10,844	7,400
Average surface pressure, psig (for venting wells)	250	290	250	198	150
Average venting time, hours	0.407	1.12	2.1	0.455	0.67
Average gas flow rate, Mscfd	127	454	433	83	46
Total emissions, scf gas/yr	6,070,440	238,833	12,027,460	98,082,094	22,045,130
Emissions per well, scfy gas/well	24,577	10,384	40,633	5,162,215	27,800

The calculated emissions shown in Tables C-1 through C-4 are based on applying Equation W-8 from 40 CFR 98 Subpart W to gas well liquid unloading without plunger lifts and Equation W-9 to gas well liquid unloading with plunger lifts. The equations and the terms are provided below.

98.233(f)(2) *Calculation Methodology 2.* Calculate the total emissions for well venting for liquids unloading using Equation W–8 of this section.

$$E_{s,n} = \sum_{p=1}^{W} \left[V_p \times \left(\left(0.37 \times 10^{-3}\right) \times CD_p^2 \times WD_p \times SP_p \right) + \sum_{q=1}^{V_p} \left(SFR_q \times \left(HR_{p,q} - 1.0 \right) \times Z_{p,q} \right) \right] \quad \texttt{(Eq. W-8)}$$

Where:

$E_{s,n}$= Annual natural gas emissions at standard conditions, in cubic feet/year.

W = Total number of wells with well venting for liquids unloading for each sub-basin.

0.37×10^{-3}= {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

CD_p= Casing internal diameter for each well, p, in inches.

WD_p= Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, p, in feet.

SP_p= Shut-in pressure or surface pressure for wells with tubing production and no packers or casing pressure for each well, p, in pounds per square inch absolute (psia) or casing-to-tubing pressure of one well from the same sub-basin multiplied by the tubing pressure of each well, p, in the sub-basin, in pounds per square inch absolute (psia).

V_p= Number of vents per year per well, p.

SFR_p= Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W–33 to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$= Hours that each well, p, was left open to the atmosphere during unloading, q.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

$Z_{p,q}$= If $HR_{p,q}$ is less than 1.0 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 1.0 then $Z_{p,q}$ is equal to 1.

98.233(f)(3) *Calculation Methodology 3.* Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W–9 of this section.

$$E_{s,n} = \sum_{p=1}^{W} \left[V_p \times \left(\left(0.37 \times 10^{-3}\right) \times TD_p^2 \times WD_p \times SP_p \right) + \sum_{q=1}^{V_p} \left(SFR_q \times \left(HR_{p,q} - 0.5 \right) \times Z_{p,q} \right) \right] \quad \texttt{(Eq. W-9)}$$

Where:

$E_{s,n}$= Annual natural gas emissions at standard conditions, in cubic feet/year.

W = Total number of wells with well venting for liquids unloading for each sub-basin.

0.37×10^{-3}= {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

TD_p= Tubing internal diameter for each well, p, in inches.

WD_p= Tubing depth to plunger bumper for each well, p, in feet.

SP_p= Flow-line pressure for each well, p, in pounds per square inch absolute (psia), using engineering estimate based on best available data.

V_p= Number of vents per year for each well, p.

SFR_p= Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W–33 to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$= Hours that each well, p, was left open to the atmosphere during each unloading, q.

0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.

$Z_{p,q}$= If $HR_{p,q}$ is less than 0.5 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5 then $Z_{p,q}$ is equal to 1.